Nos. 20-1530, 20-1531, 20-1778, 20-1780

IN THE

Supreme Court of the United States

WEST VIRGINIA, ET AL.,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,
THE NORTH AMERICAN COAL CORPORATION,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,
WESTMORELAND MINING HOLDINGS LLC,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,
NORTH DAKOTA,
v.
ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

On Writ Of Certiorari
To The United States Court Of Appeals
For The District Of Columbia Circuit

JOINT APPENDIX (VOLUME IV OF IV)
(Pages 1445–2030)

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PETITIONS FOR CERTIORARI FILED: APR. 29, 2021 (20-1530), APR. 30, 2021 (20-1531), JUNE 18, 2021 (20-1778 & 20-1780)
CERTIORARI GRANTED: OCT. 29, 2021

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VOLUME IV

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, the rule will lead to better air quality and improved health in those communities. We heard from many commenters who recognize and welcome those benefits.

There are other ways in which the actions that result from this rulemaking may affect communities in positive or potentially adverse ways and we also heard about these from commenters.

While the agency expects overall emission decreases as a result of this rulemaking, we recognize that some EGUs may operate more frequently, as a result of this rulemaking. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units, which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_X compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point but also the difficulty in anticipating prior to plan implementation where those impacts might occur. In addition to providing for a robust state planning process with opportunity for meaningful input, the EPA is encouraging states to evaluate the actual impacts of their plans once implemented and, as described below, the EPA intends to conduct an assessment of whether and where emission increases may that may result

from plan implementation and to work with states to mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. We recognize that certain communities whose economies may be affected by changes in the utility and related sectors may be particularly impacted by the final rule. The EPA encourages states to make an effort to engage with these communities, including workers and their representatives in these sectors, including EE. It is important to ensure that all communities share in the benefits of this program. And while we estimate that its benefits will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking, and we received many comments on the issues outlined above from community groups, environmental justice organizations, faith-based organizations, public

health organizations, and others.[1014] This input has informed this final rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to assist states and stakeholders to consider environmental justice and impacts to communities in plan development and implementation.

It has also prompted us to work with our federal partners to make sure that states and communities have information on federal resources available to assist communities. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs. In our discussion below we also provide models of programs that other states are currently using to assist communities in accessing available resources that states could use when developing their plans.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in state plan development. In this section, we discuss the requirements in the final rule for states, as they develop their plans, to provide opportunities for public involvement, and resources available to states and communities to enhance the success of the public process.

A. Proximity Analysis

The EPA is committed to assisting states and communities to develop plans that ensure there are no disproportionate, adverse impacts on overburdened

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[1014] Detailed information on the outreach conducted as part of this rulemaking is provided in section I of this preamble.

communities. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this final rulemaking that summarizes demographic data on the communities located near power plants.[1015] The EPA understands that, in order to prevent disproportionately, high and adverse human health or environmental effects on these communities, both states and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008–2012 to conduct a proximity analysis that can be used by states and communities as they develop state plans and as they later assess the final plans' impacts. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA-HQ-OAR-2013-0602.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the U.S. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a

[1015] The proximity analysis was conducted using the EPA's environmental justice mapping and screening tool, EJSCREEN.

3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant's air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to environmental justice considerations, we use the terms "vulnerable" or "overburdened" when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, that are central to our environmental justice and community considerations.

As stated in the Executive Order 12898 discussion located in section XII.J of this preamble, the EPA believes that all communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change by limiting

GHG emissions through the establishment of CO_2 emission guidelines for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and their states and will be useful for states as they begin developing their plans. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will disseminate the proximity analysis to states and will make it publicly available on its Clean Power Plan (CPP) Community Portal. Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: *http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/*.

Additionally, the EPA encourages states to conduct their own analyses of community considerations when developing their plans. Each state is uniquely knowledgeable about its own communities and well-positioned to consider the possible impacts of plans on vulnerable communities within its state. Conducting state-specific analyses would not only help states assess possible impacts of plan options, but it would also enhance a state's understanding of the means to engage these communities that would most effectively reach them and lead to valuable exchanges of information and concerns. A state analysis, together with the proximity analysis conducted by the EPA, would provide a solid foundation for engagement between a state and its communities.

Such state-specific analyses need not be exhaustive. An examination of the options a state is considering

for its plan, and any projections of likely resulting increases in power plant emissions affecting low-income populations, communities of color populations, or indigenous communities, would be informative for communities. The analyses could include available air quality monitoring data and information from air quality models, and, if available, take into account information about local health vulnerabilities such as asthma rates or access to healthcare. Alternatively, a simple analysis may consider expected EGU utilization in geographic proximity to overburdened communities. The EPA will provide states with information on its publicly available environmental justice screening and mapping tool, EJ SCREEN, which they may use in conducting a state-specific analysis. The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on overburdened communities. Additionally, the EPA encourages states to submit a copy of their analysis if they choose to conduct one, with their initial and final plan submittals.

B. Community Engagement in State Plan Development

In sections VIII.D–E of this preamble, the EPA explains that states need to engage meaningfully with communities and other stakeholders during the initial and final plan submittal processes. Meaningful engagement includes outreach to vulnerable communities, sharing information and soliciting input on state plan development and on any accompanying assessments such as those described above, and selecting methods for engagement to support communities' involvement at critical junctures in plan

formulation and implementation. This engagement also includes providing the public the opportunity to comment on the state's initial submittal and responding to significant comments received, including comments from vulnerable communities, as well as conducting a public hearing and responding to comments before a final state plan is submitted. Additionally, the EPA expects that states will conduct outreach meetings, which could include public hearings or listening sessions, before the initial submittal is made. The EPA also encourages states to provide background information about their proposed final state plan or their initial state plan in the appropriate languages in advance of their public hearing and at their public hearing. The EPA recommends that states provide translators and other resources at their public hearings, to ensure that members of the public can provide oral feedback.

In the initial submittal, the final rule requires that states provide information to the agency about the community engagement they have undertaken and the means by which they intend to involve vulnerable communities and other stakeholders as they develop their final plan. Furthermore, as noted in section VIII.E of this preamble, in determining if states are eligible for a 2-year extension for submission of final plans, the rule requires that states demonstrate how they are meaningfully engaging vulnerable communities and other interested stakeholders as part of their public participation process. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*, when crafting this rulemaking and recommends that states consult it to assist them

in engaging meaningfully with vulnerable communities.[1016] Additionally, states in their initial submittal and 2017 update must show how they identified the communities with whom they are engaging as they develop their plans. Some suggested actions that states could take to engage actively with the public, including conducting meaningful engagement with vulnerable communities, are outlined in section VIII.E of this preamble. Additionally, as outlined in section VIII.D, the final plan submitted by states must include an overview of the public hearing(s) conducted and information on how the state ensured that the hearing(s) were accessible to stakeholders including vulnerable communities.

The EPA is committed to supporting states in effectively engaging with communities as they develop and implement their plans. The EPA will provide training and other resources throughout the implementation process that will assist states and communities in understanding plan requirements and options for plan development. These trainings will be a continuation of those that the EPA has already conducted with communities and states both pre- and post-proposal. The EPA will reach out to a wide variety of community stakeholders, including groups representing environmental justice communities, faith-based organizations, academic organizations working with vulnerable and overburdened

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[1016] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://epa.gov/environmentaljustice/resources/policy/considering-ej-in-rule making-guide-final.pdf*. May 2015.

communities, affordable housing advocates, public health professionals, public health organizations, and other community stakeholders.

C. Providing Communities With Access to Additional Resources

In addition to providing resources to states, the EPA encourages states to be aware of existing efforts undertaken by other states aimed at providing low-income communities access to financial and technical assistance programs for EE and RE, and to consider similar approaches that may make sense for their own states. The EPA encourages states to consider targeting economic development resources to communities that are likely to be negatively affected by ongoing changes in the utility and related sectors in support of efforts to diversify their economies, attract new sources of investment, and create new jobs.

One example of a program targeted at low-income communities is the Maryland EmPOWER Low Income Energy Efficiency Program (LIEEP).[1017] The LIEEP program administered by the Maryland Department of Housing and Community Development (DHCD) helps low-income households through free installation of energy conservation materials (*i.e.*, installation, hot water system improvements, lighting retrofits, furnace cleaning, tuning and safety repairs, refrigerator retrofits, etc.). [1018] Funding for this program is provided by EmPOWER Maryland partners: Baltimore Gas and Electric, Southern

[1017] EmPOWER Maryland Low Income Energy Efficiency Programs (LIEEP). *http://www.mdhousing.org/Website/Programs/lieep/Default.aspx.*

[1018] Ibid.

Maryland Electric Cooperative, Delmarva Power, Allegheny Energy and Pepco.[1019] This program is available to both homeowners and renters.[1020] Additionally, the Maryland Department of Housing provides low-income families with home heating bill assistance and furnace repairs and replacements through the Maryland Energy Assistance Program (MEAP).[1021] Maryland's Electric Universal Service Program (EUSP) helps low-income electric customers with their electric bills.[1022]

Another example of a program is EmPower New York, which provides no-cost energy solutions to low-income populations.[1023] Currently there are about 100,000 people who are receiving assistance. Both homeowners and renters are eligible to receive assistance under this program. The types of assistance available include EE upgrades (plugging leaks, adding insulation, replacing inefficient refrigerators and freezers and new energy-efficient lighting). Other states, like the State of Colorado's Energy Outreach Colorado program, offer similar resources for low-income populations.[1024]

In 2013, the New York State Energy and Research Development Authority (NYSERDA) was able to

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[1019] Ibid.

[1020] Ibid.

[1021] Energy Assistance. *http://www.dhr.state.md.us/blog/?page_id=4326.*

[1022] Ibid.

[1023] EmPower New York. *http://www.nyserda.ny.gov/All-Programs/Programs/EmPower-New-York.*

[1024] Energy Outreach Colorado. *http://www.energyoutreach.org/about.*

secure a triple-A rated financial guarantee from the state's Clean Water State Revolving Fund (SRF) for a $24 million bond issue. Proceeds funded residential EE loans that were available to all utility customers, including low-income households. SRF eligibility was based on the beneficial impact of EE investment in reducing atmospheric deposition on impaired water bodies consistent with Section 319 of the Clean Water Act.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE, EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for communities and states on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking by encouraging that states use these types of tools in their state plans. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

The EPA recognizes the potential impacts that this rulemaking could have on jobs in communities. Therefore, in section VIII.G of this preamble, the EPA has outlined that states, in designing their state plans, should consider the effects of their plans on employment and overall economic development to

realize the opportunities for economic growth and jobs that the plans offer. To the extent possible, states should try to assure that communities that may be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth (*e.g.*, with regard to delivering EE measures and installing rooftop solar panels). Additionally, as part of the resources that we will be providing to states and low-income communities, the EPA will provide information on the Administration's Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[1025]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. Department of Energy (DOE), the U.S. Department of Housing and Urban Development (HUD), U.S. Department of Agriculture (USDA), and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not

[1025] *http://www.eda.gov/power.*

have adequate roof space to install solar systems, with a focus on low- and moderate-income communities. The Administration also set a goal to install 300 megawatts (MW) of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: the Department of Energy's Weatherization Assistance Program, Health and Human Service's Low Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

HUD supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax

Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites—many of which are in low-income communities—for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA's Green Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs—savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include HUD, DOE, and the Department of Education's "STEM, Energy, and Economic Development" program; DOE's Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the Department of Labor's Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA

Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Multi-Pollutant Planning and Co-Pollutants

As outlined in the final Clean Power Plan, states and sources have continued obligations to meet all other CAA requirements addressing conventional pollutants. Because the CAA envisions control of these other pollutants as a continuous process (through provisions such as periodic review of the NAAQS and residual risk requirements under the MACT program), the EPA believes that the Clean Power Plan provides an opportunity for states to consider strategies for meeting future CAA planning obligations as they develop their plans under this rulemaking. Multi-pollutant strategies that incorporate criteria pollutant reductions over the planning horizons specific to particular states, jointly with strategies for reducing CO_2 emissions from affected EGUs needed to meet Clean Power Plan requirements over the time horizon of this rule, may accomplish greater environmental results with lower long-term costs. Such strategies may also provide opportunities for states, communities, and affected facilities to consider the most effective means of meeting these obligations while limiting or eliminating localized emission increases that would otherwise affect overburdened communities. Furthermore, this type of multi-pollutant approach has been suggested by states and regulated sources in past rulemakings as a tool to determine the best system of emission reductions. The EPA recommends that states consider such strategies in consultation

with their communities, affected facilities, and other stakeholders.

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[1026] In the Cross-State Air Pollution Rule the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final Cross-State Air Pollution Rule anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the Cross-State Air Pollution Rule, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO_2 and NO_X on a regional and national basis.[1027] Thus, localized increases in NO_X emissions may well be more than offset by NO_X decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs—in particular, high efficiency gas-fired EGUs—with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already

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[1026] 76 FR 48348.

[1027] 76 FR 48347.

occur in response to energy demands and evolving energy sources, but the final CO_2 emission guidelines for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5}$, NO_X, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, SO_2, and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in Title V operating permits, in addition to the guidelines in this final rulemaking. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected.

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." [1028] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal- and NGCC-fired generation,

[1028] 65 FR 79831.

they assumed SO_2, NO_X, PM (and Hg) emissions to be "negligible." Their studies predict NO_X emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[1029] Many, although not all, NGCC units are also very well controlled for emissions of NO_X through the application of after combustion controls such as selective catalytic reduction.

F. Assessing Impacts of State Plan Implementation

It is important to the EPA that the implementation of state plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of state plans developed pursuant to this rulemaking and other air quality rules are, in fact, reducing emissions and improving air quality in all areas or whether there are localized air quality impacts that need to be addressed under other CAA authorities. Furthermore, the EPA recommends that states conduct evaluations of their own to determine the impacts of their plans on overburdened communities. An example of one such approach to assessing a state plan for reducing GHGs is the California Air Resources Board's (CARB), *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The*

[1029] "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL-2010/1397.

California Global Warming Solutions Act of 2006, which outlines ongoing evaluations that it will conduct to determine the impacts of its programs (throughout the implementation stages) on overburdened communities.[1030] CARB's Adaptive Management Plan for the Cap-and-Trade Program is one particular evaluation, which is intended to assess any localized emissions increases resulting from the program so that the state can appropriately respond.[1031] The EPA recommends that states consider CARB's approaches and other programs as models for conducting ongoing assessments of the impacts of their state plans on overburdened communities. The EPA will provide training for states and communities on resources that they can use to assess options for plan development and implementation that appropriately consider localized impacts, especially effects of co-pollutants, as well as training on how to develop and carry out these evaluations.

This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of state plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the

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[1030] *First Update on the Climate Change Scoping Plan: Building on the Framework Pursuant to AB32: The California Global Warming Solutions Act of 2006. http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.* May 2014.

[1031] *Adaptive Management Plan for the Cap-and-Trade Regulation. http://www.arb.ca.gov/cc/capandtrade/adaptive_management/plan.pdf.* October 2011.

implementation phase of this rulemaking and other analyses that states may develop, will enable states and communities to monitor any disproportionate emissions that may result in adverse impacts and to address them.

G. EPA Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and states as they engage with one another. Additionally, we will provide states with recommendations on best practices for engaging with vulnerable communities. The EPA, through its outreach efforts during implementation, will continue to solicit feedback from communities and states on topics for which they would like additional trainings and resources.

The EPA will also provide states with resources containing examples of analyses that other states have conducted to examine the impacts of their programs on vulnerable communities, as well as information on its publicly available environmental justice screening and mapping tool, EJ SCREEN. States are encouraged to use this preliminary information as well as other available information to conduct their own analyses. As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan (CPP) Community Portal that will be

linked to this rulemaking's Web site (*www.epa.gov/cleanpowerplan*). In addition, the EPA has expanded its set of resources that are being developed to help states and communities understand the breadth of policy options and programs that have successfully brought EE/RE to overburdened communities. The EPA is committed to continuing its engagement with states and communities from the beginning of plan development through plan implementation.

A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section XI.J of this preamble. A summary of the EPA's interactions with communities is in the EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA's responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this final rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rulemaking. The proximity analysis that the agency has conducted for this rulemaking is a central component of this approach. Not only is the proximity analysis a useful tool to help identify overburdened communities that may be impacted by this rulemaking, states can use this tool as they engage with communities in the development of their plans, consider a multi-pollutant approach, help low-income communities access EE/RE and financial assistance programs and assess the

impacts of their state plans. Additionally, in order to continue to ensure that vulnerable communities are not disproportionately impacted by this rulemaking, the EPA will also be conducting its own assessment during the implementation phase. Furthermore, the EPA will continue to engage with communities and states throughout the implementation phase of this rulemaking to help ensure that vulnerable communities are not disproportionately impacted.

X. Interactions With Other EPA Programs and Rules

A. Implications for the New Source Review Program

The new source review (NSR) program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific. As a result of the decision in *Utility Air Regulatory Group (UARG)* v. *Environmental Protection Agency (EPA)*, 134 S. Ct. 2427 (2014), a modification that increases only GHG emissions above the applicable level will not trigger the requirement to obtain a PSD permit. Under existing EPA regulations, a modifying major stationary source would trigger PSD permitting requirements for GHGs if it undergoes a change or

change in the method of operation (modification) that results in a significant increase in the emissions of a pollutant other than GHGs and results in a GHG emissions increase of 75,000 tons per year CO_2 e as well as a GHG emissions increase on a mass basis. Once it has been determined that a change triggers the requirements of the NSR program, the source must obtain a permit prior to making the change. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements.

As part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR.

While there may be instances in which an NSR permit would be required, we expect those situations to be few. As previously discussed in this preamble, states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emission guidelines. One of these flexibilities is the ability of the state to establish emission standards 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 emission standards 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 use demand-side measures or increase reliance on RE as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation. The state could also, as part of its CAA section 111(d) plan, develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit).[1032]

[1032] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. *See, e.g.*, CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or Title V permitting programs. *See, e.g.*, 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of "potential to emit").

In addition, in this final rule, we have also adjusted the date of the period for mandatory reductions to 2022, instead of 2020, and provided states with flexibility with respect to the glide path. This obviates concerns that there is insufficient time for sources that may need permits to obtain them and allows additional planning time for these changes to be undertaken in a manner that does not trigger PSD. 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 the Title V Program

In the preamble to the June 18, 2014 proposal, the EPA discussed the issue of excessive title V fees resulting inadvertently as a consequence of the promulgation of the first section 111 standard to regulate GHGs. Specifically, the EPA explained that when the first section 111 standard is promulgated for GHGs, if we do not revise 40 CFR parts 70 and 71 (the operating permit rule), then certain permitting authorities would be required to charge emissions-based fees for GHGs, resulting in fees that would be far in excess of what is required to cover the reasonable costs of the permitting programs. To avoid this situation, the EPA proposed as part of the re-proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (70 FR 1429–1519; January 8, 2014) to exempt GHGs from the list of air pollutants that are subject to fee calculation requirements under the operating permit rules. Also, we proposed several options to impose a smaller fee adjustment for GHGs that would be reasonable and

designed to recover the costs of addressing GHGs in permitting without being excessive.

In a separate action in this issue of the **Federal Register**, the EPA is finalizing changes to the operating permits rules to address the title V fee issue. In particular, we are taking final action to exempt GHGs from emissions-based fee calculation requirements under the operating permit rules. In addition, we are also finalizing a modest GHG fee adjustment to recover the costs of addressing GHGs in permitting. The GHG adjustments we are finalizing are based on accounting for the number of permit actions that require a GHG assessment in a given period, rather than accounting for emissions levels of GHGs. Finally, the EPA is also finalizing the addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2) to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under CAA section 111 for the first time.

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 standards of performance for new, modified, and reconstructed EGUs, also promulgated in this issue of the **Federal Register**). The title V fee issue is not an issue for any other subsequent CAA section 111 regulations, such as this section 111(d) standard; thus, there is no need to address any title V fee issues in this final rule as part of this action.

In the proposal, the EPA discussed that the section 111 rules would have no effect on the applicability thresholds for GHG under the operating permit rules. After the proposal for this rulemaking was published, the U.S. Supreme Court issued its opinion in *UARG* v. *EPA*, 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency*, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion, as the EPA discussed in the proposal, with respect to the effect of this final section 111 rule on the applicability thresholds for GHGs under the operating permits rules, though for different reasons.

With respect to title V, the Supreme Court said that EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA*, and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in EPA imposing a requirement that stationary sources obtain a title V permit solely because such sources

emit or have the potential to emit GHGs above the applicable major source thresholds.

C. Interactions With Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[1033] The EPA recognizes the importance of assuring that each of the rules described below 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 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.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the 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, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and

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[1033] 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.

hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.*, sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X

emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_X, and May 1, 2017, for ozone season NO_X. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_X. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (CWA) (33 U.S.C. 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[1034] The 316(b) rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2

[1034] 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.

million gallons per day) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and a national standard for establishing entrainment reduction requirements. All facilities subject to the rule must submit information on their operations for use by the permit authority in determining 316(b) permit conditions. Certain plants that withdraw very large volumes of water will also be required to conduct additional studies for use by the permit authority in determining the site-specific entrainment reduction measures for such facilities. The rule provides significant flexibility for compliance with the impingement standards and, as a result, is not projected to impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to establish appropriate entrainment reduction measures, taking into account, among other factors, remaining useful plant life and quantified and qualitative social benefits and cost. The permit writer may also consider impacts on the reliability of energy delivery within the facility's immediate area. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority.

4. Disposal of Coal Combustion Residuals From Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The CCR rule establishes technical requirements for existing and new CCR landfills and surface impoundments under the Resource Conservation and Recovery Act, Subtitle D (42 U.S.C. 6941–6949a), the nation's primary law for regulating solid waste.

These regulations address the risks from coal ash disposal—leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments by establishing requirements for where CCR landfills and surface impoundments may be located, how they must be designed, operated and monitored, when they must be inspected, and how they must be closed and cared for after closure. Additionally, the CCR rule sets out recordkeeping and reporting requirements, as well as the requirement for each facility to establish and post specific information to a publicly-accessible Web site. The final rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact existing fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) 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 U.S. under the CWA. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015.

The EPA is endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (*e.g.*, by facilitating their ability to coordinate planning and investment

decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule. Because these two rules affect similar units and may be met with similar compliance strategies, common-sense implementation timeframes were established in the CCR final rule so that utilities would not be required to make major decisions about CCR units without first understanding the implications that such decisions would have for meeting the surface water protection requirements of the final ELG rule. The EPA is taking into account these new CCR requirements for coal ash as it develops the final SE ELG rule. The EPA's goal in harmonizing the SE ELG and CCR rules is to minimize the overall complexity of the two regulatory structures and avoid creating unnecessary burden.

6. Other EPA Rules

In addition to the power sector rules discussed above, the development of SIPs for criteria pollutants (ozone, $PM_{2.5}$, and SO_2) and regional haze may also have implications for existing fossil-fired EGUs.

Regarding ozone, the proposal included a discussion of the June 6, 2013, proposed implementation rule for the 2008 ozone National Ambient Air Quality Standards (NAAQS), addressing the statutory requirements for areas EPA has designated as nonattainment for the 2008 ozone NAAQS. The final implementation rule for the 2008 ozone NAAQS was signed on February 13, 2015, and published on March 6, 2015, with an effective date of April 6, 2015. In

general, the 2008 ozone NAAQS implementation rule interprets applicable statutory requirements and provides flexibility to states to minimize administrative burdens associated with developing and implementing plans to meet and maintain the NAAQS. The rule establishes due dates for attainment plans and clarifies attainment dates for each ozone nonattainment area according to its classification based on air quality thresholds, with attainment dates starting in July 2015 through July 2032 depending on an area's classification.

On November 25, 2014, the EPA Administrator signed the proposed rulemaking for the 2015 revisions to the ozone NAAQS. The proposal was published in the **Federal Register** on December 17, 2014 (79 FR 75234). The Administrator proposed to revise the primary ozone standard to a level in the range of 0.065 to 0.070 ppm and took comment on lower levels including 0.060 ppm and on retaining the current standard of 0.075 ppm. Among other things, the ozone NAAQS proposal also proposed to retain the current indicator, averaging time, and form of the standard and included a proposed secondary ozone NAAQS in the 0.065 to 0.070 ppm range.

The proposal also outlined the key implementation milestones requiring revised SIPs, with due dates starting in October 2018 for infrastructure and interstate transport SIPs, attainment plans due 2020–21, and attainment dates of 2020–37. The EPA is under a court order to finalize its review of the ozone NAAQS by October 1, 2015.

Some commenters expressed concern with the potential impact proposed revisions to the ozone

NAAQS could have on state planning efforts and affected entities' ability to comply with any potentially new requirements associated with a revised ozone NAAQS and those related to the 111(d) emission guidelines. In particular, commenters raised issues with a potentially more stringent ozone standard and the permitting and state planning implications this may create. While there was no discussion of the proposed revisions to the ozone NAAQS in the 111(d) emission guidelines proposal, commenters expressed a desire for the EPA to coordinate promulgation of the final 111(d) emission guidelines (and any other climate regulations) with the potential revision to the ozone standard to provide certainty and flexibility for states and affected sources.

While it is premature to speculate about the outcome of the ozone NAAQS review and how a more stringent ozone NAAQS may impact sources of ozone precursor emissions, including EGUs, we believe the planning and compliance timeframes that would follow from a revised ozone NAAQS and the timeframes we are finalizing today 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, as needed. As stated in the proposal, the EPA is prepared to work with states to assist them in coordinating their efforts across these planning processes.

Regarding $PM_{2.5}$ NAAQS implementation, the proposal stated that the EPA was developing a proposed implementation rule to provide guidance to states on the development of SIPs for the 2012 $PM_{2.5}$ NAAQS. The proposed $PM_{2.5}$ SIP requirements rule was signed on March 10, 2015, and published on

March 23, 2015 (80 FR 15340). The proposal addresses a number of requirements including attainment plan due dates, attainment dates and attainment date extension criteria for Moderate and Serious nonattainment areas; determination criteria for Reasonably Available Control Measures (RACM) for Moderate areas and Best Available Control Measures (BACM) for Serious areas; plans for demonstrating reasonable further progress and for meeting periodic quantitative milestones; and criteria for reclassifying a Moderate nonattainment area to Serious. The EPA is planning to finalize the $PM_{2.5}$ implementation rule in early 2016.

There are currently only 9 areas designated nonattainment for the 2012 $PM_{2.5}$ NAAQS, with an effective date of April 15, 2015. Since the attainment plans for these areas must be completed and submitted to the EPA in September 2016, we expect that the four states with such areas should have already decided on their approach to implementing the 2012 $PM_{2.5}$ NAAQS when they begin to develop their plans for implementing the 111(d) guidelines, and will be able to coordinate the two.

Related to the SO_2 NAAQS, and as stated in the proposal, 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 date for attainment plans for these areas to be completed and

submitted to the EPA was April 2015. As such, we expect states with such areas to have already decided on their approach to implementing the SO_2 NAAQS as they start planning for implementation of the 111(d) guidelines, which should allow for coordination and consideration of SO_2 related air quality measures into their 111(d) planning. The EPA intends to address the designations for all other areas in three separate actions in the future.[1035] These designations must be completed by no later than July 2, 2016, December 31, 2017, and December 31, 2020 with attainment plans due between 2018 and 2022.

Regarding requirements under the regional haze program, several affected EGUs have deadlines in the 2016–2021 timeframe to install controls to comply with the Best Available Retrofit Technology (BART) and reasonable progress requirements of the Regional Haze Rule. Soon after these deadlines, some of the same affected EGUs may be required to reduce their utilization, convert into natural gas-fired facilities, or shut down entirely as a result of state 111(d) plans. Some commenters have expressed concern that for these affected EGUs, specifically those that choose to retire, the capital equipment installed to comply with the Regional Haze Rule would likely become stranded assets.

[1035] 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*, and the associated area designations schedule is at *http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/201503Schedule.pdf.*

While the EPA is providing considerable flexibility for states and sources under the final 111(d) emission guidelines, the EPA acknowledges the possibility that some sources could ultimately be faced with the potential for stranded assets as a result of state 111(d) plans. For these sources, however, states have the option of developing BART alternatives that replace control requirements that would otherwise result in stranded assets at a particular EGU with the aggregate emission reductions that will result from retirements, fuel switching, reduced utilization, or lesser controls at multiple EGUs.

In fact, the EPA already has experience working with states to account for these very types of changed circumstances.[1036] The EPA will continue to work with states to explore options for integrating compliance requirements across multiple regulatory programs, as warranted.

The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air

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[1036] For example, Oregon replaced its BART determination for the Boardman Coal Plant with a new requirement that accounted for a planned shutdown before the EPA took action on the state's SIP submission (76 FR 12661). Washington similarly replaced its BART determination for the TransAlta Centralia Power Plant before the EPA took action on the state's SIP submission (77 FR 72742). Oklahoma submitted a SIP revision with a new BART determination for the AEP/PSO Northeastern Power Station, which included enforceable requirements for reduced utilization and early unit retirements, to replace a FIP that had been promulgated by the EPA (79 FR 12944). Finally, the EPA finalized a BART determination for Unit 3 at the Dave Johnston Power Plant in Wyoming that included two compliance options, one of which included a federally enforceable retirement date and less costly controls.

quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

7. Final Rule Flexibilities

As discussed in Section VIII of this preamble, the EPA is providing states flexibility in developing approvable plans under CAA section 111(d), including the ability to impose source-by-source limitations reflecting the BSER performance rates to each affected EGU or to adopt rate-based or mass-based emission performance goals, and to rely on a wide range of CO_2 emission reduction measures, including measures that are not part of the BSER. The EPA is also providing states considerable flexibility with respect to the timeframes for plan development and implementation, with up to 3 years permitted for final plans to be submitted after the GHG emission guidelines are finalized, and up to 15 years for all emission reduction measures to be fully implemented. The EPA is establishing an 8-year interim period over which to achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022, more than seven years from the June 18, 2014 date of proposal of the rulemaking. The 8-year interim period from 2022 through 2029, is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates.

In light of these broad 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, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules. In addition, we believe that states will be able to design CAA section 111(d) plans that use innovative, cost-effective regulatory strategies, that spark investment and innovation across a wide variety of clean energy technologies, and that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[1037] We also believe that the broad flexibilities 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.

[1037] 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.

XI. Impacts of This Action[1038]

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final guidelines for the utility power sector. In the final emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this final action presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.[1039]

[1038] The impacts presented in this section of the preamble represent an illustrative implementation of the guidelines. As states implement the final 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.

[1039] It is important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The final guidelines are projected to result in substantial co-benefits through reductions of SO_2, NO_X and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 15 and 16 show expected CO_2 and other air pollutant emissions in the base case and reductions under the final guidelines for 2020, 2025, and 2030 for the rate-based and mass-based approaches, respectively.

TABLE 15—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER RATE-BASED ILLUSTRATIVE PLAN APPROACH

	CO_2 (millions short tons)	**SO_2 (thousand short tons)**	**NO_X (thousand short tons)**
2020 Final Guidelines:			
Base Case	2,155	1,311	1,333
Final Guidelines	2,085	1,297	1,282
Emissions Reductions	69	14	50
2025 Final Guidelines:			
Base Case	2,165	1,275	1,302
Final Guidelines	1,933	1,097	1,138
Emissions Reductions	232	178	165
2030 Final Guidelines:			
Base Case	2,227	1,314	1,293
Final Guidelines	1,812	996	1,011
Emissions Reductions	415	318	282

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

TABLE 16—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED ILLUSTRATIVE PLAN APPROACH

	CO_2 (millions short tons)	**SO_2 (thousand short tons)**	**NO_X (thousand short tons)**
2020 Final Guidelines:			
Base Case	2,155	1,311	1,333
Final Guidelines	2,073	1,257	1,272
Emissions Reductions	81	54	60
2025 Final Guidelines:			
Base Case	2,165	1,275	1,302
Final Guidelines	1,901	1,090	1,100
Emissions Reductions	265	185	203
2030 Final Guidelines:			
Base Case	2,227	1,314	1,293
Final Guidelines	1,814	1,034	1,015
Emissions Reductions	413	280	278

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

The reductions in Tables 15 and 16 do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

B. Endangered Species Act

As explained in the preamble to the proposed rule (79 FR at 34933–934), the EPA has carefully considered the requirements of section 7(a)(2) of the Endangered Species Act (ESA) and applicable ESA regulations, and reviewed relevant ESA case law and guidance, to determine whether consultation with the

U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. The EPA proposed to conclude that the requirements of ESA section 7(a)(2) would not be triggered by promulgation of the rule, and we now finalize that determination.

Section 7(a)(2) of the ESA requires federal agencies, in consultation with one or both of the Services (depending on the species at issue), 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. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[1040] Indirect effects

[1040] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25 (March 1998) (providing examples of direct effects: *e.g.*, driving an off road vehicle through the nesting habitat of a listed

are those that are "caused by the proposed action and are later in time, but still are reasonably certain to occur." *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this rule are positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_2 and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a "may affect" determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in reaching the

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species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species). Available at *https://www.fws.gov/ENDANGERED/esa-library/pdf/esa_section7_handbook.pdf.*

conclusion that ESA consultation is not required for this rule.

With respect to the projected GHG emission reductions, the EPA considered in detail in the proposal why such reductions do not trigger ESA consultation requirements under section 7(a)(2). As explained in the proposal, in reaching this conclusion the EPA was mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[1041] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the "may affect" test of the section 7 regulations and thus are not subject to ESA consultation.

As described in the proposal, the EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. Although the GHG emission reductions projected for this final rule are

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[1041] *See, e.g.*, 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: "Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases" (Oct. 3, 2008). Available at *http://www.doi.gov/solicitor/opinions/M-37017.pdf.*

large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case under the rate-based illustrative plan approach—see Table 14 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 over the lifetimes of the model years in question [1042] which are roughly five to six times those projected above 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." [1043] 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 conclusion applies to the present rule. *See, e.g.*,

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[1042] *See* 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III-68 (Oct. 15, 2012).

[1043] EPA, Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, Response to Comment Document for Joint Rulemaking at 4–102 (Docket ID EPA-OAR-HQ-2010-0799). Available at *http://www.epa.gov/otaq/climate/regulations/420r10012a.pdf*.

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). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.[1044]

With regard to non-GHG air emissions, the EPA also projects substantial reductions of SO_2 and NO_X as a collateral consequence of this final action. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. See CAA section 111(d)(1)(i). Consequently, CAA section 111(d) provides no discretion to adjust the standard based on potential impacts to endangered species of reduced

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[1044] The EPA has received correspondence from a U.S. Senator and a Member of the U.S. House of Representatives noting that the Services have identified several listed species affected by global climate change. *See* Letter from Rob Bishop, Chairman, House Committee on Natural Resources, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 11, 2015; Letter from Rob Bishop, Chairman, House Committee on Natural Resources, and James M. Inhofe, Chairman, Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated June 15, 2015. EPA's assessment of ESA requirements in connection with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and EPA.

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*, *WildEarth Guardians* v. *U.S. Envt'l Protection Agency*, 759 F.3d 1196, 1207–10 (10th Cir. 2014) (EPA has no duty to consult under section 7(a)(2) of the ESA regarding hazardous air pollutant controls that it did not require—and likely lacked authority to require—in a federal implementation plan for regional haze controls under section 169A of the CAA).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and whether any such effects are "caused by" the rule and "reasonably certain to occur" within the meaning of the ESA regulatory definition of the effects of an action. 50 CFR 402.02. As the EPA noted in the proposal, there are substantial questions as to whether any potential for relevant effects results from any element of the rule or would result instead from separate decisions and actions made in connection with the development, implementation, and enforcement of a plan to implement the standards established in the rule. *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 SIPs).[1045] The EPA recognized, for instance, that questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the proposal asserting that because

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[1045] One commenter questioned the EPA's citation to *American Trucking Assn's*. As stated by the commenter, the statute at issue in that case—the Regulatory Flexibility Act (RFA)—is distinguishable from the ESA in that it addresses only direct effects and does not consider indirect effects. The commenter misreads the EPA's citation to this case. The EPA cites this case simply to reference a decision considering the impacts of an EPA action—the revision of a NAAQS under the CAA—that in certain respects provides a useful analogy to the present rule. A NAAQS is implemented through a series of subsequent planning decisions generally taken by states by means of adoption of SIPs. States can choose to impose or avoid the types of impacts at issue in the D.C. Circuit case through their planning decisions; thus such impacts were not viewed as having been caused—for purposes of the RFA—by the EPA's promulgation of the revised NAAQS in the first instance. The standard setting and implementation mechanisms under section 111(d) are very similar. Under section 111(d), the EPA is required to establish "a procedure similar to that provided by section 7410"—the provision establishing the SIP mechanism for implementing NAAQS. Thus, the D.C. Circuit's discussion provides a useful analogy to the present rule and the various types of potential effects that may be attributable to future implementation planning decisions by states and other entities as they exercise their discretion in determining how to implement the federal guidelines, but not to promulgation of the rule itself. The EPA's citation to this case was not intended to address any comparison of the scope of effects covered by the RFA and the effects cognizable under section 7(a)(2) of the ESA. The EPA is aware that the ESA addresses both direct and indirect effects as defined by the applicable ESA regulations. The discussion supporting the EPA's ESA conclusion expressly acknowledges the relevance of indirect effects to the ESA analysis and explains why such effects are not present here.

potential increased reliance on wind or solar power may be an element of building block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule. The EPA is also aware of certain questions regarding potential effects of the rule on the Big Bend Power Station located in Florida, which discharges effluent that provides a warm water refuge for manatees. The Big Bend Power Station and another coal-fired facility located in Florida—the Crystal River Plant—are, for example, referenced in the June 11, 2015, and June 15, 2015, congressional letters to EPA cited above.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector—including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities—or any potential alterations in the operations of any particular facility are caused by the current rule or sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur. At this point, there is no reasonable certainty regarding implementation of any planning measures in any location, let alone in any location occupied by a listed species or its designated critical

habitat. The EPA cannot predict with reasonable certainty where such measures may take effect or which measures may be adopted. It is not clear, for instance, whether a particular implementation plan will call, if at all, for increased reliance on wind power, as opposed to solar power, or on some other form of low or zero carbon emitting generation. It is also entirely uncertain how a future implementation plan for a particular state might affect, if at all, operations at a specific facility.[1046] he precise steps included in an implementation plan cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this final rule for ESA purposes. These steps will flow from a series of later in time decisions generally made by other entities—usually states—in their distinct planning processes. These later decisions cannot now be required by the rule, are not caused by the rule, and are not reasonably certain to occur. The EPA also notes that the plans adopted for particular states may themselves provide wide degrees of implementation

[1046] A congressional letter of June 11, 2015, referenced above asserts that EPA's modeling suggests that the Big Bend Power Station and Crystal River Energy Complex in Florida will be prematurely retired as a result of the rule. EPA notes that any such facility-level projections associated with the rule cannot be stated with sufficient certainty to qualify as potential indirect effects under the ESA. These projections are based on numerous assumptions regarding a variety of planning and business decisions yet to be made by the implementing governments (usually states) and facility owners. Given the wide degrees of discretion and flexibility and the numerous options available for such decision making, the potential for such outcomes to be realized as currently projected is at this point too uncertain to qualify as an effect under the ESA.

flexibility, thus further increasing the uncertainty that any species-impacting activity will occur in any particular location, if at all. The Services have explained that section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[1047] These are precisely the types of speculative future activities and effects at issue here.[1048] For this additional reason, the EPA concludes that the rule does not have effects on listed species

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[1047] *See* 51 FR at 19933 (describing effects that are "reasonably certain to occur" in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–30 (March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors' assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed). Available at *https://www.fws.gov/ENDANGERED/esa-library/pdf/esa_section7_handbook.pdf*.

[1048] EPA also notes that some of the future implementing activities may involve federal actions that are subject to ESA consultation, thus providing consideration of any impacts on listed species at the appropriate point when particular activities have become reasonably certain. Several commenters on the proposal specifically noted that such future activities—*e.g.*, development of additional RE facilities such as wind farms—may call for ESA consultation. Further, EPA notes that section 9 of the ESA, which prohibits the take of individuals of most listed species, provides an additional protection for listed species as future implementing activities become reasonably certain.

that trigger the section 7(a)(2) consultation requirement.[1049]

C. What are the energy impacts?

The final guidelines have important energy market implications. Table 17 presents a variety of important

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[1049] The commenters cite certain cases that they assert support consulting under ESA section 7(a)(2). The EPA has considered these cases, each of which is distinguishable from the present rule. By way of example, a commenter cites two cases involving EPA actions: *Defenders of Wildlife* v. *EPA*, 420 F.3d 946 (9th Cir. 2005), *rev'd*, *National Association of Homebuilders* v. *Defenders of Wildlife*, 551 U.S. 644 (2007); and *Washington Toxics Coalition* v. *EPA*, 413 F.3d 1024 (9th Cir. 2005). In *Defenders of Wildlife* (a decision that was reversed by the U.S. Supreme Court), a principal relevant impact of the federal action at issue—the EPA's approval of a state's permitting program under the Clean Water Act—was that following the action, the relevant permitted activities would no longer be subject to consultation under the ESA. By contrast, promulgation of the present rule will result in no change to any ESA requirements applicable to any future activities directed by plans (either state or federal) implementing the rule. The action at issue in *Washington Toxics Coalition* involved the EPA's registration of certain pesticide active ingredients under the Federal Insecticide, Fungicide, and Rodenticide Act. Such actions provide authorization for the sale and distribution of those products, consistent with applicable labelling requirements. The EPA also notes that under the EPA's regulations, registered pesticide labels must, among other things, specify the product ingredients and the methods and sites of product application. 40 CFR 156.10. By contrast, the present rule only sets goals and describes potential pathways to meeting those goals, all of which are subject to future considerations and decisions involved in the implementation of plans (generally by states). The rule neither authorizes, nor directs, any of the future measures to meet the rule's goals. Those activities remain subject to the full range of future decision making addressing which types of measures to implement, what emitting entities will be affected, how much, and when.

energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

TABLE 17—SUMMARY TABLE OF IMPORTANT ENERGY MARKET IMPACTS FOR RATE-BASED AND MASS-BASED ILLUSTRATIVE PLAN APPROACHES
[Percent change from base case]

	Rate-based			Mass-based		
	2020	2025	2030	2020	2025	2030
Retail electricity prices	3	1	1	3	2	0
Price of coal at minemouth	–1	–5	–4	–1	–5	–3
Coal production for power sector use	–5	–14	–25	–7	–17	–24
Price of natural gas delivered to power sector	5	−8	2	4	–3	–2
Natural gas use for electricity generation	3	–1	–1	5	0	–4

These figures reflect the EPA's illustrative modeling that presumes policies that lead to generation shifts and growing use of demand-side EE 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 demand-side EE policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in the 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.

Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

D. What are the compliance costs?

The compliance costs of this final action are represented in this analysis as the change in electric power generation costs between the base case and the final rule in which states pursue a distinct set of strategies beyond the strategies taken in the base case to meet the terms of the final guidelines. The compliance costs estimates include cost estimates for demand-side EE. The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue. The illustrative analysis is designed to reflect, to the extent possible, the scope and the nature of the final guidelines. However, there is considerable uncertainty with

regards to the precise measures that states will adopt to meet the final requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

The 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 demand-side EE programs, and other actions associated with compliance. These important dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based approach for final emission guidelines to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MR&R).[1050] The EPA estimates the annual incremental compliance cost for the mass-based approach for final emission guidelines to be $1.4 billion in 2020, $3.0 billion in 2025 and $5.1 billion in 2030, including the costs associated with MR&R.

More detailed cost estimates are available in the RIA included in the rulemaking docket.

E. What are the economic and employment impacts?

The final standards are projected to result in certain changes to power system operation as a compliance with the standards. See Table 16 above for a variety

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[1050] The MR&R costs estimates are $65 million in 2020, $15 million in 2025 and $15 million in 2030 and are assumed to be the same for both rate-based and mass-based illustrative plan approaches.

of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based illustrative plan approaches.

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. Many power companies already factor a potential financial liability associated with carbon emissions 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 final rule assumes that overall electric demand will decrease as states ramp up programs that result in lower overall demand. Demand-side EE levels are expected to increase such that they achieve about a 7.8 percent reduction on overall electricity demand levels in 2030 under the final guidelines.

Changes in price or demand for electricity, natural gas, and 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 the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or demand-side EE as a result of states implementing the guidelines can result in shifts in production and

profitability for firms that supply those goods and services.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science." (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. While the economy continues moving toward full-employment, 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 the final guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that states may use. As such, the EPA's employment analysis includes projected employment impacts associated with illustrative plan approaches for these guidelines for the electric power industry, coal and natural gas production, and demand-side EE activities. These projections are derived, in part, from a detailed model of the utility power 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 result in a net decrease of approximately 25,000 job-years in 2025 for the final guidelines under the rate-based illustrative plan

approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to demand-side EE programs. Employment impacts from demand-side energy EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the final guidelines.

By its nature, demand-side EE 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 fossil-fuel fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the benefits of the final goals?

Implementing the final standards will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly-emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for these standards. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 22 of this preamble.

TABLE 18—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE FINAL GUIDELINES
[Billions of 2011$] [a]

Year	Discount rate (statistic)	Monetized climate benefits		
		2020	2025	2030
Rate-based Approach				
CO_2 Reductions (million short tons) ...	.....	69	232	415
	5 percent (average SC-CO_2)	$0.80	$3.1	$6.4
	3 percent (average SC-CO_2)	$2.8	$10	$20
	2.5 percent (average SC-CO_2)	$4.1	$15	$29
	3 percent (95th percentile SC-CO_2) ..	$8.2	$31	$61
Mass-based Approach				
CO_2 Reductions (million short tons) ...	.....	81	265	413
	5 percent (average SC-CO_2)	$0.94	$3.6	$6.4
	3 percent (average SC-CO_2)	$3.3	$12	$20
	2.5 percent (average SC-CO_2)	$4.9	$17	$29
	3 percent (95th percentile SC-CO_2) ..	$9.7	$35	$60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SC-CO_2) estimates for the analysis years and are rounded to two significant figures.

TABLE 19—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE FINAL GUIDELINES, RATE-BASED APPROACH
[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Final Guidelines, Rate-based Approach, 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	14	$0.44 to $0.99	$0.39 to $0.89
NO_X	50	$0.14 to $0.33	$0.13 to $0.30
Ozone precursor: [c]			
NO_X (ozone season only)	19	$0.12 to $0.52	$0.12 to $0.52
Total Monetized Health Co-benefits	.....	$0.70 to $1.8	$0.64 to $1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]	.....	$3.5 to $4.6	$3.5 to $4.5

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Final Guidelines, Rate-based Approach, 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	178	$6.4 to $14	$5.7 to $13
NO_X	165	$0.56 to $1.3	$0.50 to $1.1
Ozone precursor: [c]			
NO_X (ozone season only)	70	$0.49 to $2.1	$0.49 to $2.1
Total Monetized Health Co-benefits		$7.4 to $18	$6.7 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$18 to $28	$17 to $26
Final Guidelines, Rate-based Approach, 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	318	$12 to $28	$11 to $25
NO_X	282	$1.0 to $2.3	$0.93 to $2.1
Ozone precursor: [c]			
NO_X (ozone season only)	118	$0.86 to $3.7	$0.86 to $3.7

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Total Monetized Health Co-benefits		$14 to $34.....	$13 to $31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d].....		$34 to $54.....	$33 to $51

[a] All estimates 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, exposure to mercury, 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 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 20—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE FINAL GUIDELINES, MASS-BASED APPROACH
[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized Health co-benefits (7 percent discount)
Final Guidelines, Mass-based Approach, 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	54	$1.7 to $3.8	$1.5 to $3.4
NO_X	60	$0.17 to $0.39	$0.16 to $0.36
Ozone precursor: [c]			
NO_X (ozone season only)	23	$0.14 to $0.61	$0.14 to $0.61
Total Monetized Health Co-benefits	.....	$2.0 to $4.8	$1.8 to $4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]	.....	$5.3 to $8.1	$5.1 to $7.7
Final Guidelines, Mass-based Approach, 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	185	$6.0 to $13	$5.4 to $12
NO_X	203	$0.58 to $1.3	$0.52 to $1.2

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized Health co-benefits (7 percent discount)
Ozone precursor: [c]			
NO_X (ozone season only)	88	$0.56 to $2.4	$0.56 to $2.4
Total Monetized Health Co-benefits	.....	$7.1 to $17	$6.5 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]	.....	$19 to $29	$18 to $27
Final Guidelines, Mass-based Approach, 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	280	$10 to $23	$9.0 to $20
NO_X	278	$0.87 to $2.0	$0.79 to $1.8
Ozone precursor: [c]			
NO_X (ozone season only)	121	$0.82 to $3.5	$0.82 to $3.5
Total Monetized Health Co-benefits	.....	$12 to $28	$11 to $26
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]	.....	$32 to $48	$31 to $46

[a] All estimates 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, exposure to mercury, 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 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule, et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon ($SC\text{-}CO_2$) estimates presented in the T*echnical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised June 2015)* ("current TSD") to analyze CO_2 climate impacts of this rulemaking.[1051] We refer to these estimates, which were developed by the U.S. Government, as "$SC\text{-}CO_2$ estimates." The $SC\text{-}CO_2$ is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (*i.e.*, benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The $SC\text{-}CO_2$ estimates used in this analysis were developed over many years, using the best science

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[1051] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of the Treasury (May 2013, Revised July 2015). Available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.*

available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC-CO_2 Technical Support Document (2010 TSD) [1052] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[1053]

[1052] Docket ID EPA-HQ-OAR-2009-0472-114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon*, with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf*.

[1053] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf*, Docket ID EPA-HQ-OAR-2013-0495, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council,

The EPA received numerous comments on the SC-CO_2 estimates as part of this rulemaking. The comments covered a wide range of topics including the technical details of the modeling conducted to develop the SC-CO_2 estimates, the aggregation and presentation of the SC-CO_2 estimates, and the process by which the SC-CO_2 estimates were derived. Many but not all commenters were supportive of the SC-CO_2 and its application to this rulemaking. Commenters also provided constructive recommendations for potential opportunities to improve the SC-CO_2 estimates in future updates. Many of these comments were similar to those that OMB's Office of Information and Regulatory Affairs received in response to a separate request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO_2 estimates in regulatory impact analysis.[1054] With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits

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Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

[1054] *See https://www.whitehouse.gov/omb/oira/social-cost-of-carbon* for additional details, including the OMB Response to Comments and the SC-CO_2 TSDs.

and challenges of potential approaches to improving the SC-CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC-CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC-CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's separate SC-CO_2 comment process. Additionally, the EPA has carefully examined and evaluated all comments received regarding the SC-CO_2 through this rulemaking process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC-CO_2 estimates for purposes of regulatory impact analysis, including for this proceeding.

The four SC-CO_2 estimates are as follows: $12, $40, $60, and $120 per short ton of CO_2 emissions in the year 2020 (2011$).[1055] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC-CO_2 value at several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 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 SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from the final emission guidelines, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation

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[1055] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf*. The 2010 and 2013 TSDs present SC-CO_2 in 2007$ per metric ton. The estimates were adjusted to (1) short tons for using conversion factor 0.90718474 and (2) 2011$ using GDP Implicit Price Deflator, *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf*.

of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek independent expert advice on technical opportunities to improve the SC-CO_2 estimates from the Academies. The Academies process will help to ensure that the SC-CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the 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 from the illustrative compliance strategy for the final standards. Unlike the global SC-CO_2 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, we conducted air quality modeling for an illustrative scenario reflecting the proposed standards to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then

used these air quality modeling results in BenMAP [1056] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM NAAQS RIA [1057] and Ozone NAAQS RIAs.[1058] [1059] The three regions were the Eastern U.S., Western U.S., and California. To calculate the co-benefits for the final standards, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed standards by the corresponding regional emission reductions for the final standards.[1060] All

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[1056] *http://www.epa.gov/airquality/benmap/index.html.*

[1057] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter*. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA-452/R-12-003, December). Available at: <*http://www.epa.gov/pm/2012/finalria.pdf*>.

[1058] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA-452/R-08-003, March). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645*>.

[1059] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: <*http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf*>.

[1060] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors*. Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: <*http://www.epa.gov/*

benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed standards, which may not exactly match the emission reductions in this final 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.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009) [1061] and Lepeule et al. (2012).[1062] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ *c*oncentrations, which drive population exposure.

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airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf>.

[1061] Krewski D.; M. Jerrett; R.T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality*. Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute. Available at *http://www.healtheffects.org/Pubs/RR140-Krewski.pdf*.

[1062] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." *Environmental Health Perspective*, 120(7), July, pp. 965–970.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based on the American Cancer Society cohort study (Krewski et al., 2009) and one based on the extended Six Cities cohort study (Lepuele et al., 2012). We present the $PM_{2.5}$ co-benefits results as a range based on benefit-per-ton estimates calculated using 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 using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008) [1063] 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 benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004) [1064] and the upper end based on a benefit-per-ton estimate using the function from Levy et al.

[1063] Roman, H., et al. 2008. "Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S." *Environmental Science & Technology*, Vol. 42, No. 7, February, pp. 2268–2274.

[1064] Bell, M.L., et al. 2004. "Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000." *Journal of the American Medical Association*, 292(19), pp. 2372–8.

(2005).[1065] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors, 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*,[1066] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$ 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

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[1065] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. "Ozone exposure and mortality: An empiric Bayes metaregression analysis." *Epidemiology*. 16(4): p. 458–68.

[1066] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report)*. Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA-600-R-08-139F, December). Available at: *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*.

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,[1067] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 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 ($\mu g/m^3$). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 $\mu g/m^3$. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

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

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[1067] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

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 analysis of the final standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and hazardous air pollutants (*e.g.*, mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for the final guidelines. In addition, in the RIA for the final standards, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed guidelines, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

XII. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

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

This final action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the "Regulatory Impact Analysis for Clean Power Plan Final Rule" (EPA-452/R-15-003, July 2015), is available in the docket and is briefly summarized in section XI of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the guidelines. The final rule establishes: (1) Carbon dioxide (CO_2) emission performance rates for two source categories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines, and (2) guidelines for the development, submittal and implementation of state plans that implement the CO_2 emission performance rates. Actions taken to comply with the guidelines will also

reduce the emissions of directly-emitted $PM_{2.5}$, SO_2 and NO_X. The benefits associated with these $PM_{2.5}$, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the social cost of carbon estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* ("current TSD") to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC-CO_2 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 SC-CO_2 value deemed to be central in the current TSD: The model average at 3 percent discount rate.

In the final emission guidelines, the EPA has translated the source category-specific CO_2 emission performance rates into equivalent state-level rate-based and mass-based CO_2 goals in order to maximize the range of choices that states will have in developing their plans. Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the Regulatory Impact Analysis (RIA) for this rule analyzed two implementation scenarios

designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.

It is very important to note that the differences between the analytical results for the rate-based and mass-based illustrative plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the final guidelines. Rather, the two sets of analyses are intended to illustrate two different approaches to accomplish the emission performance rates finalized in the Clean Power Plan Final Rule. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances in all time periods in all places.

The EPA estimates that, in 2020, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be $2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2020, are approximately $2.5 billion for the rate-based

approach and $1.4 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) for the rate-based approach and from $3.9 billion to 6.7 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $10 billion for the rate-based approach and $12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.4 billion to $18 billion (2011$) for a 3 percent discount rate and $6.7 billion to $16 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.1 billion to $17 billion (2011$) for a 3 percent discount rate and $6.5 billion to $16 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2025, are approximately $1.0 billion for the rate-based approach and $3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the final guidelines will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand-side EE program and participant costs and MRR costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Tables 20 and 21 provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the final emission guidelines for rate-based and mass-based illustrative plan approaches, respectively.

TABLE 21—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030 UNDER THE RATE-BASED ILLUSTRATIVE PLAN APPROACH
[Billions of 2011$] [a]

	Rate-based approach		
	2020	2025	2030
Climate Benefits [b]			
5% discount rate	$0.80	$3.1	$6.4
3% discount rate	$2.8	$10	$20
2.5% discount rate	$4.1	$15	$29
95th percentile at 3% discount rate	$8.2	$31	$61

	Air Quality Co-benefits Discount Rate					
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7	$7.4 to $18	$6.7 to $16	$14 to $34	$13 to $31
Compliance Costs [d]				$2.5	$1.0	$8.4
Net Benefits [e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43

Non-Monetized Benefits.....	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.

[a] All 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 SC-CO_2 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 SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 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 SO_2 and NO_X . The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The reduction in premature fatalities each year accounts for over 98 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 final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

TABLE 22—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030 UNDER THE MASS-BASED ILLUSTRATIVE PLAN APPROACH
[Billions of 2011$] [a]

	Mass-based approach		
	2020	2025	2030
Climate Benefits [b]			
5% discount rate	$0.9	$3.6	$6.4
3% discount rate	$3.3	$12	$20
2.5% discount rate	$4.9	$17	$29
95th percentile at 3% discount rate	$9.7	$35	$60

Air Quality Co-benefits Discount Rate						
Air Quality Health Co-benefits [c]	3% $2.0 to $4.8	7% $1.8 to $4.4	3% $7.1 to $17	7% $6.5 to $16	3% $12 to $28	7% $11 to $26
Compliance Costs [d]			$1.4		$3.0	$5.1
Net Benefits [e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40

Non-Monetized Benefits.....	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility improvement.

[a] All 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 SC-CO_2 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 SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 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 SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 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 final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.*, nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X and hazardous air pollutants (*e.g.*, mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this final action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in this RIA.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule does not directly impose specific requirements on EGUs located in states or areas of Indian country. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. For areas of Indian country, the rule establishes CO_2 emission performance goals that could be addressed

through either tribal or federal plans. A tribe would have the opportunity under the Tribal Authority Rule (TAR), but not the obligation, to apply to the EPA for Treatment as State (TAS) for purposes of a CAA section 111(d) plan and, if approved by the EPA, to establish a CAA section 111(d) plan for its area of Indian country. To date, no tribe has requested or obtained TAS eligibility for purposes of a CAA section 111(d) plan. For areas of Indian country with affected EGUs where a tribe has not applied for TAS and submitted any needed plan, if the EPA determines that a CAA section 111(d) plan is necessary or appropriate, the EPA would have the responsibility to establish the plans. Because tribes are not required to implement section 111(d) plans and because no tribe has yet sought TAS eligibility for this purpose, this action is not anticipated to impose any information collection burden on tribal governments over the 3-year period covered by this ICR.

This rule does impose specific requirements on state governments with affected EGUs. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit CO_2 emissions from existing sources in the utility 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) is estimated to be a range of 505,000 to 821,000 hours at a total annual labor cost of $35.8 to $58.1 million. The lower bound estimate reflects the assumption that some states already have EE and RE programs in place. The higher bound estimate reflects the overly-conservative assumption that no states have EE and RE programs in place.

The total annual burden for the federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 54,000 hours at a total annual labor cost of $3.00 million. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action 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 emission standards on existing sources, and it is those requirements that could potentially impact small entities.

Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their SIPs. See *American Trucking Assoc.* v. *EPA*, 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the rule among small entities and, as detailed in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and in section II.D of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and U.S. Territories (79 FR 65489; November 4, 2014), has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities and electric utility associations, as well as industry leaders and trade association representatives from various industries. While formulating the provisions of the rule, the EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The emission guidelines do not impose any direct compliance requirements on EGUs located in states or areas of Indian country. As explained in section XII.B above, the rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. The rule does impose specific requirements on state governments that have affected EGUs. Specifically, states are required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. The burden for states to develop CAA section 111(d) plans in the 3-year period following promulgation of the rule was estimated and is listed in section XII.B above, but this burden is estimated to be below $100 million in any one year. Thus, this rule is not subject to the requirements of section 202 or section 205 of the UMRA.

This 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. Specifically, the state governments to which rule requirements apply are not considered small governments.

In light of the interest among governmental entities, the EPA conducted outreach with national organizations representing state and local elected officials and tribal governmental entities while formulating the provisions of this rule. Sections III.A and XI.F of the preamble to the proposed carbon

pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in areas of Indian Country and U.S. Territories (79 FR 65489; November 4, 2014) describes the extensive stakeholder outreach the EPA has conducted on setting emission guidelines for existing EGUs. The EPA considered the input provided over the course of the stakeholder outreach as well as the input provided in the many public comments when developing the provisions of these emission guidelines.

E. Executive Order 13132: Federalism

The EPA has concluded that this action may have federalism implications, pursuant to agency policy for implementing the Order, because it imposes substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the rule, as well as time to work with state legislatures as appropriate, to develop a plan submittal. Consistent with this determination, the EPA provides the following federalism summary impact statement.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79

FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach addressed 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. The National Association of Clean Air Agencies also participated. 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, as described in section III.A of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014), extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, state attorneys general, 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.

In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote

communications between the EPA and state and local governments, the EPA specifically solicited comment on the proposed action from state and local officials. The EPA received comments from over 400 entities representing state and local governments.

Several themes emerged from state and local government comments. Commenters raised concerns with the building blocks that comprise the best system of emission reduction (BSER), including the stringency of the building blocks, and the timing of achieving interim CO_2 levels. They also identified the potential for electric system reliability issues and stranded assets due to the proposed timeframe for plan submittals and CO_2 emission reductions. In addition, states commented on state plan development and implementation topics, including state plan approaches, early actions, trading programs, interstate crediting for RE, and EPA guidance and outreach.

Commenters identified overarching concerns regarding the stringency of the CO_2 goals and the timeframe for achieving reductions that encompassed the building blocks, the BSER, and associated timing for achievement of interim CO_2 levels. State commenters, in particular, identified changes to the stringency of the building blocks, concerns with the timeframe over which reductions must be achieved, and concerns with the approaches and measures used for the BSER. For the final rule, in response to stakeholder comments, the EPA has made refinements to the building blocks, the period of time over which measures are deployed, and the stringency of emission limitations that those measures can

achieve in a practical and reasonable cost way. The final BSER reflects those refinements.

To many commenters, the proposal's 2020 compliance date, together with the stringency of the interim CO_2 goal, bore significant reliability implications. In this final rule, the agency is addressing those concerns via adjustments to the compliance timeframe (an 8-year interim period that begins in 2022) and to the approach for meeting interim CO_2 emission performance rates (a glide path separated into three steps, 2022–2024, 2025–2027, and 2028–2029), as well as a more gradual phase in of the emission reduction expectations. These adjustments provide more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. The final rule also retains flexibilities presented in the proposal and offers additional opportunities, including opportunities for trading within and between states, and other multi-state compliance approaches that will further support electric system reliability. The EPA is also requiring each state to demonstrate in its final state that it has considered electric system reliability issues in developing its plan—and is providing the time to do so. Even with this foundation of flexibility in place, these final guidelines further provide states with the option of proposing amendments to approved plans in the event that unanticipated and significant reliability challenges arise.

Commenters provided compelling information indicating that it will take longer than the agency initially anticipated to for states to complete the tasks necessary to finalize a state plan, including

administrative and potential legislative processes. Recognizing this, as well as the urgent need for actions to reduce GHG emissions, the EPA is requiring states to make an initial submittal by September 6, 2016, and is allowing states two additional years to submit a final plan, if justified (to be submitted by September 6, 2018).

States commented on state plan development and implementation topics that included state plan approaches, early actions being taken into account, trading programs being allowed, interstate crediting for RE being allowed, and guidance and outreach being provided by the EPA. For the state plan approaches, commenters expressed concerns with the proposed "portfolio approach" for state plans, including concerns with enforceability of requirements, and identified a "state commitment approach" with backstop measures as an option for state plans. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing a "state measures" approach that includes a requirement for the inclusion of backstop measures.

State commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. The EPA recognizes the value of such early actions, and in this final rule is establishing the CEIP to provide opportunities for investment in RE and demand-side EE projects that deliver results in 2020 and/or 2021.

Many state commenters supported the use of mass-based and rate-based emission trading programs in

state plans, including interstate emission trading programs. The EPA also received a number of comments from states and stakeholders about the value of EPA support in developing and/or administering tracking systems to support state administration of rate-based and mass-based emission trading programs. In this final rule, states may use trading or averaging approaches and technologies or strategies that are not explicitly mentioned in any of the three building blocks as part of their overall plans, as long as they achieve the required emission reductions from affected fossil-fuel-fired EGUs. In addition, in response to concerns from states and power companies that the need for up-front interstate cooperation in developing multi-state plans could inhibit the development of interstate programs that could lower cost, the final rule provides additional options to allow individual EGUs to use creditable out-of-state reductions to achieve required CO_2 reductions, without the need for up-front interstate agreements. The EPA is committed to working with states to provide support for tracking of emissions and allowances or credits, to help implement multi-state trading or averaging approaches.

In their comments, many states identified the need for the EPA to provide guidance, including guidance on RE and EE emission measurement and verification (EM&V), and to maintain regular contact/forums with states throughout the implementation process. To provide state and local governments and other stakeholders with an understanding of the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue outreach throughout

the plan development and submittal process. Outreach will include opportunities for states to participate in briefings, teleconferences, and meetings about the final rule. The EPA's 10 regional offices will continue to be the entry point for states and tribes to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule during the first two months after the final rule is issued. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the states and tribes that are implementing the final rule. The EPA expects to issue guidance on specific topics, including evaluation, measurement and verification (EM&V) for RE and demand-side EE, state-community engagement, and resources and financial assistance for RE and demand-side EE. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with the U.S. Department of Energy and other federal agencies, will continue to make these resources available via a dedicated Web site.

A list of the state and local government commenters has been provided to OMB and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in the EPA's response to comments document on this final rulemaking, which has also been placed in the docket for this rulemaking.

As required by section 8(a) of Executive Order 13132, the EPA included a certification from its Federalism Official stating that the EPA had met the Executive Order's requirements in a meaningful and timely manner when it sent the draft of this final action to

OMB for review pursuant to Executive Order 12866. A copy of the certification is included in the public version of the official record for this final action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. Tribes are not required to develop or adopt CAA programs, but they may apply to the EPA for treatment in a manner similar to states (TAS) and, if approved, do so. As a result, tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs in their areas of Indian country. To the extent that a tribal government seeks and attains TAS status for that purpose, these emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA notes that this rule does not directly impose specific requirements on affected EGUs, including those located in areas of Indian country, but provides guidance to any tribe approved by the EPA to address CO_2 emissions from EGUs subject to section 111(d) of the CAA. The EPA also notes that none of the affected EGUs are owned or operated by tribal governments.

As described in sections III.A and XI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs (79 FR 34845–34847; June 18, 2014) and sections II.D and VI.F of the preamble to the proposed carbon pollution emission guidelines for existing EGUs in Indian Country and

U.S. Territories (79 FR 65489; November 4, 2014), the rule was developed after extensive and vigorous outreach to tribal governments. These tribes expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs located in their areas of Indian country 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 covered under treaty 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, ways of life 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.

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this action to permit them to have meaningful and timely input into its development. A summary of that consultation follows.

Prior to issuing the supplemental proposal on November 4, 2014, the EPA consulted with tribes as follows. The EPA held a consultation with the Ute Tribe, the Crow Nation, and the Mandan, Hidatsa, Arikara (MHA) Nation on July 18, 2014. On August 22, 2014, the EPA held a consultation with the Fort Mojave Tribe. On September 15, 2014, the EPA held a consultation with the Navajo Nation. The Navajo Nation sent a letter to the EPA on September 18, 2014,

summarizing the information presented at the consultation and the Navajo Nation's position on the supplemental proposal. One issue raised by tribal officials was the potential impacts of the June 18, 2014 proposal and the supplemental proposal on tribes with budgets that are dependent on revenue from coal mines and power plants, as well as employment at the mines and power plants. The tribes noted the high unemployment rates and lack of access to basic services on their lands. Tribal officials also asked whether the rules will have any impact on a tribe's ability to seek TAS. Tribal officials also expressed interest in agency actions with regard to facilitating power plant compliance with regulatory requirements. The Navajo Nation made the following recommendations in their letter of September 18, 2014: The Navajo Nation supports a mass-based CO_2 emission standard based on the highest historical CO_2 emissions since 1996; the Navajo Nation requests that the EPA grant the Navajo Nation carbon credits and that the Navajo Nation retains ownership and control of such credits; building block 2 is not appropriate for the Navajo Nation because there are no NGCC plants located on the Navajo Nation; building block 3 is not appropriate for the Navajo Nation because the Navajo people already receive virtually all of their electricity from carbon-free sources (mostly hydroelectric power) and their use of electricity is negligible compared to the generation at the power plants; building block 4 is not appropriate for the Navajo Nation because of the inadequate access to electricity, and the goal should allow for an increase in energy consumption on the Navajo Nation; the supplemental proposal should consider the useful life of the power plants located on

the Navajo Nation; and the supplemental proposal should clarify that RE projects located within the Navajo Nation that provide electricity outside the Navajo Nation should be counted toward meeting the relevant state's RE goals under the Clean Power Plan.

After issuing the supplemental proposal, the EPA held additional consultation with tribes. On November 18, 2014, the EPA held consultations with the following tribes: Fort McDowell Yavapai Nation, Fort Mojave Tribe, Hopi Tribe, Navajo Nation, and Ak-Chin Indian Community. A consultation with the Ute Indian Tribe of the Uintah and Ouray Reservation was held on December 16, 2014 and with the Gila River Indian Community on January 15, 2015. The Navajo Nation reiterated the concerns raised during the previous consultation. Several tribes also again indicated that they wanted to ensure they would be included in the development of any tribal or federal plans for areas of Indian country. The Fort Mojave Tribe and the Navajo Nation expressed concern with using data from 2012 as the basis for the goal for their areas of Indian country; in their view, that year was not representative for the affected EGU. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation. The issues raised by the Navajo Nation during the consultation included whether the EPA has the authority to set less stringent standards on a case-by-case basis, and a suggested "parity glide path" that would account and adjust for the very low electricity usage by the Navajo Nation and promote Navajo Nation economic growth and demand. Furthermore, on July 7, 2015 the EPA conducted an additional consultation with the Navajo Nation. One of the goals of the consultation was for the new

government of the Navajo Nation to deepen their understanding of the rulemaking. The questions raised by the nation had to do with goal setting and carbon credits, the timing of the rulemaking, and the proposed federal plan. Additionally, on July 14, 2015 the EPA conducted an additional consultation with the Fort Mojave Tribe. The Fort Mojave tribes expressed concerns that 2012 is not a representative year, that natural gas-fired combined cycle power plants should be treated differently from coal-fired power plants, and that the proposed goal for Fort Mojave was not appropriate. Additionally, they also expressed interest in being engaged in the federal plan process. Responses to these comments and others received are available in the Response to Comment Document that is in the docket for this rulemaking. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the executive order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

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

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. The EPA believes that the CO_2 emission reductions resulting from implementation of these final guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in section II.A of this preamble.

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

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. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous U.S. in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. 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 (NTTAA)

This rulemaking does not involve technical standards.

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. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. See, section VIII.A of this preamble where the EPA summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[1068] As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks 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. See sections XII.F and XII.G, above, where

[1068] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("Endangerment Finding").

the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. 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.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence 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 that the potential impacts of climate change raise environmental justice issues. These reports concluded 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 impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal

erosion and 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 populations and low-income populations in the U.S.[1069] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) may be uniquely vulnerable to climate change health impacts

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[1069] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment*. U.S. Global Change Research Program, 841 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp. *https://www.ipcc.ch/report/ar5/wg2/*.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp. *https://www.ipcc.ch/report/ar5/wg2/*.

in the U.S. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the U.S.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this final rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission guidelines for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_X, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS, [1070] the EPA identified low-income

[1070] "National Ambient Air Quality Standards for Particulate Matter, Final Rule," 78 FR 3086 (Jan. 15, 2013).

populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations 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 susceptibility to PM-related effects.[1071] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emissions reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and environmental justice considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on overburdened communities. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*, when determining what actions to take.[1072] As described in the

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[1071] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA-600-R-08-139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*>.

[1072] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://epa.gov/*

community and environmental justice considerations section of this preamble the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX. Additionally, as outlined in sections I and IX of this preamble, the EPA has engaged with communities throughout this rulemaking and has devised a robust outreach strategy for continual engagement throughout the implementation phase of this rulemaking.

K. Congressional Review Act (CRA)

This final action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a "major rule" as defined by 5 U.S.C. 804(2).

XIII. Statutory Authority

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

List of Subjects in 40 CFR Part 60

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

Dated: August 3, 2015.

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environmentaljustice/resources/policy/considering-ej-in-rule makingguide-final.pdf. May 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for Part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 e*t seq*.

■ 2. Add subpart UUUU to read as follows:

Subpart—UUUU Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Sec.

Introduction

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State or multi-State plans that establish emission standards limiting greenhouse gas (GHG) 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 section 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§ 60.5705 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates and equivalent statewide CO_2 emission goals.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii), with respect to GHG emissions from facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject

to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

§ 60.5710 Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a State or multi-State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715 What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27 except that under § 60.27(b) the Administrator will have 12 months after the date the final plan or plan

revision (as allowed under § 60.5785) is submitted, to approve or disapprove such plan or revision or each portion thereof. If you submit an initial submittal under § 60.5765(a) in lieu of a final plan submittal the EPA will follow the procedure in § 60.5765(b).

§ 60.5720 What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to § 60.27. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a final plan.

§ 60.5725 In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a final State or multi-State plan submittal or a negative declaration letter (if applicable).

§ 60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the F**ederal Register**. If, at a later date, an affected EGU for which construction commenced on or

before January 8, 2014 is found in your State, you will be found to have failed to submit a final plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a final State plan.

§ 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) and (b) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the CO_2 emission performance rates in Table 1 to this subpart established under § 60.5855.

(b) Approval of alternatives, not already approved by this subpart, to the CO_2 emissions goals in Tables 2, 3 and 4 to this subpart established under § 60.5855.

§ 60.5736 Will the EPA impose any sanctions?

No. The EPA will not withhold any existing federal funds from a State on account of a State's failure to submit, implement, or enforce an approvable plan or plan revision, or to meet any other requirements under this subpart or subpart B of this part.

§ 60.5737 What is the Clean Energy Incentive Program and how do I participate?

(a) This subpart establishes the Clean Energy Incentive Program (CEIP). Participation in this program is optional. The program enables States to award early action emission rate credits (ERCs) and allowances to eligible renewable energy (RE) or demand-side energy efficiency (EE) projects that

generate megawatt hours (MWh) or reduce end-use energy demand during 2020 and/or 2021. Eligible projects are those that:

(1) Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP; and

(2) Commence construction in the case of RE, or commence operation in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018 for a state that chooses not to submit a final state plan by that date; and either

(3) Generate metered MWh from any type of wind or solar resources; or

(4) Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities.

(b) The EPA will award matching ERCs or allowances to States that award early action ERCs or allowances, up to a match limit equivalent to 300 million tons of CO_2 emissions. The awards will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the State, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the State to award to the project.

(2) For EE projects implemented in low-income communities: For every two MWh in end-use demand

savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the State, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the State to award to the project.

(c) You may participate in this program by including in your State plan a mechanism that enables issuance of early action ERCs or allowances by the State to parties effectuating reductions in the calendar years 2020 and/or 2021 in a manner that would have no impact on the emission performance of affected EGUs required to meet rate-based or mass-based emission standards during the performance periods. This mechanism is not required to account for matching ERCs or allowances that may be issued to the State by the EPA.

(d) If you are submitting an initial submittal by September 6, 2016, and you intend to participate in the CEIP, you must include a non-binding statement of intent to participate in the program. If you are submitting a final plan by September 6, 2016, and you intend to participate in the CEIP, your State plan must either include requirements establishing the necessary infrastructure to implement such a program and authorizing your affected EGUs to use early action allowances or ERCs as appropriate, or you must include a non-binding statement of intent as part of your supporting documentation and revise your plan to include the appropriate requirements at a later date.

(e) If you intend to participate in the CEIP, your final State plan, or plan revision if applicable, must require that projects eligible under this program be evaluated, monitored, and verified, and that resulting

ERCs or allowances be issued, per applicable requirements of the State plan approved by the EPA as meeting § 60.5805 through § 60.5835.

State and Multi-State Plan Requirements

§ 60.5740 What must I include in my federally enforceable State or multi State plan?

(a) You must include the components described in paragraphs (a)(1) through (5) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745.

(1) *Identification of affected EGUs.* Consistent with § 60.25(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845. In addition, you must include an inventory of CO_2 emissions from the affected EGUs during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Emission standards.* You must include an identification of all emission standards for each affected EGU according to § 60.5775, compliance periods for each emission standard according to § 60.5770, and a demonstration that the emission standards, when taken together, achieve the applicable CO_2 emission performance rates or CO_2 emission goals described in § 60.5855. Allowance systems are an acceptable form of emission standards under this subpart.

(i) Your plan does not need to include corrective measures specified in paragraph (a)(2)(ii) of this section if your plan:

(A) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission performance rates in the plan for each plan period;

(B) Imposes emission standards on all affected EGUS that, assuming full compliance by all affected EGUs, mathematically assure achievement of the CO_2 emission goals; or

(C) Imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, in conjunction with applicable requirements under state law for EGUs subject to subpart TTTT of this subpart, assuming the applicable requirements under state law are met by all EGUs subject to subpart TTTT of this subpart, achieve the applicable mass-based CO_2 emission goals plus new source CO_2 emission complement allowed for in § 60.5790(b)(5).

(ii) If your plan does not meet the requirements of (a)(2)(i) or (iii) of this section, your plan must include the requirement for corrective measures to be implemented if triggered. Upon triggering corrective measures, if you do not already have them included in your approved State plan, you must submit corrective measures to EPA for approval as a plan revision per the requirements of § 60.5785(c). These corrective measures must ensure that the interim period and final period CO_2 emission performance rates or CO_2 emission goals are achieved by your affected EGUs, as applicable, and must achieve additional emission reductions to offset any emission performance shortfall. Your plan must include the requirement that corrective measures be triggered and

implemented according to paragraphs (a)(2)(ii)(A) through (H) of this section.

(A) Your plan must include a trigger for an exceedance of an interim step 1 or interim step 2 CO_2 emission performance rate or CO_2 emission goal by 10 percent or greater, either on average or cumulatively (if applicable).

(B) Your plan must include a trigger for an exceedance of an interim step 1 goal or interim step 2 goal of 10 percent or greater based on either reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(C) Your plan must include a trigger for a failure to meet an interim period goal based on reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable), or based on the adjusted CO_2 emission rate (if applicable).

(D) Your plan must include a trigger for a failure to meet the interim period or any final reporting period CO_2 emission performance rate or CO_2 emission goal, either on average or cumulatively (as applicable).

(E) Your plan must include a trigger for a failure to meet any final reporting period goal based on reported CO_2 emissions with applied plus or minus net allowance export or import adjustments (if applicable).

(F) Your plan must include a trigger for a failure to meet the interim period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(G) Your plan must include a trigger for a failure to meet any final reporting period CO_2 emission performance rate or CO_2 emission goal based on the adjusted CO_2 emission rate (if applicable).

(H) A net allowance import adjustment represents the CO_2 emissions (in tons) equal to the number of net imported CO_2 allowances. This adjustment is subtracted from reported CO_2 emissions. Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs (or affected EGUs plus EGUs covered by subpart TTTT of this part as applicable). A net allowance export adjustment represents the CO_2 emissions (in tons) equal to the number of net exported CO_2 allowances. This adjustment is added to reported CO_2 emissions.

(iii) If your plan relies upon State measures, in addition to or in lieu of emission standards on your affected EGUs, then the final State plan must include the requirements in paragraph (a)(3) of this section and the submittal must include the information listed in § 60.5745(a)(6).

(iv) If your plan requires emission standards in addition to relying upon State measures, then you must demonstrate that the emission standards and State measures, when taken together, result in the achievement of the applicable mass-based CO_2 emission goal described in § 60.5855 by your State's affected EGUs.

(3) *State measures backstop.* If your plan relies upon State measures, you must submit, as part of the plan in lieu of the requirements in paragraph (a)(2)(i) and (ii) of this section, a federally enforceable backstop

that includes emission standards for affected EGUs that will be put into place, if there is a triggering event listed in paragraph (a)(3)(i) of this section, within 18 months of the due date of the report required in § 60.5870(b). The emission standards on the affected EGUs as part of the backstop must be able to meet either the CO_2 emission performance rates or mass-based or rate-based CO_2 emission goal for your State during the interim and final periods. You must either submit, along with the backstop emission standards, provisions to adjust the emission standards to make up for the prior emission performance shortfall, such that no later plan revision to modify the emission standards is necessary in order to address the emission performance shortfall, or you must submit, as part of the final plan, backstop emission standards that assure affected EGUs would achieve your State's CO_2 emission performance rates or emission goals during the interim and final periods, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the State plan revision process described in § 60.5785. The backstop must also include the requirements in paragraphs (a)(3)(i) through (iii) of this section, as applicable.

(i) You must include a trigger for the backstop to go into effect upon:

(A) A failure to meet a programmatic milestone;

(B) An exceedance of 10 percent or greater of an interim step 1 goal or interim step 2 goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable);

(C) A failure to meet the interim period goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable); or

(D) A failure to meet any final reporting period goal based on reported CO_2 emissions, with applied plus or minus net allowance export or import adjustments (if applicable).

(ii) You may include in your plan any additional triggers so long as they do not reduce the stringency of the triggers required under paragraph (a)(3)(i) of this section.

(iii) You must include a schedule for implementation of the backstop once triggered, and you must identify all necessary State administrative and technical procedures for implementing the backstop.

(4) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860.

(5) *State reporting.* You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under § 60.5870.

(i) You must include in your plan a requirement for a report to be submitted by July 1, 2021, that demonstrates that the State has met, or is on track to meet, the programmatic milestone steps indicated in the timeline required in § 60.5770.

(b) You must follow the requirements of subpart B of this part and demonstrate that they were met in your State plan. However, the provisions of § 60.24(f) shall not apply.

§ 60.5745 What must I include in my final plan submittal?

(a) In addition to the components of the plan listed in § 60.5740, a final plan submittal to the EPA must include the information in paragraphs (a)(1) through (13) of this section. This information must be submitted to the EPA as part of your final plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a description of your plan approach and the geographic scope of the plan (*i.e.*, State or multi-State, geographic boundaries related to the plan elements), including, if applicable, identification of multi-State plan participants.

(2) You must identify CO_2 emission performance rates or equivalent statewide CO_2 emission goals that your affected EGUs will achieve. If the geographic scope of your plan is a single State, then you must identify CO_2 emission performance rates or emission goals according to § 60.5855. If your plan includes multiple States and you elect to set CO_2 emission goals, you must identify CO_2 emission goals calculated according to § 60.5750.

(i) You must specify in the plan submittal the CO_2 emission performance rates or emission goals that affected EGUs will meet for the interim period, each interim step, and the final period (including each final reporting period) pursuant to § 60.5770.

(ii) [Reserved]

(3) You must include a demonstration that the affected EGUs covered by the plan are projected to achieve the CO_2 emission performance rates or CO_2 emission goals described in § 60.5855.

(4) You must include a demonstration that each affected EGU's emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable according to § 60.5775.

(5) If your plan includes emission standards on your affected EGUs sufficient to meet either the CO_2 emission performance rates or CO_2 emission goals, you must include in your plan submittal the information in paragraphs (a)(5)(i) through (v) of this section as applicable.

(i) If your plan applies separate rate-based CO_2 emission standards for affected EGUs (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates listed in Table 1 of this subpart or uniform rate-based CO_2 emission standards equal to or lower than the rate-based CO_2 emission goals listed in Table 2 of this subpart, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(ii) If a plan applies rate-based emission standards to individual affected EGUs at a lbs CO_2/MWh rate that differs from the CO_2 emission performance rates in Table 1 of this subpart or the State's rate-based CO_2 emission goal in Table 2 of this subpart, then a further demonstration is required that the application of the CO_2 emission standards will achieve the CO_2 emission performance rates or State rate-based CO_2 emission goal. You must demonstrate through a projection that the adjusted weighted average CO_2 emission rate of

affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the rate-based CO_2 emission goal. This projection must address the interim period and the final period. The projection in the plan submittal must include the information listed in paragraph (a)(5)(v) of this section and in addition the following:

(A) An analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a State;

(B) A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;

(C) Assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible resources that can be issued ERCs;

(D) The specific calculation (or assumption) of how eligible resource MWh of electricity generation or savings are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs;

(E) If a state plan provides for the ability of renewable energy resources located in states with mass-based plans to be issued ERCs, consideration in the projection that such resources must meet geographic eligibility requirements, consistent with § 60.5800(a); and

(F) Any other applicable assumptions used in the projection.

(iii) If a plan establishes mass-based emission standards for affected EGUs that cumulatively do not

exceed the State's EPA-specified mass CO_2 emission goal, then no additional demonstration is required beyond inclusion of the emission standards in the plan.

(iv) If a plan applies mass-based emission standards to individual affected EGUs that cumulatively exceed the State's EPA-specified mass CO_2 emission goal, then you must include a demonstration that your mass-based emission program will be designed such that compliance by affected EGUs would achieve the State mass-based CO_2 emission goals. This demonstration includes the information listed in paragraph (a)(5)(v) of this section.

(v) Your plan demonstration to be included in your plan submittal, if applicable, must include the information listed in paragraphs (a)(5)(v)(A) through (L) of this section.

(A) A summary of each affected EGU's anticipated future operation characteristics, including:

(*1*) Annual generation;

(*2*) CO_2 emissions;

(*3*) Fuel use, fuel prices (when applicable), fuel carbon content;

(*4*) Fixed and variable operations and maintenance costs (when applicable);

(*5*) Heat rates; and

(*6*) Electric generation capacity and capacity factors.

(B) An identification of any planned new electric generating capacity.

(C) Analytic treatment of the potential for building unplanned new electric generating capacity.

(D) A timeline for implementation of EGU-specific actions (if applicable).

(E) All wholesale electricity prices.

(F) A geographic representation appropriate for capturing impacts and/or changes in the electric system.

(G) A time period of analysis, which must extend through at least 2031.

(H) An anticipated electricity demand forecast (MWh load and MW peak demand) at the State and regional level, including the source and basis for these estimates, and, if appropriate, justification and documentation of underlying assumptions that inform the development of the demand forecast (*e.g.*, annual economic and demand growth rate or population growth rate).

(I) A demonstration that each emission standard included in your plan meets the requirements of § 60.5775.

(J) Any ERC or emission allowance prices, when applicable.

(K) An identification of planning reserve margins.

(L) Any other applicable assumptions used in the projection.

(6) If your plan relies upon State measures, in addition to or in lieu of the emission standards required by paragraph § 60.5740(a)(2), the final State plan submittal must include the information under paragraphs (a)(5)(v) and (a)(6)(i) through (v) of this section.

(i) You must include a description of all the State measures the State will rely upon to achieve the

applicable CO_2 emission goals required under § 60.5855(e), the projected impacts of the State measures over time, the applicable State laws or regulations related to such measures, and identification of parties or entities subject to or implementing such State measures.

(ii) You must include the schedule and milestones for the implementation of the State measures. If the State measures in your plan submittal rely upon measures that do not have a direct effect on the CO_2 emissions measured at an affected EGU's stack, you must also demonstrate how the minimum emission, monitoring and verification (EM&V) requirements listed under § 60.5795 that apply to those programs and projects will be met.

(iii) You must demonstrate that federally enforceable emission standards for affected EGUs in conjunction with any State measures relied upon for your plan, are sufficient to achieve the mass-based CO_2 emission goal for the interim period, each interim step in that interim period, the final period, and each final reporting period. In addition, you must demonstrate that each emission standard included in your plan meets the requirements of § 60.5775 and each State measure included in your plan submittal meets the requirements of § 60.5780.

(iv) You must include a CO_2 performance projection of your State measures that shows how the measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, will result in the achievement of the future CO_2 performance at affected EGUs. Elements of this projection must include those specified in paragraph

(a)(5)(v) of this section, as applicable, and the following for the interim period and the final period:

(A) A baseline demand and supply forecast as well as the underlying assumptions and data sources of each forecast;

(B) The magnitude of energy and emission impacts from all measures included in the plan and applicable assumptions;

(C) An identification of State-enforceable measures with electricity savings and RE generation, in MWh, expected for individual and collective measures and any assumptions related to the quantification of the MWh, as applicable.

(7) Your plan submittal must include a demonstration that the reliability of the electrical grid has been considered in the development of your plan.

(8) Your plan submittal must include a timeline with all the programmatic milestone steps the State intends to take between the time of the State plan submittal and January 1, 2022 to ensure the plan is effective as of January 1, 2022.

(9) Your plan submittal must adequately demonstrate that your State has the legal authority (*e.g.*, through regulations or legislation) and funding to implement and enforce each component of the State plan submittal, including federally enforceable emission standards for affected EGUs, and State measures as applicable.

(10) Your State plan submittal must demonstrate that each interim step goal required under § 60.5855(c), will be met and include in its supporting documentation, if applicable, a description of the

analytic process, tools, methods, and assumptions used to make this demonstration.

(11) Your plan submittal must include certification that a hearing required under § 60.23(c)(1) 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 § 60.23(d) and (f).

(12) Your plan submittal must include documentation of any conducted community outreach and community involvement, including engagement with vulnerable communities.

(13) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority and funding to implement and enforce each component of its plan, including emissions standards and/or State measures that the plan relies upon;

(ii) Materials supporting that the CO_2 emission performance rates or CO_2 emission goals will be achieved by affected EGUs identified under the plan, according to paragraph (a)(3) of this section;

(iii) Materials supporting any calculations for CO_2 emission goals calculated according to § 60.5855, if applicable; and

(iv) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA electronically according to § 60.5875.

§ 60.5750 Can I work with other States to develop a multi-State plan?

A multi-State plan must include all the required elements for a plan specified in § 60.5740(a). A multi-State plan must meet the requirements of paragraphs (a) and (b) of this section.

(a) The multi-State plan must demonstrate that all affected EGUs in all participating States will meet the CO_2 emission performance rates listed in Table 1 of this subpart or an equivalent CO_2 emission goal according to paragraphs (a)(1) or (2) of this section. States may only follow the procedures in (a)(1) or (2) if they have functionally equivalent requirements meeting § 60.5775 and § 60.5790 included in their plans.

(1) For States electing to demonstrate performance with a CO_2 emission rate-based goal, the CO_2 emission goals identified in the plan according to § 60.5855 will be an adjusted weighted (by net energy output) average lbs CO_2/MWh emission rate to be achieved by all affected EGUs in the multi-State area during the plan periods; or

(2) For States electing to demonstrate performance with a CO_2 emission mass-based goal, the CO_2 emission goals identified in the multi-State plan according to § 60.5855 will be total mass CO_2 emissions by all affected EGUs in the multi-State area during the plan periods, representing the sum of all individual mass CO_2 goals for states participating in the multi-state plan.

(b) Options for submitting a multi-State plan include the following:

(1) States participating in a multi-State plan may submit one multi-State plan submittal on behalf of all participating States. The joint submittal must be signed electronically, according to § 60.5875, 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. The joint submittal must address plan components that apply jointly for all participating States and components that apply for each individual State in the multi-State plan, including necessary State legal authority to implement the plan, such as State regulations and statutes.

(2) States participating in a multi-State plan may submit a single plan submittal, signed by authorized officials from each participating State, which addresses common plan elements. Each participating State must, in addition, provide individual plan submittals that address State-specific elements of the multi-State plan.

(3) States participating in a multi-State plan may separately make individual submittals that address all elements of the multi-State plan. The plan submittals must be materially consistent for all common plan elements that apply to all participating States, and also must address individual State-specific aspects of the multi-State plan. Each individual State plan submittal must address all required plan components in § 60.5740.

(c) A State may elect to participate in more than one multi-State plan. If your State elects to participate in more than one multi-State plan then you must identify

in the State plan submittal required under § 60.5745, the subset of affected EGUs that are subject to the specific multi-State plan or your State's individual plan. An affected EGU can only be subject to one plan.

(d) A State may elect to allow its affected EGUs to interact with affected EGUs in other States through mass-based trading programs or a rate-based trading program without entering into a formal multi-State plan allowed for under this section, so long as such programs are part of an EPA-approved state plan and meet the requirements of paragraphs (d)(1) and (2) of this section, as applicable.

(1) For States that elect to do mass-based trading under this option the State must indicate in its plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.

(2) For States that elect to use a rate-based trading program which allows the affected EGUs to use ERCs from other State rate-based trading programs, the plan must require affected EGUs within their State to comply with emission standards equal to the sub-category CO_2 emission performance rates in Table 1 of this subpart.

§ 60.5760 What are the timing requirements for submitting my plan?

(a) You must submit a final plan with the information required under § 60.5745 by September 6, 2016, unless you are submitting an initial submittal, allowed under § 60.5765, in lieu of a final State plan submittal, according to paragraph (b) of this section.

(b) For States seeking a two year extension for a final plan submittal, you must include the information in § 60.5765(a) in an initial submittal by September 6, 2016, to receive an extension to submit your final State plan submittal by September 6, 2018.

(c) You must submit all information required under paragraphs (a) and (b) of this section according to the electronic reporting requirements in § 60.5875.

§ 60.5765 What must I include in an initial submittal if requesting an extension for a final plan submittal?

(a) You must sufficiently demonstrate that your State is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018, by addressing the following required components in an initial submittal by September 6, 2016, if requesting an extension for a final plan submittal:

(1) An identification of final plan approach or approaches under consideration and a description of progress made to date on the final plan components;

(2) An appropriate explanation of why the State requires additional time to submit a final plan by September 6, 2018; and

(3) A demonstration or description of the opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during the time in preparation of the initial submittal and the plans for engagement during development of the final plan.

(b) You must submit an initial submittal allowed in paragraph (a) of this section, information required under paragraph (c) of this section (only if a State elects to submit an initial submittal to request an extension for a final plan submittal), and a final State plan submittal according to § 60.5870. If a State submits an initial submittal, an extension for a final State plan submittal is considered granted and a final State plan submittal is due according to § 60.5760(b) unless a State is notified within 90 days of the EPA receiving the initial submittal that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section. If the EPA notifies the State that the initial submittal does not meet such requirements, the EPA will also notify the State that it has failed to submit the final plan required by September 6, 2016.

(c) If an extension for submission of a final plan has been granted, you must submit a progress report by September 6, 2017. The 2017 report must include the following:

(1) A summary of the status of each component of the final plan, including an update from the 2016 initial submittal and a list of which final plan components are not complete.

(2) A commitment to a plan approach (*e.g.*, single or multi-State, rate-based or mass-based emission performance level, rate-based or mass-based emission standards), including draft or proposed legislation and/or regulations.

(3) An updated comprehensive roadmap with a schedule and milestones for completing the final plan,

including any updates to community engagement undertaken and planned.

§ 60.5770 What schedules, performance periods, and compliance periods must I include in my plan?

(a) The affected EGUs covered by your plan must meet the CO_2 emission requirements required under § 60.5855 for the interim period, interim steps, and the final reporting periods according to paragraph (b) of this section. You must also include in your plan compliance periods for each affected EGU regulated under the plan according to paragraphs (c) and (d) of this section.

(b) Your plan must require your affected EGUs to achieve each CO_2 emission performance rate or CO_2 emission goal, as applicable, required under § 60.5855 over the periods according to paragraphs (b)(1) through (3) of this section.

(1) The interim period.

(2) Each interim step.

(3) Each final reporting period.

(c) The emission standards for affected EGUs regulated under the plan must include the following compliance periods:

(1) For the interim period, affected EGUs must have emission standards that have compliance periods that are no longer than each interim step and are imposed for the entirety of the interim step either alone or in combination.

(2) For the final period, affected EGUs must have emission standards that have compliance periods that are no longer than each final reporting period and are

imposed for the entirety of the final reporting period either alone or in combination.

(3) Compliance periods for each interim step and each final reporting period may take forms shorter than specified in this regulation, provided the schedules of compliance collectively end on the same schedule as each interim step and final reporting period.

(d) If your plan relies upon State measures in lieu of or in addition to emission standards for affected EGUs regulated under the plan, then the performance periods must be identical to the compliance periods for affected EGUs listed in paragraphs (c)(1) through (3) of this section.

§ 60.5775 What emission standards must I include in my plan?

(a) Emission standard(s) for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An affected EGU's emission standard is quantifiable if it can be reliably measured in a manner that can be replicated.

(c) An affected EGU's emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An affected EGU's emission standard is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in another State plan unless incorporated in multi-State plan.

(e) An affected EGU's emission standard is permanent if the emission standard must be met for each compliance period, unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision that the emission reductions from the emission standard are no longer necessary for the State to meet its State level of performance.

(f) An affected EGU's emission standard is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The affected EGUs 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, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, its allowances if it is subject to a mass-based emission standard, or its ERCs if it is subject to a rate-based emission standard) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), in the case of a State,

pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§ 60.5780 What State measures may I rely upon in support of my plan?

You may rely upon State measures in support of your plan that are not emission standard(s) on affected EGUs, provided those State measures meet the requirements in paragraph (a) of this section.

(a) Each State measure is quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity (*e.g.*, entities other than affected EGUs with no federally enforceable obligations under a State plan), and your plan supporting materials include the methods by which each State measure meets each of the following requirements in paragraphs (a)(1) through (5) of this section.

(1) A State measure is quantifiable with respect to an affected entity if it can be reliably measured in a manner that can be replicated.

(2) A State measure is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State to independently evaluate, measure, and verify compliance with the State measure.

(3) A State measure is non-duplicative with respect to an affected entity if it is not already incorporated as a State measure or an emission standard in another State plan or State plan supporting material unless incorporated in a multi-State plan.

(4) A State measure is permanent with respect to an affected entity if the State measure must be met for at least each compliance period, or unless either it is replaced by another State measure in an approved plan revision, or the State demonstrates in an approved plan revision that the emission reductions from the State measure are no longer necessary for the State's affected EGUs to meet their mass-based CO_2 emission goal.

(5) A State measure is enforceable against an affected entity if:

(i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected entities responsible for compliance and liable for violations can be identified;

(iv) Each compliance activity or measure is enforceable as a practical matter; and

(v) The State maintains the ability to enforce violations and secure appropriate corrective actions.

(b) [Reserved]

§ 60.5785 What is the procedure for revising my plan?

(a) EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart B of this part, including the requirement in § 60.5745(a)(3) to demonstrate achievement of the CO_2 emission performance rates or CO_2 emission goals in § 60.5855.

If one (or more) of the elements of the plan set in § 60.5740 require revision with respect to achieving the CO_2 emission performance rates or CO_2 emission goals in § 60.5855, a request must be submitted to the Administrator indicating the proposed revisions to the plan to ensure the CO_2 emission performance rates or CO_2 emission goals are met. In addition, the following provisions in paragraphs (b) through (d) of this section may apply.

(b) You may submit revisions to a plan to adjust CO_2 emission goals according to § 60.5855(d).

(c) If your State is required to submit a notification according to § 60.5870(d) indicating a triggering of corrective measures as described in § 60.5740(a)(2)(i) and your plan does not already include corrective measures to be implemented if triggered, you must revise your State plan to include corrective measures to be implemented. The corrective measures must ensure achievement of the CO_2 emission performance rates or State CO_2 emission goal. Additionally, the corrective measures must achieve additional CO_2 emission reductions to offset any CO_2 emission performance shortfall relative to the overall interim period or final period CO_2 emission performance rate or State CO_2 emission goal. The State plan revision submission must explain how the corrective measures both make up for the shortfall and address the State plan deficiency that caused the shortfall. The State must submit the revised plan and explanation to the EPA within 24 months after submitting the State report required in § 60.5870(a) indicating the CO_2 emission performance deficiency in lieu of the requirements of § 60.28(a). The State must implement corrective measures within 6 months of the EPA's

approval of a plan revision adding them. The shortfall must be made up as expeditiously as practicable.

(d) If your plan relies upon State measures, your backstop is triggered under § 60.5740(a)(3)(i), and your State measures plan backstop does not include a mechanism to make up the shortfall, you must revise your backstop emission standards to make up the shortfall. The shortfall must be made up as expeditiously as practicable.

(e) Reliability Safety Valve:

(1) In order to trigger a reliability safety valve, you must notify the EPA within 48 hours of an unforeseen, emergency situation that threatens reliability, such that your State will need a short-term modification of emission standards under a State plan for a specified affected EGU or EGUs. The EPA will consider the notification in § 60.5870(g)(1) to be an approved short-term modification to the State plan without needing to go through the full State plan revision process if the State provides a second notification to the EPA within seven days of the first notification. The short-term modification under a reliability safety valve allows modification to emission standards under the State plan for an affected EGU or EGUs for an initial period of up to 90 days. During that period of time, the affected EGU or EGUs will need to comply with the modified emission standards identified in the initial notification required under § 60.5870(g)(1) or amended in the second notification required under § 60.5870(g)(2). For the duration of the up to 90-day short-term modification, the CO_2 emissions of the affected EGU or EGUs that exceed their obligations under the originally approved State plan will not be

counted against the State's CO_2 emission performance rate or CO_2 emission goal. The EPA reserves the right to review any such notification required under § 60.5870(g), and, in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must continue to operate under the approved State plan emission standards. As described more fully in § 60.5870(g)(3), at least seven days before the end of the initial 90-day reliability safety valve period, the State must notify the appropriate EPA regional office whether the reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards established in the State plan prior to the short-term modification or whether a serious, ongoing reliability issue necessitates the affected EGU or EGUs emitting beyond the amount allowed under the State plan.

(2) Plan revisions submitted pursuant to § 60.5870(g)(3) must meet the requirements for State plan revisions under § 60.5785(a).

§ 60.5790 What must I do to meet my plan obligations?

(a) To meet your plan obligations, you must demonstrate that your affected EGUs are complying with their emission standards as specified in § 60.5740, and you must demonstrate that the emission standards on affected EGUs, alone or in conjunction with any State measures, are resulting in achievement of the CO_2 emission performance rates or statewide CO_2 emission goals by affected EGUs using the procedures in paragraphs (b) through (d) of this section. If your plan requires the use of allowances for

your affected EGUs to comply with their mass-based emission standards, you must follow the requirements under paragraph (b) of this section and § 60.5830. If your plan requires the use of ERCs for your affected EGUs to comply with their rate-based emission standards, you must follow the requirements under paragraphs (c) and (d) of this section and §§ 60.5795 through 60.5805.

(b) If you submit a plan that sets a mass-based emission trading program for your affected EGUs, the State plan must include emission standards and requirements that specify the allowance system, related compliance requirements and mechanisms, and the emission budget as appropriate. These requirements must include those listed in paragraphs (b)(1) through (5) of this section.

(1) CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs.

(2) Requirements for State allocation of allowances consistent with § 60.5815.

(3) Requirements for tracking of allowances, from issuance through submission for compliance, consistent with § 60.5820.

(4) The process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions) consistent with § 60.5825.

(5) Requirements that address potential increased CO_2 emissions from new sources, beyond the emissions expected from new sources if affected EGUs were given emission standards in the form of the subcategory-specific CO_2 emission performance rates. You may meet this requirement by requiring one of the

options under paragraphs (b)(5)(i) through (iii) of this section.

(i) You may include, as part of your plan's supporting documentation, requirements enforceable as a matter of State law regulating CO_2 emissions from EGUs covered by subpart TTTT of this part under the mass-based CO_2 goal plus new source CO_2 emission complement applicable to your State in Table 4 of this subpart. If you choose this option, the term "mass-based CO_2 goal plus new source CO_2 emission complement" shall apply rather than "CO_2 mass-based goal" and the term "CO_2 emission goal" shall include "mass-based CO_2 goal plus new source CO_2 emission complement" in these emission guidelines.

(ii) You may include requirements in your State plan for emission budget allowance allocation methods that align incentives to generate to affected EGUs or EGUs covered by subpart TTTT of this part that result in the affected EGUs meeting the mass-based CO_2 emission goal;

(iii) You may submit for the EPA's approval, an equivalent method which requires affected EGUs to meet the mass-based CO_2 emission goal. The EPA will evaluate the approvability of such an alternative method on a case by case basis.

(c) If you submit a plan that sets rate-based emission standards on your affected EGUs, to meet the requirements of § 60.5775, you must follow the requirements in paragraphs (c)(1) through (4) of this section.

(1) You must require the owner or operator of each affected EGU covered by your plan to calculate an adjusted CO_2 emission rate to demonstrate compliance

with its emission standard by factoring stack emissions and any ERCs into the following equation:

$$CO_2 emission\ rate = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO_2 emission rate = An affected EGU's adjusted CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.

M_{CO2} = Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWh_{op} = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWh_{ERC} = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (d) of this section).

(2) Your plan must specify that an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if the ERC meets the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) An ERC must have a unique serial number.

(ii) An ERC must represent one MWh of actual energy generated or saved with zero associated CO_2 emissions.

(iii) An ERC must only be issued to an eligible resource that meets the requirements of § 60.5800 or to an affected EGU that meets the requirements of § 60.5795 and must only be issued by a State or its State agent through an EPA-approved ERC tracking

system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(iv) An ERC must be surrendered and retired only once for purpose of compliance with this regulation through an EPA-approved ERC tracking system that meets the requirements of § 60.5810, or by the EPA through an EPA-administered tracking system.

(3) Your plan must specify that an ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of a CO_2 emission performance rate or CO_2 emission goal. The plan must additionally include provisions that address requirements for revocation or adjustment that apply if an ERC issued by the State is subsequently found to have been improperly issued.

(4) Your plan must include provisions either allowing for or restricting banking of ERCs between compliance periods for affected EGUs, and provisions not allowing any borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

Emission Rate Credit Requirements

§ 60.5795 What affected EGUs qualify for generation of ERCs?

(a) For issuance of ERCs to the affected EGUs that generate them, the plan must specify the accounting method and process for ERC issuance. For plans that require that affected EGUs meet a rate-based CO_2 emission goal, where all affected EGUs have identical

emission standards, you must specify the accounting method listed in paragraph (a)(1) of this section for generating ERCs. For plans that require affected EGUs to meet the CO_2 emission performance rates or CO_2 emission goals where affected EGUs have emission standards that are not equal for all affected EGUs, you must specify the accounting methods listed in paragraphs (a)(1) and (2) of this section for generating ERCs.

(1) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be generated by and issued to an affected EGU that is in compliance with its emission standard, based on the difference between its emission standard and its reported CO_2 emission rate for the compliance period; and

(2) You must include the calculation method for determining the number of ERCs, denominated in MWh, that may be issued to affected EGUs that meet the definition of a stationary combustion turbine based on the displaced emissions from affected EGUs not meeting the definition of a stationary combustion turbine, resulting from the difference between its annualized net energy output in MWh for the calendar year(s) in the compliance period and its net energy output in MWh for the 2012 calendar year (January 1, 2012, through December 31, 2012).

(b) Any ERCs generated through the method described as required by paragraph (a)(2) of this section must not be used by any affected EGUs other than steam generating units or IGCCs to demonstrate compliance as prescribed under § 60.5790(c)(1).

(c) Any states in a multi-State plan that requires the use of ERCs for affected EGUs to comply with their emission standards must have functionally equivalent requirements pursuant to paragraphs (a)(1) and (2) of this section for generating ERCs.

§ 60.5800 What other resources qualify for issuance of ERCs?

(a) ERCs may only be issued for generation or savings produced on or after January 1, 2022, to a resource that qualifies as an eligible resource because it meets each of the requirements in paragraphs (a)(1) through (4) of this section.

(1) Resources qualifying for eligibility only include resources that increased installed electrical generation nameplate capacity, or implemented new electrical savings measures, on or after January 1, 2013. If a resource had a nameplate capacity uprate, ERCs may be issued only for the difference in generation between its uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and deliver energy to or save electricity on, the electric grid in the contiguous United States.

(3) The resource must be located in either:

(i) A State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation; or

(ii) A State with a mass-based CO_2 emission goal, and the resource can demonstrate (*e.g.*, through a power purchase agreement or contract for delivery) that the electricity generated is delivered with the intention to meet load in a State with affected EGUs which are subject to rate-based emission standards pursuant to this regulation, and was treated as a generation resource used to serve regional load that included the State whose affected EGUs are subject to rate-based emission standards. Notwithstanding any other provision of paragraph (a)(4) of this section, the only type of eligible resource in the State with mass-based emission standards is renewable generating technologies listed in (a)(4)(i) of this section.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: Wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion only);

(iv) Nuclear power;

(v) A non-affected combined heat and power (CHP) unit, including waste heat power;

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex post savings, not "projected" or "claimed" savings; or

(vii) A category identified in a State plan and approved by the EPA to generate ERCs.

(b) Any resource that does not meet the requirements of this subpart or an approved State plan cannot be issued ERCs for use by an affected EGU with its compliance demonstration required under § 60.5790(c).

(c) ERCs may not be issued to or for any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of this part, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(2) EGUs that do not meet the applicability requirements of §§ 60.5845 and 60.5850, except CHP units that meet the requirements of a CHP unit under paragraph (a);

(3) Measures that reduce CO_2 emissions outside the electric power sector, including, for example, GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA for issuance of ERCs in connection with a specific State plan.

(d) You must include the appropriate requirements in paragraphs (d)(1) through (3) of this section for an applicable eligible resource in your plan.

(1) If qualified biomass is an eligible resource, the plan must include a description of why the proposed

feedstocks or feedstock categories should qualify as an approach for controlling increases of CO_2 levels in the atmosphere as well as the proposed valuation of biogenic CO_2 emissions. In addition, for sustainably-derived agricultural and forest biomass feedstocks, the state plan must adequately demonstrate that such feedstocks appropriately control increases of CO_2 levels in the atmosphere and methods for adequately monitoring and verifying these feedstock sources and related sustainability practices. For all qualified biomass feedstocks, plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches.

(2) If waste-to-energy is an eligible resource, the plan must assess both the capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Additionally the plan must include a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission rate (*i.e.*, that which is generated from biogenic materials).

(3) If carbon capture and utilization (CCU) is an eligible resource in a plan, the plan must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation from affected EGUs and provide monitoring, reporting, and verification requirements to demonstrate the reductions.

(e) States and areas of Indian country that do not have any affected EGUs, and other countries, may provide ERCs to adjust CO_2 emissions provided they are connected to the contiguous U.S. grid and meet the other requirements for eligibility and eligible resources and the issuance of ERCs included in these emission guidelines, except that such States and other countries may not provide ERCs from resources described in § 60.5800(a)(4)(vi).

§ 60.5805 What is the process for the issuance of ERCs?

If your plan uses ERCs your plan must include the process and requirements for issuance of ERCs to affected EGUs and eligible resources set forth in paragraphs (a) through (f) of this section.

(a) *Eligibility application.* Your plan must require that, to receive ERCs, the owner or operator must submit an eligibility application to you that demonstrates that the requirements of your State plan as approved by the EPA as meeting § 60.5795 (for an affected EGU) or § 60.5800 (for an eligible resource) are met, and, in the case of an eligible resource, includes at a minimum:

(1) Documentation that the eligibility application has only been submitted to you, or pursuant to an EPA-approved multi-State collaborative approach;

(2) An EM&V plan that meets the requirements of the State plan as approved by the EPA as meeting § 60.5830; and

(3) A verification report from an independent verifier that verifies the eligibility of the eligible resource to be issued an ERC and that the EM&V plan

meets the requirements of the State plan as approved by the EPA of meeting § 60.5805.

(b) *Registration.* Your plan must require that any affected EGU or eligible resource register with an ERC tracking system that meets the requirements of § 60.5810 prior to the issuance of ERCs, and your plan must specify that you will only register an affected EGU or eligible resource after you approve its eligibility application and determine that the requirements of paragraph (a) of this section are met.

(c) *M&V reports.* For an eligible resource registered pursuant to paragraph (b) of this section, your plan must require that, prior to issuance of ERCs by you, the owner or operator must submit the following:

(1) An M&V report that meets the requirements of your State plan as approved by the EPA as meeting § 60.5835; and

(2) A verification report from an independent verifier that verifies that the requirements for the M&V report are met.

(e) *Issuance of ERCs.* Your plan must specify your procedure for issuance of ERCs based on your review of an M&V report and verification report, and must require that ERCs be issued only on the basis of energy actually generated or saved, and that only one ERC is issued for each verified MWh.

(f) *Tracking system.* Your plan must require that ERCs may only be issued through an ERC tracking system approved as part of the State plan.

(g) *Error adjustment.* Your plan must include a mechanism to adjust the number of ERCs issued if any

are issued based on error (clerical, formula input error, etc.).

(h) *Qualification status of an eligible resource.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an eligible resource, such that it can no longer be issued ERCs for at least the duration that it does not meet the requirements for being issued ERCs in your State plan.

(i) *Qualification status of an independent verifier*—(1) *Eligibility.* To be an independent verifier, a person must be approved by the State as:

(A) An independent verifier, as defined by this regulation; and

(B) Eligible to verify eligibility applications, EM&V plans, and/or M&V reports per the requirements of the approved State plan as meeting §§ 60.5830 and 60.5835 respectively.

(2) *Revocation of qualification.* Your plan must include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer verify eligibility applications, EM&V plans or M&V reports for at least the duration of the period it does not meet the requirements of your State plan.

§ 60.5810 What applicable requirements are there for an ERC tracking system?

(a) Your plan must include provisions for an ERC tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of ERCs, transfers of ERCs among accounts, surrender of ERCs

by affected EGUs as part of a compliance demonstration, and retirement or cancellation of ERCs; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of ERCs and functionality to generate reports based on such information, which must include, for each ERC, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an ERC tracking system may provide for transfers of ERCs to or from another ERC tracking system approved in a State plan, or provide for transfers of ERCs to or from an EPA-administered ERC tracking system used to administer a Federal plan.

Mass Allocation Requirements

§ 60.5815 What are the requirements for State allocation of allowances in a mass-based program?

(a) For a mass-based trading program, a State plan must include requirements for CO_2 allowance allocations according to paragraphs (b) through (f) of this section.

(b) Provisions for allocation of allowances for each compliance period prior to the beginning of the compliance period.

(c) Provisions for allocation of set-aside allowance, if applicable, must be established to ensure that the eligible resources must meet the same requirements for the ERC eligible resource requirements of § 60.5800, and the State must include eligibility

application and verification provisions equivalent to those for ERCs in § 60.5805 and EM&V plan and M&V report provisions that meet the requirements of § 60.5830 and § 60.5835.

(d) Provisions for adjusting allocations if the affected EGUs or eligible resources are incorrectly allocated CO_2 allowances.

(e) Provisions allowing for or restricting banking of allowances between compliance periods for affected EGUs.

(f) Provisions not allowing any borrowing of allowances from future compliance periods by affected EGUs.

§ 60.5820 What are my allowance tracking requirements?

(a) Your plan must include provisions for an allowance tracking system, if applicable, that meets the following requirements:

(1) It electronically records the issuance of allowances, transfers of allowances among accounts, surrender of allowances by affected EGUs as part of a compliance demonstration, and retirement of allowances; and

(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of set aside allowances, if applicable, and functionality to generate reports based on such information, which must include, for each set aside allowance, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.

(b) If approved in a State plan, an allowance tracking system may provide for transfers of allowances to or from another allowance tracking system approved in a State plan, or provide for transfers of allowances to or from an EPA-administered allowance tracking system used to administer a Federal plan.

§ 60.5825 What is the process for affected EGUs to demonstrate compliance in a mass-based program?

(a) A plan must require an affected EGU's owners or operators to demonstrate compliance with emission standards in a mass based program by holding an amount of allowances not less than the tons of total CO_2 emissions for such compliance period from the affected EGUs in the account for the affected EGU's emissions in the allowance tracking system required under § 60.5820 during the applicable compliance period.

(b) In a mass-based trading program a plan may allow multiple affected EGUs co-located at the same facility to demonstrate that they are meeting the applicable emission standards on a facility-wide basis by the owner or operator holding enough allowances to cover the CO_2 emissions of all the affected EGUs at the facility.

(1) If there are not enough allowances to cover the facility's affected EGUs' CO_2 emissions then there must be provisions for determining the compliance status of each affected EGU located at that facility.

(2) [Reserved]

Evaluation Measurement and Verification Plans and Monitoring and Verification Reports

§ 60.5830 What are the requirements for EM&V plans for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any EM&V plan that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allowance that can be used in accordance with § 60.5790, must meet the EM&V criteria approved as part of your State plan.

(b) Your plan must require each EM&V plan to include identification of the eligible resource.

(c) Your plan must require that an EM&V plan must contain specific criteria, as applicable to the specific eligible resource.

(1) For RE resources, your plan must include requirements discussing how the generation data will be physically measured on a continuous basis using, for example, a revenue-quality meter.

(2) For demand-side EE, your plan must require that each EM&V plan quantify and verify electricity savings on a retrospective (ex-post) basis using industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings. Your plan must also require each EM&V plan to include an assessment of the independent factors that influence the electricity savings, the expected life of the savings (in years), and a baseline that represents what would have happened in the absence of the demand-side EE activity. Additionally, your plan must require that each EM&V

plan include a demonstration of how the industry best-practices protocol and methods were applied to the specific activity, project, measure, or program covered in the EM&V plan, and include an explanation of why these protocols or methods were selected. EM&V plans must require eligible resources to demonstrate how all such best-practice approaches will be applied for the purposes of quantifying and verifying MWh results. Subsequent reporting of demand-side EE savings values must demonstrate and explain how the EM&V plan was followed.

§ 60.5835 What are the requirements for M&V reports for eligible resources?

(a) If your plan requires your affected EGUs to meet their emission standards in accordance with § 60.5790, your plan must include requirements that any M&V report that is submitted in accordance with the requirements of § 60.5805, in support of the issuance of an ERC or set-aside allocation that can be used in accordance with § 60.5790, must meet the requirements of this section.

(b) Your plan must require that each M&V report include the following:

(1) For the first M&V report submitted, documentation that the energy-generating resources, energy-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 60.5805(a).

(2) Each M&V report submitted must include the following:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of energy savings;

(iii) Documentation (including data) of the energy generation and/or energy savings from any activity, project, measure, resource, or program addressed in the EM&V plan, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings; and

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource from the description of the resource in the approved eligibility application during the period covered by the M&V report and the date on which the change occurred, and/or demonstration that the eligible resource continued to meet the requirements of § 60.5800.

Applicability of Plans to Affected EGUs

§ 60.5840 Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State or States develop to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a final plan to implement and enforce the emission guidelines contained in this subpart, or an initial submittal for which an extension to submit a final plan can be granted, by September 6, 2016, or the EPA

disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720, applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5845 What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section, as applicable, except as provided in § 60.5850.

(1) Serves a generator or generators connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.*, capable of selling greater than 25 MW of electricity);

(2) Has a base load rating (*i.e.*, design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.

§ 60.5850 What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) EGUs that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Steam generating units and IGCCs that are, and always have been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(c) Non-fossil units (*i.e.*, units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(d) Stationary combustion turbines not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline);

(e) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;

(f) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(g) EGUs that are a municipal waste combustor unit that is subject to subpart Eb of this part; and

(h) EGUs that are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

§ 60.5855 What are the CO_2 emission performance rates for affected EGUs?

(a) You must require, in your plan, emission standards on affected EGUs to meet the CO_2 emission performance rates listed in Table 1 of this subpart except as provided in paragraph (b) of this section. In addition, you must set CO_2 emission performance rates for the interim steps, according to paragraph (a)(1) of this section, except as provided in paragraph (b) of this section.

(1) You must set CO_2 emission performance rates for your affected EGUs to meet during the interim step periods on average and as applicable for the two subcategories of affected EGUs.

(2) [Reserved]

(b) You may elect to require your affected EGUs to meet emission standards that differ from the CO_2 emission performance rates listed in Table 1 of this subpart, provided that you demonstrate that the affected EGUs in your State will collectively meet their CO_2 emission performance rate by achieving statewide emission goals that are equivalent and no less stringent than the CO_2 emission performance rates listed in Table 1, and provided that your equivalent statewide CO_2 emission goals take one of the following forms:

(1) Average statewide rate-based CO_2 emission goals listed in Table 2 of this subpart, except as provided in paragraphs (c) and (d); or

(2) Cumulative statewide mass-based CO_2 emission goals listed in Table 3 of this subpart, except as provided in paragraphs (c) and (d) of this section.

(c) If your plan meets CO_2 emission goals listed in paragraphs (b)(1) or (2) of this section you must develop your own interim step goals and final reporting period goal for your affected EGUs to meet either on average (in the case of rate-based goals) or cumulatively (in the case of mass-based goals). Additionally the following applies if you develop your own goals:

(1) The interim period and interim steps CO_2 emission goals must be in the same form, either both rate (in units of pounds per net MWh) or both mass (in tons); and

(2) You must set interim step goals that will either on average or cumulatively meet the State's interim period goal, as applicable to a rate-based or mass-based CO_2 emission goal.

(d) Your plan's interim period and final period CO_2 emission goals required to be met pursuant to paragraph (b)(1) or (2) of this section, may be changed in the plan only according to situations listed in paragraphs (d)(1) through (3) of this section. If a situation requires a plan revision, you must follow the procedures in § 60.5785 to submit a plan revision.

(1) If your plan implements CO_2 emission goals, you may submit a plan or plan revision, allowed in § 60.5785, to make corrections to them, subject to EPA's approval, as a result of changes in the inventory of affected EGUs; and

(2) If you elect to require your affected EGUs to meet emission standards to meet mass-based CO_2 emission

goals in your plan, you may elect to incorporate, as a matter of state law, the mass emissions from EGUs that are subject to subpart TTTT of this part that are considered new affected EGUs under subpart TTTT of this part.

(e) If your plan relies upon State measures in addition to or in lieu of emission standards, you must only use the mass-based goals allowed for in paragraph (b)(2) of this section to demonstrate that your affected EGUs are meeting the required emissions performance.

(f) Nothing in this subpart precludes an affected EGU from complying with its emission standard or you from meeting your obligations under the State plan.

§ 60.5860 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet rate-based or mass-based emission standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, each compliance period shall include only "valid operating

hours" in the compliance period, *i.e.*, full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.*, carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU

is equipped with emission controls that produce non-combustion CO_2 (*e.g.*, from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner

or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter

to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) For both rate-based and mass-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation

and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of 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. The owner or operator must use the following procedures to calculate net energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.*, full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\text{TDF}} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

Where:

P_{net} = Net energy output of your affected EGU for each valid operating hour (as defined in 60.5860(a)(2)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(v) of this section in MWh.

$(Pt)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lbs)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6 x 10^9 J/MWh or 3.413 x 10^6 Btu/MWh.

(vi) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section), over the entire compliance period. Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours plus any ERC replacement generation (as shown in § 60.5790(c)), to determine the CO_2 emissions rate (lb/net MWh) for the compliance period.

(vii) For mass-based standards, sum all of the values of P_{net} for all operating hours, over the entire compliance period.

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing 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, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of 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 EGUs and the operating time must be expressed as "stack operating hours" (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing 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), the hourly CO_2 mass emissions and the "stack operating time" (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with § 60.5775 or § 60.5780, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) For mass-based standards, the owner or operator of an affected EGU must determine the CO_2 mass emissions (tons) for the compliance period as follows:

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(3) or (4) of this section, except that a complete data record is required, *i.e.*, CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV shall be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of 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 (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(5)(i)(A) and (B) of this section.

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, as described in paragraphs (b)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(iv) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (c)(2)(iv)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you at the end of each compliance period the information in paragraphs (d)(1) through (5) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each

affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(v) ERC replacement generation (if any), properly justified (see paragraph (c)(5) of this section); and

(vi) The calculated CO_2 mass emission rate for the compliance period (lbs/net MWh).

(3) For mass-based standards, each report must include:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period; and

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period.

(vi) Notwithstanding the requirements in paragraphs (c)(3)(i) through (c)(3)(iii) of this section, if the compliance period is a discrete number of calendar years (*e.g.*, one year, three years), in lieu of reporting the information specified in those paragraphs, the owner or operator may report:

(A) The cumulative annual CO_2 mass emissions (tons) for each year of the compliance period, derived from the electronic emissions report for the fourth calendar quarter of that year, submitted to EPA under § 75.64(a) of this chapter; and

(B) The sum of the cumulative annual CO_2 mass emissions values from paragraph (c)(3)(v)(A) of this section, if the compliance period includes multiple years.

(4) For each affected EGU's compliance period, the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate or cumulative mass in units of the emission standard required in §§ 60.5790(b) through (c) and 60.5855, as applicable.

(5) If the owner or operator of an affected EGU is complying with an emission standard by using ERCs, they must include in the report a list of all unique ERC serial numbers that were retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5800 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(6) If the owner or operator of an affected EGU is complying with an emission standard by using allowances, they must include in the report a list of all unique allowance serial numbers that were retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired and if the allowance was a set-aside allowance the eligible resource identification information sufficient to demonstrate that it meets the requirements of § 60.5815(c) and qualifies to be issued set-aside allowances (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5745(a)(4), if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, the owner or operator must

report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98 subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, the approval conditioned on monitoring and reporting of operations. The Administrator may

also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision, and provide public notice of any proposed action on a petition before the Administrator takes final action.

Recordkeeping and Reporting Requirements

§ 60.5865 What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, State measures, and the status of meeting the plan requirements defined in the plan for each interim step and the interim period. After 2029, States must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emission performance rates or CO_2 emissions goals are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in Part 75 meets the recordkeeping requirement of this section and you are not required to keep records of

information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 10 years, for the interim period, and 5 years, for the final period, from the date the record is used to determine compliance with an emissions standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5870 What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f) of this part, you must report the information in paragraphs (b) through (f) of this section.

(b) You must submit a report covering each interim step within the interim period and each of the final 2-calendar year periods due no later than July 1 of the year following the end of the period. The interim period reporting starts with a report covering interim step 1 due no later than July 1, 2025. The final period reports start with a biennial report covering the first final reporting period (which is due by July 1, 2032), a 2-calendar year average of emissions or cumulative sum of emissions used to determine compliance with the final CO_2 emission performance rate or CO_2 emission goal (as applicable). The report must include the information in paragraphs (b)(1) through (4) of this section.

(1) The report must include the emissions performance achieved by all affected EGUs during the reporting period, consistent with the plan approach according to § 60.5745(a), and identification of

whether each affected EGU is in compliance with its emission standard and whether the collective of all affected EGUs covered by the State are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the plan.

(2) The report must include a comparison of the CO_2 emission performance rate or CO_2 emission goal identified in the State plan for the applicable interim step period versus the actual average, cumulative, or adjusted CO_2 emission performance (as applicable) achieved by all affected EGUs.

(i) For interim step 3, you do not need to include a comparison between the applicable interim step 3 CO_2 emission performance rate or emission goal; you must only submit the average, cumulative or adjusted CO_2 emission performance (as applicable) of your affected EGUs during that period in units of your applicable CO_2 emission performance rate or emission goal.

(3) The report must include all other required information, as specified in your State plan according to § 60.5740(a)(5).

(4) If applicable, the report must include a program review that your State has conducted that addresses all aspects of the administration of the State plan and overall program, including State evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and State issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the approved plan, whether reported annual MWh of generation and savings from qualified ERC resources

are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the State and the conduct of independent verifiers, including the quality of verifier reviews.

(c) If your plan relies upon State measures, in lieu of or in addition to emission standards, then you must submit an annual report to the EPA in addition to the reports required under paragraph (b) of this section for the interim period. In the final period, you must submit biennial reports consistent with those required under paragraph (b) of this section. The annual reports in the interim period must be submitted no later than July 1 following the end of each calendar year starting with 2022. The annual and biennial reports must include the information in paragraphs (c)(1) and (2) of this section for the preceding year or two years, as applicable.

(1) You must include in your report the status of implementation of federally enforceable emission standards (if applicable) and State measures.

(2) You must include information regarding the status of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement must be consistent with the State measures included in the State plan submittal.

(d) If your plan includes the requirement for emission standards on your affected EGUs, then you must submit a notification, if applicable, in the report required under paragraph (b) of this section to the

EPA if your affected EGUs trigger corrective measures as described in § 60.5740(a)(2)(i). If corrective measures are required and were not previously submitted with your state plan, you must follow the requirements in § 60.5785 for revising your plan to implement the corrective measures.

(e) If your plan relies upon State measures, in lieu of or in addition to emission standards, than you must submit a notification as required under paragraphs (e)(1) and (2) of this section.

(1) You must submit a notification in the report required under paragraph (c) of this section to the EPA if at the end of the calendar year your State did not meet a programmatic milestone included in your plan submittal. This notification must detail the implementation of the backstop required in your plan to be fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs in its State that the backstop has been triggered.

(2) You must submit a notification in the report required under paragraph (b) of this section to the EPA if you trigger the backstop as described in § 60.5740(a)(3)(i). This notification must detail the steps that will be taken by you to implement the backstop so that it is fully in place within 18 months of the due date of the report required in paragraph (b) of this section. In addition, the notification must describe the steps taken by the State to inform the affected EGUs that the backstop has been triggered.

(f) You must include in your 2029 report (which is due by July 1, 2030) the calculation of average CO_2

emissions rate, cumulative sum of CO_2 emissions, or adjusted CO_2 emissions rate (as applicable) over the interim period and a comparison of those values to your interim CO_2 emission performance rate or emission goal. The calculated value must be in units consistent with the approach you set in your plan for the interim period.

(g) The notifications listed in paragraphs (g)(1) through (3) of this section are required for the reliability safety valve allowed in § 60.5785(e).

(1) As required under § 60.5785(e), you must submit an initial notification to the appropriate EPA regional office within 48 hours of an unforeseen, emergency situation. The initial notification must:

(i) Include a full description, to the extent that it is known, of the emergency situation that is being addressed;

(ii) Identify the affected EGU or EGUs that are required to run to assure reliability; and

(iii) Specify the modified emission standards at which the identified EGU or EGUs will operate.

(2) Within 7 days of the initial notification in § 60.5870(g)(1), the State must submit a second notification to the appropriate EPA regional office that documents the initial notification. If the State fails to submit this documentation on a timely basis, the EPA will notify the State, which must then notify the affected EGU(s) that they must operate or resume operations under the original approved State plan emission standards. This notification must include the following:

(i) A full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU or EGUs to operate under modified emission standards from those originally required in the State plan including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern;

(ii) A description of how the State is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner;

(iii) An indication of the maximum time that the State anticipates the affected EGU or EGUs will need to operate in a manner inconsistent with its or their obligations under the State's approved plan;

(iv) A written concurrence from the relevant reliability coordinator and/or planning authority confirming the existence of the imminent reliability threat and supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided;

(v) The modified emission standards or levels that the affected EGU or EGU will be operating at for the remainder of the 90-day period if it has changed from the initial notification; and

(vi) Information regarding any system-wide or other analysis of the reliability concern conducted by the relevant planning authority, if any.

(3) At least 7 days before the end of the 90-day reliability safety valve period, the State must notify the appropriate EPA regional office that either:

(i) The reliability concern has been addressed and the affected EGU or EGUs can resume meeting the original emission standards in the State plan approved prior to the short-term modification; or

(ii) There still is a serious, ongoing reliability issue that necessitates the affected EGU or EGUs to emit beyond the amount allowed under the State plan. In this case, the State must provide a notification to the EPA that it will be submitting a State plan revision according to paragraph § 60.5785(a) of this section to address the reliability issue. The notification must provide the date by which a revised State plan will be submitted to EPA and documentation of the ongoing emergency with a written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the affected EGU or EGUs to operate beyond the requirements of the State plan and that there is no other reasonable way of addressing the ongoing reliability emergency but for the affected EGU or EGUs to operate under an alternative emission standard than originally approved under the State plan. After the initial 90-day period, any excess emissions beyond what is authorized in the original approved State plan will count against the State's overall CO_2 emission goal or emission performance rate for affected EGUs.

§ 60.5875 How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States who claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the September 6, 2016, deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the

State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ 60.5880 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, B, and TTTT, of this part.

Adjusted CO_2 Emission Rate Means

(1) For an affected EGU, the reported CO_2 emission rate of an affected EGU, adjusted as described in § 60.5790(c)(1) to reflect any ERCs used by an affected EGU to demonstrate compliance with its CO_2 emission standards; or

(2) For a State (or states in a multi-state plan) calculating a collective CO_2 emission rate achieved under the plan, the actual CO_2 emission rate during a plan reporting period of the affected EGUs subject to the rate specified in the plan, adjusted by the ERCs used for compliance by those EGUs (total CO_2 mass divided by the sum of the total MWh and ERCs).

Affected electric generating unit or *Affected EGU* means a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions in section § 60.5845.

Allowance means an authorization for each specified unit of actual CO_2 emitted from an affected EGU or a facility during a specified period.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an allowance for each specified unit of CO_2 emitted from that affected EGU or facility during a specified period and which limits the total amount of

such allowances for a specified period and allows the transfer of such allowances.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Biomass means biologically based material that is living or dead (*e.g.*, trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in § 60.5855.

Combined cycle unit 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 unit or *CHP unit*, (also known as "cogeneration") means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means a discrete time period for an affected EGU to comply with either an emission standard or State measure.

Demand-side energy efficiency project means an installed piece of equipment or system, a modification of an existing piece of equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Eligible resource means a resource that meets the requirements of § 60.5800(a).

Emission Rate Credit or ERC means a tradable compliance instrument that meets the requirements of § 60.5790(c).

EM&V plan means a plan that meets the requirements of § 60.5830.

ERC tracking system means a system for the issuance, surrender and retirement of ERCs that meets the requirements of § 60.5810.

Final period means the period that begins on January 1, 2030, and continues thereafter. The final period is comprised of final reporting periods, each of which may be no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final reporting period means an increment of plan performance within the final period, with each final reporting period being no longer than two calendar years (with a calendar year beginning on January 1 and ending on December 31), with the first final reporting period in the final period beginning on January 1, 2030, and ending no later than December 31, 2031.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

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.

Independent verifier means a person (including any individual, corporation, partnership, or association) who has the appropriate technical and other qualifications to provide verification reports. The independent verifier must not have, or have had, any direct or indirect financial or other interest in the subject of its verification report or ERCs that could impact their impartiality in performing verification services.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of eight calendar years from January 1, 2022, to December 31, 2029. The interim period is composed three interim steps, interim step 1, interim step 2, and interim step 3.

Interim step means an increment of plan performance within the interim period.

Interim step 1 means the period of three calendar years from January 1, 2022, to December 31, 2024.

Interim step 2 means the period of three calendar years from January 1, 2025, to December 31, 2027.

Interim step 3 means the period of two calendar years from January 1, 2028, to December 31, 2029.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

M&V report means a report that meets the requirements of § 60.5835.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility.

Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

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 allowance export/import means a net transfer of CO_2 allowances during an interim step, the interim period, or a final reporting period which represents the net number of CO_2 allowances (issued by a State) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another State. This net transfer is determined based on compliance account holdings at the end of the plan performance period. Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.*,

steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.*, steam delivered to an industrial process for a heating application).

Programmatic milestone means the implementation of measures necessary for plan progress, including specific dates associated with such implementation. Prior to January 1, 2022, programmatic milestones are applicable to all state plan approaches and measures. Subsequent to January 1, 2022, programmatic milestones are applicable to state measures.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that are adopted, implemented, and enforced as a matter of State law. Such measures are enforceable only per State law, and

are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating

application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix

D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.*, solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

TABLE 1 TO SUBPART UUUU OF PART 60—CO_2 EMISSION PERFORMANCE RATES
[Pounds of CO_2 per net MWh]

Affected EGU	Interim rate	Final rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine....	832	771

TABLE 2 TO SUBPART UUUU OF PART 60—STATEWIDE RATE-BASED CO_2 EMISSION GOALS

[Pounds of CO_2 per net MWh]

State	Interim emission goal	Final emission goal
Alabama	1,157	1,018
Arizona	1,173	1,031
Arkansas	1,304	1,130
California	907	828
Colorado	1,362	1,174
Connecticut	852	786
Delaware	1,023	916
Florida	1,026	919
Georgia	1,198	1,049
Idaho	832	771
Illinois	1,456	1,245
Indiana	1,451	1,242
Iowa	1,505	1,283
Kansas	1,519	1,293
Kentucky	1,509	1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	1,293	1,121
Maine	842	779
Maryland	1,510	1,287
Massachusetts	902	824
Michigan	1,355	1,169
Minnesota	1,414	1,213
Mississippi	1,061	945

State	Interim emission goal	Final emission goal
Missouri	1,490	1,272
Montana	1,534	1,305
Nebraska	1,522	1,296
Nevada	942	855
New Hampshire	947	858
New Jersey	885	812
New Mexico	1,325	1,146
New York	1,025	918
North Carolina	1,311	1,136
North Dakota	1,534	1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

TABLE 3 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 EMISSION GOALS

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240
Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684
Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Wyoming	286,240,416	63,268,824

TABLE 4 TO SUBPART UUUU OF PART 60—STATEWIDE MASS-BASED CO_2 GOALS PLUS NEW SOURCE CO_2 EMISSION COMPLEMENT

[Short tons of CO_2]

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346
Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850
New York	272,940,440	63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	361,531,056	82,001,704
Oregon	72,774,608	17,644,106
Pennsylvania	804,705,296	181,863,274

State	Interim emission goal (2022–2029)	Final emission goals (2 year blocks starting with 2030–2031)
Rhode Island	29,819,360	7,168,032
South Carolina	234,516,064	52,606,510
South Dakota	31,963,696	7,161,036
Tennessee	257,149,584	57,329,988
Texas	1,707,356,792	396,210,498
Utah.....	220,386,616	50,601,386
Virginia.....	240,240,880	55,660,348
Washington	97,691,736	23,127,324
West Virginia	469,488,232	103,714,614
Wisconsin	252,985,576	56,617,764
Wyoming.....	295,724,848	66,945,204

[FR Doc. 2015-22842 Filed 10-22-15; 8:45 am]

BILLING CODE 6560-50-P

Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

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EPA-452/R-19-003
June 2019

Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impact Division
Research Triangle Park, NC

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CHAPTER 2: IMPACTS OF THE REPEAL OF THE CPP

2.1 Introduction

As the EPA explained in the preamble, the repeal of the Clean Power Plan (CPP) and the promulgation of a new set of 111(d) guidelines are two separate actions. Consistent with that position, the EPA is providing a separate analysis of both actions in this RIA. The bulk of the RIA focuses on an analysis of the ACE rule against a baseline that does not include the CPP. This is because the ACE action only occurs after the repeal of the CPP.

This chapter presents EPA's analysis of the CPP repeal. It explains how after reviewing the comments, the EPA ultimately concluded that while deregulatory in nature and important to address the overreach of the CPP, fully considering a number of factors, the most likely result of implementation of the CPP would be no change in emissions and therefore no cost savings or changes in health disbenefits relative to a world without the CPP. This conclusion (i.e., that repeal of the CPP has no effect against a baseline that includes the CPP)—is appropriate for several reasons, consistent with OMB's guidance that the baseline for analysis "should be the best assessment of the way the world would look absent the proposed action."[1] It is the EPA's consideration of the weight of the evidence, taking into account the totality of the available information, as presented below, that leads to the finding and conclusion that there is likely to be no difference between a world where the CPP is

[1] OMB circular A-4, at 15.

implemented and one where it is not. As further explained in this section, the EPA comes to this conclusion not through the use of a single analytical scenario or modeling alone, but rather through the weight of evidence that includes: several IPM scenarios that explore a range of changes to assumptions about implementation of the CPP, consideration of the ongoing evolution and change of the electric sector, and recent commitments by many utilities that include long-term CO_2 reductions across the EGU fleet.

Setting aside the Agency's position that the CPP is an unlawful exercise of authority under section 111(d), the rule would have little or no impact regardless of the outcome of the petitions for judicial review of the CPP. The EPA has conducted several IPM modeling scenarios of CPP that demonstrate there is likely to be little or no difference between a future scenario with the CPP and one without it. To establish this, the EPA conducted updated modeling for three CPP implementation scenarios, and also considered the most up-to-date information about the electric sector that is not yet incorporated into the EPA's modeling. The EPA first modeled the CPP under one of its previous implementation assumptions—i.e., with mass-based compliance beginning in 2022 and no interstate trading, primarily for consistency purposes. This modeling shows the CPP is "non-binding" in more than half of the states even under these conservative assumptions. That is, the CPP does not require additional CO_2 emission reductions beyond the baseline (for many states) and thus does not "bind" affected sources to an emission reduction requirement

in the sense of driving further emission-reducing actions.

However, these implementation assumptions for the CPP no longer reflect reasonable expectations regarding how the CPP hypothetically would be implemented. As explained below, the EPA does not believe implementation of CPP state-level goals would be implemented without interstate trading. Further, due to the judicial stay of the CPP in February of 2016, it is not reasonable to assume CPP implementation would begin in 2022. For these reasons, the EPA has conducted new analysis of the CPP using revised assumptions, with implementation beginning in 2025 and states engaging in interstate trading.[2]

EPA examined two additional CPP scenarios: one with national trading and one with regional trading (and both with delayed implementation of CPP). While the national trading scenario is theoretically possible[3], based on discussions that states were having prior to the stay of CPP, EPA believes that some level of regional trading would have been the most likely outcome of CPP implementation. As is further explained below, there are a number of reasons to believe that these modeling scenarios are overstating future emissions and that given the small differences seen between these modeling scenarios and the no

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[2] The preamble of the CPP final rule discusses multi-state plans and multi-state coordination that would facilitate interstate trading under the CPP (80 Fed Reg 64838–40).

[3] EPA views the development of a national GHG allowance trading market as less likely, due to a number of considerations, such as the regionalized nature of organized electricity markets as well as efforts that were going on at the state level when the rule was stayed.

CPP case, the CPP would ultimately be extremely unlikely to result in emission reductions beyond a business as usual case.

The conclusions that can be drawn from this modeling are supported by the most up-to-date information regarding this sector, including very recent changes not yet incorporated into the EPA's modeling. There have been significant changes in the electric sector since the EPA finalized the CPP in August of 2015 that lead the EPA to different conclusions about the potential impacts of the CPP. These include fundamental shifts in fuel supply, continued advances and cost declines for key power generating technologies, market operation and policy evolution, and end-use demand influences. These changes can be observed using recent historical data trends, current utility operations and planning, and utility announcements and power sector projections.

These trends can also be seen in the evolution of the EPA's modeling of the CPP, even under its prior assumptions. The EPA has modeled the CPP assuming a mass-based implementation with no interstate trading four times, beginning with the final CPP in August of 2015. Key results of these modeling exercises are summarized in the table below. In each of the cases summarized below, the EPA made a conservative assumption by assuming no interstate trading. However, each iterative modeling effort reflected updated information on key inputs such as the cost of new generation technologies, firmly committed coal retirements, state and federal policies, and projected demand (amongst others). While these scenarios represent a less likely current scenario (both because they assume no interstate trading and

because they make no account for the current stay of the Clean Power Plan), they do provide useful information to document progress that has been made at the state level since the CPP was finalized. In particular, EPA believes allowance prices provide a useful measuring stick to assess both the degree of stringency and magnitude of impact of the CPP requirements.

Table 2-1 Select IPM Results for CPP

IPM Modeling Projections of CPP

(Using a Mass-based approach where State-by-State Goals must be met)

Scenario that includes CPP, for the year 2030	Final CPP RIA (v5.15)	Ozone NAAQS Transport NODA (v5.16)	Proposed ACE (v6.17)	Final ACE (IPM 2018)
Average Marginal Cost, all States ($/ton CO_2)	$11	$4	$2	$2
Highest Marginal Cost ($/ton CO_2)	$26	$17	$11	$13
# of States with $0/ton	7	18	30	27
Total Power Sector CO_2 (million short tons)	1,814	1,839	1,737	1,681
% below 2005	32.4%	31.4%	35.3%	37.3%

As can be seen from the results in Table 2-1, if the CPP were to be implemented even with the conservative assumption of no interstate cooperation and ignoring any delay in implementation due to the Supreme Court stay, the impacts of the CPP would be significantly less than the EPA projected in its original CPP analysis. In August of 2015, the EPA projected that only 7 of the 47 states with CPP obligations were already on track to meet those obligations (15%). Now the EPA is projecting that at least 27 states (57%) are on track to meet or exceed their targets. These

reductions are attributable to trends that result in emission reductions regardless of the CPP. Even for states that are not currently projected as on track to meet their goals, those targets have become significantly easier to attain. The marginal cost for achieving a state goal in the state with the highest marginal cost has fallen from $26/ton to $13/ton.[4] More detail on the state by state results can be found in Table 2-4, which shows that in August of 2015, EPA projected that 7 states would have allowance prices of $20 or more. In the modeling using the 2018 IPM, EPA projects that none do (notably, for two of those states Arizona and Utah, EPA is now projecting an allowance price of zero). The table also shows that 29 states had an allowance price of $10 or more. In the IPM 2018 modeling, there are only two. One of those states, Colorado, is home to utilities that have made significant CO_2 reduction commitments that are not fully reflected in the IPM modeling. Further, as presented below, under reasonable revised assumptions of delayed implementation and interstate trading, the CPP is non-binding entirely (in the sense of not requiring any additional CO_2 emission reductions beyond the baseline).

Given these findings, as well as ongoing market trends and numerous recent utility CO_2 reduction announcements, the EPA believes repeal of the CPP under current and reasonably projected market conditions and regulatory implementation is not anticipated to have a meaningful effect on emissions of CO_2 or other pollutants or regulatory compliance

[4] Marginal costs are reported in 2016$ per short ton of CO_2 throughout this chapter.

costs. As a result, this analysis demonstrating no significant difference in a scenario with CPP implementation and one without satisfies any regulatory impact analysis that may be required by statute or executive order for repeal of the CPP.

Section 2.2 provides information pertaining to the changes that have occurred in the electric sector that have led to these projected changes. Section 2.3 explores the impact of alternative trading assumptions and Section 2.4 summarizes key changes that may not be fully incorporated into the EPA's current modeling. Section 2.5 examines several states projected to have emission-reduction shortfalls in the EPA's modeling (i.e., higher baseline emissions than their CPP goals) and provides additional real-world context for interpreting these modeling outputs. Section 2.6 summarizes why these considerations together lead the EPA to conclude that, even if the CPP were upheld, emissions projections would not be noticeably different from a case where the CPP is not implemented. As a result, the cost and benefit impacts of CPP repeal are de minimis. Finally, Section 2.7 presents additional summary information from IPM runs used to support this analysis.

2.2 Market Trends for the Electric Sector Relevant to Consideration of the Impact of the Repeal of the CPP

A critical element of ongoing assessment and evaluation of the power sector are the current trends underway, whereby the sector is experiencing a greater degree of change in generation mix than it has historically. While many of these trends are incorporated into the EPA's updated modeling

analysis and result in lower emissions projections absent any CO_2 regulatory considerations for power plants at the federal level, there is significant evidence that these trends are occuring at a faster rate than most electric sector modeling has been projecting (see, for instance, the discussion of the evolution of the levelized cost of electricity by generation type below). The anticipation of a lower emissions future in the baseline is due to large-scale market trends that are multi-faceted in nature. These include fundamental shifts in fuel supply, continued advances and cost declines for key power generating technologies, market operation and policy evolution, and end-use demand influences. These changes can be observed using recent historical data trends, current utility operations and planning, and utility announcements and power sector projections for the future that go through 2030, and beyond.

Ultimately, these trends are anticipated to result in the continued decline of coal-fired generation and capacity and significant increases in natural gas-fired generation and capacity. At the same time, renewable energy has continued to be the fastest growing form of new utility-scale electric-generating capacity and is expected to account for a significant portion of all new capacity into the future. In addition, electricity demand is only slowly rising. This places additional economic pressures on older and less-efficient technologies (like many existing coal-fired plants), which struggle to compete with the newer capacity coming online that generally has lower operating

costs. These findings have been summarized in a recent report from DOE:[5]

- "The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation."
- "Another factor contributing to the retirement of power plants is low growth in electricity demand."
- "Dispatch of variable renewable energy (VRE) has negatively impacted the economics of baseload plants."

The changes in the generation mix away from coal and toward lower- and zero-emitting generation are significantly more pronounced than the EPA and other analysts projected when the EPA finalized the CPP. These trends mean that the states would be able to meet their goals and, ultimately, the sources to meet their emission standards, with less planning burden, at significantly less cost, and with less impact on the sector than the EPA previously estimated when it finalized the CPP.

2.2.1 Recent Data Trends

2.2.1.1 Age of the Coal Fleet & Retirements

The current fleet of coal-fired power plants was mostly built prior to 1990,[6] with an average age of 39 years. Nearly all of the utility-scale power plants in

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[5] U.S. Department of Energy. (2017). Staff Report to the Secretary on Electricity Markets and Reliability. Retrieved from https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report20on%20Electricity%20Markets%20and%20Reliability_0.pdf

[6] EIA, Today in Energy (April 17, 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=30812.

the U.S. that were retired from 2008 through 2017 were fueled by fossil fuels, and coal-fired power plants accounted for the highest percentage.[7] The average age of coal-fired power plants that have retired since 2008 is 52 years. Older power plants tend to become uneconomic over time as they become more costly to maintain and operate, and as newer and more efficient alternative generating technologies are built. As a result, coal's share of total U.S. electricity generation has been declining for over a decade, while generation from natural gas and renewables has increased significantly. The reduction in coal demand from power plants has also resulted in declining coal consumption, with expected total U.S. coal consumption in 2018 of 691 million short tons (a 4% decline from 2017 and the lowest level since 1979).[8]

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[7] EIA, Today in Energy (December 19, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37814.

[8] EIA, Today in Energy (December 28, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37817.

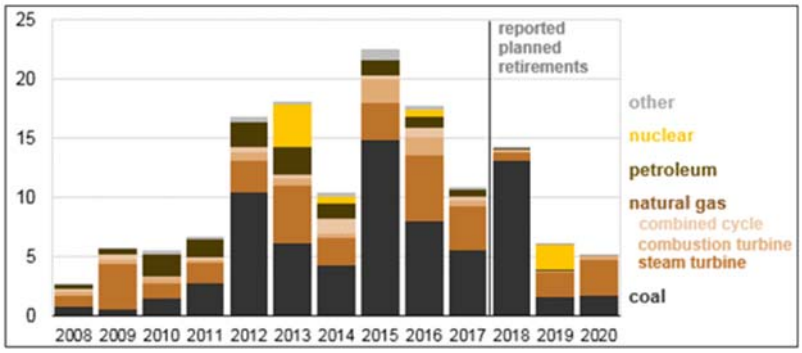

Figure 2-1 U.S. Utility-scale Electric Generating Capacity Retirements (2008–2020), Gigawatts

Source: EIA, Today in Energy (December 19, 2018)

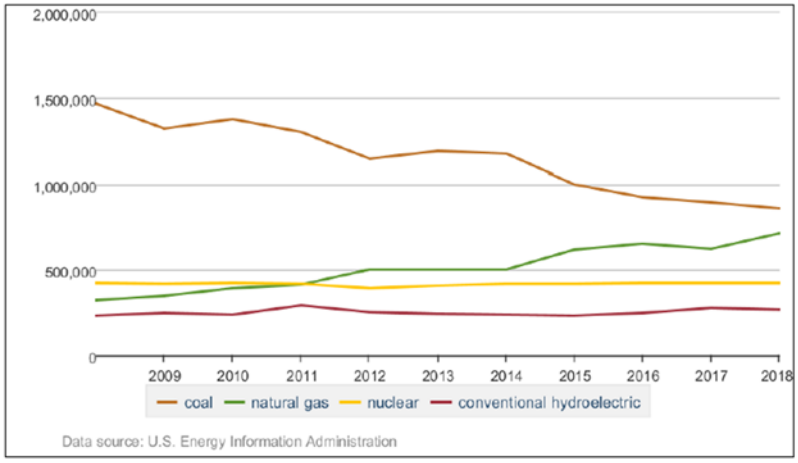

Figure 2-2 Net Generation, United States, Electric Utility, Annual (thousand megawatthours)

Source: EIA Electricity Data Browser

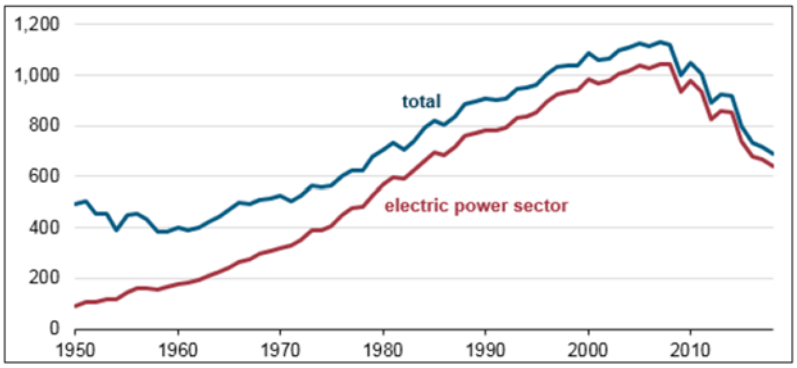

Figure 2-3 U.S. Coal Consumption (1950–2018) (million short tons)

Source: EIA[9]

2.2.1.2 Natural Gas Supply and Price Trends

Technological advances in the natural gas industry have led to an abundance of natural gas supply, resulting in a highly competitive (low price) fuel supply that is increasingly being relied upon by the power sector, particularly as new pipeline infrastructure continues to be built across the country. U.S. natural gas production hit a new record in 2018, with both the highest volume and largest annual increase in production on record.[10]

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[9] EIA, Today in Energy (December 28, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37817.

[10] EIA, Today in Energy (March 14, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=38692.

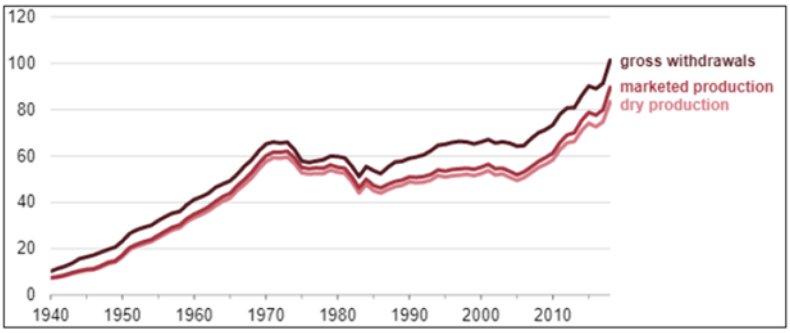

Figure 2-4 U.S. Annual Natural Gas Production (1940–2018) (billion cubic feet per day)

Source: EIA[11]

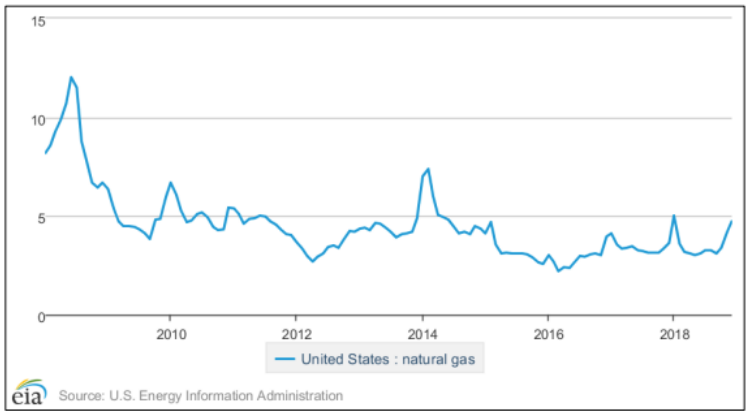

Figure 2-5 Average Cost of Fossil Fuels for Electricity Generation (per Btu) for All Sectors, Monthly (dollars per million Btu)

Source: EIA, Natural Gas Monthly Report

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[11] EIA, Today in Energy (March 14, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=38692.

2.2.1.1 Renewable Energy

The costs of renewable generation have fallen significantly due to technological advances, improvements in performance, and local, state, and federal incentives such as the recent extension of federal tax credits.[12] According to Lazard, a financial advisory and asset management firm, current unsubsidized levelized cost of electricity for alternative energy technologies is lower than the operating cost alone of conventional technologies like coal or nuclear, which is expected to lead to ongoing and significant deployment of renewable energy. Levelized cost of electricity is only one metric used to compare the cost of different generating technologies. It contains a number of uncertainties including utilization and regional factors.[13] While this chart illustrates general trends, unit specific build decisions will incorporate many other variables.

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[12] Lazard, Levelized Cost of Energy 2017. https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

[13] U.S. Energy Information Administration, 2019. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

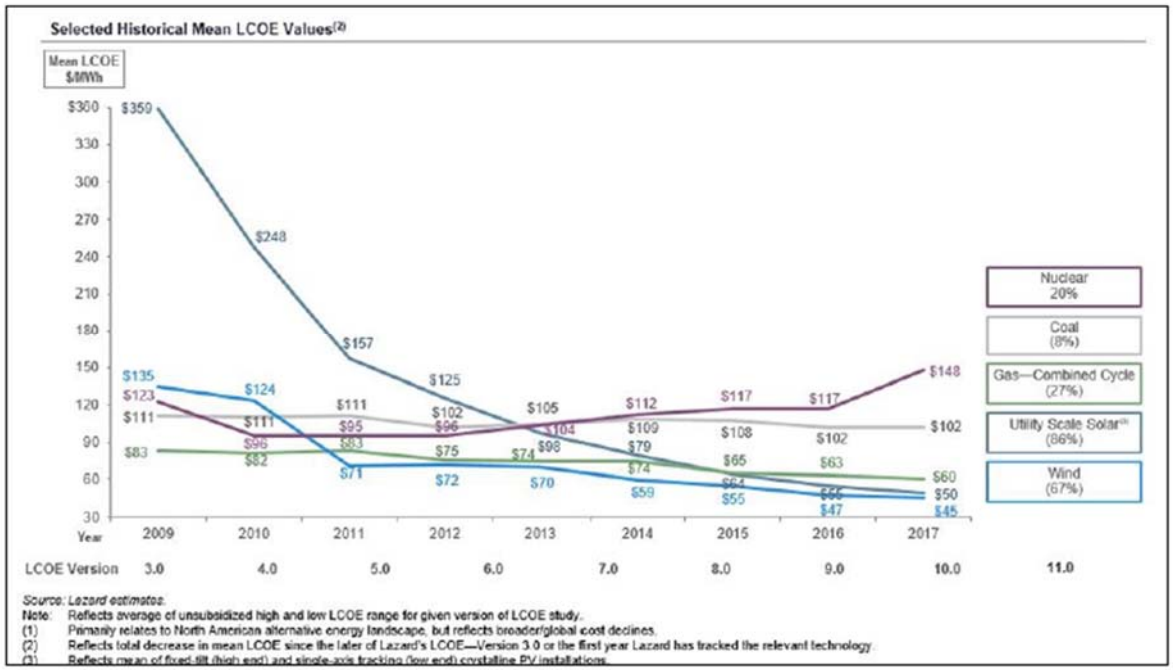

Figure 2-6 Selected Historical Mean LCOE Values

Source: Lazard, Levelized Cost of Energy 2017

As a result, the existing coal fleet continues to experience economic pressures. The cost trends, along with other developments, have served as the main drivers for pronounced, ongoing changes in the nation's generation mix that have resulted in lower CO_2 emissions.

2.2.2 Utility Climate and Clean Energy Announcements and Commitments

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and recently announced plans of many power plants across the industry—spanning all types of companies in all locations. Furthermore, many utilities have made commitments to move toward cleaner energy. Throughout the country, utilities have included commitments towards cleaner energy in public releases, planning documents, and integrated resource plans (IRPs). For strategic business reasons, most major utilities plan to increase their renewable energy holdings and continue reducing CO_2 emissions, regardless of what federal regulatory requirements might exist. The Edison Electric Institute (EEI) has confirmed these developments: "While the CPP was stayed by the Supreme Court in 2016, the power sector will have complied with the final 2030 goals of the rule—in terms of gross emissions reductions—before the 2022 start date included in that program."[14] This trend is not unique to the largest owner-operators of coal-fired generation; smaller utilities, public power,

[14] EEI Comments on ACE, at 4 (Oct. 31, 2018).

cooperatives, and municipal entities are also contributing to these changes.

There are many recent examples of electric utilities who have publicly announced near- and long-term emission reduction commitments. Here are but a few examples of emission reduction targets of 80%+ (relative to 2005 levels) that have recently been announced by major utilities:

- Xcel Energy (with power plants that operate in MN, CO, MI, MN, NM, ND, SD, TX, and WI): 50% reduction in CO_2 emissions by 2022 (and 100%) and carbon-free by 2050)[15] This includes a commitment to close all coal plants in Minnesota by 2030[16]
- DTE Energy (MI): 30% reduction in CO_2 by the early 2020s, 50% by 2030, 80% by 2040 and 80%+ by 2050[17] (these goals were recently accelerated)[18]
- Ameren Energy (MO): 35% by 2030, 50% by 2040, and 80% by 2050[19]

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[15] Xcel Energy, Integrated Resource Plan(s), *available at* https://www.xcelenergy.com/environment/carbon_reduction_plan.

[16] https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_to_end_all_coal_use_in_the_upper_midwest

[17] DTE Energy, IRP (under public review), *available at* http://newsroom.dteenergy.com/index.php?s=26817&item=137217#sthash.6EU4Hz0y.mSpR9OKB.dpbs.

[18] http://newsroom.dteenergy.com/2019-03-28-DTE-Energy-accelerates-carbon-reduction-goal-a-full-decade-will-reduce-emissions-80-percent-by-2040#sthash.UY40RqAg.dpbs

[19] Ameren Missouri, Integrated Resource Plan, *available at* https://www.ameren.com/missouri/company/environment-and-sustainability/integrated-resource-plan.

- Consumers Energy (MI): 80% by 2040 and transition to zero coal use[20]
- MidAmerican Energy (IA): 100% RE goal[21]
- NIPSCO (IN): 90% reduction by 2028, and phase-out all coal[22]
- First Energy (FE): 90% reduction by 2045[23]
- American Electric Power (AEP): 60% reduction by 2030 and 80% by 2050[24] (from year 2000 levels)
- Alliant Energy: 40% reduction by 2030 and 80% by 2050[25] and phase-out all coal
- WEC Energy Group: 40% reduction by 2030 and 80% by 2050[26]

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[20] Consumers Energy IRP, *available at* https://www.consumersenergy.com/community/sustainability/energy-mix/renewables/integrated-resource-plan.

[21] MidAmerica Energy, Our 100% Renewable Vision, https://www.midamericanenergy.com/our-renewable-energy-vision.aspx.

[22] NIPSCO IRP, available at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15

[23] First Energy, available at https://firstenergycorp.com/content/fecorp/environmental/initiatives.html

[24] AEP, available at https://www.aep.com/news/releases/read/1503/AEPs-Clean-Energy-Strategy-Will-Achieve-Significant-Future-Carbon-Dioxide-Reductions

[25] Alliant Energy, available at https://sustainability.alliantenergy.com/energy-climate/

[26] WEC Energy, available at https://www.wecenergygroup.com/csr/climate-report.pdf

While the EPA does not account for statements from utilities regarding their future plans in the economic modeling that are not technically legally enforceable, the number and scale of these announcements is significant on a systemic level. These statements are also part of long-term planning processes that cannot be easily revoked, since there is considerable stakeholder involvement, including by regulators, in the planning process. The direction in which these companies have publicly stated they are moving is consistent across the sector and undergirded by market fundamentals lending economic credibility to these commitments and confidence that there is a high likelihood that most will be implemented. Thus, these announcements are sufficiently consequential to be considered in identifying the appropriate economic baseline.

2.2.3 Recent Emissions Trends & Future Projections

The aforementioned market trends and business decisions have resulted in declining power sector CO_2 emissions since 2005, which are also expected to produce a notably lower emissions future as higher emitting sources of electricity are replaced with lower-emitting sources. In 2012, aggregate CO_2 emissions from sources covered by the CPP were 19 percent below 2005 levels. When the EPA finalized the CPP in August 2015, the Agency projected that, by 2030, the power sector would reduce its CO_2 emissions 32 percent below 2005 levels with the CPP. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels 24 percent below 2005 levels, in the aggregate. Even after the CPP was stayed, in 2016, sources were

28 percent below 2005 levels. In both 2017 and 2018 sources were 30 percent below 2005 levels.[27]

The evolution of these overarching power sector trends can be seen in the EIA's Annual Energy Outlook (AEO), which includes energy projections of the future. The AEO includes a CO_2 projection in a baseline scenario, similar to the EPA's baseline projections using IPM, which show how these trends have been absorbed into the AEO over time (see Figure 2-7). Figure 2-7 also demonstrates the extent to which recent power sector modeling has consistently tended to under-estimate the degree of CO_2 projected in the future. If the current trendline in this figure continues, power sector emissions will be well below the original 2022 and 2030 aggregate mass-based goals in the CPP, marked by "Xs" in the graph.

[27] EPA, Air Markets Program Data (affected sources under CPP), *available at* https://ampd.epa.gov/ampd.

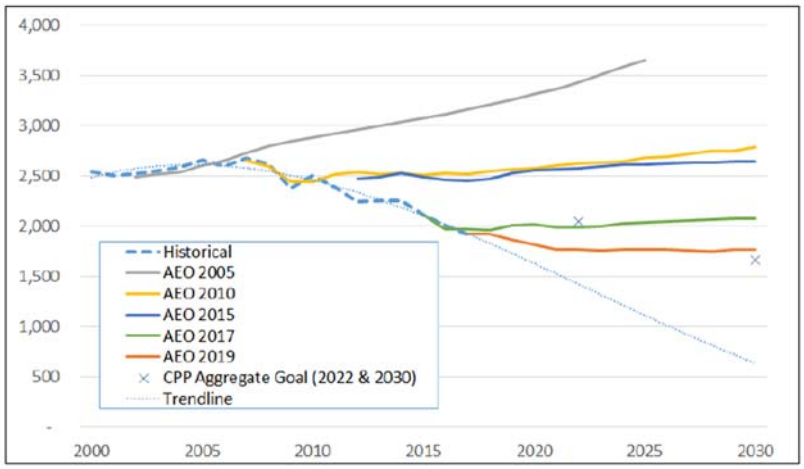

Figure 2-7 Power Sector CO_2 Emissions (million short tons)

Source: EIA AEO, and EPA for CO_2 data (AMPD database).

For example, the AEO estimates from 2005 and 2010 were just prior to the large domestic expansion of gas supplies. Also, while renewable energy was being deployed in that time period, it was on a much smaller scale and at a cost not nearly as competitive as it is today. As such, there was an expectation of continued generation from coal-fired sources for the foreseeable future. Only after 2015 did the AEO begin to more concretely factor these trends into the projections, which can be seen in the notable decline in the CO_2 emissions projection. The most recent AEO, for 2019, shows CO_2 emissions significantly lower than the AEO from four years earlier (2015). As Figure 2-7 demonstrates, each successive AEO projection has suggested that CO_2 emissions would either flatten or decrease from previous iterations of the AEO, and has

been continually revised downward following the trendline of the historical data.

2.3 CPP Stay/Delayed Implementation and Trading Assumptions

The implementation timing of the CPP, and the manner in which it would be implemented, are no longer valid due to changed circumstances since the CPP was finalized in 2015. These changes, in conjunction with the trends discussed above, have further weakened the effect the CPP was previously anticipated to have relative to a no-CPP baseline.

2.3.1 Delayed implementation of the CPP

The Supreme Court issued a stay of the CPP in February of 2016, effectively pausing the rule during judicial review. The litigation challenging the CPP has been held in abeyance since 2017, when the EPA announced its intentions to reconsider and potentially repeal the CPP. Given the resulting delay in implementation already to-date, the timing of reduction requirements under the CPP, as it was finalized in 2015, is no longer reasonable to assume, since states and sources have been under no obligation to plan for or to implement the rule. In a hypothetical world where CPP comes back into effect, its deadlines for compliance would likely require adjustment.

Under the original schedule for CPP implementation, state plans were due in September of 2018 at the latest. The first compliance period was scheduled to begin in 2022. Subsequent compliance periods, corresponding with increasingly stringent state goals would have run from 2025–2027, and 2028–2029, with final CPP goals going into effect in 2030. Two-year compliance periods would have run

perpetually from 2030 with no further change in stringency.

The deadline for state plan submittals in 2018 has already passed. Thus, the start of the initial compliance period would unlikely be 2022, as originally promulgated in the CPP, since States have been under no obligation to develop and submit state plans to implement the program since it was stayed. As such, for purposes of this analytical exercise, an appropriate implementation time horizon for CPP would involve adjusting the compliance deadlines, possibly by delaying them for several years.[28] Over three years have passed since the stay was issued, which is a logical starting point when considering a tolling timeframe. Hence, the EPA considers a three-year delayed implementation of CPP as a reasonable starting point when considering a hypothetical implementation of that rule.[29] For purposes of the

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[28] Although not determinative, a similar period of tolling was the result in the Cross-State Air Pollution Rule (CSAPR) litigation, where roughly three years elapsed between the D.C. Circuit Court of Appeals' stay of the rule and its order granting EPA's motion to lift the stay. *See* Order, Document #1518738, *EME Homer City Generation, L.P. v. EPA*, No. 11-1302 (D.C. Cir. issued Oct. 23, 2014); Interim Final Rule, 79 Fed. Reg. 71663 (Dec. 3, 2014); Final Rule, 81 Fed. Reg. 13275 (March 14, 2016). And a similar approach to tolling was taken in lifting the stay of the NO_X SIP Call. Order, *Michigan v. EPA*, No. 98-1497 (D.C. Cir. issued June 22, 2000).

[29] The EPA does not intend for this hypothetical scenario for implementation of the CPP to reflect or imply a binding commitment at this stage to adjust deadlines in this manner for the CPP in the unlikely event that it would be implemented. Such a determination would require a full analysis of all the facts and

EPA's updated modeling in this analysis, we assume that CPP compliance commences in 2025, with final goals going into effect beginning in 2033. This serves to further diminish the effect of the CPP, since the later it is implemented the more likely that market trends will have already resulted in emissions that are lower than the CPP goals. Furthermore, in a mass-based implementation scenario, with emissions already generally below the goals for the first compliance period (starting in 2025), there will be more allowances available to be banked for use in subsequent compliance periods than there otherwise would have been without tolling the deadlines.

To demonstrate the effect of delaying implementation of the CPP, in the maps below, State-level emissions from existing sources are shown in two ways. The first map shows emissions for each state from the baseline projection (i.e. a scenario with no 111(d) CO_2 requirement for existing EGUs) for the year 2030, relative to each state's respective mass-based goal for CPP for 2030 (prior to any consideration of implementation delay for CPP). Positive values indicate that a state's projected baseline CO_2 emissions in the baseline projection are lower than the state-level CPP goal (i.e., the state's emissions in 2030 are below the 2030 goal), while negative values indicate that a state's emissions in the baseline in 2030 are higher than the goal. It should be noted that these values from the baseline are conservative in light of additional long-term changes in the generation mix (e.g., coal plant retirements and utility

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circumstances at the time such a determination would need to be made.

announcements) that have been announced or included in IRPs since this modeling was performed, as discussed in Section 2.2.3 above. In other words, the shortfalls in emission reductions apparently facing some states are in all likelihood smaller than the numbers below suggest, and again, these figures do not factor in any delay in CPP implementation.

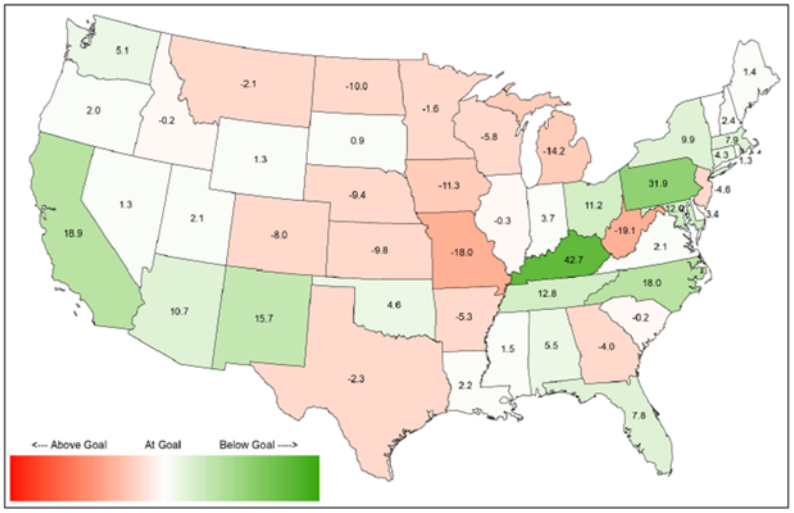

Figure 2-8 State-Level CO_2 Short Tons Emissions Comparison: Baseline Emissions vs. CPP Goals for 2030

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

The second map shows data in a similar manner, but uses baseline emissions from 2025 (instead of 2030) and compares the annual CPP goals for the interim compliance period beginning in year 2022. This comparison is intended to show how a three-year delayed implementation of CPP would appear, relative to the baseline projection in the initial year of the program. This comparison shows even more states

with emissions in the baseline below the CPP goals, and fewer states above the goal (as well as the potential number of allowances that are available for compliance in later years). Collectively, all states taken together are considerably below the goals.

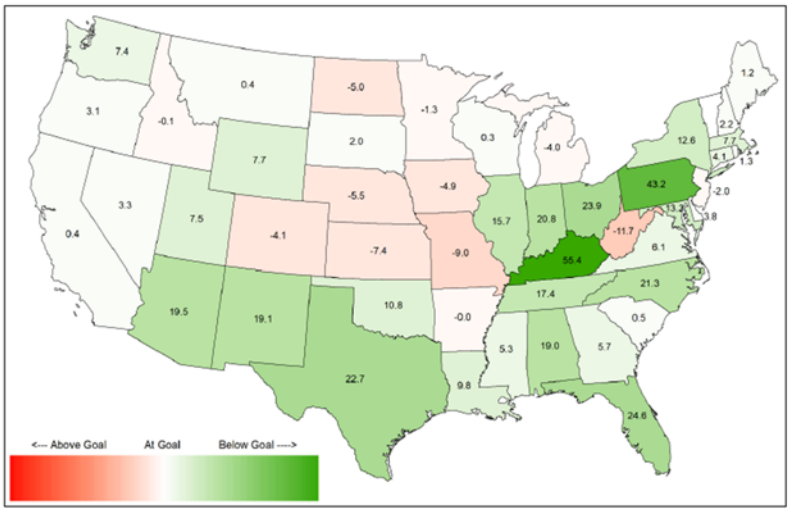

Figure 2-9 State-Level CO_2 Short Tons Emissions Comparison: Baseline Emissions in 2025 vs. CPP Goals for 2022

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

2.3.2 Interstate Trading under the CPP

The CPP provided significant flexibility to States to meet their goals and allowed for multiple compliance pathways for implementing the rule. In particular, interstate mass-based trading was of interest to many states and sources. To facilitate efficient and flexible implementation of the CPP, the EPA released draft Model Trading Rules language in 2016 to assist States as they considered possible compliance pathways.

Emissions trading systems allow for compliance with an overall emissions limit or goal by allocating or auctioning emissions allowances (equal to the overall budget or goal) to emitting sources. Sources must surrender allowances equal to their emissions for that period, thus ensuring that total emissions are no more than the goal expressed as an emissions budget. This system can be implemented at the State level, i.e., without interstate trading, which was represented in the RIA for the final CPP (2015) and subsequent representations of the CPP (2018 ACE Proposed Rule RIA, 2017 CPP repeal RIA and in this Chapter). The assumed implementation of trading at the state-level in the 2015 final CPP RIA was determined to be most appropriate to demonstrate that each state could meet the goals cost-effectively, even without the assumption of broader trading.[30]

The EPA did not analyze interstate trading scenarios at the time it promulgated the CPP, even though the EPA encouraged states to join multi-state plans to increase compliance flexibility. This increased compliance flexibility may lead to lower CO_2 reductions. Applying Circular A-4's guidance that the baseline used in an analysis "should be the best assessment of the way that the world would look absent the proposed action," and because the analysis is no longer being used to make a regulatory decision that could be impacted by consideration of the CPP on individual states, the EPA believes it is appropriate to revisit this approach and assess interstate trading scenarios under the CPP.

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[30] See CPP Final Rule RIA (2015), Chapter 3 for more detail.

There is a significant history of states using interstate trading when such flexibility is allowed (e.g., such opportunities were generally welcomed by states or implemented by them directly in the NOx SIP Call, CAIR, CSAPR and WRAP). There was significant interest amongst a broad and diverse set of stakeholders during the CPP rulemaking who advocated for allowing such implementation flexibility. Such a scenario would still be as reasonable to assume as no interstate trading, and in fact represents a more likely CPP implementation scenario.

Stakeholders and commenters to the EPA have consistently sought compliance flexibility through averaging or trading programs, which the CPP explicitly allowed. Many industry and state commenters on ACE again sought for the EPA to allow broad-based trading options as a flexible means of implementation of a section 111(d) program for the power sector.[31]

The EPA has now modeled and analyzed a new CPP scenario with IPM to help shed light on a potential interstate-trading compliance scenario (coupled with a three-year delay in implementation). Another possible implementation of CPP is sub-national, regional trading. To shed light on possible quantitative effects of these alternatives, the EPA has conducted additional modeling, as described below. As noted elsewhere in this chapter, the EPA has also modeled

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[31] *See, e.g.*, EEI Comments on ACE, at 22 (Oct. 31, 2018); UARG Comments on ACE, at 73–75 (Oct. 31, 2018); Texas CEQ Comments on ACE, at 8 (Oct. 31, 2018); Pennsylvania DEP Comments on ACE, at 8 (Oct. 31, 2018).

the CPP again for purposes of the final ACE rule, with no interstate trading and without any consideration of delayed implementation of CPP in order to provide the public with the ability to understand the analysis in a manner consistent with previous CPP modeling.

2.3.2.1 National Trading

The EPA has looked at the impacts of interstate trading in two ways. First the agency has done new CPP modeling essentially assuming nation-wide trading combined with a three-year implementation delay.[32] Second, the agency modeled regional trading and used information from state-level goals and baseline modeling to explore the impacts of regional trading.

The nation-wide trading scenario allows for greater flexibility across sources and States (i.e., interstate trading) and assumes delayed implementation timeframes as described previously (i.e., compliance beginning in 2025 and final goals taking effect in 2033). In this scenario, sources must collectively comply with a national-level mass-based CPP emission target. The CPP scenarios included in this chapter focus on mass-based implementation due to the relative ease of modeling mass (vs. rate) in the model. In addition, the rate-based and mass-based forms of implementation of the CPP goals were included to provide flexibility and specifically designed

[32] California and the states that comprise the Regional Greenhouse Gas Initiative were excluded from the national CPP trading scenario; the state requirements from those existing programs were kept in place, and the CPP goals for CA and RGGI were met independently without trading (CPP goals were non-binding).

to produce equivalent levels of stringency. All of the numeric values, data, and formulas used for establishing goals under CPP were developed with a consistent framework.

As the more detailed results in section 2.7 show, this scenario results in almost no impact from the CPP. A CPP scenario that allows for broader trading, when implemented in IPM, shows that the CPP has no impact because business-as-usual industry trends result in emission levels at the national scale that are already within the collective state budgets of the CPP under this form of implementation. While there are very small changes in costs (less than $5 million nationwide in any given year), there are no changes in CO_2 emissions. In other words, when modeled, this scenario produces essentially the same outcomes as the baseline scenario.[33] This supports the conclusion that CPP would likely have little or no impact.

2.3.2.2 Regional Trading

The EPA has also modeled an IPM scenario with regional (i.e., sub-national) trading using six smaller hypothetical trading regions. Based on discussions that states were having prior to the stay of CPP, EPA believes that some level of regional trading would have been the most likely outcome of CPP implementation. The regions that the EPA examined are roughly based upon a combination of the North American Electric Reliability Corporation regional alignment for the U.S. and Regional Transmission Organizations

[33] For more detail on these scenarios, see Addendum.

(RTO)/Independent System Operators (ISO) regions.[34] NERC is tasked with ensuring the reliability of the North American bulk power system, while RTO/ISO boundaries help facilitate organized wholesale electricity markets (see Figures 2-10 and 2-11).

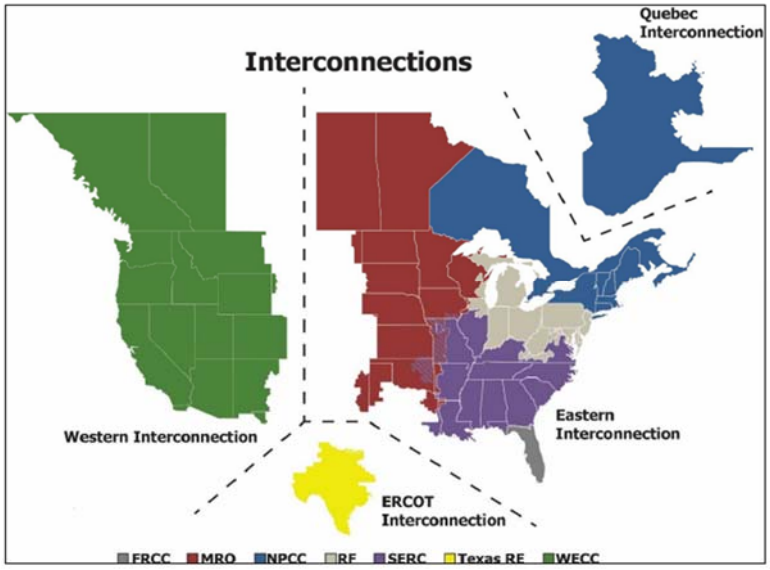

Figure 2-10 NERC Interconnections

Source: North American Electric Reliability Corporation

[34] https://www.nerc.com/AboutNERC/keyplayers/pages/default.aspx and https://www.ferc.gov/industries/electric/indus-act/rto.asp

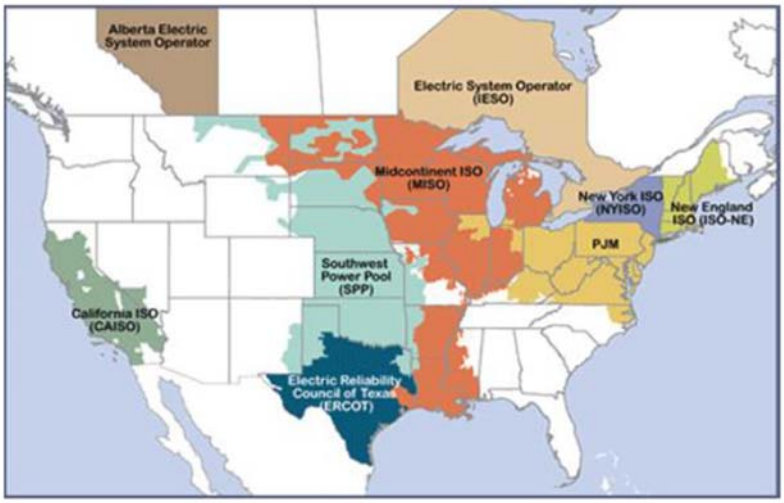

Figure 2-11 RTO/ISO Regions

Source: Federal Energy Regulatory Commission

Groupings of states were then determined based upon the rough boundaries of electricity markets (i.e., NERC and RTO/ISO regions) and state borders, which do not always conform. All states are assumed to join a regional trading grouping to take advantage of greater compliance flexibility, even when it fully encompasses an RTO/ISO or NERC region (i.e., ERCOT and FRCC), unless there was an existing GHG regulatory structure already in place[35] (i.e., California). Furthermore, some states were grouped into trading regions that extend over multiple RTO/ISO or NERC regions, in particular where power markets are not coterminous with state borders (e.g., Central and Midwest states). The resulting six regions, as shown in the map below, are used as the basis for an illustrative CPP scenario with regional

[35] States in RGGI were grouped into a single region for this same reason.

trading. This scenario also includes delayed implementation, as previously discussed.

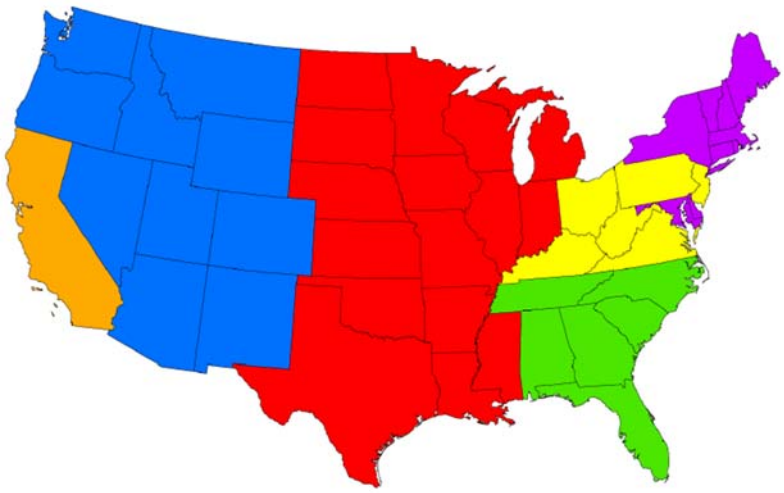

Figure 2-12 CPP Trading Regions: PJM (yellow), Southeast (green), Northeast/RGGI (purple), Midwest/Central (red), West (blue), and California (orange)

This scenario yields very small impacts, and the collective regional CPP goals require CO_2 emission reductions beyond the baseline for only one region (the Midwest/Central region). This hypothetical regional trading scenario would result in compliance with the CPP goals with no additional effort, except for one region. In addition, the CPP is only minimally binding in that region, with a marginal cost of less than $1/ton of CO_2. The marginal cost for all other regions is zero. Table 2-2 presents national CO_2 emissions changes and Table 2-3 presents compliance costs, which is the increase in system-wide generation costs, for the CPP with Regional Trading and Tolling relative to a

baseline with no 111(d) requirement for existing EGUs.[36]

In addition to the regions chosen for this illustrative scenario, there are a variety of alternative regional trading groupings that would result in compliance with the CPP targets with little or no additional effort, if modeled. Further, even if some regions faced a shortfall, it is reasonable to anticipate that utilities in those regions could easily take steps to avoid any meaningful impact of a CPP emissions budget. Any administrative boundaries for the hypothetical trading groups don't constrain the flow of electricity. Generation will, in part, shift to where the mass-based goals are already below the CPP budget in a business as usual, and therefore existing fossil generation will increase in other regions in response to emission reductions in regions with a shortfall.

Table 2-2 Projected CO_2 Electric Sector Emission Impacts, Relative to Baseline

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions Change (MM Short Tons)			CO_2 Emissions Change Percent Change		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Baseline	1,774	1,743	1,719						
CPP with Regional Trading and Tolling	1,767	1,733	1,709	-8	-10	-10	-0.4%	-0.6%	-0.6%

Table 2-3 Annualized Compliance Costs, Relative to Baseline (millions of 2016$)

	2025	2030	2035
CPP with Regional Trading and Tolling	-$32	$27	$139

Additional information is presented below for the Midwest/Central region in order to provide more context, since it is the only binding region from the Regional Trading and Tolling scenario. Figure 2-13 presents the historical CO_2 emissions from affected

[36] These costs do not include costs for monitoring, reporting, and recordkeeping.

sources in the Midwest/Central region, and compares regional CO_2 emissions projections from the previous baseline projection (used in 2015 when CPP was finalized) to the current baseline from this Final ACE rule. This figure also shows the regional CPP goals for the Midwest/Central Region that are reflected in the Regional Trading scenario, although the figure does not show the goals being tolled (3 years). First, the figure demonstrates how much lower baseline emissions are now projected to be for this region than they were in 2015, due to the ongoing trends and changes in the electric power sector. Second, the data shows that the current baseline emissions projections are very close to the goals, and only a modest amount of additional reductions would be necessary to meet the regional goals (indeed, the projected marginal cost of doing so is less than \$1/ton CO_2). Third, the baseline projections should be considered in the context of the recent utility and announcements that are not reflected in the baseline, which were mentioned earlier in this chapter. These long-term planning announcements from utilities in this region, if realized, would reduce baseline emissions well below the CPP goals shown in the figure.

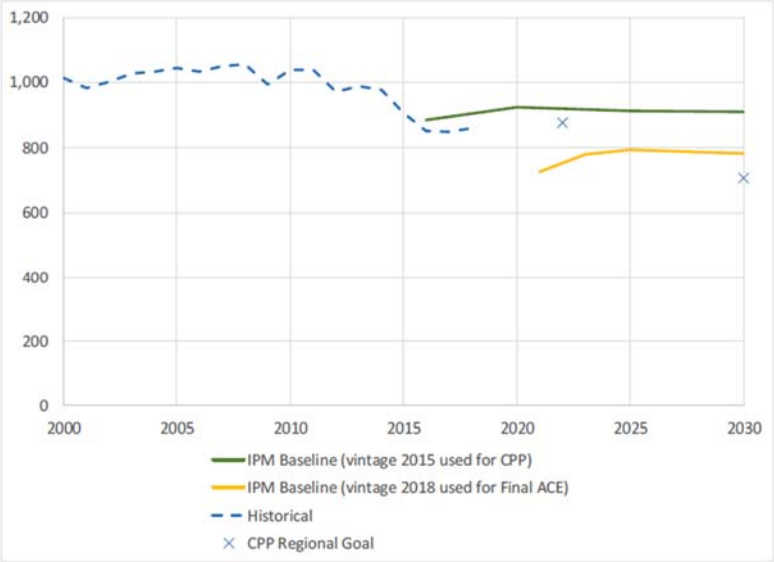

Figure 2-13 CO_2 Emissions for the Midwest/Central Region: Historical and Baseline Projections from IPM (million short tons)

Figure 2-13 also shows that the previous baseline projections for the Midwest/Central region were well above the regional CPP goals, while the updated modeling projects emissions to be well below the CPP goals prior to 2030 for this region. This highlights the dramatic changes underway in the industry. More specifically, the previous modeling projected baseline emissions to be roughly 4 percent above the 2022 CPP goal, while the updated modeling projects emissions in this region to be 11 percent below the 2022 CPP goal. In 2030, affected sources are projected to further reduce CO_2 emissions significantly in the updated modeling, making 63 percent of the reduction merely under baseline conditions (comparing the deficit in 2030 from previous projections to the remaining deficit

in the current projections). It is important to note that the baseline does not necessarily include all the numerous commitments that major utilities have announced and are planning in this particular geographic region (also discussed earlier in this chapter). These activities are partially quantified below, for additional context.

Several large investor-owned electric utilities have made long-term decarbonization commitments across their respective generating fleets in the Midwest/Central region, and have also recently accelerated these plans due to continually evolving market dynamics. Some of these commitments are not included in the projected baseline, but it is possible to estimate the emissions implications attributable to these kinds of commitments in a simple manner (because banking is not accounted for in this static analysis looking solely at the impact of the retirements in a single year, the true impact may be understated since some of these newly announced retirements occur before 2030, they allow for additional banking of allowances). EPA's current modeling assumes operation of these units post 2030, such that removal of those units based on utility plans not only reduces the emissions shortfall, but also reduces the demand for allowances. The subsequent data focuses on utilities that have announced longer-term goals with specificity, with regards to particular power plants that will be removed from service by 2030, and is only a partial list. In the recent reference case, some of these units are projected to emit roughly 31 million tons of CO_2 in 2030 (these estimates are not incorporated into the modeled emissions projections

shown in Table 2-2).[37] This accounts for over 40 percent of the difference between the baseline emissions in 2030 compared to the CPP goals for the Midwest/Central region (the difference between the "X" and the yellow line on Figure 2-13). These particular CO_2 emission reduction estimates that are not in the baseline, along with the other non-quantified reductions that are anticipated, lead EPA to believe that CPP would be non-binding in the Midwest/Central region. Removing these units from service will result in reductions of criteria pollutants and toxic emissions, in addition to the CO_2 emissions reductions that are planned. It is also important to note that the CPP scenario with regional trading and tolling resulted in a projected marginal cost for the Midwest/Central region of only 75 cents in 2030, while the projected marginal cost in all other regions was zero.

This analysis is only partial and does not include a quantitative assessment of other power plants that are owned by utilities with longer-term climate commitments because they have not clearly indicated which power plants will be retired. Also, many of the utility commitments begin prior to 2030 but also include additional significant milestones for 2030, 2040 and 2050. The non-modeled CO_2 reduction commitments in this region, along with the marginal

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[37] IPM Reference Case parsed file for 2030, CO_2 emissions for the following operating power plants: Allen S. King, Belle River, Dan E Karn, JH Campbell, Michigan City, RM Schahfer, and Sherburne County. These units were chosen due to the specificity of plans laid out by their owners, and is not meant to be a comprehensive reflection of all units that might be part of long term climate commitments.

cost of 75 cents from the CPP Regional Trading and Tolling scenario, suggests that the baseline emissions will be lower than the CPP goal for this region.

2.4 Modeling Inputs and Key Areas of Uncertainty

The EPA conducts power sector analysis using IPM, a sophisticated modeling tool with detailed representation of the electric power system. This tool undergoes continual updates and enhancements to best represent the electric power system and is similar to the AEO, in that it provides baseline projections that help guide and shape regulatory efforts. As previously discussed, there have been notable fuel, technology, and other system changes that have led to revised projections of CO_2, which are incorporated into the EPA's current analysis of CPP and Final ACE and inform the EPA's choice of baseline. However, given the pace of change, key uncertainties are identified and discussed below.

2.4.1 Routine Baseline Updates and Model Considerations

The EPA routinely updates its analytics and modeling platforms in order to provide the most current framework in which to evaluate its actions. Over the past few years, there have been changes to the market economics for power plants that involve a myriad of changes that have been incorporated to best reflect the behaviors and the relative economics of power plant operators. For example:

- Routine EGU inventory updates:
    - New Electric Capacity: Inclusion of recent builds and deployment of new capacity across the country, which consists mostly of

renewable energy (wind and solar) and natural gas (simple and combined cycle) due to low-cost natural gas supply

- Retirements of Existing Capacity: Retirement of existing capacity that has been removed from service due to economic and regulatory considerations (mostly aging coal capacity and some nuclear capacity)

- Electric Demand: Changes to expected electric demand levels, whereby overall growth is expected to be very small for the foreseeable future
- Fuels: Robust and cost-effective supplies of natural gas with additional pipeline capacity, particularly in the Eastern U.S.
- New or Amended State Laws or Regulations: Examples include updated climate or energy programs, energy storage mandates, new or revised RPS standards, consent decrees, and other regulatory requirements for certain power plants at the State level
- Changes to Federal Law: Examples include changes to corporate income taxes and extensions to renewable energy tax credits found in the December 2017 Tax Reform Bill

These updates and changes are reflected in the EPA's current modeling framework using IPM (see Chapter 3 of this RIA for more detail).

While the EPA makes every effort to incorporate the most up-to-date information into its modeling and analysis, such modeling may overstate emissions projections and costs of emission reductions whenever

there are important and unanticipated developments in clean energy policy and technology not incorporated in previous analysis. Several examples illustrate why the pace of change in the power sector is likely to be greater than what the modeling produces:

- Legislative changes at the national and state levels. These include: 1) Changes to the 45Q tax credit to encourage more carbon capture and storage, 2) State legislative efforts in New Jersey to join RGGI, and 3) Increased renewable and clean energy mandates in states like New Mexico.[38]
- The EPA does not include in its modeling commitments made as part of IRPs that States and electric utilities develop for long-term planning, since they are not legally binding documents and can be changed and amended over time (some specific IRPs were mentioned above). However, these documents often undergo significant public review and stakeholder engagement, and utilities typically follow through with such plans unless there are unusual circumstances.
- Models do not reflect the future perfectly, and there may be greater and/or faster technology evolution and change than assumed in this modeling as many nascent technologies continue to develop. For example, energy

[38] New Mexico recently passed legislation that will double renewable energy use in the state by 2025, require 50% renewable energy by 2030 and 100 percent carbon free electricity generation by 2045 (New Mexico SB 489, available at https://www.nmlegis.gov).

storage (battery technology), advanced gas turbines, distributed energy, and end-use efficiency technologies are emerging and increasingly important areas of policymaking and investment that are likely to have impacts on the turnover of the existing fleet.

- Increased corporate commitments to procure renewable power that may go beyond State renewable standards.
- Potential changes to the cost to operate coal plants, since they have increased ramping up and down more routinely (as a group) due to market conditions, causing increased wear and tear to coal-fired units. This is important both because so many units are now being operated in a more cyclic function and because the coal-fired fleet is continuing to age. The average age of coal-steam EGUs greater than 25 MW is projected to be over 50 years old in 2030, and nearly 30 percent of these units (or almost 20 percent of total capacity) will be over 60 years old.

Other areas of uncertainty include:

- Uncertainty about the compliance pathways states would take if the CPP were eventually upheld and implemented. The EPA's analysis has primarily focused on a mass-based approach for existing sources at the state level with some additional analysis of larger trading regions.
- States also had the flexibility to use state goals that include new sources and to use rate-based trading. Full consideration of these options

would likely show additional states already in compliance with the CPP.

Any of these changes would further ease the CPP compliance burden and further increase the chance that baseline emissions would be further below CPP requirements in most, if not all states, even under conservative implementation assumptions.

2.5 Additional State-level Information

This section presents several perspectives using the EPA analysis to assess the degree of effort needed to meet the CPP goals in various states. State-level data is presented showing state-level emissions, CPP goals, and the cost to meet the CPP state goals. These costs, consistent with the electric sector trends, have decreased over time for the vast majority of states.

First, emissions for each state in the baseline in 2030 are shown in Figure 2-14, along with their mass-based CPP goals. The states are ordered, from left to right, with the greatest emission-reduction shortfall on the far left and the greatest surplus in emission reduction on the far right. This approach does not incorporate any delay in CPP implementation and shows many more states already meeting their goals in the baseline in 2030 than states that are not.

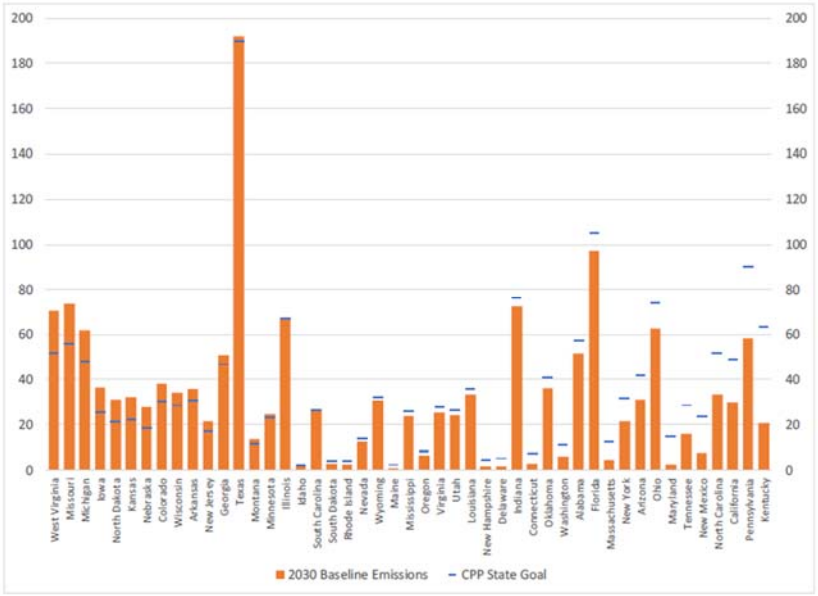

Figure 2-14 State-Level CO_2 Emissions in the EPA Baseline for 2030, Ordered by Largest Shortfall to Greatest Surplus Compared to CPP State Goals (thousand short tons)

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

The degree of shortfall shown in some states is likely overstated. As indicated earlier in this chapter, there are many states with hypothetical shortfalls that also have major investor-owned utilities that have announced clean energy targets well below what is modeled in the baseline, since the EPA does not incorporate these longer-term goals or IRPs into the modeling. These states include Missouri (Ameren), Michigan (DTE Energy and Consumers Energy), Iowa (MidAmerican Energy), Colorado, Minnesota, North Dakota, and Wisconsin (Xcel Energy).

Second, when the CPP is modeled with each state required to meet its goal, the model produces a marginal cost of compliance on a dollar per ton basis for each state. This data is shown below in Table 2-4 for various modeling iterations of CPP over the last few years, including for final ACE, using IPM. A closer look shows the marginal cost to meet the CPP state goal in 2030 has decreased over time for the vast majority of states. This is true even without implementation delay or interstate emissions trading.

In addition, the states with the highest projected marginal costs of complying with their respective state-level CPP goal are also states with electric utilities that have committed to large reductions in carbon emissions by 2030 and beyond. For example, New Jersey has committed to joining the RGGI trading program while the CPP was stayed, and was one of the states with slightly higher marginal cost under the CPP modeling. In Colorado, the state with the highest projected marginal cost of CO_2 reductions, Xcel energy (the largest utility in the state) has committed to an 80% reduction in CO_2 from 2005 levels (Xcel also has generating assets in seven other

states). Additionally, the Platte River Power Authority board of directors has committed to 100% renewable power by 2030 (also operating in Colorado).[39] These commitments would significantly reduce the chance that the CPP would be binding in Colorado. In Missouri, Ameren has committed to a 35% reduction in GHGs by 2030 (relative to 2005) on the way to an 80% reduction in 2050. In Michigan, the states' two largest utilities, Detroit Edison and Consumers Power, have announced ambitious carbon reduction targets.

Table 2-4 2030 Projected Marginal Cost of Mass-Based State-Level CPP Emissions Goals, by State ($/ton CO_2)

For 2030	Final CPP RIA[40] (v5.15)	Ozone NAAQS Transport NODA[41] (v5.16)	Proposed ACE[42] (v6.17)	Final ACE (IPM 2018)
AL	$11	$0	$0	$0
AR	$10	$8	$2	$4
AZ	$20	$5	$0	$0
CA	$15	$0	$0	$0
CO	$21	$11	$11	$13
CT	$1	$7	$0	$0
DE	$0	$0	$0	$0
FL	$12	$3	$0	$0
GA	$15	$2	$1	$0

[39] https://www.prpa.org/news/platte-river-board-passes-energy-policy/.

[40] https://19january2017snapshot.epa.gov/airmarkets/analysis-clean-power-plan_.html.

[41] https://www.epa.gov/airmarkets/epas-power-sector-modeling-support-notice-data-availability-preliminary-interstate-ozone.

[42] https://www.epa.gov/airmarkets/analysis-proposed-ace-rule.

For 2030	Final CPP RIA[40] (v5.15)	Ozone NAAQS Transport NODA[41] (v5.16)	Proposed ACE[42] (v6.17)	Final ACE (IPM 2018)
IA	$15	$6	$3	$6
ID	$24	$1	$2	$2
IL	$10	$5	$1	$0
IN	$17	$4	$0	$0
KS	$20	$10	$4	$5
KY	$2	$2	$0	$0
LA	$2	$0	$0	$0
MA	$0	$4	$0	$0
MD	$4	$0	$0	$0
ME	$2	$9	$0	$0
MI	$5	$0	$5	$5
MN	$17	$4	$2	$3
MO	$16	10	$4	$5
MS	$10	$1	$0	$0
MT	$20	$12	$8	$8
NC	$1	$0	$0	$0
ND	$12	$7	$7	$8
NE	$24	$17	$9	$10
NH	$0	$0	$0	$0
NJ	$5	$9	$7	$7
NM	$13	$0	$0	$0
NV	$14	$3	$0	$0
NY	$0	$0	$0	$0
OH	$14	$5	$0	$0
OK	$14	$0	$0	$0
OR	$0	$0	$0	$0
PA	$6	$0	$0	$0
RI	$0	$3	$0	$0
SC	$6	$0	$0	$1
SD	$14	$3	$1	$1
TN	$15	$3	$0	$0
TX	$13	$8	$0	$0
UT	$26	$10	$1	$0
VA	$4	$0	$0	$0
WA	$0	$0	$0	$0
WI	$16	$8	$2	$3

For 2030	Final CPP RIA[40] (v5.15)	Ozone NAAQS Transport NODA[41] (v5.16)	Proposed ACE[42] (v6.17)	Final ACE (IPM 2018)
WV	$15	$5	$5	$4
WY	$18	$0	$0	$0

The modeling presented in Table 2-4 shows more than half of the states have no marginal cost, indicating that the CPP is likely to have no effect in those states. Several more states show marginal costs of less than $2/ton. Of the remaining states, several have major utilities that have announced long-term plans to support cleaner energy sources and replace existing coal plants with renewable energy. Given this information—which, again, uses the older, more conservative assumptions for CPP implementation—it is clear that there are multiple, flexible compliance pathways that states and utilities could undertake to implement the CPP either for no or virtually no cost.

2.6 Conclusion

Based on the analysis presented above, it is abundantly clear that national existing-source power sector emissions even without the CPP in effect are below the requirements set forth under the CPP, when the goals of the CPP are viewed collectively. This is also true at the regional level. Considering the national emission trends, the regional trends, the flexibility of the CPP, and the delayed time-line of the CPP, it is likely that there would be no difference between a baseline that includes the CPP and one that does not. For all these reasons, the EPA believes that repeal of the CPP under current and reasonably projected market conditions and regulatory

implementation is not anticipated to have a meaningful effect on emissions of CO_2 other pollutants or regulatory compliance costs. As a result, this analysis demonstrating no significant difference in a scenario with CPP implementation and one without also satisfies any regulatory impact analysis that may be required by statute or executive order for repeal of the CPP.

2.7 Addendum: IPM Power Sector Projections

This section presents new results and projections from IPM for four scenarios:[43]

- Baseline: No regulatory requirements for existing EGUs under 111(d).
- CPP with National Trading and Tolling: This includes delaying implementation of CPP by three years and allowing nearly unlimited trading across all states.[44]
- CPP with Regional Trading and Tolling: This includes delaying implementation of CPP by

[43] All of these CPP scenarios capture the ability for EGUs to bank allowances. The detailed IPM results for these scenarios can be found in the ACE docket and on EPA's IPM website at: https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

[44] For purposes of this scenario, California and the Regional Greenhouse Gas Initiative (RGGI) states are excluded from trading with other states for CPP, and must meet their respective legally binding state/regional commitments in addition to the CPP goals (for RGGI, the CPP goals are aggregated and trading is allowed amongst RGGI states). The CPP requirements are non-binding for California and RGGI because the state commitments are more stringent.

three years and allowing trading within six geographic regions shown in Figure 2-12.

- CPP with Limited Trading: This follows the same assumed CPP implementation as presented in the Final CPP and proposed ACE RIAs, where each state had to meet its goal individually and implementation begins in 2022.

The modeling results and projections show that the CPP, accounting for trading and tolling, produces the same outcomes as the baseline scenario. That is, the CPP has no impact under this form of CPP implementation. Below are key results of the IPM scenarios, including CO_2 emissions, systemwide costs, and generation mix.

Note that the modeling for both CPP scenarios reflects an option to improve heat rates between about 2% and 4% at a cost of $110/kW, based on assumptions made in conjunction with the finalization of the CPP in 2015. This option is not available in the baseline modeling. In the CPP with Trading and Tolling scenario, the model projects the deployment of a small amount of HRI-retrofitted capacity (about 150 MW) based on market fundamentals. This small deployment of HRI affects the cost and emissions projections in the modeling, as reflected in the small differences presented below. These differences in projections do not result from the CPP-based CO_2 emissions constraints, for which the model projects a $0 allowance price.

Table 2-5 Emissions Projections

	Baseline	CPP (National Trading and Tolling)	Percent Change from Baseline	CPP (Limited Trading)	Percent Change from Baseline	CPP (Regional Trading and Tolling)	Percent Change from Baseline
CO_2 (million short tons)							
2025	1,774	1,774	0.0%	1,733	-2.3%	1,767	-0.4%
2030	1,743	1,743	0.0%	1,681	-3.5%	1,733	-0.6%
2035	1,719	1,719	0.0%	1,667	-3.0%	1,709	-0.6%
SO_2 (thousand tons)							
2025	912.6	913.2	0.1%	894.8	-1.9%	902.4	-1.1%
2030	885.6	887.2	0.2%	853.6	-3.6%	878.7	-0.8%
2035	817.0	815.6	-0.2%	769.7	-5.8%	807.5	-1.2%
NOx (thousand tons)							
2025	844.4	844.4	0.0%	803.1	-4.9%	838.1	-0.7%
2030	810.1	810.1	0.0%	761.6	-6.0%	803.7	-0.8%
2035	752.8	753.2	0.0%	712.6	-5.3%	747.1	-0.8%
Hg (tons)							
2025	4.7	4.7	0.0%	4.5	-3.4%	4.7	-0.6%
2030	4.5	4.5	0.0%	4.3	-4.5%	4.4	-0.7%
2035	4.0	4.0	0.0%	3.9	-3.4%	4.0	-1.0%

Note: million short tons, thousand short tons, and short tons for CO_2, SO_2/NO_X, and Hg respectively.

Table 2-6 Annual Compliance Costs (Millions 2016$)

	2025	2030	2035
CPP (National Trading and Tolling)	$1.8	$0.2	$5.1
CPP (Limited Trading)	$689.6	$929.0	$517.8
CPP (Regional Trading and Tolling)	-$32.0	$27.2	$138.6

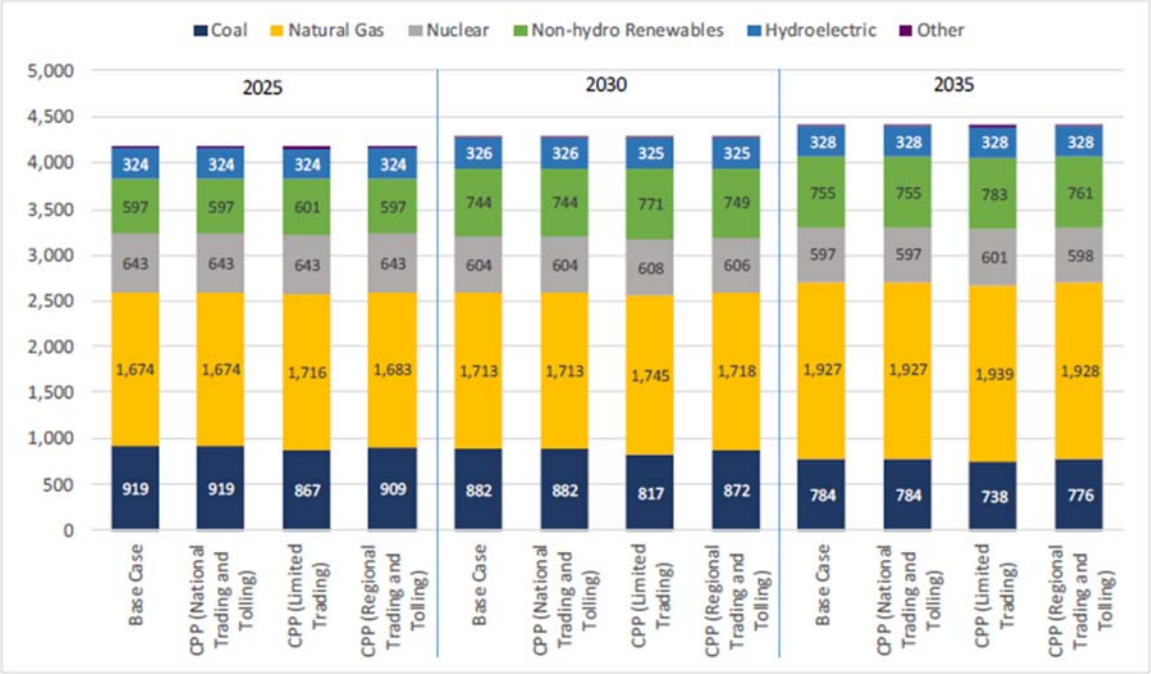

Figure 2-15 Generation Mix (GWh)

Source: IPM

Table 2-7 Installed Generating Capacity (GW)

	Baseline	CPP (National Trading and Tolling	Percent Change from Baseline	CPP (Limited Trading)	Percent Change from Baseline	CPP (Regional Trading and Tolling)	Percent Change from Baseline
2025							
Coal	172	172	0%	167	-3%	171	-1%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	3	3	0%	5	79%	3	21%
Combustion Turbine	151	151	0%	151	0%	151	0%
Oil/Gas Steam	72	72	0%	72	0%	72	0%
Non-Hydro Renewables	210	210	0%	213	1%	211	0%
Hydro	110	110	0%	110	0%	110	0%
Nuclear	81	81	0%	81	0%	81	0%
Other	12	12	0%	12	0%	12	0%
Total	1,073	1,073	0%	1,073	0%	1073	0%
2030							
Coal	170	170	0%	165	-3%	168	-1%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	12.7	12.7	0%	15	22%	13	5%
Combustion Turbine	152	152	0%	151	0%	152	0%
Oil/Gas Steam	72	72	0%	71	0%	72	0%
Non-Hydro Renewables	266	266	0%	272	3%	267	1%
Hydro	111	111	0%	110	0%	110	0%
Nuclear	77	77	0%	77	1%	77	0%
Other	13	13	0%	13	0%	13	0%
Total	1,133	1,133	0%	1,138	0%	1134	0%
2035							
Coal	165	165	0%	162	-2%	165	0%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	38	38	0%	42	9%	39	2%
Combustion Turbine	164	164	0%	161	-2%	163	-1%
Oil/Gas Steam	72	72	0%	71	0%	72	0%
Non-Hydro Renewables	270	270	0%	277	3%	272	1%
Hydro	111	111	0%	111	0%	111	0%
Nuclear	75	75	0%	76	1%	76	0%
Other	13	13	0%	13	0%	13	0%
Total	1,170	1,170	0%	1,175	0%	1171	0%

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR PART 60

[EPA-HQ-OAR-2017-0355; FRL-9995-70-OAR]

RIN 2060-AT67

Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing three separate and distinct rulemakings. First, the EPA is repealing the Clean Power Plan (CPP) because the Agency has determined that the CPP exceeded the EPA's statutory authority under the Clean Air Act (CAA). Second, the EPA is finalizing the Affordable Clean Energy rule (ACE), consisting of Emission Guidelines for Greenhouse Gas (GHG) Emissions from Existing Electric Utility Generating Units (EGUs) under CAA section 111(d), that will inform states on the development, submittal, and implementation of state plans to establish performance standards for GHG emissions from certain fossil fuel-fired EGUs. In ACE, the Agency is finalizing its determination that heat rate improvement (HRI) is the best system of emission reduction (BSER) for reducing GHG—specifically carbon dioxide (CO_2)—emissions from existing coal-fired EGUs. Third, the EPA is finalizing new regulations for the EPA and state implementation of

ACE and any future emission guidelines issued under CAA section 111(d).

DATES: Effective September 6, 2019.

ADDRESSES: The EPA has established a docket for these actions under Docket ID No. EPA-HQ-OAR-2017-0355. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/* or in hard copy at the EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The EPA's Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: For questions about these final actions, contact Mr. Nicholas Swanson, Sector Policies and Programs Division (Mail Code D205-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-4080; fax number: (919) 541-4991; and email address: *swanson.nicholas@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms:

ACE Affordable Clean Energy Rule

AEO Annual Energy Outlook

ANPRM Advance Notice of Proposed Rulemaking

BACT Best Available Control Technology

BSER Best System of Emission Reduction

Btu British Thermal Unit

CAA Clean Air Act

CCS Carbon Capture and Storage (or Sequestration)

CFR Code of Federal Regulation

CO_2 Carbon Dioxide

CPP Clean Power Plan

EGU Electric Utility Generating Unit

EIA Energy Information Administration

EPA Environmental Protection Agency

FIP Federal Implementation Plan

GHG Greenhouse Gas

HRI Heat Rate Improvement

IGCC Integrated Gasification Combined Cycle

kW Kilowatt

kWh Kilowatt-hour

MW Megawatt

MWh Megawatt-hour

NAAQS National Ambient Air Quality Standards
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NSPS New Source Performance Standards
NSR New Source Review
OMB Office of Management and Budget
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RIA Regulatory Impact Analysis
RTC Response to Comments
SIP State Implementation Plan
SO_2 Sulfur Dioxide
UMRA Unfunded Mandates Reform Act
U.S. United States
VFD Variable Frequency Drive

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

I. General Information

A. Executive Summary

With this document, the EPA is, after review and consideration of public comments, finalizing three

separate and distinct rulemakings. First, the EPA is finalizing the repeal of the CPP which was proposed at 82 FR 48035 (Oct. 16, 2017) ("Proposed Repeal"). Second, the EPA is promulgating ACE, which consists of emission guidelines for states to develop and submit to the EPA plans that establish standards of performance for CO_2 emissions from certain existing coal-fired EGUs within their jurisdictions. Third, the EPA is finalizing implementing regulations that provide direction to both the EPA and states on the implementation of ACE and any future emission guidelines issued under CAA section 111(d). This document does not include any final action concerning the New Source Review (NSR) reforms the EPA proposed in conjunction with the ACE proposal; the EPA intends to take final action on the proposed NSR reforms in a separate final action at a later date.

First, the EPA is repealing the CPP. In proposing to repeal the CPP, the Agency proposed a change in the legal interpretation of CAA section 111, on which the CPP was based, to an interpretation of the CAA that "is consistent with the CAA's text, context, structure, purpose, and legislative history, as well as with the Agency's historical understanding and exercise of its statutory authority."[1] After further review of the EPA's statutory authority under CAA section 111 and in consideration of public comments, the Agency is finalizing the repeal of the CPP. The discussion of the repeal action, along with the EPA's explanation that it intends the repeal of the CPP to be independent from the other final actions in this document, can be found in section II below.

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[1] Proposed Repeal, 82 FR 48036.

Second, the EPA is finalizing ACE, which consists of emission guidelines to inform states in the development, submittal, and implementation of state plans that establish standards of performance for CO_2 from certain existing coal-fired EGUs within their jurisdictions. In these emission guidelines, the EPA has determined that the BSER for existing EGUs is based on HRI measures that can be applied to a designated facility. ACE also clarifies the roles of the EPA and the states under CAA section 111(d). With the promulgation of this action, it is the states' responsibility to use the information and direction herein to develop standards of performance that reflect the application of the BSER. Per the CAA, states may also consider source-specific factors—including, among other factors, the remaining useful life of an existing source—in applying a standard of performance to that source. In this way, the state and federal roles complement each other as the EPA has the authority and responsibility to determine BSER at the national level, while the states have the authority and responsibility to establish and apply standards of performance for their existing sources, taking into consideration source-specific factors where appropriate. A full discussion of ACE can be found in section III of this preamble.

Third, the EPA is finalizing new implementing regulations that apply to ACE and any future emission guidelines promulgated under CAA section 111(d). The purpose of the new implementing regulations is to harmonize aspects of our existing regulations with the statute, in a new 40 CFR part 60, subpart Ba, by making it clear that states have broad discretion in establishing and applying emissions standards

consistent with the BSER. The new implementing regulations also provide changes to the timing requirements for the EPA and states to take action to more closely align with the CAA section 110 state implementation plan (SIP) and federal implementation plan (FIP) deadlines. The discussion of the final revisions to the implementing regulations is found in section IV below.

The implementing regulations (and ACE which is promulgated consistent with those regulations) make clear that the EPA, states, and sources all have distinct roles, responsibilities, and flexibilities under CAA section 111(d). Specifically, the EPA identifies the BSER; states establish standards of performance for existing sources within their jurisdiction consistent with that BSER and also with the flexibility to consider source-specific factors, including remaining useful life; and sources then meet those standards using the technologies or techniques they believe is most appropriate. As this preamble explains, in the case of ACE, the EPA has identified the BSER as a set of heat rate improvement measures. States will establish standards of performance for existing sources based on application of those heat rate improvement measures (considering source-specific factors, including remaining useful life). Each regulated source then must meet those standards using the measures they believe is appropriate (*e.g.*, via the heat rate improvement measures identified by the EPA as the BSER, other heat rate improvement measures, or other approaches such as CCS or natural gas co-firing).

These three rules have been informed by more than 1.5 million public comments on the Proposed Repeal

and 500,000 public comments on the proposals for ACE and the new implementing regulations. Per CAA section 307(d)(6)(B), the EPA is providing a response to the significant comments received for each of these actions in the docket. After careful consideration of the comments, the EPA is finalizing these three rules, with revisions to what it proposed where appropriate, to provide states guidance on how to address CO_2 emissions from coal-fired power plants in a way that is consistent with the EPA's authority under the CAA.

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

In addition to being available in the docket, an electronic copy of this document is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this document at *https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-emission-guidelines-greenhouse.* Following publication in the **Federal Register,** the EPA will post the **Federal Register** version of these final rules and key technical documents at this same website.

C. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of these final actions is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by September 6, 2019. Under CAA section 307(b)(2), the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider a rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Repeal of the Clean Power Plan

A. Background for the Repeal of the Clean Power Plan

1. The Clean Power Plan

The EPA promulgated the CPP under section 111 of the CAA.[2] Section 111(b) authorizes the EPA to issue nationally applicable new source performance standards (NSPS) limiting air pollution from "new sources" in source categories that cause or

[2] 42 U.S.C. 7411.

significantly contribute to air pollution that may reasonably be anticipated to endanger public health or welfare.[3] In 2015, the EPA issued such a rule for GHG emissions—in particular, CO_2—from certain new fossil fuel-fired power plants[4] in light of the Agency's assessment "that GHGs endanger public health, now and in the future."[5] CAA section 111(d) provides that, under certain circumstances, when the EPA issues a CAA section 111(b) standard, the EPA must develop procedures requiring each state to submit a plan to the EPA that establishes performance standards for *existing* sources in the same category.[6] The EPA relied on CAA section 111(d) to issue the CPP, which, for the first time, required states to submit plans specifically designed to limit CO_2 emissions from certain existing fossil fuel-fired power plants.

The CPP established emission guidelines for states to follow in limiting CO_2 emissions from those existing fossil fuel-fired power plants. Those emission guidelines included both state-specific "goals" and

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[3] *Id.* 7411(b)(1).

[4] The CPP identified "[f]ossil fuel-fired EGUs" as "by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2." 80 FR 64510, 64522 (October 23, 2015).

[5] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 80 FR 64510, 64518 (October 23, 2015); *see also* Endangerment and Cause or Contribute Findings for Greenhouse Gases Under section 202(a) of the CAA, 74 FR 66496 (December 15, 2009) (2009 Endangerment Finding). The substance of the 2009 Endangerment Finding, which addressed GHG emissions from mobile sources, is not at issue in this action.

[6] 42 U.S.C. 7411(d)(1) (emphasis added).

alternative, nationally uniform CO_2 emission performance rates for two types of existing fossil fuel-fired power plants: Electric utility steam generating units and stationary combustion turbines.[7]

In the CPP, the EPA determined that the BSER for CO_2 emissions from existing fossil fuel-fired power plants was the combination of: (1) Heat rate (*e.g.*, efficiency) improvements to be conducted at individual power plants, in combination with (2, 3) two other sets of measures based on the shifting of generation at the fleet-wide level from one type of energy source to another. The EPA referred to these three sets of measures as "building blocks":[8]

1. Improving heat rate at affected coal-fired steam generating units;

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for decreased generation from higher-emitting affected steam generating units; and

3. Substituting increased generation from new zero-emitting renewable energy generating capacity for decreased generation from affected fossil fuel-fired generating units.

While building block 1 relied on measures that could be applied directly to individual sources, building blocks 2 and 3 employed measures that were expressly designed to shift the balance of coal-, gas-, and renewable-generated power across the power grid.

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[7] *See* 80 FR 64707.

[8] *Id.*

2. Legal Challenges to the CPP, Executive Order 13783, and the EPA's Review of the CPP

On October 23, 2015, 27 states and a number of other parties sought judicial review of the CPP in the U.S. Court of Appeals for the D.C. Circuit.[9] After some preliminary briefing, the Supreme Court stayed implementation of the CPP, pending judicial review.[10] The case was then referred to an *en banc* panel of the D.C. Circuit, which held oral argument on September 27, 2016.

On March 28, 2017, President Trump issued Executive Order 13783, which affirms the "national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation."[11] The Executive Order directs all executive departments and agencies, including the EPA, to "immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law."[12] The Executive Order further affirms that it is "the policy of the United States that necessary and

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[9] *See West Virginia* v. *EPA*, No. 15-1363 (and consolidated cases) (D.C. Cir. October 23, 2015).

[10] *West Virginia* v. *EPA*, 136 S. Ct. 1000 (2016).

[11] *See* Executive Order 13783, section 1(a).

[12] *Id.* section 1(c).

appropriate environmental regulations comply with the law."[13] Moreover, the Executive Order specifically directs the EPA to review and initiate reconsideration proceedings to "suspend, revise, or rescind" the CPP "as appropriate and consistent with law."[14]

In a document signed the same day as Executive Order 13783 and published in the **Federal Register** at 82 FR 16329 (April 4, 2017), the EPA announced that, consistent with the Executive Order, it was initiating its review of the CPP and providing notice of forthcoming proposed rulemakings consistent with the Executive Order.

In light of Executive Order 13783, the EPA's initiation of a review of the CPP, and notice of the EPA's forthcoming rulemakings, the EPA asked the D.C. Circuit to hold the CPP litigation in abeyance, and, on April 28, 2017, the court (still sitting en banc) granted motions to hold the cases in abeyance for 60 days and directed the parties to file briefs addressing whether the cases should be remanded to the Agency rather than held in abeyance.[15] Since then, the D.C. Circuit has issued a series of orders holding the cases in abeyance. While the case has been in abeyance, the EPA has been reviewing the CPP and providing status reports to the court describing the progress of its rulemaking.

In the course of the EPA's review of the CPP, the Agency also reevaluated its interpretation of CAA

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[13] *Id.* section 1(e).

[14] *Id.* section 4(a)–(c).

[15] Order, Document No. 1673071 (per curiam).

section 111, and, on that basis, the Agency proposed to repeal the CPP.[16]

3. Public Comment and Hearings on the Proposed Repeal

Publication of the Proposed Repeal in the **Federal Register** opened comment on the proposal for an initial 60-day public comment period. The EPA held public hearings on November 28 and 29, 2017, in Charleston, West Virginia, and then extended the public comment period until January 16, 2018. In response to requests for additional opportunities for oral testimony, the EPA held three listening sessions in Kansas City, Missouri; San Francisco, California; and Gillette, Wyoming. The EPA also reopened the public comment period until April 26, 2018, giving stakeholders 192 days to review and comment on the proposal. The EPA received more than 1.5 million comments on the Proposed Repeal.

B. Basis for Repealing the Clean Power Plan

1. Authority To Revisit Existing Regulations

The EPA's ability to revisit existing regulations is well-grounded in the law. Specifically, the EPA has inherent authority to reconsider, repeal, or revise past decisions to the extent permitted by law so long as the Agency provides a reasoned explanation. The authority to reconsider prior decisions exists in part because the EPA's interpretations of statutes it administers "[are not] instantly carved in stone," but must be evaluated "on a continuing basis."[17] This is

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[16] *See* Proposed Repeal, 82 FR 48035 (October 16, 2017).

[17] *Chevron U.S.A. Inc.* v. *NRDC*, *Inc.*, 467 U.S. 837, 863–64 (1984).

true when, as is the case here, review is undertaken "in response to . . . a change in administrations."[18] Indeed, "[a]gencies obviously have broad discretion to reconsider a regulation at any time."[19]

2. Legal Basis for Repeal of the Clean Power Plan

The CPP departed from the EPA's traditional understanding of its authority under section 111 of the CAA and promulgated a rule in excess of its statutory authority. Because the CPP significantly exceeded the Agency's authority, it must be repealed.[20] Fundamentally, the CPP read the statutory term "best system of emission reduction" so broadly as to encompass measures the EPA had never before envisioned in promulgating performance standards under CAA section 111. In contrast to its traditional regulations that set performance standards based on the application of equipment and practices at the level of an individual facility, the EPA in the CPP set standards that could only be achieved by a shift in the energy generation mix at the grid level, requiring a shift from one type of fossil-fuel-fired generation to another, and from fossil-fuel-fired generation as a whole towards renewable sources of energy. The text of the CAA is inconsistent with that interpretation, and the context, structure, and legislative history

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[18] *National Cable & Telecommunications Ass'n* v. *Brand X internet Services*, 545 U.S. 967, 981 (2005).

[19] *Clean Air Council* v. *Pruitt*, 862 F.3d 1, 8–9 (D.C. Cir. 2017).

[20] As noted above, the EPA received more than 1.5 million comments on the Proposed Repeal. The Agency's consideration of and responses to significant comments are reflected in section II.B.2 of this preamble.

confirm that the statutory interpretation underlying the CPP was not a permissible construction of the Act.

a. CAA Requirements and Background

In 1970, Congress enacted section 111(b) of the CAA, authorizing the EPA to promulgate "standards of performance" for new stationary sources in certain source categories.[21] Congress also directed the EPA, under CAA section 111(d), to "prescribe regulations which shall establish a procedure"[22] for states to establish standards[23] for existing sources of certain air pollutants to which a standard of performance would apply if such existing source were a new source.[24]

Since 1990, new- and existing-source CAA section 111 rulemakings have been governed by the same statutory definitions.[25] The CAA defines the term "standard of performance" in two sections. CAA section 111(a)(1) defines it, for purposes of section 111 (which contains the new- and existing-source

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[21] CAA Amendments of 1970, Public Law 91-604, 84 Stat, at 1683–84 (Dec. 31, 1970); see *also* 42 U.S.C. 7411(b).

[22] *See* section IV (addressing changes to the implementing regulations).

[23] As originally enacted, CAA section 111 required states to establish "emission standards" for existing sources, but Congress replaced that term with "standard of performance" as part of the CAA Amendments of 1977. *See* Public Law 95-95, 91 Stat, at 699 (Aug. 7, 1977) ("Section 111(d)(1) . . . is amended by striking out 'emissions standards' in each place it appears and inserting in lieu thereof 'standards of performance' "].

[24] CAA Amendments of 1970, 84 Stat, at 1684; see also 42 U.S.C. 7411(d).

[25] *See infra* n.51.

performance standard authority in, respectively, CAA section 111(b) and 111(d)), as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (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.[26]

And CAA section 302(*l*) defines "standard of performance" as "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous reduction."[27]

EPA's role under CAA section 111(d) is narrow. Indeed, CAA section 111(d) tasks states with "establish[ing] standards of performance for any existing source" and "provid[ing] for the implementation and enforcement of such standards of performance." It requires further that the regulations the EPA is directed to adopt must permit the state "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard [of performance] applies."[28] After all, Congress found that "air pollution prevention . . . and

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[26] 42 U.S.C. 7411(a)(1).

[27] 42 U.S.C. 7602(*l*).

[28] 42 U.S.C. 7411(d)(1).

air pollution control at its source is the primary responsibility of States and local governments."[29]

In contrast to CAA section 111(b) (where the EPA may directly establish performance standards for emissions from new sources), the EPA implements CAA section 111(d) by issuing regulations that it calls "emission guidelines" [30] These guidelines provide states with information to assist them in developing state plans establishing standards of performance for existing designated facilities within their jurisdiction that are submitted to the EPA for review. Such information includes the EPA's determination of the "best system of emission reduction," which is commonly referred to as the BSER.

b. The Plain Meaning of CAA Sections 111(a)(1) and (d)

CAA section 111(d) provides that "each State shall submit to the Administrator a plan which (A) establishes *standards of performance* for any existing source for [certain air pollutants] . . . and (B) provides for the implementation and enforcement of such standards of performance."[31] Given how Congress has defined the phrase "standard of performance" for purposes of CAA section 111, the plain meaning of CAA section 111(d), therefore is that states shall submit a plan which "establishes [a standard for emissions of air pollutants which reflects the degree of

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[29] 42 U.S.C. 7401(a)(3).

[30] *See American Elec. Power Co.* v. *Connecticut*, 564 U.S. 410, 424 (2011). *See generally* Section IV, *infra* (discussing the promulgation of revised implementing regulations governing the EPA's issuance of emission guidelines); 40 CFR part 60, subpart B.

[31] 42 U.S.C. 7411(d)(1) (emphasis added).

emission limitation achievable through the application of the [BSER] . . .] for any existing source."

While CAA section 111(a)(1) provides that the EPA determines the BSER upon which existing-source performance standards are based, Congress expressly limited the universe of systems of emission reduction from which the EPA may choose the BSER to those systems whose "application" to an "existing source" will yield an "achievable" "degree of emission limitation."[32] "[W]here . . . the statute's language is plain," courts explain, our " 'sole function . . . is to enforce it according to its terms.' "[33]

The EPA begins with the meaning of "application," as it appears in CAA section 111(a)(1). In the absence of a statutory definition, the term must be construed in accordance with its ordinary or natural meaning.[34] Here the ordinary meaning of "application" refers to the "act of applying" or the "act of putting to use."[35]

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[32] *Id.*

[33] *Air Line Pilots Ass'n* v. *Chao*, 167 F.3d 602, 791 (D.C. Cir. 2018) (quoting *United States* v. *Ron Pair Enterprises*, 489 U.S. 235, 241 (1989)).

[34] *See Leocal* v. *Ashcroft*, 543 U.S. 1, 10 (2004).

[35] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) ("1: an act of applying: a (1) : an act of putting to use <~ of new techniques> (2): a use to which something is put <new ~s for old remedies>"). Definitions are also provided from when CAA section 111(a)(1) was last amended, *see* The Oxford English Dictionary (2d ed. 1989) ("The action of applying; the thing applied. 1. a. The action of putting a thing to another, of bringing into material or effective contact"), and first enacted, *see* American Heritage Dictionary of the English Language (2d ed. 1969) ("1. The act of applying or putting something on. 2.

Accordingly, a standard of performance must reflect the degree of emission limitation that can be achieved by putting the BSER into use. Furthermore, the ordinary and natural use of the term "application," which is derived from the verb "to apply," requires both a direct object and an indirect object. In other words, someone must apply *something* to *something else* (*e.g.*, the application of general rules to particular cases). In the case of CAA section 111, the direct object is the BSER. CAA section 111(d) also provides that the indirect object is the "existing source"—"each State shall submit to the Administrator a plan which (A) establishes standards of performance *for any existing source*" (emphasis added). The Act further defines an "existing source" as "any stationary source other than a new source,"[36] and in turn defines a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant."[37] Consequently, CAA section 111 unambiguously limits the BSER to those systems that can be put into operation *at* a building, structure, facility, or installation. Such systems include, for example, add-on controls (*e.g.*, scrubbers) and inherently lower-emitting processes/practices/designs.

Conversely, the plain language of CAA section 111 does not authorize the EPA to select as the BSER a system that is premised on application to the source category as a whole or to entities entirely outside the regulated source category. First, Congress specified

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Anything that is applied, such as a cosmetic or curative agent. 3. The act of putting something to a special use or purpose.").

[36] 42 U.S.C. 7411(a)(6)

[37] 42 U.S.C. 7411(a)(3).

that "standards of performance" are established "for new sources *within such category*" [38] and "for any existing source."[39] CAA section 111, therefore, does not allow for the establishment of standards for the source category or for entities not within the source category. Instead, CAA section 111 standards must be established for individual sources. Second, because CAA section 111 standards reflect an "achievable" "degree of emission limitation" through application of the BSER, an owner or operator must be able to achieve an applicable standard by applying the BSER to the designated facility. Accordingly, the BSER—like standards of performance—cannot be premised on a system of emission reduction that is implementable only through the combined activities of sources or non-sources. Thus, the EPA is precluded from basing BSER on strategies like generation shifting and corresponding emissions offsets because these types of systems cannot be put into use at the regulated building, structure, facility, or installation.[40]

c. Statutory Structure and Purpose Confirm That a "System of Emission Reduction" Must Be Applied to an Individual Source and That CAA Section 111 is

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[38] 42 U.S.C. 7411(b)(1)(B) (requiring the Administrator to establish performance standards "for new sources *within such category*" rather than for the category itself as a whole) (emphasis added)

[39] 42 U.S.C. 7411(d)(1)(A).

[40] The CPP's BSER was in part designed to consist of generation-shifting. *See, e.g.*, 80 FR 64,776 (final rule) (describing 'building blocks' 2 and 3 as "processes of shifting dispatch from steam generators to existing NGCC units and from both steam generators and NGCC units to renewable generators.").

Intended to Best Design, Build, Equip, Operate, and Maintain Sources so as To Reduce Emissions

While the plain meaning of CAA section 111 provides that the BSER must be applied to a building, structure, facility, or installation, Congress' intent is also manifest in the statutory structure and purpose. "Statutory construction," the Supreme Court instructs, "is a holistic endeavor."[41] The interpretation of a phrase "is often clarified by the remainder of the statutory scheme—because the same terminology is used elsewhere in a context that makes its meaning clear, or because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law."[42]

(1) The Statutory Structure Limits a "System of Emission Reduction" to "Systems" That Have a Potential for Application to an Individual Source

The conclusion that CAA section 111 standards are limited as described above is confirmed by considering the section's place in the overall statutory scheme. Congress tied CAA section 111 to the Best Available Control Technology ("BACT") provisions in CAA section '165.[43] Section 165 provides that "[a]ny major

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[41] *Czyzewski* v. *Jevic Holding Corp.*, 137 S. Ct. 973, 985 (2017) (citing *United Savings Ass'n* v. *Timbers of Inwood Forest Associates*, 484 U.S. 365, 371 (1988)).

[42] *Utility Air Regulatory Group* v. *EPA*, 573 U.S. 302, 321 (2014).

[43] 42 U.S.C. 7479(3) ("In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 or 7412 of this title.").

stationary source or major modification subject to [preconstruction requirements] must conduct an analysis to ensure the application of [BACT]."[44] A permitting authority must "conduct a BACT analysis on a case-by-case basis . . . and must evaluate the amount of emission reductions that each available emissions-reducing *technology or technique* would achieve, as well as the energy, environmental, economic and other costs . . . ."[45] The EPA has long recommended that permitting agencies conduct this analysis through a top-down assessment of the best available and feasible control technologies for the emissions subject to BACT.[46] "Based on this [technology] assessment, the permitting authority must [then] establish a numeric emission limitation that reflects the maximum degree of reduction achievable. . ."[47]

In no event, Congress specified, can application of BACT result in greater emissions than allowed by "any applicable standard established pursuant to

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[44] U.S. EPA, DRAFT New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, B. 1 (October 1990) ("NSR Manual"), *available at https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf*. Though the EPA never finalized this draft, it continues to follow the analytical approach to the BACT analysis contained within the NSR Manual. *See also* U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) ("GHG Permitting Guidance"), *available at https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf*

[45] GHG Permitting Guidance at 17 (emphasis added).

[46] *See id.* at 17–44.

[47] *Id.* at 17, 44–46.

section [1]11 or [1]12 . . . ."[48] To ensure such an exceedance does not occur, NSPS serve as the base upon which BACT determinations are made and are commonly viewed as the BACT "floor."[49] However, because Congress refers to "any applicable standard established pursuant to section [1]11," without reference to either subsection (b) or (d), any applicable existing source standard would also function as a BACT "floor."[50]

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[48] 42 U.S.C. 7479(3).

[49] GHG Permitting Guidance, 25 n.64 ("While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final.").

[50] Accordingly, certain commenters incorrectly argue that the scope of CAA section 169 is irrelevant to regulating existing sources under CAA section 111(d) because *only* CAA section 111(b) standards (*i.e.*, NSPS), not CAA section 111(d) existing-source standards, apply to sources subject to BACT. However, both CAA section 111(b) and (d) rely on the same definition of "standard of performance" in CAA section 111(a), and the term's statutory history (that is, its evolution through repeated acts of Congress from 1970 to 1990) supports the conclusion that Congress intended for the term to have the same meaning under both programs. Between the 1970 and 1977 CAA Amendments, "standards of performance" applied only to the regulation of new sources under CAA section 111(b); existing sources, on the other hand, were required to meet "emission standards," which was an undefined term. *See* Public Law 91-604, 84 Stat, at 1683–84. Between the 1977 and 1990 CAA Amendments, CAA section 111(a)(1) provided three context-specific definitions: One definition applied to *all* new stationary sources regulated under CAA section 111(b) (basing standards on the best technological system of continuous emission reduction ("TSCER")); the second applied only to new *fossil-fuel-fired* sources regulated under CAA section 111(b) (basing standards on the TSCER *and* requiring a

The EPA has consistently taken the position that BACT encompasses "all 'available' control options . . . that have the potential for practical *application to the emissions unit* and the regulated pollutant under evaluation."[51] This is so because BACT reflects a level of control that the permitting agency "determines is achievable *for such facility* through *application of* production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control."[52] Put simply, both the statutory text and the EPA's long-standing interpretation provide that BACT is limited to control options that can be applied to the source itself and does not include control options that go beyond the source.

Because CAA section 111 operates as a floor to BACT, section 111 cannot be interpreted to offer a broader set of tools than are available under section 165. Also, because BACT is limited to control options

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percent reduction in emissions); and a third applied to *existing* sources regulated under CAA section 111(d) (basing standards on the best system of continuous emission reduction). *See* Public Law 95-95, 91 Stat, at 699–700. In 1990, however, Congress replaced the three separate definitions with a singular definition of "standard of performance" under CAA section 111(a)(1), to apply throughout CAA section 111, based on application of the BSER. *See* Public Law 101-549, 104 Stat. at 2631. The legislative history of CAA section 111 demonstrates that Congress knew full well how to require either that the regulations applying to new and existing sources would be different in definition and scope (as in both the 1970 and 1977 versions of the Act) or that they would be the same and demonstrates that in 1990 they plainly chose the latter course.

[51] GHG Permitting Guidance, 24 (emphasis added).

[52] 42 U.S.C. 7479(3) (emphasis added).

that are applied to an individual source, so too with section 111. The explicit statutory link of CAA section 111 standards to BACT, the statutory definition of the latter, the Agency's consistent position that BACT must apply to and be achievable for a particular facility, and the text of CAA section 111(b) and 111(d), confirm the conclusion that the text of 111(a)(1) can only be read to mean that standards of performance (and the BSER on which they are predicated) are likewise measures applied to individual facilities.

(2) The Purpose of CAA Section 111 is To Design, Build, Equip, Operate, and Maintain Individual Sources so as To Reduce Emissions

Congress intended that CAA section 111 would set minimum requirements[53] on individual sources to be

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[53] In a 1978 BACT guidance document, the EPA explained that performance standards reflect emission limits "which can reasonably be met by all new or modified sources in an industrial category, even though some individual sources are capable of lower emissions. Additionally, because of resource limitations in the EPA, revision of new source standards must lag somewhat behind the evolution of new or improved technology. Accordingly, new or modified facilities in some source categories may be capable of achieving lower emission levels that [sic] NSPS without substantial economic impacts. The case-by-case BACT approach provides a mechanism for determining and applying the best technology in each individual situation. Hence, NSPS and NESHAP are Federal guidelines for BACT determinations and establish minimum acceptable control requirements for a BACT determination." U.S. EPA, Guidelines for Determining Best Available Control Technology, 3 (December, 1978).

Further, while some commenters suggest that the BSER must reflect the "greatest degree of emission control," citing to section 113 of Senate bill 4358 (S. 4358, at 6, 1970 Legis. Hist, at 554–55), Congress imposed no such requirement. *See Sierra Club*, 657 F.2d at 330 ("we believe it is clear that this language is far

designed, built, equipped, operated, and maintained to reduce emissions. This purpose is evidenced in the history of CAA section 111(a)(1)'s text and corroborated by legislative history. CAA section 111 was originally enacted as part of the 1970 CAA Amendments. In that enactment, state plans under CAA section 111(d) were to establish "emission standards" rather than "standards of performance." The EPA's CAA section 111(d) implementing regulations, issued in 1975, provided that, in the case of existing sources, the EPA would issue "emissions guidelines," that these guidelines would "reflect the degree of emission reduction achievable through the application of the [BSER] which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities," and that state plans establishing standards of performance for existing sources would be developed in light of these guidelines.[54] Then in 1977, Congress replaced the term "emission standard" under CAA section 111(d) with the phrase "standard of performance"—a phrase defined for all of CAA section 111 in section 111(a)(1). Thus, the history behind CAA section 111(a)(1) is relevant to understanding EPA's authority for both sections 111(b) and (d).

The 1970 enactment of CAA section 111 represents a choice between two alternative approaches to direct federal regulation of stationary sources. Under the

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different from the words Congress would have chosen to mandate that the EPA set standards at the maximum degree of pollution control technologically achievable.").

[54] 40 FR 53346.

House bill, the Administrator would have been authorized to establish "emission standards" for new sources of pollutants that may contribute substantially to endangerment of the public health or welfare. These standards would have "require[d] that new sources of such emissions be *designed and equipped* to maximize emission control insofar as technologically and economically feasible." [55] The House bill did not contain any analogous provisions for existing sources. Nevertheless, the House bill contemplated that under CAA section 111, individual sources would be designed to emit less.

Under the Senate approach, the Administrator would have established "standards of performance" for new sources based "on the greatest emission control possible through application of [the] latest available control technology."[56] This would have ensured "that new stationary sources are *designed, built, equipped, operated, and maintained* so as to reduce emission[s] to a minimum."[57] Accordingly, such standards would have reflected "the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods."[58] A separate provision governing emissions of "selected agents" authorized the Administrator to develop "emission standards" for both new and existing

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[55] H.R. Conf. Rep. No. 91-1783, 46 (December 17, 1970) (emphasis added)

[56] *Id*. (describing the approach under the Senate amendment).

[57] S. Rep. No. 91-1196, 15–16 (September 17, 1970) (emphasis added).

[58] *Id.* at 17.

sources.[59] However, the Senate "recognize[d] that certain old facilities may use equipment and processes which are not suited to the application of control technology. The [Administrator] would be authorized therefore to waive the application of standards. . . ."[60]

The conference substitute settled on the language largely reflected in the current wording of CAA section 111(a)(1); the differences between the 1970 enactment and the current version are not relevant to this discussion. As explained above, *both* the Senate and House bills contemplated only control measures that would lead to better design, construction, operation, and maintenance of an individual source [61] and, in the case of existing sources under the Senate bill, the waiver of standards if certain sources could not apply new control technologies. Accordingly, recognizing that a "system of emission reduction" is limited to control technologies or techniques that can be integrated into an individual source's design or operation (*i.e.*, add-on controls and lower-emitting processes/practices/designs) is the only interpretation compatible with the fundamental principle, reflected in the original competing drafts of the provision, that

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[59] *Id.* at 18–19.

[60] *Id.* at 19.

[61] References to "other alternatives," "other means," or "other methods" in the Senate bill and accompanying report are not evidence that Congress intended to confer boundless discretion. In fact, these terms must be interpreted in light of the other specifically listed control techniques. For example, the Senate bill's reference to "control technology," "processes," and "operating methods" are properly read to denote measures that can be applied to individual sources—and "other alternatives" must be interpreted *ejusdem generis:* in the same fashion.

sources should be designed, built, equipped, operated, and maintained to reduce emissions.[62]

d. The CPP Unlawfully Exceeds the Scope of CAA Section 111(a)(1) and Must Be Repealed

Before the CPP, the EPA had issued only six CAA section 111(d) rulemakings, in the form of a "guideline document" with corresponding "emission guidelines."[63] Conversely, the EPA has issued around

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[62] To be sure, the Agency does not contend that a "system of emission reduction" is limited to technological improvements. Indeed, the CAA Amendments of 1990 make clear that CAA section 111 is not to be limited to "technological systems." *See supra* n. 51 (discussing amendments to CAA section 111(a)(1)). But that does not mean CAA section 111 therefore authorizes basing BSER on generation shifting "measures," such as substitute generation from lower- or non-polluting power plants, which cannot be applied to individual sources like add-on controls or inherently lower-emitting processes/practices/designs.

[63] (*See* 1) Phosphate Fertilizer Plants, Final Guideline Document Availability, 42 FR 12022 (March. 1, 1977) [Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants, March 1977, Doc. No. EPA-450/2-77-005]; 2) Emission Guideline for Sulfuric Acid Mist, 42 FR 55796 (October 18, 1977); 3) Kraft Pulp Mills; Final Guideline Document; Availability, 44 FR 29828 (May 22, 1979) [Kraft Pulping, "Control of Emissions from Existing Mills," March 1979, Doc. No. EPA-450/2-78-003b]; 4) Primary Aluminum Plants; Availability of Final Guideline Document, 45 FR 26294 (Apr. 17, 1980) [Primary Aluminum: Guidelines for Control of Fluoride Emissions from Existing Primary Aluminum Plants, December 1979, Doc. No. EPA-450/2-78-049b]; 5) Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, 61 FR 9905 (March 12, 1996); and 6) Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 FR 28606 (May 18, 2005) (hereafter, the Clean Air Mercury Rule or CAMR) (vacated in *New Jersey* v. *EPA*, 517 F.3d

seventy CAA section 111(b) rulemakings, including several for new fossil-fuel-fired steam-generating units.[64] Every one of those rulemakings applied technologies, techniques, processes, practices, or design modifications directly to individual sources.

In the CPP, the EPA determined that the BSER for reducing CO_2 emissions from existing fossil fuel-fired power plants was the combination of three "building blocks":

1. Improving heat rate at individual affected coal-fired steam generating units;

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for decreased generation from higher-emitting affected steam generating units; and

3. Substituting increased generation from new zero-emitting renewable energy generating capacity for decreased generation from affected fossil fuel-fired generating units.

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574 (D.C. Cir. 2007) (reviewing an action that sought to shift regulation of certain emissions from power plants from the CAA section 112 hazardous air pollutants regime to the section 111 standards regime and holding that the EPA failed to comply with the delisting requirements of section 112(c)(9) and thus vacating the corresponding section 111 standards for electric utility steam generating units). This list of six CAA section 111(d) rulemakings does not include any guideline documents mandated by and carried out in compliance with CAA section 129 (governing solid waste incinerator units).

[64] *See generally* 40 CFR part 60, subparts D-TTTT. In fact, steam-generating units were among the first sources regulated under section 111(b). *See* 36 FR 24876 (December 23, 1971) (promulgating standards for steam generators, portland cement plants, incinerators, nitric acid plants, and sulfuric acid plants).

This was the first time the EPA interpreted the BSER to authorize measures wholly outside a particular source.[65] The EPA reached this determination by interpreting the statutory term "application" as if it instead read "implementation" (without pointing to any legal basis for equating those terms), and interpreting the phrase "system of emission reduction" broadly as "a set of measures that work together to reduce emissions and that are implementable by the sources themselves."[66] "As a practical matter," the Agency continued, "the 'source' includes the 'owner or operator' of any building, structure, facility, or installation for which a standard of performance is

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[65] CAMR, which relied in part on a cap-and-trade mechanism, was still ultimately "based on control technology available in the relevant timeframe," an approach fundamentally different than the CPP's second and third "building blocks," which were not based on systems that could be applied to or at individual sources. Indeed, the rule explained that the BSER refers to "the combination of the cap-and-trade mechanism *and the technology needed* to achieve the chosen cap level." 70 FR 28620 (emphasis added). Accordingly, the Agency concluded that it would be "reasonable to establish a cap on [the basis of using a particular technology] and require compliance with that cap at a later point in time when the necessary technology becomes widely available." *Id.* To the extent that CAMR's BSER (*i.e.*, the combined control technology and cap-and-trade program) is premised on application to the source category (as opposed to an individual source), however, CAMR would be unlawful. Trading as a compliance mechanism under CAA section 111 is discussed in section III.F.2.a of this preamble.

[66] 80 FR 64762 (citing the Oxford Dictionary of English (3rd ed.) (2010), among others). The EPA reached this interpretation in part on the assumption that "the terms 'implement' and 'apply' are used interchangeably." *See* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 84 n.175.

applicable." [67] The EPA then concluded that the breadth of a dictionary definition of the word "system" established the bounds of its statutory authority, finding that the phrase " 'system of emission reduction' . . . means a set of measures that source owners or operators can implement to achieve an emission limitation applicable to their existing source."[68]

In reviewing the CPP, the EPA concludes that the interpretation relied upon in the CPP ignored or misinterpreted critical statutory elements and rules of statutory construction. After reconsidering the relevant statutory text, structure, and purpose, the Agency now recognizes that Congress "spoke to the precise question" of the scope of CAA section 111(a)(1) and clearly precluded the unsupportable reading of that provision asserted in the CPP. Accordingly, this action repeals the CPP.[69]

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[67] 80 FR 64762.

[68] *Id.* The EPA acknowledged, nonetheless, that "regulatory requirements" in the CPP would be based "on measures the affected EGUs can implement to assure that electricity is generated with lower emissions" and that "do not require reductions in the total amount of electricity produced." *Id.* at 64778. But the EPA did not exclude such "measures" (*i.e.*, reduced utilization and demand-side energy efficiency) as being outside the scope of the dictionary definition of "system." Indeed, the EPA believed they would play an important compliance role under the CPP. *See id.* at 64753–657 (discussing reduced utilization and demand-side energy efficiency measures under rate-based and mass-based state plans]. *See also* n. 83, *infra.*

[69] One commenter asserted that, rather than repeal the CPP, the EPA should retain building block 1. As explained in the Proposed Repeal, however, while heat rate improvement measures may be considered in a CAA section 111 standard,

(1) The CPP Is Impermissibly Based on "Implementation" Rather Than "Application" of the BSER

CAA section 111(a)(1) provides that standards of performance reflect an emission limitation achievable "through the application of the [BSER] . . . ." In the Legal Memorandum accompanying the CPP, the Agency stated in a footnote that "the terms 'implement' and 'apply' are used interchangeably."[70] Thus, the Agency decided, "the system must be limited to measures that can be implemented—"appl[ied]"—by the sources themselves . . . ."[71] But Congress does not in fact use these terms interchangeably in the Act, and in CAA section 111(a)(1), as in other source-focused standard-setting provisions in the Act, used a term ("application") meaningfully different than the one CPP read into that section ("implementation")—and the term that Congress actually used is one that

"building block 1, as analyzed, cannot stand on its own. 80 FR 64758 n. 444; see also *id.* at 64658 (discussing severability of the building blocks)." 82 FR 48039 n.5. Accordingly, today's action repeals the whole of the CPP and does not retain building block 1 as the BSER. In any case, as discussed in the ACE proposal, "building block 1, as constructed in [the] CPP, does not represent an appropriate BSER, and ACE better reflects important changes in the formulation and application of the BSER in accordance with the CAA." 83 FR 44756 (discussing the EPA's change in approach to analyzing heat rate improvement measures). See section III for the EPA's evaluation of heat rate improvement measures under ACE.

[70] Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 84 n.175.

[71] 80 FR 64720.

reflects the CAA's other source-focused standard-setting provisions.[72]

The Act is replete with provisions calling for the "implementation" of "a system," [73] "control measures," [74] "emission reduction measures," [75] and even "steps, *by owners or operators of stationary sources*," [76] but CAA section 111(a)(1) is not among them. Congress defines "implementing" under CAA section 105(a)(1)(A) as "any activity related to the planning, developing, establishing, carrying-out,

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[72] *See, e.g.*, 42 U.S.C. 7412(d)(2) (describing MACT as "through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications, (B) enclose systems or processes to eliminate emissions, (C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point, (D) are design, equipment, work practice, or operational standards . . . , or (E) are a combination of the above;"); *id.* at 7479(3) (describing BACT as "achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control").

[73] 42 U.S.C. 7412(r)(7)(H)(vii) ("the Administrator . . . shall develop and implement a system for providing off-site consequence analysis information").

[74] *Id*. 7511a(b)(2) ("Such plan provisions shall provide for the implementation of all reasonably available control measures").

[75] *Id*. 7412(i)(5)(C) ("prior to implementation of emissions reduction measures").

[76] *Id*. 7410(a)(2)(F) (emphasis added) ("require, as may be prescribed by the Administrator—(i) the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps, by owners or operators of stationary sources").

improving, or maintaining of such programs [for the prevention and control of air pollution or implementation of national primary and secondary ambient air quality standards]." [77] But again, "applying" is not included in this list defining "implementing." In the case of the Act's standard-setting provisions, on the other hand, BACT and maximum achievable control technology (MACT) requirements—like CAA section 111—are based on "application of" control measures to individual sources.

Functionally, the two terms send different signals. "Implementation" requires a subject and direct object (I implement the plan), whereas "application" requires a subject, direct object, and indirect object (I apply the protocol to the subject). That is, an owner or operator can implement a system (without anything more and without any particular object of the system being implied), but an owner/operator must apply a system *to* another object (*i.e.*, the source). CAA section 111 illustrates this distinction. Congress provided, in CAA section 111(d)(1), that state plans must provide "for the implementation and enforcement of such standards of performance," but that EPA's regulations must also permit a state "in applying a standard of performance to any particular source" to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies. Thus, whereas state plans more broadly "implement" the CAA section 111(d) program, states "appl[y]" standards to individual sources. Congress could have defined a standard of performance as reflecting the "implementation of the

[77] 42 U.S.C. 7405(a)(1)(A).

BSER by the owner or operator of a stationary source," but Congress did not. Simply put, equating the terms "implement" and "apply" conflicts with the plain language of CAA section 111(a)(1) and their use throughout the Act; this conflict is compounded by the conflation of the source with its owner, different concepts that are separately defined, *see* CAA section 111(a)(3), (5).

Now take generation shifting, the basis for the second and third "building blocks" of the CPP's BSER. The CPP recognized that an owner or operator of a regulated source can "shift" power-producing operations to a different facility, such as a nuclear power plant, through bilateral contracts for capacity or by reducing utilization. But just because generation shifting is "implementable" by an owner or operator (*i.e.*, just because an owner or operator of a given source can subsidize generation elsewhere that will reduce demand for generation from that) does not mean that generation shifting can be "applied" to the source.[78] And indeed, the CPP shifted generation from one regulated source category to another and from both those regulated source categories together to other forms of electricity generation outside any regulated source category. Because the CPP is premised on "implementation of the BSER by a source's owner or operator" and not "application of the [BSER]" to an individual source, the rule contravenes the plain language of CAA section 111(a)(1) and must be repealed.

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[78] A contract, for example, is neither a "system" nor "applied to" a source.

(2) Dictionary Definitions Cannot Confer an "Infinitude" of Possibilities

Although the word "system" is not defined in the CAA, "[t]he meaning—or ambiguity—of certain words or phrases may only become evident when placed in context." [79] Thus, the issue is not whether the dictionary provides a broad definition of the word "system," but what are the permissible bounds of the *legal* meaning of the word "system." The precise question in this case is whether the word "system" as used in CAA section 111 encompasses any "set of measures" [80] to reduce emissions, or whether it is limited to lower-emitting processes, practices, designs, and add-on controls that are applied at the level of the individual facility.

"System," as used in CAA section 111, cannot be read to encompass *any* "set of measures" that would—through some chain of causation—lead to a reduction in emissions. As an initial matter, Congress did not use the phrase "set of measures" in CAA section 111. On its own, this phrase could create unbounded discretion in the Agency. Moreover, even when the term "measures" is used elsewhere in the Act, it is intended to be limited. For example, CAA section 112 emission standards are derived "through application of *measures,* processes, methods, systems or techniques." "Measures," are further defined to include measures which:

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[79] *King* v. *Burwell*, 135 S. Ct. 2480, 2489 (2015) (quoting *FDA* v. *Brown & Williamson Corp.*, 529 U.S. 120, 132 (2000)).

[80] 80 FR 64762.

- Reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,
- enclose systems or processes to eliminate emissions,
- collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,
- are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h) of CAA section 111, or
- are a combination of the above.[81]

"Measures," as Congress provides, are limited to control measures that can be integrated into an individual source's design or operation. "Measures" do not include shifting production away from the regulated source. The CPP read "system" in CAA section 111(a)(1) to mean any "set of measures," relying on the dictionary, and then determined that there was no limitation on those "set of measures" so long as they were measures that could be implemented through obligations placed on the owner or operator of a source.[82] At both steps, the CPP relied on an absence of an express textual commandment forbidding these open-ended interpretations. That methodology is untenable.

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[81] 42 U.S.C. 7412(d)(2).

[82] The CPP identified purported limitations to the underlying legal interpretation (*e.g.*, "system" does not extend to measures that directly target consumer behavior), *see* 80 FR 64776–779, but those purported limitations still led to an interpretation that far exceeded the bounds of the authority actually conferred by Congress on the EPA.

Construing "system" to offer such an "infinitude"[83] of possibilities would have significant implications. The fact is, fossil fuel-fired EGUs operate within an interconnected "system." Thus, any action that would affect electricity rates will have generation-shifting and potentially emission-reduction consequences. By the very nature of the interconnected grid, EPA's authority to determine the BSER under CAA section 111 is, under the Agency's prior interpretation, stretched to every aspect of the entire power sector. This cannot have been the intent of the Congress that enacted CAA section 111.

The D.C. Circuit has previously disapproved of a federal agency's expansive reading of its authority in analogous circumstances. In *Cal ISO*, the D.C. Circuit vacated the Federal Energy Regulatory Commission's ("FERC") attempt to reform a utility's governing structure on the theory that FERC's statutory authority over "practice[s] . . . affecting [a] rate" gave FERC "authority to regulate anything done by or connected with a regulated utility, as any act or aspect of such an entity's corporate existence could affect, in some sense, the rates."[84]

Upholding FERC's interpretation of "practice" to include replacing the governing board of California's Independent System Operator Corporation, the Court warned, could authorize FERC to "dictate the choice of CEO, COO, and the method of contracting for services, labor, office space, or whatever one might

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[83] See *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401 (D.C. Cir. 2004) ("*Cal ISO*").

[84] *Id.*

imagine . . . ."[85] But where "the text *and reasonable inferences from it* give a clear answer . . . that . . . is 'the end of the matter.'"[86] There is no need, therefore, to consider "such parade of horribles."[87]

The Court explained that, "no matter how important the principle of ISO independence is to the Commission, '[the FERC Order] is merely a regulation,' and cannot be the basis to override the limitations of 'statutes enacted by both houses of Congress and signed into law by the president."[88] The court reasoned that both "the history of the application of this and similar statutes and by the implications of FERC's amorphous defining of the term" firmly barred FERC's attempt to stretch its authority.[89] On this point, Congress's intent is "crystal clear"—FERC had no authority to "reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a 'practice' for ratemaking authority purposes."[90]

The EPA's prior interpretation underlying the CPP is untenable for the same reasons. The EPA began, like FERC, with an ordinary statutory term ("system") and then read into it maximally broad authority to shift generation away from coal-fired and gas-fired power plants to other electricity producers on the basis

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[85] *Id.* at 403.

[86] *Id.* at 401 (citing *Brown* v. *Gardiner*, 513 U.S. 115, 120 (1994)) (emphasis in original).

[87] *Id.* at 403.

[88] *Id.* at 404.

[89] *Id.* at 404.

[90] *Id.*

that generation shifting would cause those regulated sources to be displaced and therefore not be a source of emissions. But for nearly 45 years prior to the CPP, this Agency had never understood CAA section 111 to confer upon it the implicit power to restructure the utility industry through generation-shifting measures. Indeed, the EPA has issued many rules under CAA section 111 (both the limited set of existing-source rules under CAA section 111(d) and the much larger set of new-source rules under CAA section 111(b)). In all those rules, the EPA determined that the BSER consisted of add-on controls or lower-emitting processes/practices designs that can be applied to individual sources.[91]

The CPP deviated from this settled understanding of CAA section 111. By embracing an expansive dictionary definition of "system,"[92] the EPA ignored that the text and structure of the Act expressly limited the scope of the term "system" in a way that foreclosed the CPP's expansive definition. The Agency concluded that actions that would cause generation to shift from higher-emitting to lower- or non-emitting power generators represent a means of reducing CO_2 emissions from existing fossil fuel-fired electric generating units—and thus constituted a "system" within the meaning of CAA section 111. Taken to its logical end, however, any action affecting a generator's

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[91] See *supra* n. 66 (discussing CAMR).

[92] 80 FR at 64720 (defined by the Oxford Dictionary of English as "a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or independent elements").

operating costs could impact its order of dispatch and lead to generation shifting. This could include, for example, minimum wage requirements or production caps. It is axiomatic that "Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes."[93] Because Congress clearly did not authorize CAA section 111 standards to be based on *any* "set of measures," the EPA need not address the potential consequences of deviating from our historical practice under CAA section 111 when determining whether the CPP's interpretation was a permissible reading of the statute. Like the D.C. Circuit in *Cal ISO*, the EPA concludes that the text and reasonable inferences from it give a clear answer: "system" does not embody any conceivable "set of measures" that might lead to a reduction in emissions, but is limited to measures that can be applied to and at the level of the individual source

[93] *Whitman* v. *American Trucking*, 531 US 457, 466 (2001). *See also* Letter from Neil Chatterjee, Chairman, Fed. Energy Reg. Comm'n, to Andrew Wheeler, Administrator, EPA at 5 (Oct. 31, 2018) (Docket ID# EPA-HQ-OAR-2017-0355-24053) ("The Supreme Court has explained several times that Congress 'does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes.' The challenges posed by global climate change present 'question[s] of deep 'economic and political significance' that [are] central to [the] statutory scheme[s]' administered by both the Agency and the Commission.") (internal citation omitted).

(3) Basing BSER on Generation Shifting Is Not Authorized by Congress

On the question of whether basing BSER on generation shifting is precluded by the statute, the major question doctrine instructs that an agency may issue a major rule only if Congress has *clearly* authorized the agency to do so. As the Supreme Court has stated, "We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.'"[94] Although the Court has not articulated a bright-line test, its cases indicate that a number of factors are relevant in distinguishing major rules from ordinary rules: "the amount of money involved for regulated and affected parties, the overall impact on the economy, the number of people affected, and the degree of congressional and public attention to the issue."[95]

While the EPA believes that today's action is based on the only permissible reading of the statute and would reach that conclusion even without consideration of the major question doctrine, the EPA believes that that doctrine should apply here and that its application confirms the unambiguously expressed intent of CAA section 111. The CPP is a major rule. At the time the CPP was promulgated, its generation-shifting scheme was projected to have billions of dollars of impact on regulated parties and the economy, would have affected every electricity customer (*i.e.*, all Americans), was subject to litigation involving almost

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[94] *Utility Air Regulatory Group* v. *EPA*, 573 U.S. 302, 324 (2014) (quoting Brown & Williamson, 529 U.S. at 159).

[95] *U.S. Telecom Ass'n* v. *FCC*, 855 F.3d 381, 422–23 (D.C. Cir. 2017) (internal citations omitted).

every State in the Union, and, as discussed in the following section, would have disturbed the state-federal and intra-federal jurisdictional scheme. Building blocks 2 and 3 are far afield from the core activity of CAA section 111—indeed, no section 111 rule of the scores issued has ever been based on generation shifting since the enactment of CAA section 111 in 1970. Because the CPP is a major rule, the interpretative question raised in CAA section 111(a)(1) (*i.e.*, whether a "system of emission reduction" can consist of generation-shifting measures) must be supported by a clear-statement from Congress.[96] As explained above, however, it is not—indeed, Congress has directly spoken to this precise question and precluded the interpretation of CAA section 111 advanced by the EPA in the CPP.

Further evidence comes from the notable absence of a valid limiting principle to basing a CAA section 111 rule on generation shifting. In the CPP, the EPA explained that the Agency "has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production."[97] But by shifting focus to the entire grid (which includes regulated sources and non-sources), the Agency could empower itself to order the wholesale restructuring of any industrial sector (whether or not it has authority

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[96] The EPA acknowledges that for the reasons noted above, its position on this major rule issue has evolved since the EPA addressed it in the CPP, 80 FR 64,783. *See FCC* v. *Fox Television Stations, Inc.*, 556 U.S. 502 (2009).

[97] 80 FR 64762.

to even regulate all the actors within that sector—so long, in keeping with the interpretation underlying the CPP, as it can place obligations on the owners and operators over whom it does have authority to carry out a "system" that goes beyond the EPA's actual direct reach). Appealing to such factors as "cost" and "feasibility" [98] as putative constraints on EPA's authority, furthermore, does not provide any assurance—indeed, the D.C. Circuit traditionally "grant[s] the [A]gency a great degree of discretion in balancing them."[99] Thus, it is not reasonable to find in this statutory scheme Congressional intent to endow the Agency with discretion of this breadth to regulate a fundamental sector of the economy.

As a final point, the CPP not only advanced a broad reading of CAA section 111(a)(1), the rule applied that interpretation to "the source category as a whole"[100] to cause a reduction in coal-fired generation.[101] To do so, the CPP relied on "emission reduction approaches that focus on the machine as a whole—that is, the overall source category—by shifting generation from dirtier to cleaner sources in addition to emission reduction approaches that focus on improving the emission rates of individual sources." [102] Consequently, it was

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[98] *See* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 117–20.

[99] *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[100] 80 FR 64727.

[101] *Id.* at 64665.

[102] 80 FR 64725–726; see also *id.* at 64726 (noting "consideration of emission reduction measures at the source-category level").

designed as "an emission guideline for an entire category of existing sources . . ."[103] However, by acting as a guideline for an entire category, the CPP ignored the statutory directive to establish standards *for* sources and overextended federal authority into matters traditionally reserved for states: "administration of integrated resource planning and . . . utility generation and resource portfolios."[104]

(4) Basing BSER on Generation Shifting Encroaches on FERC and State Authorities

The Federal Power Act (FPA) establishes the dichotomy between federal and state regulation in the electricity sector by drawing "a bright line easily ascertained, between state and federal jurisdiction."[105] The Supreme Court recently observed that, under the FPA, FERC has "exclusive jurisdiction over wholesale sales of electricity in the interstate market" and establishing the associated just and reasonable rates and charges.[106] However, "the law places beyond FERC and leaves to the States alone, the regulation of 'any other sale'—most notably, any retail sale—of electricity."[107] Therefore, under the FPA, Congress

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[103] CPP RTC Chapter 1A, 170–72.

[104] *New York* v. *FERC*, 535 US 1, 24 (2002).

[105] *Fed. Power Comm'n* v. *S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964).

[106] *Hughes* v. *Talen Energy Marketing, LLC*, 136 S.Ct. 1288, 1291–92 (2016) (citing 16 U.S.C. 824(b)(1), 824d(a) and 824e(a)).

[107] *Id.* at 1292 (quoting *FERC* v. *Electric Power Supply Assn.*, 136 S.Ct. 760, 766 (2016) (EPSA) (quoting 824(b)). The States' reserved authority includes control over in-state "facilities used for the generation of electric energy." 824(b)(1); see *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new

limited the jurisdiction of FERC "to those matters which are not subject to regulation by the States," including "over facilities used for the generation of electric energy."[108] Indeed, "the States retain their traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost, and other related state concerns."[109] "Such responsibilities include "authority over the need for additional generating capacity [and] the type of generating facilities to be licensed."[110] Thus, the FPA "not only establishes an affirmative grant of authority to the federal government to regulate wholesale sales and transmission of electricity in interstate commerce, but also draws a line where that exclusive authority ends and the state's exclusive authority to regulate other matters . . . begins."[111]

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power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.").

[108] 16 U.S.C. 824(a), 824(b)(1); see also *id.* 824o(i)(2) ("This section does not authorize . . . [FERC] to order the construction of additional generation or transmission capacity"). There are other jurisdictional limitations under the FPA. For example, publicly-owned and many cooperatively owned utilities are subject to only some elements of the FPA. *Id.* 824(f), 824(b)(2). And entities not operating in interstate commerce, *i.e.*, entities in Alaska, Hawaii, and the Electric Reliability Council of Texas portion of Texas, are also subject to only limited FERC jurisdiction.

[109] *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983).

[110] *Id.* at 212.

[111] Dennis, Jeffrey S., et al., Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies, 3 (December 2016), *available at* https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split-Implications

Courts have observed that regulation of other areas may incidentally affect areas within these exclusive domains, but there is no room for direct regulation by States in areas of FERC domain or vice-versa, and such regulation that would achieve indirectly what could not be done directly is also prohibited.[112] Just as "FERC has no authority to direct or encourage generation"[113] absent clear authority from Congress, neither does (indeed, *a fortiori* so much the less does) the EPA.[114] The EPA has no more ability to "do indirectly what it could not do directly" than FERC would with respect to matters that the FPA left to the states. Historically, any traditional environmental regulation of the power sector may have incidentally affected these domains without indirectly or directly

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%20for%20Emerging%20Electricity%20Technologies.pdf; *see also* 16 U.S.C. 824o(i)(2) ("This section does not authorize . . . [FERC] to order the construction of additional generation or transmission capacity").

[112] *Hughes*, 136 S. Ct. at 1297–98. *See also* EPSA, 753 F.3d at 221, 224 ("the Federal Power Act unambiguously restricts FERC from regulating the retail market" and quoting *Altamont Gas Transmission Co.* v. *FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996)) (noting that "FERC cannot 'do indirectly what it could not do directly'").

[113] CRS, The Federal Power Act (FPA) and Electricity Markets, 9 (March 10, 2017), *available at https://www.everycrsreport.com/files/20170310_R44783_dd3f5c7c0c852b78f3ea62166ac5ebdbd158Bel2.pdf.*

[114] *See* 80 FR 64745 (explaining that "the BSER also reflects other CO2 reduction strategies that *encourage* increases in generation from lower- or zero-carbon EGUs") (emphasis added); *cf.* 42 U.S.C. 7651(b) (providing that one purpose of Title IV (but not the CAA overall) is to encourage the "use of renewable and clean alternative technologies").

regulating within them. For example, an on-site control, such as a scrubber, may affect rate determinations as it is factored into potentially recovered costs. The CPP, however, included a BSER that was based largely on measures and subjects exclusively left to FERC and the states, rather than inflicting only permissible, incidental effects on those domains.

The CPP identified as part of the BSER generation-shifting measures. Increased renewable generation capacity, building block 3, falls within a state's authority to determine its generation mix and to direct the planning and resource decisions of utilities under its jurisdiction.[115] Additionally, increased utilization of natural gas combined cycle (NGCC) plants, building block 2, falls within that state authority and within FERC's authority to determine just and reasonable rates by requiring a conclusion that the associated costs of increased utilization rates are reasonable, and, further ignores these areas of exclusive regulation by neglecting to consider changes to regional transmission organization (RTO) and ISO dispatch procedures necessary to achieve the increased utilization rates. By including generation-shifting measures within the states' and FERC's purview in the BSER, rather than relying on traditional controls within the EPA's purview, the EPA established a rule predicated largely upon actions in the power sector outside of the scope of the Agency's authority to compel.

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[115] *See* S.Cal. Edison Co., 71 FERC 61,269 (June 2, 1995); see also *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205, 212 (1983).

Some generation shifting may be an incidental effect of implementing a properly established BSER (*e.g.*, due to higher operation costs), but basing the BSER itself on generation shifting improperly encroaches on FERC and state authorities.

Further, the actual effect of the CPP as anticipated by the EPA was that the states would impose standards of performance based on the EPA's BSER, and sources would largely rely on generation-shifting measures to comply with those standards. In its analysis of potential energy impacts associated with the rule, the CPP modeling "presume[d] policies that lead to generation shifts and growing use of demand-side [energy efficiency] and renewable electricity generation out to 2029."[116] In this manner, the CPP could directly shape the generation mix of a complying state. It is clear from the FPA that Congress intended the states to have that authority, not the relevant federal agency, FERC. Given that even FERC would not have such authority, the only reasonable inference is that Congress did not intend to give the EPA that authority via CAA section 111.[117] Federal law "may not be interpreted to reach into areas of state sovereignty unless the language of the federal law compels the intrusion,"[118] and, as discussed above, basing BSER on generation shifting is not authorized by Congress here. Such an interpretation is also

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[116] 80 FR 64927.

[117] *See Solid Waste Agency of Northern Cook County* v. *U.S. Army Corps of Engineers*, 531 U.S. 159, 172 (2001) (citing *Edward J. DeBartolo Corp.* v. *Florida Gulf Coast Building & Constr. Trades Council*, 485 U.S. 568, 575 (1988)).

[118] *Am. Bar Ass'n* v. *FTC*, 430 F.3d 457 (D.C. Cir. 2005).

consistent with the cooperative-federalism framework of the CAA.[119] While the EPA has previously asserted that the CPP only provides emissions guidelines, leaving the states with the flexibility to create their own compliance measures,[120] the guidelines are based on actions outside of the EPA's authority to directly or indirectly compel and the practical effect of implementing the guidelines is that many of those actions likely must be taken.

(5) Commenters' Attempt To Recharacterize the BSER in the CPP as Applying to Sources By Pointing to "Reduced Utilization" Is Unavailing and Clearly Precluded by the CAA

(a) The CPP Rejected "Reduced Utilization" as a "System" for Purposes of CAA Section 111.

Some commenters claim reduced utilization can be "applied to" a source as an "operational method" for reducing emissions. In the CPP, however, the EPA was clear that reduced utilization on its own "does not fit within our historical and current interpretation of the BSER."[121] The EPA explained: "Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions,"[122] and the EPA has historically based

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[119] *See, e.g.*, 42 U.S.C. 7401(b)(3) and (4), 7402(a) and (b), and 7416.

[120] 80 FR 64762 ("States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO2 emission performance rates").

[121] 80 FR 64780.

[122] *Id.*

pollution control on "methods that allow the same amount of production but with a lower-emitting process."[123] In proposing to repeal the CPP, the EPA noted that, "[w]hereas some emission reduction measures (such as a scrubber) may have an incidental impact on a source's production levels, reduced utilization is directly correlated with a source's output."[124] Accordingly, "predicating a section 111 standard on a source's non-performance would inappropriately inject the Agency into an owner/operator's production decisions."[125] The EPA is finalizing our proposal that reduced utilization cannot be considered a "best system of emission reduction" under CAA section 111(a)(1) because, as the EPA said in the CPP, the EPA has never identified reduced utilization as the BSER and the EPA interprets CAA section 111 to authorize emission limits based on controls that reduce emissions without restricting production. In addition, because the CPP was not premised on "reduced utilization"—indeed, the EPA expressly renounced that as a basis for the CPP—commenters' attempt to justify the CPP on that basis is unavailing.

(b) Standards of Performance Cannot Be Based on Reduced Utilization

Even if the CPP could be reframed as employing reduced utilization, it would fail to satisfy statutory criteria.

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[123] 80 FR 64782 n.602.

[124] 83 FR 44752.

[125] *Id.*

CAA section 302(*l*) provides that a "standard of performance" means "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous reduction." Previously, the Agency has argued that the definitions in CAA section 111(a)(1) "are more specific" and therefore controlling,[126] but, to the extent that section 302(*l*) applies, that definition is met when a standard "applies continuously in that the source is under a continuous obligation to meet its emission rate . . . ."[127]

Here, the Agency concludes that CAA section 302(*l*) is relevant to interpreting CAA section 111.[128] Statutes should be construed "so as to avoid rendering superfluous" any statutory language: "a statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or

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[126] *See* Brief of Respondent at 129–30, *New Jersey* v. *EPA*, No. 05-1097 (consolidated) (D.C. Cir. May 4, 2007).

[127] 80 FR 64841. *See also* 70 FR 28617 ("Even if the 302(*l*) definition applied to the term 'standard of performance' as used in section 111(d)(1), [the] EPA believes that a cap-and-trade program meets the definition. . . . That is, there is never a time when sources may emit without needing allowances to cover those emissions.").

[128] Indeed, the provisions of CAA section 302 are supplanted by provision-specific definitions only to the extent that those specific provisions "expressly" do so. *See, e.g.*, *Alabama Power* v. *Costle*, 636 F.2d 323, 370 (D.C. Cir. 1979) (holding that CAA section 169(1) is controlled by the general definition in CAA section 302(j) with respect to the "rule requirement" in CAA section 302(j) that is not expressly supplanted by CAA section 169(1)).

superfluous, void or insignificant. . . ."[129] Under the CAA, only section 111 requires the establishment of "standards of performance." Thus, ignoring the generally applicable definition in CAA section 302(*l*) in interpreting CAA section 111 would read it out of the statute. Nor is this a situation where Congress provided that the provision-specific definition in CAA section 111 was to supplant the general definition in CAA section 302(*l*). First, the opening phrase of CAA section 302 indicates that the section 302 definitions apply "[w]hen used in this chapter." By contrast, the definitions provisions in some statutes begins with text that expressly provides that the general statutory definitions are supplanted by provision-specific definitions. *See, e.g.*, Clean Water Act (CWA) section 502 (33 U.S.C. 1362) (which begins "Except as otherwise specifically provided. . . ."). Second, one of the CAA section 302 definitions expressly states that it is supplanted by provision-specific definitions.[130]

However, the Agency was wrong to conclude that "a requirement of continuous emission reduction" means only that a standard of performance need apply "on a continuous basis." In fact, Congress used such phrasing in the preceding definition under CAA section 302(k). The terms "emission limitation" and "emission standard" mean "a requirement. . . which limits the quantity, rate, or concentration of emissions

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[129] *Hibbs* v. *Winn*, 542 U.S. 88, 101 (2004). Cf. Brief of Respondent at 129, *New Jersey* v. *EPA* ("[s]pecific terms prevail over the general in the same or another statute which might otherwise be controlling." (citation and quotation marks omitted)).

[130] *See* CAA section 302(j) (which defines "major stationary source" and "major emitting facility" and begins "Except as otherwise expressly provided, ...")

of air pollutants *on a continuous basis*, including any requirement relating to the operation or maintenance of a source *to assure continuous emission reduction*. . . ."[131] Whereas emission limitations and emission standards apply "on a continuous basis, *including any* requirement . . . to assure continuous emission reduction," standards of performance *must* impose a "requirement of continuous emission reduction."

When Congress made explicit the requirement for "continuous emission reduction," it was to "affirm the decisions of four U.S. courts of appeals cases that the [A]ct requires continuous emission reductions to be applied."[132] Thus, as scholar David Currie observed,

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[131] 42 U.S.C. 7602(k) (emphasis added). *See* H.R. 6161, Rep. No. 95-294, 92 (May 12, 1977) ("Without an enforceable emission limitation *which will be complied with at all times*, there can be no assurance that ambient standards will be attained and maintained. Any emission limitation under the [CAA], therefore must be *met on a constant basis*. . . .") (emphasis added).

[132] H.R. Conf. Rep. No. 95-564, 514 (Aug. 3, 1977); see also H.R. No. 95-294, 190 (May 12, 1977) ("To make clear the committee's intent that intermittent or supplemental control measures are not appropriate technological systems for new sources (and to prevent the litigation which has been conducted with respect to use of intermittent or supplemental systems at existing sources), the committee adopted language clearly stating that continuous emission reduction technology would be required to meet the requirements of this section."); and *id.* at 92 ("By defining the terms 'emission limitation,' 'emmission [sic] standard,' and 'standard of performance,' the committee has made clear that constant or continuous means of reducing emissions must be used to meet these requirements."). For example, "The Sixth Circuit has agreed with the Fifth, upholding the EPA's rejection of a provision that would have allowed 'intermittent' controls when necessary to meet ambient standards, adding on the basis of a stray remark of the Supreme Court in *Train* that 'emission

Congress "intended to forbid reliance on intermittent control strategies, such as temporary use of low-sulfur fuels or *reductions in plant output. . . .*"[133] Because standards of performance cannot be based on intermittent control strategies, basing BSER on reduced utilization is statutorily precluded for purposes of CAA section 111.

Finally, basing the BSER on reduced utilization contravenes the plain meaning of a "standard of performance." As the Supreme Court held most recently in *Weyerhaeuser* v. *FWS*, 139 S. Ct. 361 (2018),[134] and previously in *Solid Waste Agency of Northern Cook County*, courts must give statutory terms meaning, even where they are part of a larger statutorily defined phrase.[135] In the phrase "standard of performance," the term "performance" is defined as "[t]he accomplishment, execution, carrying out, . . . [or]

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standards' were only those limiting the 'composition' of an emission, not restrictions on operation or on the content of fuels." David P. Currie, Federal Air-Quality Standards and Their Implementation, 365 American Bar Foundation Research Journal, 376 n.58 (1976).

[133] David P. Currie, Direct Federal Regulation of Stationary Sources Under the Clean Air Act, 128 U. Pa. L. Rev. 1389, 1431 (1980) (emphasis added). Professor Curie also suggests that "the requirement of continuous controls . . . may even have been implicit in the original section 111." *Id.*

[134] 139 S.Ct. at 368–69 (rejecting environmental group's contention that statutory definition of "critical habitat" is complete and does not require independent inquiry into meaning of the term "habitat," which the statute left undefined).

[135] 531 U.S. at 172 (requiring that the word "navigable" in the Clean Water Act's statutorily defined term "navigable waters" be given "effect").

doing of any action or work,"[136] and thus refers to the source's manufacturing or production of product. Reduced utilization does not involve improvements to a source's emissions during "performance;" instead it calls for non-performance—the cessation or limitation of manufacturing or production—of a source. Accordingly, reduced utilization cannot form the basis of a "standard of performance" under CAA section 111.

The definition of "standard of performance," and the scope of the "best system of emission reduction" contained within, confers considerable discretion on the EPA to interpret the statute and make reasonable policy choices pursuant to *Chevron* step two as to what is the best system to reduce emissions of a particular pollutant from a particular type of source. However, by making clear that the "application" of the BSER must be to the source, Congress spoke directly in *Chevron* step one terms to the question of whether the BSER may contain measures other than those that can be put into operation at a particular source: It may not. The approach to BSER in the CPP is thus unlawful and the CPP must be repealed.

C. Independence of the Repeal of the Clean Power Plan

Although this action appears in the same document as the ACE rule and the revisions to the emission

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[136] The Oxford English Dictionary (2d ed. 1989) (1. The carrying out of a command, duty, purpose, promise, etc.; execution, discharge, fulfilment. 2. a. The accomplishment, execution, carrying out, working out of anything ordered or undertaken; the doing of any action or work; working, action (personal or mechanical") and American Heritage Dictionary of the English Language (2d ed. 1969) ("1. The act of performing, or the state of being performed." [perform 1. To begin and carry through to completion]).

guidelines implementing regulations, the repeal of the CPP is a distinct final agency action that is not contingent upon the promulgation of ACE or the new implementing regulations. As explained above, Congress spoke directly to the question of whether CAA section 111 authorizes the EPA to issue regulations pursuant to CAA section 111(d) that call for the establishment of standards of performance based on the types of measures that comprised the second and third building blocks of the CPP's BSER permits the Agency's to consider generation-shifting as a potential system of emission reduction in developing emission guidelines. The answer to that question is no.

The CPP described itself as a "significant step forward in reducing [GHG] emissions in the U.S." and relied "in large part on already clearly emerging growth in clean energy innovation, development and deployment. . . ." 80 FR 64663. Market-based forces have already led to significant generation shifting in the power sector. However, the fact that those market forces have had that result does not confer authority on the EPA beyond what Congress conferred in the CAA.

The EPA does not deny that, if it were validly within the Agency's authority under the statute, regulations that can only be complied with through widespread implementation of generation shifting might be a workable policy for achieving sector-wide carbon-intensity reduction goals. But what is not legal cannot be workable. The CPP's reliance on generation shifting as the basis of the BSER is simply not within the grant of statutory authority to the Agency. The text of CAA section 111 is clear, leaving no interpretive

room on which the EPA could seek deference for the CPP's grid-wide management approach. Accordingly, EPA is obliged to repeal the CPP to avoid acting unlawfully.

Because the EPA exceeded its statutory authority when it promulgated the CPP, the EPA's repeal of that rule will remain valid even if a future reviewing court were to find fault with the separate and distinct legal interpretations and record-based findings underpinning the ACE rule (see Section III) or the new implementing regulations (see Section IV). The EPA today repeals the CPP as a separate action, distinct from its promulgation of the ACE rule and of revisions to its regulations implementing section 111(d). The EPA would repeal the CPP today even if it were not yet prepared to promulgate these other regulations, or indeed if it knew that those other regulations would not survive judicial review.

III. The Affordable Clean Energy Rule

A. The Affordable Clean Energy Rule Background

1. Regulatory Background

In December 2017, the EPA published an Advanced Notice of Proposed Rule Making (ANPRM) to solicit comment on what the Agency should include in CAA section 111(d) emission guidelines, including soliciting comment on the respective roles of the states and the EPA; what systems of emission reduction might be available and appropriate for reducing GHG emissions from existing coal-fired EGUs; and potential flexibilities that could be afforded under the NSR program to improve the implementation of a future

rule. [137] The EPA received more than 270,000 comments on the ANPRM.

Informed by the ANPRM, the EPA then published the ACE proposal, which consisted of three distinct actions: (1) Emission guidelines for GHG emissions from existing coal-fired EGUs, based on application of HRI measures as the BSER; (2) new emission guideline implementation regulations; and (3) revisions to the NSR program to facilitate the implementation of efficiency projects at EGUs.[138]

In this final action, the EPA has determined that the BSER for CO_2 emissions from existing coal-fired EGUs is HRI, in the form of a specific set of technologies and operating and maintenance practices that can be applied at and to certain existing coal-fired EGUs, which is consistent with the legal interpretation adopted in the repeal of the CPP (see above section II). Also, in this action, the EPA has provided information for state plan development. The state plan development discussion is consistent with the new implementing regulations for CAA section 111(d) emission guidelines discussed separately in section IV of this preamble.

As noted above, the EPA also proposed revisions to the NSR program in parallel with the ACE rule and the new implementing regulations. The EPA is not finalizing NSR revisions at this time; instead, the EPA intends to take final action on the proposed revisions at a later date in a separate notification of final action.

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[137] *See* 82 FR 61507 (December 28, 2017).

[138] *See* 83 FR 44746 (August 31, 2018).

2. Public Comment and Hearing on the ACE Proposal

The Administrator signed the ACE proposal on August 21, 2018, and, on the same day, the EPA made this version available to the public at *https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.* The 60-day public comment period on the proposal began on August 31, 2018, the day of publication in the **Federal Register.** The EPA held a public hearing on October 1, 2018, in Chicago, Illinois, and extended the public comment period until October 31, 2018, to allow for 30 days of public comment following the public hearing. The EPA received nearly 500,000 comments on the ACE proposal.

B. Legal Authority To Regulate EGUs

In the CPP, the EPA stated that the Agency's then-concurrent promulgation of standards of performance under CAA section 111(b) regulating CO_2 emissions from new, modified, and reconstructed EGUs triggered the need to regulate existing sources under CAA section 111(d).[139] In ACE, the EPA is not re-opening any issues related to this conclusion, but for the convenience of stakeholders and the public, the EPA summarizes the explanation provided in the CPP here.

CAA section 111(d)(1) requires the Agency to promulgate regulations under which the 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." Under CAA section 111(a)(2) and 40 CFR 60.15(a), a

[139] *See* 80 FR 64715.

"new source" is defined as any stationary source, the construction, modification, or reconstruction of which is commenced after the publication of proposed regulations prescribing a standard of performance under CAA section 111(b) applicable to such source. In the CPP, the EPA noted that, at that time, the Agency was concurrently finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from new sources, which provided the requisite predicate for applicability of CAA section 111(d).[140]

The EPA explained in the CAA section 111(b) rule (80 FR 64529) that "section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list 'if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.' " Then, for the source categories listed under CAA section 111(b)(1)(A), the Administrator promulgates, under CAA section 111(b)(1)(B), "standards of performance for new sources within such category." The EPA further took the position that, because EGUs had previously been listed, it was unnecessary to make an additional finding as a prerequisite for regulating CO_2. The Agency expressed the view that, under CAA section 111(b)(1)(A), findings are category-specific and not pollutant-specific, so a new finding is not needed with regard to a new pollutant. The Agency further asserted that, even if it were required to make a pollutant-specific finding, given the large amount of CO_2 emitted from this source category (the largest

[140] *Id.*

single stationary source category of emissions of CO_2 by far) that EGUs would easily meet the standard for making such a listing. The Agency further took the position that, given the large amount of emissions from the source category, it was not necessary in that rule "for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution."[141]

That CAA section 111(b) rulemaking remains in effect, although the EPA has proposed to revise it.[142] That rule continues to provide the requisite predicate for applicability of CAA section 111(d).

C. Designated Facilities for the Affordable Clean Energy Rule

The EPA is finalizing that a designated facility[143] subject to this regulation is any coal-fired electric utility steam generating unit that: (1) Is not an integrated gasification combined cycle (IGCC) unit (*i.e.*, utility boilers, but not IGCC units); (2) was in operation or had commenced construction on or before January 8, 2014;[144] (3) serves a generator capable of

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[141] *See* 80 FR 64531.

[142] *See* 83 FR 65424.

[143] The term "designated facility" means "any existing facility which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility." *See* 40 CFR 60.21a(b).

[144] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources. January 8, 2014, is the date the proposed GHG standards of performance

selling greater than 25 megawatts (MW) to a utility power distribution system; and (4) has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) heat input of coal fuel (either alone or in combination with any other fuel). Consistent with the new implementing regulations, the term "designated facility" is used throughout this preamble to refer to the sources affected by these emission guidelines.[145] For this action, consistent with prior CAA section 111 rulemakings concerning EGUs, the term "designated facility" refers to a single EGU that is affected by these emission guidelines.

The EPA's applicability criteria for ACE differ from those in the CPP because the EPA's determination of the BSER is only for coal-fired electric utility steam generating units. In the ACE proposal, the EPA did not identify a BSER for IGCC units, oil- or natural gas-fired utility boilers, or fossil fuel-fired stationary combustion turbines and, thus, such units are not designated facilities for purposes of this action. In the ACE proposal (and previously in the ANPRM), the EPA solicited information on the cost and performance of technologies that may be considered as the BSER for fossil fuel-fired stationary combustion turbines and other fossil-fuel fired EGUs. The EPA currently does not have adequate information to determine a BSER

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for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

[145] The EPA recognizes, however, that the word "facility" is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

for these EGUs and, if appropriate, the EPA will address GHG emissions from these EGUs in a future rulemaking.

A coal-fired EGU for purposes of this rulemaking (and consistent with the definition of such units in the Mercury and Air Toxics Standards (MATS) (77 FR 9304)) is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the three previous calendar years. Further, for purposes of this rulemaking, the following EGUs will be excluded from a state's plan: (1) Those units subject to 40 CFR part 60, subpart TTTT as a result of commencing a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 megawatt-hour (MWh) or less on an annual basis; (3) a stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine; (4) an IGCC unit; (5) non-fossil-fuel units (*i.e.*, units capable of combusting at least 50 percent non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (6) units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less; (7) a municipal waste combustor unit subject to 40 CFR part 60, subpart Eb; (8) commercial

or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or (9) a steam generating unit that fires more than 50-percent non-fossil fuels.

D. Regulated Pollutant

The air pollutant regulated in this final action is GHGs. However, the standards in this rule are expressed in the form of limits solely on emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[146] The EPA is not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent significantly less than one percent of total estimated GHG emissions (as CO_2 equivalent) from fossil fuel-fired electric power generating units.[147] Notwithstanding the form of the standard, consistent with other EPA regulations

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[146] In the 2009 Endangerment Finding for mobile sources, the EPA defined the relevant "air pollution" as the atmospheric mix of six long-lived and directly emitted greenhouse gases: Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). *See* 74 FR 66497. Additionally, note that the new CAA section 111(d) implementing regulations at 40 CFR 60.22a(b)(1) do not change the requirement of the previous implementing regulations, 40 CFR 60.22(b)(1) that emission guidelines provide information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant. For this emission guideline, that information is contained in the 2009 Endangerment Finding.

[147] EPA Greenhouse Gas Reporting Program; *www.epa.gov/ghgreporting/*.

addressing GHGs, the air pollutant regulated in this rule is GHGs.[148]

E. Determination of the Best System of Emission Reduction

1. Guiding Principles in Determining the BSER

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that under CAA section 110,[149] under which states submit state plans that establish "standards of performance" for emissions of certain air pollutants from existing sources which, if they were new sources, would be subject to new source standards under CAA section 111(b), and that provide for the implementation and enforcement of those standards of performance. Because CAA section 111(a)(1) defines "standard of performance" for purposes of all of section 111, and because federal standards for new sources established under section 111(b) and standards for existing sources established by a state plan under section 111(d) are both "standards of performance," it is the EPA's responsibility to determine the BSER for designated facilities for standards developed under both CAA section 111(b) for new sources and section 111(d) for existing sources. [150] In making this

[148] *See, e.g.*, 79 FR 34960.

[149] CAA section 110 governs state implementation plans, or SIPs, which states develop and submit for EPA approval and which are used to ensure attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) for criteria pollutants.

[150] *See also* 40 CFR 60.22a. However, while the BSER underlying both new- and existing-source performance standards is determined by the EPA, the performance standards for new sources are directly established by the EPA under section 111 (b),

determination, the EPA identifies all "adequately demonstrated" "system[s] of emission reduction" for a particular source category and then evaluates those systems to determine which is the "best,"[151] while "taking into account" the factors of "cost . . . non-air quality health and environmental impact and energy requirements."[152] Because CAA section 111 does not set forth the weight that should be assigned to each of

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whereas states establish performance standards (applying the BSER) for existing sources in their jurisdiction in their state plans under section 111(d), and Congress has expressly required that EPA permit states, in establishing performance standards for existing sources, to take into account the remaining useful life of the source and other source-specific factors. *See* 42 U.S.C. 7411(d)(1).

[151] The D.C. Circuit recognizes that the EPA's evaluation of the "best" system must also include "the amount of air pollution as a relevant factor to be weighed . . . ." *Sierra Club* v. *Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981). Additionally, a system cannot be "best" if it does more harm than good due to cross-media environmental impacts. *See Portland Cement*, 486 F. 2d at 384; *Sierra Club*, 657 F.2d at 331; see *also Essex Chemical Corp.*, 486 F.2d 427, 439 (D.C. Cir. 1973) (remanding standard to consider solid waste disposal implications of the BSER determination). Nevertheless, CAA section 111 does not require the "greatest degree of emission control" or "mandate that the EPA set standards at the maximum degree of pollution control technologically achievable." *Sierra Club*, 657 F.2d at 330.

[152] The EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide or nationwide basis. Considered on a source-specific basis, "energy requirements" entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs. As discussed in this document, a consideration of "energy requirements" informs the EPA's judgment that repowering and refueling coal-fired facilities to be fueled by natural gas is not appropriate for consideration as BSER here.

these factors, courts have granted the Agency a great degree of discretion in balancing them.[153]

The CAA limits "standards of performance" to systems that can be applied at and to a stationary source (*i.e.*, as opposed to off-site measures that are implemented by an owner or operator, such as subsidizing lower-emitting sources) and that lead to continuous emission reductions (*i.e.*, are not intermittent control techniques). Such systems include add-on controls and lower-emitting processes/practices/designs that can be applied to a designated facility, *i.e.*, a building, structure, facility, or installation regulated under CAA section 111.[154] As discussed in section II of this preamble, this is the only permissible interpretation of the scope of the EPA's authority under CAA section 111. But this clear outer bound on the EPA's authority leaves the Agency considerable room for interpretation and policy choice within that scope in determining the BSER that has been adequately demonstrated to address a particular source category's emission of a given pollutant. Case law under CAA section 111(b) explains that "[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[155] While some of these cases suggest that "[t]he Administrator may make a

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[153] *Lignite Energy*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[154] *See* section 111(a)(3) for definition of "stationary source."

[155] *Essex Chemical Corp.*, 486 F.2d 375, 433–34 (D.C. Cir. 1973).

projection based on existing technology,"[156] the D.C. Circuit has also noted that "there is inherent tension" between considering a particular control technique as both "an emerging technology and an adequately demonstrated technology."[157] Nevertheless, the EPA appears to "have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."[158] The essential question, therefore, is whether the BSER is "available."[159]

In considering the availability of different systems of emission reduction, the "EPA must examine the effects of technology on the grand scale," because CAA section 111 standards are, after all, "a national standard with long-term effects." [160] To that end, the Agency must "consider the representativeness for the industry as a whole of the tested plants on which it

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[156] *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

[157] *Sierra Club* v. *Costle*, 657 F.2d 298, 341 n.157 (D.C. Cir.1981); see also *NRDC* v. *Thomas*, 805 F.2d 410, n.30 (D.C. Cir. 1986) (suggesting that "a standard cannot both require adequately demonstrated technology and also be technology-forcing").

[158] *Sierra Club*, 657 F.2d at 364. It is not clear whether these cases would have applied the same technology-forcing philosophy to the regulation of existing sources, as at least one case noted that section 111 "looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for new plants—old stationary source pollution being controlled through other regulatory authority." *Portland Cement*, 486 F.2d at 391 (emphasis added).

[159] *See Portland Cement* v. *Ruckelshaus*, 486 F.2d at 391.

[160] *Id.* at 330.

relies. . . ."[161] A CAA section 111 standard, therefore, "cannot be based on a 'crystal ball' inquiry."[162]

Whereas the EPA establishes performance standards for new sources under CAA section 111(b), section 111(d) provides *that states* are primarily responsible for regulating existing sources. This bifurcated approach dovetails with testimony offered during development of the CAA Amendments of 1970 (which established the section 111 program)—specifically, Secretary Finch explained that "existing stationary sources of air pollution are so numerous and diverse that the problems they pose can most efficiently be attacked by state and local agencies."[163] Indeed, Congress eventually made explicit the requirement that the EPA allow states to take into account the "remaining useful life" of an existing source, "among other factors," when applying a standard of performance to any particular source.[164] Accordingly, the Agency's identification of the BSER is based on what is "adequately demonstrated" and broadly achievable for a source category across the country, while each state—which will be more familiar with the operational and design characteristics of actually existing sources within their borders—is

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[161] *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416, 432–33 (D.C. Cir. 1980).

[162] *Essex Chemical Corp.*, 486 F.2d at 391.

[163] Testimony of Robert Finch, Secretary of Health, Education, and Welfare (which regulated air pollution prior to the establishment of the EPA) in support of S. 3466/H.R. 15848, before the House Subcommittee on Public Health and Welfare, H. Hearing (May 16, 1970), 1970 CAA Legis. Hist, at 1369.

[164] 42 U.S.C. 7411(d)(1).

responsible for developing source-specific standards reflecting application of the BSER. [165] Indeed, Congress has expressly provided that the EPA must permit states to take into consideration a source's remaining useful life, among other factors, when applying a standard of performance to a particular source.[166]

In the ACE proposal, the EPA provided a discussion of the identified systems of emission reduction and explained why certain systems were eliminated from consideration at a preliminary state or were otherwise determined not to be the "best system." The EPA received public comments that challenged or refuted the Agency's evaluation of these systems of emission reduction. A discussion of those reduction measures and a summary of significant public comments are provided below.

The EPA proposed that "heat rate improvement" (HRI, which may also be referred to as "efficiency improvement") is the BSER for existing coal-fired EGUs. In this action, after consideration of public comments, the EPA is finalizing its proposed determination that HRI is the BSER. The basis for the final determination and a summary of significant public comments received on the proposed determination are discussed below.

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[165] This approach is analogous to the NAAQS program: Where "[e]ven with air quality standards being set nationally . . . the steps needed to deal with existing stationary sources would necessarily vary from one State to another and, within States, from one area to another. . . ." *Id.*

[166] 42 U.S.C. 7411(d)(1).

2. Heat Rate Improvement Is the BSER for Existing Coal-Fired EGUs

a. Background and BSER Determination

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy or fuel heat input (typically measured in British thermal units, Btu) required to generate a unit of electricity (typically measured in kilowatt-hours, kWh). The lower an EGU's heat rate, the more efficiently it converts heat input to electrical output. As a result, an EGU with a lower heat rate consumes less fuel per kWh of electricity generated and, as a result, emits lower amounts of CO_2—and other air pollutants—per kWh generated (as compared to a less efficient unit with a higher heat rate). Heat rate data from existing coal-fired EGUs indicate that there is potential for improvement across the source category.

Heat rate improvement measures can be applied—and some measures have already been applied—to all existing EGUs (supporting the Agency's determination that HRI measures are the BSER). However, the U.S. fleet of existing coal-fired EGUs is a diverse group of units with unique individual characteristics that are spread across the country.[167] As a result, heat rates of existing coal-fired EGUs in the U.S. vary substantially. Thus, even though the

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[167] For example, the current fleet of existing fossil fuel-fired EGUs is quite diverse in terms of size, age, fuel type, operation (*e.g.*, baseload, cycling), boiler type, *etc.* Moreover, geography and elevation, unit size, coal type, pollution controls, cooling system, firing method, and utilization rate are just a few of the parameters that can impact the overall efficiency and performance of individual units.

variation in heat rates among EGUs with similar design characteristics, as well as year-to-year variation in heat rate at individual EGUs, indicate that there is potential for HRI that can improve CO_2 emission performance across the existing coal-fired EGU fleet, this potential may vary considerably at the unit level—including because particular units may not be able to employ certain HRI measures, or may have already done so. Accordingly, the EPA identified several available technologies and equipment upgrades, as well as best operating and maintenance practices, that EGU owners or operators may apply to improve an individual EGU's heat rate. The EPA referred to these HRI technologies and techniques as "candidate technologies" and solicited comment on their technical feasibility, applicability, performance, and cost.

The EPA received numerous public comments, both supporting and opposing, the proposed determination that HRI is the BSER. Many commenters supported the proposed concept of a unit-specific, state-led evaluation of HRI potential as a means of establishing a unit-specific standard of performance. The commenters argued that it is not possible to adopt uniform, nationally applicable standards of performance based on implementation of particular HRI technologies because each individual unit is subject to a unique combination of factors that can affect the unit's heat rate and HRI potential, many of which are geographically driven and outside the control of a source. The EPA agrees with these commenters. As previously mentioned, the U.S. fleet of existing coal-fired EGUs is diverse in terms of size, vintage, fuel usage, design, geographic location, *etc.*

The HRI potential for each unit will be influenced by source-specific factors such as the EGU's past and projected utilization rate, maintenance history, and remaining useful life (among other factors). Therefore, standards of performance must be established from a unit-level evaluation of the application of the BSER and consideration of other factors at the unit level. States are in the best position to make those evaluations and to consider of other unit-specific factors, and indeed CAA section 111(d)(1) directs EPA to permit states to take such factors into consideration as they develop plans to establish performance standards for existing sources within their jurisdiction.

Other commenters opposed the proposed use of unit-specific HRI plans because the commenters believe that this interpretation is inconsistent with the legislative history and that this approach does not enable significant emissions reductions. Some commenters said that defining BSER in terms of operational efficiency (heat rate) is not consistent with the understanding reflected in the EPA's historic practice in all previous CAA section 111(d) rules, where the BSER was determined based on a specific emission reduction technology. The EPA disagrees with the contention. The EPA proposed that HRI through the application of a specific set of emission reduction technologies (discussed in more detail below) and operational practices is the BSER. That approach is consistent with the direction given in the statute. It is also an approach that recognizes the challenges of applying a single specific emission reduction technology within such a diverse population of designated facilities.

After consideration of public comment, the EPA affirms its determination that, as proposed, HRI is the BSER for existing coal-fired EGUs.

b. The List of Candidate Technologies

While a large number of HRI measures have been identified in a variety of studies conducted by government agencies and outside groups,[168] some of those identified technologies have limited applicability and many provide only negligible HRI. The EPA stated in the proposal that it believed that requiring a state in developing its plan to evaluate the applicability to each of its sources of the entire list of potential HRI options—including those with limited applicability and with negligible benefits—would be overly burdensome to the states. Therefore, the EPA identified and proposed a list of the "most impactful" HRI technologies, equipment upgrades, and best operating and maintenance practices that form the list of "candidate technologies" constituting the BSER. The candidate technologies of the BSER are listed in Table 1 below. Those technologies, equipment upgrades, and best operating and maintenance practices were deemed to be "most impactful" because they can be applied broadly and are expected to provide significant HRI without limitations due to geography, fuel type, *etc.* The EPA solicited comment on each of the proposed candidate technologies and on whether any additional technologies should be added to the list, and on whether there is additional information that the EPA should be aware of and

[168] *See* Table 3 in ANPRM, 82 FR 61515.

consider in determining the BSER and establishing the candidate technologies for HRI measures.

The EPA received numerous public comments on the list of candidate technologies. Some commenters stated that there are additional available HRI technologies that should be added to the list of candidate technologies, while many other commenters agreed that the proposed list of "candidate technologies" is reasonable and should be considered the core group for states to evaluate in establishing standards of performance. Commenters agreed that the proposed list of "candidate technologies" focuses the states' standard-setting process on those HRI measures with the greatest ability to impact CO_2 emissions. Commenters further stated that the EPA's proposed candidate technology list will limit the burden on states by eliminating the need to consider measures that would almost certainly be rejected due to negligible emission reduction benefits, disproportionate costs, or availability. However, commenters also noted that there may be additional HRI opportunities available to a significant number of designated facilities and that states should not be required to limit their evaluations to just the "candidate technologies" in establishing unit-specific standards of performance. Some commenters suggested that the EPA establish a process whereby HRI solutions can be added to the list of "candidate technologies."

Commenters also stated that some of the equipment upgrades and operating practices proposed as candidate technologies have the potential to improve an EGU's *net* heat rate by reducing auxiliary load but

would have no impact on the unit's *gross* heat rate.[169] Comments regarding gross versus net heat rate, and gross- versus net-based standards of performance, are discussed in more detail below in section III.F.1.c of this preamble.

The EPA considered the public comments on the BSER technologies and believes that the proposed list still represents the most broadly applicable and impactful collection of HRI measures. Therefore, the EPA is, in this action, finalizing the proposed technologies, equipment upgrades, and best operating and maintenance practices provided in Table 1 of the proposal[170] as the final list of "candidate technologies" whose applicability to each designated facility within their boundaries states must evaluate in establishing a standard of performance for that source in their state plans under CAA section 111(d).

The technologies and operating and maintenance practices listed and described below are generally available and appropriate for all types of EGUs. However, some existing EGUs will have already implemented some of the listed HRI technologies, equipment upgrades, and operating and maintenances practices. There will also be unit-specific physical or cost considerations that will limit or prevent full implementation of the listed HRI technologies and

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[169] The *gross heat rate* is the fuel heat input required to generate a unit of electricity (typically presented in Btu/kWh-gross). The *net heat rate* is the fuel heat input required to generate a unit of electricity minus the electricity that is used to power facility auxiliary equipment (typically presented in Btu/kWh-net).

[170] *See* 83 FR 44757.

equipment upgrades. States will consider these and other factors when establishing unit-level standards of performance. The final list of "candidate technologies"—with the range of expected percent HRI—is provided below in Table 1.

TABLE 1—SUMMARY OF MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI Measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Two of the technologies shown in Table 1—"Blade Path Upgrade (Steam Turbine)" and "Redesign/Replace Economizer"—are candidate technologies that are expected to offer some of the largest improvements in unit-level heat rate. However, based on public comments from the ANPRM and the ACE proposal, those also are HRI technologies that have the most potential to trigger NSR requirements. Industrial stakeholders and commenters have indicated, if such HRI trigger NSR, the resulting requirements for analysis, permitting, and capital investments will greatly increase the cost of implementing those HRI technologies and, in the absence of NSR reforms, states will be more likely to determine that those technologies are not cost-effective when analyzing "other factors" in determining a standard of performance for an individual facility.

For the ACE proposal, the EPA reflected this in assumptions made in the power sector modeling, using the Integrated Planning Model (IPM), to assess potential costs and benefits of the proposed rule. In that modeling, the EPA assumed two different levels of potential HRI (in percentage terms)—a lower expected HRI without NSR reform and a higher expected HRI with NSR reform.[171]

As mentioned earlier in this preamble, the EPA is not taking final action on the proposed NSR reforms in this final rulemaking action; the EPA intends to take final action on that proposal in a separate final action at a later date. Without finalization of NSR reforms, the EPA anticipates that states in some

[171] *See* 80 FR 44783.

instances may determine, when considering other factors, that the candidate technologies, "Blade Path Upgrade (Steam Turbine)" and "Redesign/Replace Economizer," are less appropriate for application to a particular source or sources than the EPA anticipated would be when it proposed the ACE Rule. Nevertheless, the EPA is retaining these two candidate technologies as part of the final BSER, because it still expects these technologies to be generally applicable across the fleet of existing EGUs, and because the costs of the technologies themselves are generally economical and reasonable.

c. Level of Stringency Associated With the BSER

As discussed in section III.B above, the EPA has the authority and responsibility to determine the BSER. CAA section 111(d)(1), meanwhile, clearly assigns states the role of developing a plan that establishes standards of performance for designated facilities (with EPA's authority to promulgate a federal plan serving as a backstop in the event that a state fails to develop a satisfactory plan [172]). Based on these statutory divisions of roles and responsibilities, the EPA proposed to determine the BSER as HRI achievable through implementation of certain technologies, equipment upgrades, and improved O&M practices. The EPA also declined to propose a standard of performance that presumptively reflects application of the BSER because the establishment of standards of performance for existing sources is the states' role. [173] While declining to provide a

[172] *See* section 111(d)(2).

[173] *See* 83 FR 44764.

presumptive standard, the EPA also proposed to provide *information* on the degree of emission limitation achievable through application of the BSER by providing a range of reductions and costs associated with each of the candidate technologies identified as part of the BSER.[174]

The EPA received numerous comments from states and industry requesting that the EPA provide a presumptive standard, or at minimum, additional guidance and clarity on how states could derive a standard of performance that meets the requirements of this regulation. Additionally, several commenters contended that under CAA section 111(a)(1), the EPA is legally obligated to identify "the degree of emission limitation achievable through the application of the [BSER]" (*i.e.*, a level of stringency) because such degree of emission limitation is inextricably linked with the determination of the BSER, which is the EPA's statutory role and responsibility. Upon consideration of these comments, especially the widespread request for more guidance from the EPA on developing appropriate standards of performance, the EPA agrees that it has a responsibility under the CAA to identify the degree of emission reduction that it determines to be achievable through the application of the BSER.

While the CAA provides that the responsibility to establish standards of performance is a state's responsibility, the EPA is identifying the degree of emission limitation achievable through the application of the BSER (*i.e.*, the level of stringency) associated with the candidate technologies. By

[174] *See* 83 FR 44757, Table 1.

providing the level of emissions reductions achievable using the candidate technologies the EPA is fulfilling its responsibility as part of the BSER determination. In this instance, the EPA has identified the degree of emission limitation achievable through application of the BSER by providing ranges of expected reductions associated with each of the technologies. These ranges are provided in Table 1, clearly presenting the percentage improvement ranges that can be expected when each candidate technology comprising the BSER is applied to a designated facility. Defining the ranges of HRI as the degree of emission limitation achievable through application of the BSER is consistent with the EPA's position at proposal, where EPA noted that "while the HRI potential range is provided as guidance for the states, the actual HRI performance for each of the candidate technologies will be unit-specific and will depend upon a range of unit-specific factors. The states will use the information provided by the EPA as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies."[175] For purposes of the final ACE rule, states will utilize the ranges of HRI the EPA has provided in developing standards of performance but may ultimately establish standards of performance for one or more existing sources within their jurisdiction that reflect a value of HRI that falls outside of these ranges. See section III.F.1.a of this preamble.

It is reasonable for the EPA to express the "degree of emission limitation achievable through application of the BSER" as a set of ranges of values, rather than

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[175] *See* 83 FR 44763.

a single number, that reflects application of the candidate technologies as a whole. This approach is reasonable in light of the nature of what the EPA has identified as the adequately demonstrated BSER (as well as of the structure of section 111 in general and the interplay between section 111(a)(1) and section 111(d) in particular): A suite of candidate technologies that the EPA anticipates will be generally applicable to EGUs at the fleet-wide level but not all of which may be applicable or warranted at the level of a particular facility due to source-specific factors such as the site-specific operational and maintenance history, the design and configuration, the expected operating plans, *etc.* Because of the importance for applicability of the BSER of these source-specific factors, and because the application and installation of the candidate technologies will result in varying degrees of reductions based on application of each of the BSER technologies into the existing infrastructure of the EGU, the EPA has provided ranges of HRI associated with each technology. This accounts for some of the variation that is expected among the designated facilities (*see* section III.F.1.a.(1) of this preamble for discussion of variable emission performance at and between designated facilities). While these ranges represent the degree of emission reduction achievable through application of the BSER, a particular designated facility may have the potential for more or less HRI as a result of the application of the candidate technology based on source-specific characteristics. As further discussed in section III.F. of this preamble, the level of stringency associated with each candidate technology is to be used by states in the process of establishing a standard of performance, and in this

process, states may also consider source-specific factors such as variability that may result in a different level of stringency.[176]

d. Detail on the HRI Technologies & Techniques

(1) Neural Network/Intelligent Sootblower

Neural networks. Computer models, known as neural networks, can be used to simulate the performance of the power plant at various operating loads. Typically, the neural network system ties into the plant's distributed control system for data input (process monitoring) and process control. The system uses plant specific modeling and control modules to optimize the unit's operation and minimize the emissions. This model predictive control can be particularly effective at improving the plant's performance and minimizing emissions during periods of rapid load changes—conditions that commenters claimed to be more prevalent now than was the case 5 to 10 years ago. The neural network can be used to optimize combustion conditions, steam temperatures, and air pollution control equipment.

Intelligent Sootblowers. During operations at a coal-fired power plant, particulate matter (PM) (ash or soot) builds up on heat transfer surfaces. This build-up degrades the performance of the heat transfer equipment and negatively affects the efficiency of the plant. Power plant operators use steam injection "sootblowers" to clean the heat transfer surfaces by

[176] As described later in the preamble in section III.F., the EPA envisions states will develop standards of performance for designated facilities in a two-step process where states first apply the BSER and then consider source-specific factors such as remaining useful life.

removing the ash build-up. This is often done on a routine basis or as needed based on monitored operating characteristics. Intelligent sootblowers (ISB) are automated systems that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup.

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed. The ISB software/control system is often incorporated into the neural network software package mentioned above. As such, the HRIs obtained via installation of neural network and ISB systems are not necessarily cumulative.

The efficiency improvements from installation of ISB are often greatest for EGUs firing subbituminous coal and lignite due to more significant and rapid fouling at those units as compared to EGUs firing bituminous coal.

Commenters recommended that the EPA disaggregate its analysis of neural networks and ISB because these technologies do not have to be deployed together and implementing one without the other may be appropriate in many cases. The EPA agrees that the technologies do not have to be implemented together and states must evaluate the applicability and effectiveness of both technologies. The technologies were listed together to emphasize that they are often implemented together and that the resulting HRIs from each are not necessarily additive.

(2) Boiler Feed Pumps

A boiler feed pump (or boiler feedwater pump) is a device used to pump feedwater into a boiler. The

water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler. The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. For example, boiler feed pumps can require power in excess of 10 MW on a 500-MW power plant. Therefore, the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation. Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade.

Commenters stated that because upgrading an electric boiler feed pump impacts only *net* heat rate (and not *gross* heat rate), it should be excluded from the candidate technologies list. The EPA disagrees that candidate technologies affecting only the *net* heat rate should be removed from the candidate technologies list. These technologies improve the efficiency and reduce emissions from the plant by reducing the auxiliary power load, allowing for more of the produced power to be placed on the grid. As is discussed below in section III.F.1.c., the state will determine whether to establish standards of performance as *gross* output-based standards or as *net* output-based standards. If states establish *gross* output-based standards, it will be up to the states to determine how to account for emission reductions that are attributable to technologies affecting only the *net* output.

(3) Air Heater and Duct Leakage Control

The air pre-heater is a device that recovers heat from the flue gas for use in pre-heating the incoming

combustion air (and potentially for other uses such as coal drying). Properly operating air pre-heaters play a significant role in the overall efficiency of a coal-fired EGU. The air pre-heater may be regenerative (rotary) or recuperative (tubular or plate). A major difficulty associated with the use of regenerative air pre-heaters is air in-leakage from the combustion air side to the flue gas side. Air in-leakage affects boiler efficiency due to lost heat recovery and affects the axillary load since any in-leakage requires additional fan capacity. The amount of air leaking past the seals tends to increase as the unit ages. Improvements to seals on regenerative air pre-heaters have enabled the reduction of air in-leakage.

The EPA received comments that claimed the applicability of air pre-heater seals is limited, and that low-leakage seals are not feasible on certain units while other commenters agreed that the HRI estimates for leakage reduction are reasonable, and HRI improvement from 0.25 to 1.0 percent is achievable. The EPA agrees that the HRI estimates for air heater and duct in-leakage are reasonable. The EPA agrees that low-leakage seals are not feasible for certain units (*e.g.*, those using recuperative air heaters). However, the EPA is finalizing a determination that this candidate technology is an element of the BSER because limiting air in-leakage in the air heater and associated duct work can be evaluated on all units and limiting the amount of air in-leakage will improve the efficiency of the unit.

(4) Variable Frequency Drives (VFDs)

VFD on induced draft (ID) fans. The increased pressure required to maintain proper flue gas flow

through downstream air pollutant control equipment may require additional fan power, which can be achieved by an ID fan upgrade/replacement or an added booster fan. Generally, older power plant facilities were designed and built with centrifugal fans.

The most precise and energy-efficient method of flue gas flow control is the use of VFD. The VFD controls fan speed electrically by using a static controllable rectifier (thyristor) to control frequency and voltage and, thereby, the fan speed. The VFD enables very precise and accurate speed control with an almost instantaneous response to control signals. The VFD controller enables highly efficient fan performance at almost all percentages of flow turndown.

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives on fans can greatly enhance plant performance at off-peak loads. Additionally, units with oversized fans can benefit from VFD controls. Under these scenarios, VFDs can significantly improve the unit heat rate. VFDs as motor controllers offer many substantial improvements to electric motor power requirements. The drives provide benefits such as soft starts, which reduce initial electrical load, excessive torque, and subsequent equipment wear during startups; provide precise speed control; and enable high-efficiency operation of motors at less than the maximum efficiency point. During load turndown, plant auxiliary power could be reduced by 30–60 percent if all large motors in a plant were efficiently controlled by VFD. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater and condenser

circulation water pumps, can have significant impacts. There are circumstances in which the HRI has been estimated to be much higher than that shown in Table 1, depending on the operation of the unit. Cycling units realize the greatest gains representative of the upper range of HRI, whereas units which were designed with excess fan capacity will exhibit the lower range.

VFD on boiler feed pumps. VFDs can also be used on boiler feed water pumps as mentioned previously. Generally, if a unit with an older steam turbine is rated below 350 MW, the use of motor-driven boiler feedwater pumps as the main drivers may be considered practical from an efficiency standpoint. If a unit cycles frequently then operation of the pumps with VFDs will offer the best results on heat rate reductions, followed by fluid couplings. The use of VFDs for boiler feed pumps is becoming more common in the industry for larger units. And with the advancements in low pressure steam turbines, a motor-driven feed pump can improve the thermal performance of a system up to the 600-MW range, as compared to the performance associated with the use of turbine drive pumps.

Some commenters stated that VFDs should be excluded from the candidate technologies list because the efficiency improvements are likely near zero when the EGU operates as a baseload unit. Commenters further stated that VFD installation may not be reasonable because of their high cost, large physical size, and significant cooling requirements. The EPA agrees that VFD HRIs will be less effective for units that operate consistently at high capacity factors at base load conditions. However, due to the changing

nature of the power sector (increased use of natural gas-fired generating sources, more intermittent renewable generating sources, *etc.*), many coal-fired EGUs are cycling more often and the heat rate of such units will benefit from installation of VFD technology. In evaluating the applicability of the BSER technologies, states will consider "other factors" that will include expected utilization rate, remaining useful life, physical/space limitations, *etc.* That evaluation of "other factors" will identify whether implementation of a BSER candidate technology is reasonable. The EPA is finalizing a determination that this candidate technology is an element of the BSER because it contributes to emission reductions and it is broadly applicable at reasonable cost.

Commenters also stated that VFDs only impact *net* heat rate, so efficiency improvements may not be cost-effective. As stated earlier, if the states choose to establish *gross* output-based standards of performance, it will be up to the states to determine how to account for emission reductions attributable to improvement to *net* heat rate.

(5) Blade Path Upgrade (Steam Turbine)

Upgrades or overhauls of steam turbines offer the greatest opportunity for HRI on many units. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. The typical turbine upgrade depends on the history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs. The availability of advanced design tools, such as

computational fluid dynamics (CFD), coupled with improved materials of construction and machining and fabrication capabilities have significantly enhanced the efficiency of modern turbines. These improvements in new turbines can also be utilized to improve the efficiency of older steam turbines whose efficiency has degraded over time.

Commenters stated that steam turbine blade path upgrades may not be achievable for every turbine because of the potentially significant variability in an individual turbine's parameters when considering costs. Commenters further noted that these are large investments that can require lengthly outages and long lead times.

Other commenters noted that these steam turbine blade path upgrades have been commercially available for over 10 years and that the HRI estimates in Table 1 appear reasonable.

The EPA agrees that steam turbine blade path upgrades are commercially available and that the HRI estimates in Table 1 appear to be consistent with other estimates of HRI achievable from this type of upgrade. As mentioned earlier, based on public comments responding to the ANPRM and the ACE proposal, this HRI measure has the potential to trigger NSR requirements (in the absence of NSR program reforms), and the EPA anticipates that, among the candidate technologies identified as comprising the BSER, states may be relatively more likely to determine in light of the resulting requirements for analysis, permitting, and capital investments that this candidate technology is not economically feasible when evaluating it in the process of establishing

standards of performance for particular existing sources within their jurisdiction. Nevertheless, the EPA is finalizing a determination that steam turbine blade bath upgrades are part of the BSER because the EPA anticipates they will still be generally available and feasible at a sufficient scale among the nationwide fleet.

(6) Redesign/Replace Economizer

In steam power plants, economizers are heat exchange devices used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater. This use of waste heat reduces the need to use extracted energy from the system and, therefore, improves the overall efficiency or heat rate of the unit. As with most other heat transfer devices, the performance of the economizer will degrade with time and use, and power plant representatives contend that economizer replacements are often delayed or avoided due to concerns about triggering NSR requirements. In some cases, economizer replacement projects have been undertaken concurrently with retrofit installation of selective catalytic reduction (SCR) systems because the entrance temperature for the SCR unit must be controlled to a specific range.

Commenters stated that redesigning or replacing an economizer may be limited for some units by the need to maintain appropriate temperatures at a downstream SCR system for nitrous oxides (NO_X) control. Commenters also stated that applicability of this measure will be site-specific because boiler layout and construction varies widely between units. Commenters stated that the values in Table 1 appear to reflect a major economizer redesign which may not

be possible for many units. The EPA agrees that there will likely be site-specific factors that must be considered to determine whether economizer redesign/replacement is a feasible HRI option (as is the case for all the BSER candidate technologies). Nevertheless, the EPA is finalizing a determination that economizer upgrades (or replacement) are part of the BSER because the EPA anticipates they will still be generally available and feasible at a sufficient scale among the nationwide fleet. As mentioned earlier, states may take into consideration site-specific characteristics ("other factors") when establishing a standard of performance for each unit.

(7) HRI Techniques—Best Operating and Maintenance Practices

Many unit operators can achieve additional HRI by adopting best O&M practices. The amount of achievable HRI will vary significantly from unit to unit, ranging from no improvement to potentially more than 2.0 percent depending on the unit's historical O&M practices. In setting a standard of performance for a specific unit or subcategory of units, states will evaluate the opportunities for HRI from the following actions.

(a) Adopt HRI Training for O&M Staff

EGU operators can obtain HRI by adopting "awareness training" to ensure that all O&M staff are aware of best practices and how those practices affect the unit's heat rate.

Some commenters agreed that HRI training can improve staff awareness of plant efficiency measures, which should result in improved plant performance. Other commenters stated that the benefits of HRI

training are highly variable and depend on existing equipment and staff. Some commenters stated that the operating staff already routinely undergo HRI training and that states should not be required to consider these measures in developing their plans. The EPA agrees that the benefits will be variable from unit to unit depending upon the unit's historical O&M practices. If operating staff at a source already undergo routine HRI training, then the state will note that in the standard-setting process. Just as an EGU that has recently installed new or reconstructed boiler feed pumps would not be expected to replace those pumps, a source that already has an effective HRI training program in place would not be expected to implement a new HRI training program. The EPA is finalizing a determination that this practice is an element of the BSER because it can result in emission reductions and can be broadly implemented at reasonable cost.

(b) Perform On-Site Appraisals To Identify Areas for Improved Heat Rate Performance

Some large utilities have internal groups that can perform on-site evaluations of heat rate performance improvement opportunities. Outside (*i.e.*, third-party) groups can also provide site-specific/unit-specific evaluations to identify opportunities for HRI.

Commenters stated that the benefits of on-site appraisals are variable, speculative, and site-specific. Commenters stated that no state should determine what opportunities a coal-fired EGU might find during an on-site appraisal, and, therefore, that states should not be required to evaluate the applicability of on-site appraisals when developing their plans and

establishing standards of performance for existing sources within their jurisdiction. The EPA agrees that the benefits of on-site appraisals will be variable and site-specific. As with other BSER measures, it will be up to each state to determine the extent of this requirement. States may require that the owner/operator perform an on-site appraisal to identify areas for HRI or the state may choose to have a third party conduct an on-site HRI appraisal.

(c) Improved Steam Surface Condenser—Cleaning

Effective operation of the steam surface condenser in a power plant can significantly improve a unit's heat rate. In fact, in many cases ineffective operation can pose the most significant hindrance to a plant trying to maintain its original design heat rate. Since the primary function of the condenser is to condense steam flowing from the last stage of the steam turbine to liquid form, it is most desirable from a thermodynamic standpoint that this occurs at the lowest temperature reasonably feasible. By lowering the condensing temperature, the backpressure on the turbine is lowered, which improves turbine performance.

Condenser cleaning. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly increases the backpressure of the condenser and degrades the quality of the water. Condenser tube cleaning can be performed using either on-line methods or more rigorous off-line methods.

Commenters stated that improved steam surface condenser cleaning is a viable O&M option.

Commenters stated that the need for such cleaning can be determined by enhanced monitoring of condenser performance. The EPA agrees with this assessment and notes that many owner/operators may already have steam surface condenser cleaning as part of routine O&M for their units. The EPA is finalizing a determination that this O&M practice is an element of the BSER because it provides opportunity for heat rate improvement and is broadly applicable.

e. Cost of HRI

The EPA finds that the costs of the HRI technologies and practices that the EPA has identified as the BSER and provided in Table 1 are reasonable because they improve the efficiency of the units to which they are applied. This results in lower operating costs (especially lower fuel costs). In fact, these HRI technologies and practices are the types of efficiency improvement measures that some owners and operators have reasonably implemented at times over the course of the operating life of their EGUs. In specific circumstances the cost to implement one or more of the technologies may be determined to be unreasonable—after consideration of source-specific factors. This will be determined when states establish standards by applying the BSER and taking other factors, including remaining useful life, into consideration.

(1) Reasonableness of Cost

As mentioned earlier, under CAA section 111(a)(1), the EPA determines "the best system of emission reduction which (taking into account the *cost* of achieving such reduction . . .) . . . has been adequately demonstrated." 42 U.S.C. 7411(a)(1) (emphasis

added). In several cases, the D.C. Circuit has elaborated on this cost factor in various ways, stating that the EPA may not adopt a standard for which costs would be "exorbitant,"[177] "greater than the industry could bear and survive," [178] "excessive," [179] or "unreasonable."[180] These formulations appear to be synonymous and suggest a cost-reasonableness standard. Therefore, in this action, the EPA has evaluated whether the costs of HRI are considered to be reasonable as a general matter across the fleet of existing sources.

Any efficiency improvement made by an EGU will also reduce the amount of fuel consumed per unit of electricity output; fuel costs can account for a large percentage of the overall costs of power production. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving HRIs after any savings from reduced fuel expenses. So, over some time period (depending upon, among other factors, the extent of HRIs, the cost to implement such improvements, and the unit utilization rate), the savings in fuel cost associated with HRIs may be sufficient to cover the costs of implementing the HRI measures. Thus, the net costs of HRIs associated with reducing CO_2 emissions from designated facilities can be relatively low depending upon each EGU's individual circumstances. It should be noted that this cost evaluation is not an attempt to determine the affordability of the HRI in a business or economic

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[177] *Lignite Energy*, 198 F.3d at 933.

[178] *Portland Cement*, 513 F.2d at 508.

[179] *Sierra Club*, 657 F.2d at 343.

[180] *Id.*

sense (*i.e.*, the reasonableness of the imposed cost is not determined by whether there is an economic payback within a predefined time period). However, the ability of EGUs to recoup some of the costs of HRIs through fuel savings supports a finding that costs are reasonable. While some EGUs may not realize the full potential of cost recuperation from fuel savings, the EPA finds that the net costs of implementing HRIs as an approach to reducing CO_2 emissions from fossil fuel-fired EGUs are reasonable because they are not exorbitant or excessive. In fact, these HRIs are the types of efficiency improvement measures that some owners and operators have reasonably implemented at times over the course of the operating life of their EGUs.

It will be up to the states to, either directly or indirectly, take cost into consideration in establishing unit-specific standards of performance. CAA section 111(d) explicitly allows the states to take into consideration, among other factors, the remaining useful life of the existing source in applying the standard of performance. For example, a state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable when consideration is given to the timeframe for the planned retirement of the source (*i.e.*, the source's remaining useful life). A state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable because the source is already implementing that HRI technology and it would not be reasonable to expect the source to replace that HRI technology with a newer version of the same technology.

There are several ways that cost can be considered. For example, when evaluating costs for criteria pollutants in a BACT analysis or for a "beyond-the-floor" analysis for HAP under CAA section 112, the emphasis is focused on the cost of control relative to the amount of pollutant removed—a metric typically referred to as the "cost-effectiveness." There have been relatively few BACT analyses evaluating GHG reduction technologies for coal-fired EGUs. Therefore, there are not a large number of GHG cost-effectiveness determinations to compare against as a measure of the cost reasonableness. Nevertheless, in PSD and title V permitting guidance for GHG emissions, the EPA noted that "it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification—through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis."[181] The EPA has also noted that a "number of energy efficiency technologies are available for application to both existing and new coal-fired EGU projects that can provide incremental step improvements to the overall thermal efficiency."[182]

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[181] See page 21, "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA-457/B-11-001, March 2011; *https://www.epa.gov/sites/production/files/2015-12/documents/ghgpermitting guidance.pdf*.

[182] *See* page 25, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units," October 2010; *https://www.epa.gov/sites/production/files/2015-12/documents/electric generation.pdf*.

(2) Cost of the HRI Candidate Technologies Measures

The estimated costs for the BSER candidate technologies are presented below in Table 2. These are cost ranges from the 2009 Sargent & Lundy Study[183] updated to $2016.[184] These costs correspond to ranges of HRI (percent) presented earlier in Table 1.

[183] "Coal-Fired Power Plant Heat Rate Reductions" Sargent & Lundy report SL-009597 (2009) Available in the rulemaking docket at EPA-HQ-OAR-2017-0355-21171.

[184] The conversion factor comes from Federal Reserve Economic Data (FRED). *See https://fred.stlouisfed.org*.

TABLE 2—SUMMARY OF COST ($2016/KW) OF HRI MEASURES

HRI Measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	4.7	4.7	2.5	2.5	1.4	1.4
Boiler Feed Pumps	1.4	2.0	1.1	1.3	0.9	1.0
Air Heater & Duct Leakage Control	3.6	4.7	2.5	2.7	2.1	2.4
Variable Frequency Drives	9.1	11.9	7.2	9.4	6.6	7.9
Blade Path Upgrade (Steam Turbine)	11.2	66.9	8.9	44.6	6.2	31.0
Redesign/Replace Economizer	13.1	18.7	10.5	12.7	10.0	11.2
Improved O&M Practices	Minimal capital cost					

These costs presented in Table 2 represent both capital and O&M costs. Investments in HRI measures at EGUs should also result in fuel savings which can offset some or all of the cost of the HRI. However, the EPA does not suggest that HRI measures should meet any particular economic criterion (*e.g.*, pay for themselves through reduced fuel costs) in order to be applied in state plans for the establishment of source-specific standards of performance.

The technical applicability and efficacy of HRI measures and the cost of implementing them are dependent upon site specific factors and can vary widely from site to site. Because there is inherent flexibility provided to the states in applying the standards of performance, there is a wide range of potential outcomes that are highly dependent upon how the standards are applied (and to what degree states take into consideration other factors, including remaining useful life).

Because the heat rate improvement technologies result in fuel savings and other potential cost savings and the listed candidate technologies are the types of improvements and equipment upgrades that have been previously undertaken, the EPA finds that the costs of the HRI technologies and practices that have been identified as the BSER and provided in Table 1 are reasonable.

f. Non-Air Quality Health and Environmental Impacts, Energy Requirements, and Other Considerations

As directed by CAA section 111(a)(1), the EPA has taken into account non-air quality health and environment requirements for each of the candidate

BSER technologies listed in Tables 1 and 2. None of the candidate technologies, if implemented at a coal-fired EGU, would be expected to result in any deleterious effects on any of the liquid effluents (*e.g.*, scrubber liquor) or solid by-products (*e.g.*, ash, scrubber solids). The EPA has also taken into account energy requirements. All of these candidate technologies, when implemented, would have the effect of improving the efficiency of the coal-fired EGUs to which they are applied. As such, the EGU would be expected to use less fuel to produce the same amount of electricity as it did prior to the efficiency (heat rate) improvement. None of the candidate technologies is expected to impose any significant additional auxiliary energy demand.

Implementation of heat rate improvement measures also would achieve reasonable reductions in CO_2 emissions from designated facilities in light of the limited cost-effective and technically feasible emissions control opportunities. In the same vein, because existing sources face inherent constraints that new sources do not, existing sources present different, and in some ways more limited, opportunities for technological innovation or development. Nevertheless, the final emissions guidelines encourage technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency leading to reasonable reductions in CO_2 emissions.

3. Discussion of "Rebound Effect"

At proposal, the EPA solicited comment on potential CO_2 emissions and generation changes that might

occur as a result of efficiency improvements at designated facilities, including potential increased generation to the point of a net increase in emissions from a particular facility, also referred to as the "rebound effect." In some instances, it is possible that certain sources increase in generation (relative to some baseline) as a result of lower operating costs from adoption of candidate technologies to improve their efficiency. The EPA conducted analysis and modeling for the ACE proposal, and found that while there were instances (in some scenarios) where a limited number of designated facilities that adopted HRI increased generation to the point of increasing mass emissions notwithstanding the lower emissions rate resulting from HRI adoption, due to their improved efficiency and marginally improved economic competitiveness relative to other electric generators, the designated facilities as a group reduce emissions because they can generate higher levels of electricity with a lower overall emission rate.

Some commenters on the proposed rule highlighted environmental and legal concerns with the rebound effect as undermining the BSER, while others commented that the concern was de minimis, not rooted in any legal basis, and not germane to establishing standards of performance. On one side, some commenters asserted that the determined BSER is not properly designed because it would not achieve emission reductions if it results in higher utilization and, therefore, emission increases. Some doubted the EPA claims of lower systemwide emissions and said the EPA had not adequately analyzed the concern. Some asserted that the assumptions used in the analysis do not reflect real world considerations that

efficiency of all fossil fuel plants degrades over time, rather than being static. Also, some asserted that the EPA had understated the amount of coal capacity that will likely retire in its analysis, and, thus, the remaining coal fleet will consist of more efficient and competitive units that may end up emitting more than the EPA's analysis shows. In addition, some asserted that the EPA's proposed NSR reforms allow sources to extend lifetimes without requiring controls, exacerbating rebound issues.

Other commenters asserted that CAA section 111 does not require the Agency to obtain absolute reductions in emissions at a sector-wide level, and the EPA's obligation is to determine the BSER through evaluation of emissions performance per output at the unit-level. Some commenters stated that any rebound effect from more efficient units is most likely to come at expense of lower-efficiency coal units, negating the effect. Also, commenters contended that rebound is unlikely to change the dispatch order and/or utilization of units based upon the levels of HRI that are reasonable and part of ACE, and, thus, any rebound effect would be de minimis.

The EPA agrees with the commenters who do not see the rebound effect as undermining the BSER determination in this rule, because this rule is aimed at improving a source's emissions *rate* performance at the unit-level. Indeed, in repealing the "percent reduction" requirement from the 1977 CAA Amendments, Congress expressly acknowledged that standards of performance were to be expressed as an

emissions rate.[185] In addition, as noted above, this rule results in overall reductions of emissions of CO_2. Because the BSER in this rule improves the emissions rate of designated facilities and results in overall reductions, the limited rebound effect that may occur does not undermine the BSER.

Nonetheless, to the extent commenters have asserted that ACE would cause an increase in aggregate CO_2 emissions due to some sources operating more, this concern is not supported by our analysis. The EPA conducted updated modeling and analysis for the final ACE rule (see Chapter 3 of the RIA for more details) and confirmed that aggregate CO_2 emissions from the group of designated facilities are anticipated to decrease (outweighing any potential CO_2 increases related to increased generation by certain units).

The final ACE rule establishes the BSER, and a framework for states to determine rate-based standards of performance for designated facilities. The BSER for ACE is expressed as a rate-based approach, which should necessarily result in rate-based emission reductions. The modeling and analysis show individual units and the entire coal fleet reducing emission rates, as well as an aggregate decrease in mass emissions. As such, any potential "rebound effect" is determined to be small and

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[185] *See* 1990 CAA Amendments, section 403, 104 Stat. at 2631 ("the Administrator shall promulgate revised regulations for standards of performance . . . that, at a minimum, require any source subject to such revised standards to emit sulfur dioxide at a *rate* not greater than would have resulted from compliance by such source with the applicable standards of performance under this section prior to such revision") (emphasis added).

manageable (if necessary) and does not require any specific remedy in the final rule. However, if a state determines that the source-specific factors of a designated facility dictate that the rebound effect is an issue that should be considered in setting the standard of performance, that is within the state's discretion to consider in the process of establishing a standard of performance for that particular existing source. As noted above and as a result of modeling, the EPA does not expect these considerations to be necessary in the state plan development process.

4. Systems That Were Evaluated But Are Not Part of the Final BSER

The EPA identified several systems of GHG emission reduction that may be applied at or to designated facilities but did not propose that they should be part of the BSER. The Agency solicited comment on the rationale for eliminating or not identifying those alternative systems as part of the BSER. After consideration of public comments, the EPA is not revising its proposed determination and is not including any additional or different systems of emission reduction in the final BSER determination. A description of the considered systems of emission reduction that are not part of the final BSER along with a summary of significant public comments is provided below.

The EPA previously considered co-firing (including 100 percent conversion) with natural gas and implementation of carbon capture and storage (CCS) as potential BSER options. *See* 80 FR 64727. In that analysis, the EPA found some natural gas co-firing and CCS measures to be technically feasible but

determined that switching from coal to gas is "a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements. . ."[186] and that the cost to implement CCS for existing source standards is not reasonable and that "CCS is not an appropriate component of the [BSER]."[187] A more detailed description of the current consideration of these technologies is provided below,

a. Natural Gas Repowering

Coal-fired utility boilers can reduce their emissions by firing natural gas instead of—or in combination with—coal. This can be done in three different ways: (1) By repowering, (2) by co-firing, or (3) by refueling. *Repowering* is when an existing coal-fired boiler is replaced with one or more natural gas-fired stationary combustion turbines, while still utilizing the existing steam turbines. *Co-firing* and *refueling* involve the burning of natural gas at an existing boiler.[188]

In the ACE proposal, the EPA did not consider natural gas repowering as a potential system of emission reduction (*i.e.*, as a candidate for the BSER) based on the reasoning that this option would fundamentally redefine the existing sources subject to

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[186] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units; Chapter 6, June 10, 2014, Available at Docket Item No. EPA-HQ-OAR-2013-0602-36852.

[187] *Id.* Chapter 7

[188] Co-firing and refueling are discussed in section III.E.4.b of this preamble.

the rule.[189] Some commenters argued, however, that coal-fired utility boilers can reduce emissions through natural gas repowering and it should be the BSER. Other commenters argued that the 'redefining the source' concept from PSD was inappropriate for application to NSPS. After considering public comments on this issue, the EPA concludes that repowering should not be considered for purposes of CAA section 111(d). As described in more detail below, repowering is not a "system" of emission reduction for a source at all because it cannot be applied to the existing sources subject to this rule (steam generating units). Rather, repowering these existing units would replace them entirely with a different type of source (stationary combustion turbines) that would be subject to the NSPS in 40 CFR part 60, subpart TTTT.[190] Even if repowering were to be evaluated to determine if it was part of the BSER, the EPA has found non-air quality health and environmental impacts and energy requirements that demonstrate that repowering is not part of the BSER.[191]

As described above, a "standard of performance" under CAA section 111(d) must be "establishe[d]" for

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[189] *See* 83 FR 44753.

[190] The EPA is not concluding whether or not the 'redefining the source' concept can or should be applied in the context of the NSPS program.

[191] These non-air quality health and environmental impacts and energy requirements are discussed in more detail below in the discussion of refueling and co-firing. Except to the extent that discussion involves the inefficient combustion of natural gas, the non-air quality health and environmental impacts and energy requirements found for these technologies are similar, if not identical, to those the EPA has found for repowering.

an "existing source." However, repowering a coal-fired boiler—that is, the replacement of a boiler with a stationary combustion turbine—creates a "new source," which is regulated directly by the EPA under 40 CFR part 60, subpart TTTT (establishing standards for the control of GHG emissions from new, modified, or reconstructed steam generating units, IGCCs, or *stationary combustion turbines*). The "best system of emission reduction" for an *existing* source, therefore, simply cannot be the creation of a *new* source that is regulated under separate authority. Otherwise, the EPA could subvert the provisions of CAA section 111(d) (which authorizes states to regulate existing sources in the first instance) and require all existing sources to transform into "new sources," which the Agency can directly regulate under CAA section 111(b). Therefore, repowering a coal-fired boiler is not a "system" within the scope of the BSER.

b. Natural Gas Co-Firing and Refueling

Some coal-fired utility boilers use natural gas or other fuels (such as distillate fuel oil) for startup operations, for maintaining the unit in "warm standby," or for NO_X control (either directly as a combustion fuel or in configuration referred to as natural gas reburn). During such periods of natural gas co-firing, an EGU's CO_2 emission rate is reduced as natural gas is a less carbon intensive fuel than coal. For example, at 10 percent natural gas co-firing, the net emissions rate (lb/MWh-net) of a typical unit could decrease by approximately 4 percent.

Commenters stated that the EPA should determine that natural gas co-firing is the BSER because it is technically feasible, readily available, achieves

significant emission reductions, and may be the most cost-effective option for some facilities. Some commenters also provided data (from EIA) to assert that co-firing is widely used and adequately demonstrated at coal-fired EGUs. The commenters contended that a significant number of coal-fired EGUs have the capacity to burn both natural gas and coal. One commenter asserted that 35 percent of coal-fired utility boilers across 33 states co-fired with natural gas. Another commenter provided a table listing coal-fired EGUs that have recently converted to natural gas or are co-firing with natural gas. One commenter cited data from the EIA and claimed that 48 percent of steam generating EGUs are already co-firing some amount of natural gas.

While the EPA agrees with the assertion that there are existing coal plants that have some access to a supply of natural gas, the EPA disagrees that the data demonstrate that co-firing is a system of emission reduction that has been or that could be implemented on a nationwide scale at reasonable cost. The EPA believes that commenters have conflated operational co-firing (*i.e.*, co-firing coal and natural gas to generate electricity) with startup co-firing (*i.e.*, only using natural gas to heat up a utility boiler or to maintain temperature during standby periods). Coal-fired boilers always use a secondary fuel (most often natural gas or distillate fuel oil), utilizing burners specifically configured to bring the boiler from a cold, non-operating status to a temperature where coal, the primary fuel, can be safely introduced for normal operations.

The EPA conducted its own analysis using EIA fuel use data from 2017.[192] The EPA's analysis supports the assertion that nearly 35 percent of coal-fired units co-fired (in either sense of co-firing as described above) with natural gas in 2017. However, very few—less than four percent of coal-fired units—co-fired with natural gas in an amount greater than five percent of the total annual heat input. This strongly suggests that most of the natural gas that was utilized at these sites was used as a secondary fuel for unit startup or to maintain the unit in "warm standby" rather than as a primary fuel for generation of electricity. Further, the small number of units that co-fired with greater than five percent natural gas during 2017 operated at an average capacity factor of only 24 percent—indicating that they are not the most economical units and are not dispatched as frequently as those units that used less than five percent natural gas. For comparison, in 2017, 62 percent of coal-fired utility boilers co-fired with some amount of distillate fuel oil and, as with natural gas, the vast majority of those units used less than 5 percent distillate fuel oil (again, strongly suggesting that it is primarily used as a secondary fuel for startup and warm standby).

The EPA also disagrees that the data demonstrate that co-firing can be considered at the national level as an adequately demonstrated system of emission reduction and that there are easy paths to expand it at a reasonable cost. The EIA 923 fuel use data indicated that about 65 percent of coal-fired utility boilers use

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[192] See the memorandum "2017 Fuel Usage at Affected Coal-fired EGUs," available in the rulemaking docket (Docket ID No. EPA-HQ-OAR-2017-0355).

something other than natural gas as the secondary fuel for periods of startup and standby operations. Distillate fuel oil is by far the most commonly used secondary fuel. While the use of distillate fuel oil does not necessarily mean that the unit lacks access to natural gas, it suggests that for many of those units, there is an inadequate supply to serve even as a secondary fuel for startup and standby operations. The 2018 average price [193] of distillate fuel oil was more than four times higher than that of natural gas; so, if there was an adequate supply of natural gas, then it would be much more economically favorable to utilize that natural gas rather than the much more expensive distillate fuel oil. As explained earlier, for plants that require additional or new pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. Therefore, a 50-mile gas pipeline would add $50 million—$100/kW for a typical 500 MW unit—to the capital costs of adding co-firing capability.

As mentioned earlier, the EPA has previously evaluated the costs associated with using natural gas refueling or co-firing as a GHG mitigation option. *See* 79 FR 34875. For a typical base-load coal-fired EGU, the average cost of CO_2 reductions achieved through co-firing with 10 percent natural gas would be approximately $136 per ton of CO_2. While a utility boiler that is converted to 100 percent natural gas-fired can offset some of the capital costs by reducing

[193] The 2018 average U.S. power generation fuel costs for natural gas was $3.52 per million Btu while the cost for distillate fuel oil for power generation was $16.13 per million Btu. U.S. EIA Short Term Energy Outlook, *https://www.eia.gov/outlooks/steo/tables/pdf/2tab.pdf*.

its fixed operating and maintenance costs (though, as discussed below, the costs would still be considerably higher than the HRI technologies that the EPA identified as the BSER), a unit that is co-firing natural gas with coal would continue to bear the fixed costs associated with equipment needed for coal combustion, raising the cost per ton of CO_2 reduced.

In determining the BSER, CAA section 111(a)(1) also directs the EPA to take into account non-air quality health and environmental impacts and energy requirements. The EPA is unaware of any significant non-air quality health or environmental impacts associated with natural gas co-firing. However, in taking energy requirements into account, the EPA notes that co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and, as noted above, can lead to less efficient operation of utility boilers. NGCC stationary combustion turbine units are much more efficient at using natural gas as a fuel for generating electricity and it would not be an environmentally positive outcome for utilities and owner/operators to redirect natural gas from the more efficient NGCC EGUs to the less efficient utility boilers to satisfy an emission standard at the utility boiler. Some commenters disagreed with the EPA's claim that increased use of natural gas in a utility boiler would come at the expense of its use in more efficient NGCC units. The EPA did not intend to imply that there is now (or that there will be) a restricted supply of natural gas. Instead, the EPA suggested that, if there were to be an increase in the use of natural gas, the more efficient use for that increased natural gas would be as fuel for under-utilized NGCC units rather than in less

efficient utility boilers. The EPA does not believe that establishing a BSER that, for all practical purposes, would mandate increased use of natural gas in utility boilers is good policy.

Given that a natural gas co-firing-based BSER would result in standards that are more costly than standards based on application of the candidate technologies for heat rate improvements, that such a BSER would encourage inefficient use of natural gas, that implementation would be even more expensive and challenging for those units that currently have limited or no access to natural gas, the EPA concludes that co-firing natural gas in coal-fired boilers is not the BSER.

Some commenters requested that co-firing be added to the list of HRI candidate technologies (discussed in more detail below), the combination of which would represent the BSER. However, whereas all coal-fired utility boilers can apply (or have already applied) HRI measures, natural gas co-firing does not satisfy the same CAA section 111(a)(1) criteria (see above). Moreover, co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product.[194] And depending on the design of the boiler and extent of modifications, some

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[194] Natural gas firing or co-firing degrades the boiler's efficiency (relative to the use of coal) primarily due to the increased production of water. Some of the heat that is produced in the combustion process will be used to heat that flue gas moisture (which will exit with the stack gases) rather than to converting water in the boiler tubes to steam. The efficiency declines because there is less heat available to produce useful steam.

boilers may be forced to de-rate (a reduction in generating capacity) to maintain steam temperatures at or within design limits, or for other technical reasons. Accordingly, natural gas co-firing cannot be applied in combination with the HRI measures identified as the BSER. However, natural gas co-firing might be appropriate for certain sources as a compliance option. Fora discussion of compliance options, see below section III.F.2.

Some commenters also suggested that the EPA's concerns about using gas inefficiently were not persuasive because the United States has such an abundant supply of natural gas. The EPA disagrees for many of the same reasons that the Agency relied upon to reject the consideration of natural gas as the BSER. First, it is on the higher end of the cost of the measures the EPA considered even for units with ready natural gas availability; second, many designated facilities do not have natural gas availability, so it is not broadly applicable.

The same factors discussed above lead the Agency to conclude that refueling also cannot be BSER. *Refueling* is when an existing coal-fired boiler is converted to a natural gas-fired boiler (*i.e.*, firing 100% natural gas). In the ACE proposal, the EPA did not consider natural gas refueling as a potential system of emission reduction (*i.e.*, as a candidate for the BSER) based on the reasoning that this option would fundamentally redefine the existing sources subject to the rule.[195] Some commenters argued, however, that coal-fired utility boilers can reduce emissions through natural gas refueling and should be the BSER. Other

[195] *See* 83 FR 44753.

commenters argued that the 'redefining the source' concept from PSD was inappropriate for application to NSPS.[196] After considering public comments on this issue, the EPA concludes that natural gas refueling, like natural gas co-firing, is not the BSER.

The EPA has previously evaluated the costs associated with using natural gas refueling or co-firing as a GHG mitigation option.[197] The capital costs of plant modifications required to switch a coal-fired EGU completely to natural gas are roughly $100–300/kW, not including any costs associated with constructing additional pipeline capacity. Many coal-fired plants do not have immediate and ready access to any supply of natural gas. Others that do have access to a supply of natural gas have only a limited supply (*i.e.*, enough for startup and warm standby firing, but not enough for full load firing). For plants that require additional pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. A 50-mile gas pipeline would add $50 million—$100/kW for a typical 500 MW unit—to the capital costs of the conversion.

While a coal-fired utility boiler that is converted to a 100 percent natural gas-fired boiler could offset some of the capital costs by reducing its fixed operating and maintenance costs, in most cases, the most significant cost change associated with switching from coal to gas is likely to be the difference in fuel cost. Using the

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[196] As with repowering, the EPA is not concluding whether or not the "redefining the source" concept can or should be applied in the context of the NSPS program.

[197] *See* 79 FR 34875.

EIA's projections of future coal and natural gas prices, switching a utility boiler from coal-fired to natural gas-fired could more than double the unit's fuel cost per MWh of generation. For a typical base-load coal-fired EGU, the average cost of CO_2 reductions achieved through gas conversion would be approximately $75 per ton of CO_2. This cost could also be much higher as there would very likely be an increase in natural gas prices corresponding to the increased demand from widespread coal-to-gas conversion.

The EPA also found that consideration of energy requirements (as required by CAA section 111(a)(1)) provides additional reasons why refueling natural gas in a utility boiler should not be considered BSER.[198] Burning natural gas in a utility boiler is not the best use of such fuel as it is much less efficient than burning it in a combustion turbine. New natural gas combined cycle (NGCC) units can convert the heat input from natural gas to electricity with an efficiency of more than 50 percent.[199] A coal-fired utility boiler that is repurposed to burn 100 percent natural gas will see a reduction in efficiency of up to five percent (to less than 40 percent efficiency) as the higher hydrogen content in the natural gas fuel will lead to higher moisture losses that will negatively impact the boiler efficiency.[200] Widespread refueling is not a practice

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[198] *See* 83 FR 44762.

[199] "Cost and Performance Baseline for Fossil Energy Plants Volume la: Bituminous Coal (PC) and Natural Gas to Electricity" Rev. 3, DOE/NETL-2015/1723 (July 2015).

[200] "Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers", Babcock Power

that the EPA should be promoting as it is not the most efficient use of natural gas. Utilities choosing to increase use of natural gas in a combined cycle or simple cycle combustion turbine is a more efficient way to utilize natural gas for electricity generation. In reaching this determination, the EPA is mindful of Congress's direction to "tak[e] into account . . . energy requirements" in determining the best system of emission reduction in CAA section 111(a)(1). Consideration of "energy requirements" is one of the factors informing the EPA's judgment that it would be inappropriate to base performance standards on an inherently energy-inefficient practice such as refueling.

NGCC units have become the preferred option for intermediate and baseload natural gas power generation. Other technologies (such as simple cycle aeroderivative turbines) offer significant advantages for peaking purposes in that they can start up quickly and require fewer staff to operate. Some combination of aeroderivative turbines and flexible combined cycle units offer advantages in both efficiency and the flexibility to change loads when compared to utility boilers. For these reasons, the power sector has moved away from the use of gas-fired boilers. There have been no new natural gas-fired utility boilers built since the 1980s.

There have been some cases where coal-fired utility boilers have chosen to refuel (*i.e.*, have chosen to convert to natural gas-firing). In those cases, the motivation was largely to preserve reserve capacity

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Services, Presented at 2014 ASME Power Conference (July 2014), Baltimore, MD. Available in the rulemaking docket.

without investing in the air pollution controls needed to meet air emission standards—especially MATS.[201] The EPA examined fuel use data submitted by plant owner/ operators to the U.S. Energy Information Administration (EIA) on Form 923.[202] According to that data, there were 131 natural gas-fired utility boilers[203] in 2012 and 170 such units in 2017. The average capacity factor for those units was only 11 percent in 2012 and 2017. Between 2012 (before the MATS compliance date) and 2017 (after MATS was fully in effect), 39 utility boilers converted from coal-fired units to become natural gas-fired utility boilers. Those natural gas-fired utility boilers operated at an average capacity factor of less than 10 percent, indicating that they were likely utilized only during periods of high demand.

These non-air quality health and environmental impacts and energy requirements demonstrate that refueling is not the BSER.

c. Biomass Co-Firing

The EPA previously proposed that co-firing of biomass in coal-fired utility boilers is not the BSER for existing fossil fuel-fired sources due to cost and

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[201] *See* 40 CFR part 63, subpart UUUUU.

[202] Monthly fuel use data is submitted to the EIA on Form 923. Available at *https://www.eia.gov/electricity/data/eia923/*. For details of the EPA data analysis, see the memorandum "2017 Fuel Usage at Affected Coal-fired EGUs" available in the rulemaking Docket ID No. EPA-HQ-OAR-2017-0355.

[203] Natural gas-fired utility boilers are those with capacity of more than 25 MW that use more than 90 percent natural gas on a heat input basis.

achievability considerations.[204] Although biomass co-firing methods are technically feasible and can be cost-effective for some designated facilities, these factors and others (namely, that any potential net reductions in emissions from biomass use occur outside of the regulated source and are outside of the control of the designated facility, which is incompatible with the interpretation of the EPA's authority and the permissible scope of BSER as set forth in section II above) are the considerations that prevent its adoption as the BSER for the source category.

In the ACE proposal, the EPA sought comment on the inclusion of forest-derived and non-forest biomass as non-BSER compliance options for affected units to meet state plan standards.[205] In response, the EPA received comments both supporting and opposing the use of biomass for compliance (as discussed in section III.F.2.b); however, commenters also spoke to the appropriateness of including biomass firing as part of the BSER. Some commenters noted that co-firing with biomass cannot be a "system of emission reduction" as it increases CO_2 emissions at the source. Commenters further asserted that the EPA has failed to demonstrate how firing biomass meets the CAA section 111 requirements and the criteria for qualifying as a system of emission reduction described in the Proposed Repeal and the ACE proposal.

Upon consideration of comments and in accordance with the plain language of CAA section 111 (discussed above in section II.B), the EPA is now clarifying that

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[204] *See* ACE proposal and 80 FR 64756.

[205] *See* 83 FR 44766.

biomass does not qualify as a system of emission reduction that can be incorporated as part of, or in its entirety, as the BSER. As described in section III.F.2 of this preamble, the BSER determination must include systems of emission reduction that are achievable at the source. While the firing of biomass occurs at a designated facility, biomass firing in and of itself does not reduce emissions of CO_2 emitted from that source. Specifically, when measuring stack emissions, combustion of biomass emits more mass of emissions per Btu than that from combustion of fossil fuels, thereby increasing CO_2 emissions at the source. Recognition of any potential CO_2 emissions reductions associated with biomass utilization at a designated facility relies on accounting for activities not applied at and largely not under the control of that source, including consideration of offsite terrestrial carbon effects during biomass fuel growth, which are not a measure of emissions performance at the level of the individual designated facility. Use of biomass in affected units is therefore not consistent with the plain meaning of "standard of performance" and cannot be considered as part of the BSER.[206]

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[206] Notwithstanding this conclusion in the context of CAA section 111(d), the EPA believes that a PSD permitting authority may still reach the conclusion that use of some type(s) of biomass is BACT for greenhouse gases in the context of a PSD permit application where the applicant proposes to use biomass, as discussed in the EPA's Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production (March 2011). While biomass combustion may result in more greenhouse gas emissions (in particular CO_2) per unit of production than combustion of fossil fuels, a comparative analysis of biomass and other fuels may not be required in the BACT context. As EPA has observed, "where a

Additionally, many commenters agreed with the ACE proposal that biomass co-firing should not be part of the BSER because it is not sufficiently cost-effective, there is not a reliable supply of biomass fuel accessible nationally, co-firing with biomass has a negative impact on unit heat rate, and co-firing requirements would "redefine the source." Many commenters supported inclusion of fuel co-firing as a component of the BSER but focused primarily on argument for natural gas co-firing (as discussed earlier). Some of these commenters specifically asserted that biomass use is a widely available and proven GHG reduction technology.

As discussed by the EPA previously in the ACE proposal and other instances,[207] biomass fuel use

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proposed bioenergy facility can demonstrate that utilizing a particular type of biogenic fuel is fundamental to the primary purpose of the project, then at the first step of the top-down process, permitting authorities can rely on that to determine that use of another fuel would redefine the proposed source." Bioenergy BACT Guidance at 15. Moreover, even if biomass is compared to fossil fuels and ranked lower at Step 3 of a top-down BACT analysis, broader offsite environmental, economic, and energy considerations related to biomass use (*e.g.*, any potential offsite net carbon sequestration associated with growth of the biomass feedstock) may be considered in Step 4 of a top-down BACT analysis. See Bioenergy BACT Guidance at 20–21. It is therefore consistent to determine that the firing of biomass does not qualify as a "standard of performance" for setting or complying with the BSER because it does not reduce the GHG emissions of a fossil fuel-fired source, while also allowing the consideration of any potential offsite environmental, economic, or energy attributes when considering an application that treats biomass as BACT for a proposed biomass facility in the PSD permitting context.

[207] *See* 80 FR 64756.

opportunities are dependent upon many regional considerations and limitations—namely fuel supply proximity, reliability and cost—that prevent its adoption as BSER on a national level (whereas nearly all sources can or have implemented some form of HRI measures). The infrastructure, proximity, and cost aspects of co-firing biomass at existing coal EGUs are similar in nature and concept to those of natural gas. While there are a few existing coal-fired EGUs that currently co-fire with biomass fuel, those are in relatively close proximity to cost-effective biomass supplies. Therefore, even if biomass firing could be considered a "system of emission reduction," the EPA is not able to include the use of biomass fuels as part of the BSER in this action due to the current cost and achievability considerations and limitations discussed above. Additional discussion on biomass is provided in section III.F.2.b. below.

d. Carbon Capture and Storage (CCS)[208]

In the ACE proposal, the EPA noted that while CCS is an advanced emission reduction technology that is currently under development, the Agency must balance the promotion of innovative technologies against their economic, energy, and non-air quality health and environmental impacts. The EPA proposed that neither CCS nor partial CCS are technologies

[208] CCS is sometimes referred to as Carbon Capture and Sequestration. It is also sometimes referred to as CCUS or Carbon Capture Utilization and Storage (or Sequestration), where the captured CO_2 is utilized in some useful way and/or permanently stored (for example, in conjunction with enhanced oil recovery). In this document, the EPA considers these terms to be interchangeable and for convenience will exclusively use the term CCS.

that can be considered the BSER for existing fossil fuel-fired EGUs and explicitly solicited comment on any new information regarding the availability, applicability, costs, or technical feasibility of CCS technologies.

Many commenters agreed with EPA's proposed finding that CCS (including partial CCS) should not be part of the BSER. The commenters stated that it is not adequately demonstrated, sufficiently cost-effective, or nationally available. Other commenters disagreed and claimed that CCS is technically feasible and adequately demonstrated and should be part of BSER, asserting that the EPA has previously provided evidence in the record during the 2016 denial of petitions for reconsideration of the CPP that CCS had been successfully implemented at power plants. Commenters also asserted that there are many vendors that offer carbon capture technologies for power plants, which demonstrates that the technology is commercially available and adequately demonstrated.

CCS is a difficult and complicated process, requiring numerous pieces of process equipment to capture CO_2 from the exhaust gas, compress it for transport, transport it in a CO_2 pipeline, inject it, and then monitor the injection space to ensure the CO_2 remains stored. Currently there are only two large-scale commercial applications of post-combustion CCS at a coal-fired power plant—the Boundary Dam project in Saskatchewan, Canada and the Petra Nova project at the W.A. Parish plant near Houston, Texas. [209]

[209] Several commenters noted that the Petra Nova project received funding from the U.S. Department of Energy (DOE)

Commenters noted that both of the demonstration projects were heavily subsidized by government support and were able to generate additional income from the sale of captured CO_2 for enhanced oil recovery (EOR) and, without these subsidies, neither project would have been economically viable.

Commenters addressed the cost of installing CCS on an existing coal-fired EGU and noted that it can be much costlier and more technically challenging to retrofit the technology to an existing EGU as compared to installation on a newly constructed unit (where the system can be incorporated into the design and space allocation of the new plant). Other commenters claimed that CCS can achieve significant emission reductions (up to 90 percent), that there is opportunity for some sources to generate income from the sale of captured CO_2, and that there are additional financial incentives from the recently approved 2018 Internal Revenue Code (IRC) section 45Q tax credits for stored CO_2, so now CCS may be more cost-effective than HRI options for some facilities. One commenter performed modeling runs that included the section 45Q tax credit and found that, for some sources, CCS would provide much greater emission reductions than HRI options at a reasonable cost and concluded that

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through the Clean Coal Power Initiative and stated that the project is, pursuant to section 402(i) of the Energy Policy Act of 2005 (EPAct05), therefore, precluded from being used to demonstrate that the technology is "adequately demonstrated" under section 111 of the CAA. Some commenters noted that the DOE funding was only for the initial 60 MW slip-stream demonstration project, but the CCS project at Petro Nova was later expanded to a 240 MW slip-stream and no federal funding was received for this expansion.

the EPA should include CCS as part of the BSER. Other commenters minimized the impact of the section 45Q tax credit for a variety of reasons.

Several commenters claimed that access to appropriate CO_2 storage locations is critical to the feasibility and cost of CCS. They described the geographic limitations of both deep saline aquifers and depleted oil fields (EOR fields) noting that 15 states have little or no demonstrated storage capacity or have very limited storage capacity and that EOR sites are similarly geographically limited, with 19 states having little or no demonstrated EOR opportunity. However, other commenters claimed that a technology need not be feasible at every site to be a component of BSER especially since the EPA is relying on site-specific analyses. The commenters noted that not all HRI options are applicable to every source, so the EPA cannot disregard CCS from the BSER options based on "national availability."

Commenters noted that 60 GW (or about 20 percent) of the coal-fired power plant capacity might be amenable to CCS based on locality and that North America has widespread and abundant geologic storage options with the capacity to sequester over 500 years of the U.S.'s current energy-related CO_2 emissions. Commenters claimed that 90 percent of existing coal-fired power plants are within 100 miles from the center of a basin with adequate storage capacity and more than half of the existing plants are less than 10 miles from the center of a basin.

The EPA has considered all these public comments and has concluded that, as proposed, CCS is not the BSER for emissions of CO_2 from existing coal-fired

EGUs—nor does it constitute a component of the BSER, as some commenters have suggested. As discussed in section III.E.1, above, concerning the "guiding principles" for identifying the BSER under CAA section 111(d), the BSER is based on what is adequately demonstrated and broadly achievable across the country. Under CAA section 111(b)(1), the EPA determines "standards of performance" for new sources and under section 111(d)(1), the states determine "standards of performance" for existing sources within their jurisdiction. Importantly, the term "standard of performance" is given a uniform definition under section 111(a)(1) for purposes of both new and existing sources, and, in accordance with that definition, the Administrator is required to determine the BSER as a predicate for the standards of performance for both new and existing sources. In this manner, the text and structure of section 111 indicate that the EPA must make the BSER determination at the national, source-category level. Thus, the EPA disagrees with the commenters who argue that because the EPA is emphasizing that standard setting will be done on a unit-by-unit (rather than fleetwide) basis, all viable emission reduction options should be evaluated at the unit level.

Whereas HRI measures are broadly applicable to the entire existing coal-fired power plant fleet, the EPA determines that CCS or partial CCS is not. The EPA agrees that there may be some existing coal-fired EGUs that find the application of CCS to be technically feasible and an economically viable control option, albeit only under very specific circumstances. However, the high cost of CCS, including the high capital costs of purchasing and installing CCS

technology and the high costs of operating it, including high parasitic load requirements, prevent CCS or partial CCS from qualifying as BSER on a nationwide basis.

According to the DOE National Energy Technology Laboratory (NETL), the incremental cost from capital expenditures alone of installing partial or full capture CCS [210] on a new coal-fired EGU ranged from $626 (for 16% capture) to $2,098 (for full capture) per kW (2011 dollars).[211] These costs are for new CCS equipment installed on a new facility, but they fairly represent the costs of new CCS equipment installed on an existing facility; indeed, these costs are probably lower than the actual costs of installing new CCS equipment on an existing facility, because the costs of retrofitting pollution controls on an existing facility generally are greater than the costs of installing pollution controls on a new facility. In contrast, as noted elsewhere, the cost of the HRI that constitute the BSER for this rule range from $25–$47 per kW (2016 dollars). Thus, the costs of partial CCS, considering only the capital costs and not the operating costs, are far higher than—more than 13 times—the cost of what the EPA has identified as the BSER.

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[210] Full capture is considered to occur when 100 percent of the flue gas is treated, resulting in a 90 percent reduction in emissions of CO_2 relative to a power plant without carbon capture.

[211] "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO2 Capture Rate in Coal-Fired Power Plants," une 22, 2015; DOE/NETL-2015/1720 *https://www.netl.doe.gov/projects/files/[FRDoc.SupplementSensitivitytoCO2CaptureRatein[FRDoc.CoalFiredPowerPlants_062215.pdf.*

Viewing the costs of CCS through other prisms yields the same determination. According to NETL, the capital costs of a CCS system with 90 percent capture increases the cost of a new coal-fired power plant approximately 75 percent relative to the cost of constructing a new coal-fired power plant without post-combustion control technology. Furthermore, the additional auxiliary load required to support the CCS system consumes approximately 20 percent of the power plant's potential generation.[212] The NETL Pulverized Coal Carbon Capture Retrofit Database tool (April 2019) [213] estimates that the operating costs of existing coal-fired EGUs range from 22 to 44 $/MWh.[214] The incremental increase in generating costs, including the recovery of capital costs over a 30-year period, due to CCS range from 56 to 77 $/MWh[215]

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[212] A CCS system requires both auxiliary steam and electricity to operate. According to NETL, a full capture system consumes 53 MW of direct electrical load and steam that could have otherwise been used to generate approximately 86 MW of electricity.

[213] *https://www.netl.doe.gov/energy-analysis/details?id=2949.*

[214] Existing coal-fired power plants have generally already paid off the initial construction (*i.e.*, capital) expenses.

[215] Variable operating costs represent approximately $15/MWh and the remaining costs are recovered capital over a 30-year period. The capital costs assume the power plant can recover the costs over 30 years. If the actual remaining useful life of the power plant itself is less, the costs would be higher because the capital would have to be recovered over a shorter time period. The average age of the remaining coal fleet is approximately 42 years, and the average age of retirement for coal-fired power plants is currently 54 years *(http://www.americaspower.org/wp-content/uploads/2018/03/Coal-Facts-August-31-2018.pdf).* Therefore, a significant

For reference, according to the EIA, the average electricity price for all sectors in March of 2019 was 103.8 $/MWh.[216] About 60 percent of these latter costs (60 $/MWh) are associated with generation and 40 percent with transmission and distribution of the electricity. [217] Thus, the incremental increase in generating costs due to CCS by itself would equal or exceed the average generation cost of electricity for all sectors. The costs of partial CCS are less than full CCS, but due to economies of scale, costs do not reduce as quickly as reductions in the capture rate. For example, the capital costs of treating only 18 percent of the flue gas (a 16 percent reduction in emissions of CO_2) are about 30 percent of the capital costs of treating all of the flue gas (full capture or a 90 percent reduction in emissions of CO_2). Similarly, at full capture, treating only 18 percent of the flue gas (a 16 percent reduction in emissions of CO_2) still increases the cost of electricity by about 28 percent of the increase that results from treating all of the flue gas.[218] Again, these costs are probably lower than the actual costs of installing new CCS equipment on an existing facility. Not only are these costs far higher than what the EPA has identified as the BSER, they would almost certainly force the closure of the coal-

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portion of the existing coal-fired will likely retire in less than 30 years.

[216] *https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t-epmt_5_6_a.*

[217] *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&cases=ref2019&sourcekey=0.*

[218] "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants," June 22, 2015; DOE/NETL-2015/1720.

fired power plants that would be required to install them. Many of those plants have a marginal profit margin, as demonstrated by the high rate of plant closure and the relatively low amounts of operation (*i.e.*, capacity factors) in recent years. Thus, these costs must be considered exorbitant. *See* section III.E.1. for a discussion of the guiding principles in determining the BSER.

As noted above, the Boundary Dam project in Saskatchewan, Canada and the Petra Nova project at the W.A. Parish plant near Houston, Texas are the only large-scale commercial applications of post-combustion CCS at a coal-fired power plant. They both have retrofit CCS or partial CCS, and they both received significant governmental subsidies—including, for the Petra Nova project, both direct federal grants from the DOE through the Clean Coal Power Initiative and the IRC section 45Q tax credits—and relied on nearby EOR opportunities. Due to the high costs of CCS, all of these subsidies and EOR opportunities were essential to the commercial viability of each project.[219]

Some commenters have asserted that the costs of CCS are reasonable and explain, as a central part of their assertion, that the availability of tax credits under section 45Q, as revised by the Bipartisan Budget Act of 2018, significantly lowers the costs of

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[219] The EPA discussed the government funding and the EOR revenue from the transport of captured CO_2 to the Hilcorp's West Ranch Oil Field in "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units," 80 FR 64510, 64551 (October 23, 2015).

CCS. In fact, they have asserted, that the tax credits, which have an initial value of $35 per tonne (*i.e.*, metric ton) for CO_2 stored through EOR, offset about 70% of the cost of CCS, with EOR offsetting the rest.[220] However, the section 45Q tax credits are limited in time: The credit for equipment placed in service after the date of enactment of the Bipartisan Budget Act of 2018 is available, in general, only for facilities and equipment for which construction begins before January 1, 2024. IRC section 45Q(d)(1). Under the present rule, state plans are not required to be submitted until mid-2022 and the states have the authority to determine their sources' compliance schedule; compliance schedules are generally expected to last 24 months (*i.e.*, until mid-2024), but could in some instances be longer, as noted in preamble section III.F.1.a.(2).[221] In order for sources to implement CCS and be able to rely on the 45Q tax credit, they would have to complete all planning, including arranging all financing, preconstruction permitting, and commence construction within about 18 months (by December 31, 2023) of the state plan submittal. The EPA considers that timetable to be impracticably short for most sources, considering the complexity of implementation of CCS. In addition, the tax credit is, in general, available only for the 12-year period beginning on the date the equipment is originally placed in service. IRC section 45Q(a)(3)–(4). Thus, it would not be available to offset much of the capital costs of the CCS systems

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[220] EPA-HQ-OAR-2017-0355-24266 at 18.

[221] By comparison, the implementation period for the CPP began three years after the state plan submittal. *See* 80 FR at 64669.

that are recovered over a 30-year period.[222] Further, like any federal income tax credit, the 45Q tax credits do not provide a benefit to a company that does not owe federal income tax, and thus it may not benefit some coal-fired power plant owners. Accordingly, the 45Q tax credits cannot be considered to offset the high costs of CCS for the industry as a whole. While nearby EOR opportunities are available for some EGUs, they alone cannot offset the high costs of CCS, as is evident from the comments discussed above.

In addition, nearby EOR opportunities are not available for many EGUs, which, as a result, would incur higher costs for constructing and operating pipelines to transport CO_2 long distances. Throughout the country, 29 states are identified as having oil reservoirs amenable to EOR, of which only 12 states have active EOR operations.[223] The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and

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[222] The NETL Pulverized Coal Carbon Capture Retrofit Database tool (April 2019) defaults to a capital recovery factor based on 30 years. Capital recovery factors based on 10 and 20 years are also selectable. If shorter periods are selected, the $/MWh for capital recovery would be higher. Table 10-12 of The Integrated Planning Model (version 6) uses a 15-year capital recovery factor for environmental retrofits, *https://www.epa.gov/sites/production/files/2019-03/documents/chapter_10.pdf*. Recovering costs over a 12-year period, as opposed to a 30-year period, increased the capital recovery factor by 40 percent.

[223] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL) and EPA Greenhouse Gas Reporting Program, *see https://www.epa.gov/ghgreporting*.

southeast New Mexico. States where EOR is utilized include Alabama, Arkansas, Colorado, Louisiana, Michigan, Mississippi, Montana, New Mexico, Oklahoma, Texas, Utah, and Wyoming, whereas coal-fired generation capacity is located across the country. [224] For example, Georgia, Minnesota, Missouri, Nevada, North Carolina, South Carolina, and Wisconsin have coal-fired generation capacity but do not have oil reservoirs that have been identified as amenable for EOR. In addition, some of the states with the largest amounts of coal-fired generation capacity have no active EOR operations, including Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Even in states that are identified as having potential oil and gas storage capacity, the amount of storage resource varies by state. In some states, the total oil and gas storage resource is smaller than the annual energy-related CO_2 emissions from coal, including Indiana and Virginia.[225] The limited geographic availability of EOR, and the consequent high costs of CCS for much of the coal fleet, by itself means that CCS cannot be considered to be available across the existing coal fleet.

The high costs of CCS inform the Administrator's determination that this technology is not BSER. Some

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[224] U.S. Energy Information Administration, Electric Power Annual 2017, *see https://www.eia.gov/electricity/annual/pdf/epa.pdf.*

[225] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL) and U.S. Energy Information Administration, Energy-Related Carbon Dioxide Emissions by State, 2005–2016, *see https://www.eia.gov/environment/emissions/state/analysis/*

commenters have suggested that CCS be treated as BSER for some facilities on a unit-by-unit basis, but the EPA believes that this would be inconsistent with its role under section 111(a)(1) to determine as a general matter what is the BSER that has been adequately demonstrated, taking into account, among other factors, cost. To treat CCS as BSER for a handful of facilities would result in those facilities becoming subject to high costs from CCS—potentially much higher than those imposed on other facilities for whom CCS is not treated as BSER. This potential disparate impact of costs is inconsistent with the Administrator's role in determining BSER and is another reason why the Administrator is finalizing a determination that CCS is not BSER.

Nevertheless, while many commenters argued that CCS should not be considered part of the BSER, they supported its use as a potential compliance option for meeting an individual unit's standard of performance. The EPA agrees with this assessment. Evaluation of the technical feasibility (*e.g.*, space considerations, integration issues, *etc.*) and the economic viability (*e.g.*, the prospects and availability of long-term contractual arrangements for sale of captured CO_2, the cost of constructing a CO_2 pipeline, the availability of tax credits, *etc.*) of a CCS project is heavily dependent on source-specific characteristics. Accordingly, state plans may authorize such projects for compliance with this rule.

F. State Plan Development

1. Establishing Standards of Performance

CAA sections 111(d)(1) and 111(a)(1) collectively establish and define certain roles and responsibilities

for the EPA and the states. As discussed in section III.B above, the EPA has the authority and responsibility to determine the BSER. CAA section 111(d)(1) clearly contemplates that states will submit plans that establish standards of performance for designated facilities (*i.e.*, existing sources).

States have broad flexibility in setting standards of performance for designated facilities. However, there is a fundamental obligation under CAA section 111(d) that standards of performance reflect the degree of emission limitation achievable through the application of the BSER, which derives from the definition for purposes of section 111 of "standard of performance" in those terms, with no distinction made between new-source and existing-source standards. In establishing such standards of performance, the statute expressly provides that states may consider a source's remaining useful life and other factors. Accordingly, based on both the mandatory and discretionary aspects of CAA section 111(d), a certain level of process is required of state plans: Namely, they must demonstrate the application of the BSER in establishing a standard of performance, and if the state chooses, the consideration of remaining useful life and other factors in applying a standard of performance to a designated facility. The EPA anticipates that states can correspondingly establish standards of performance by performing two sequential steps, or alternatively, as further described later in this section, by performing these two steps simultaneously. The two steps to establish standards of performance are: (1) Reflect the degree of emission limitation achievable through application of the BSER,

and, if the state chooses, (2) consider the remaining useful life and other source-specific factors.

If a state chooses to develop standards of performance through a sequential (*i.e.*, two step) process, the state would as the first step apply the BSER to a designated facility's emission performance (*e.g.*, the average emission rate from the previous three years or a projected emission rate under specific conditions such as load) and calculate the resulting emission rate. In this step, states fulfill the obligation that standards of performance reflect the degree of emission limitation achievable by evaluating the applicability of each of the candidate technologies that comprise the BSER to a specific designated facility and calculating a corresponding standard of performance based on the application of all candidate technologies that the state determines are applicable to the specific designated facility. A state may determine the most appropriate methodology to calculate a standard of performance (which for purposes of this regulation will be in the form of an emission rate, as further described in section III.F.1.c. of this preamble) by applying the BSER to a designated facility based on the characteristics of the specific source (*e.g.*, load assumptions and compliance timelines). For example, a state can start with the average emission rate of a particular designated facility and adjust it to reflect the application of each candidate technology and the associated emission rate reduction.

As the second step, under this two-step, sequential process approach, after the state calculates the emission rate that reflects application of the BSER, the state may adjust that rate by considering the remaining useful life of the designated facility and

other source-specific factors. It should be noted that the state is not required to take this second step and consider remaining useful life and other factors. Rather, the state has the discretion to do so. A discussion on how a state can consider remaining useful life and other factors, if it so chooses, can be found in section III.F.1.b. below. States also have the discretion to apply a specific standard of performance to a group of existing sources within their jurisdiction, or to all existing sources within their jurisdiction.

As just described, the EPA believes it would be reasonable for states to follow a sequential two-step process to establish standards of performance. However, a state may develop its own process for calculating standards of performance outside of this two-step process, such as a hybridized approach which blends the two sequential steps into one combined step, so long as the state plan submission demonstrates application of the BSER in determining each standard of performance, (*i.e.*, evaluation of applicability of each and all candidate technologies to each designated facility). For example, if a state determines that the designated facility is able to implement only four of the six candidate technologies (due to the remaining useful life or other factors), the state is required to demonstrate in its plan submission that it in fact considered the two remaining candidate technologies in making this determination.

For the two-step approach, a state could do this by explaining in its plan submission that it considered the application of each of the candidate technologies in the first instance, but in the second step the state determined that the two candidate technologies should not be part of the methodology to calculate the

EGU's standard of performance because of remaining useful life or other factors. The state should additionally provide a rationale for why and how it considered remaining useful life and other factors to discount a particular candidate technology from the calculation of a standard of performance (*e.g.*, by explaining that such technology has already been implemented by a particular source).

For a hybridized approach, when the state is applying the BSER and determining the emission reductions associated with the candidate technologies for a specific designated facility, it may be readily apparent that two of the candidate technologies are not reasonable to install because, for example, those technologies have recently been updated at the unit, independent of this final rule. This hybridized approach, which blends application of the BSER and associated stringency with consideration of remaining useful life and other factors in one step to calculate a standard of performance, may be appropriate provided that the state plan clearly demonstrates the standard of performance (expressed as a degree of emission limitation) that would result from application of the BSER and provides a rationale for why and how remaining useful life and other factors were considered to discount a particular candidate technology from the calculation of a standard of performance. This is one illustrative way in which states can demonstrate, in establishing a standard of performance, that they have both fulfilled their obligation to apply the degree of emission limitation achievable through the BSER to each designated facility and also properly invoked their discretion in considering remaining useful life and other factors.

In this section of the preamble, the EPA addresses discrete aspects of the standard-setting process. It is intended to provide states clarity and direction on each of these aspects to assist the states in developing standards of performance. The EPA is not requiring a specific method for states to develop standards of performance.

a. Application of the BSER

As described in other parts of this section, while the EPA's role is to determine the BSER, CAA section 111(d)(1) squarely places the responsibility of establishing a standard of performance for an existing designated facility on the state as part of developing a state plan. This final rule requires states to evaluate the applicability of each of the candidate technologies (HRI measures) that the EPA has determined constitute the BSER in establishing a standard of performance for each designated facility within their jurisdiction. The BSER is a list of candidate technologies that are HRI measures, which states will evaluate and apply to existing sources, establishing a standard of performance that is appropriately tailored to each existing source.[226] In establishing a standard of performance, a state may consider remaining useful life and other factors as appropriate based upon the specific characteristics of those units. In general, the EPA envisions that the states would set standards based on considerations most appropriate to

[226] Because the candidate technologies that comprise the BSER can, at least in some cases, be applied in combination at an individual source, states should evaluate both individual candidate technologies and combinations of candidate technologies to appropriately establish standards of performance.

individual sources or groups of sources (*e.g.*, subcategories). These may include consideration of historical emission rates, effect of potential HRIs (informed by the information in the EPA's candidate technologies described earlier in section III.E), or changes in operation of the units, among other factors the state believes are relevant. As such, states have considerable flexibility in determining standards of performance for units, as contemplated by the express statutory text.

States have discretion to apply the same standard of performance to groups of existing sources within their jurisdiction, as long as they provide a sufficient explanation for this choice and a demonstration that this approach will result in standards of performance achievable at the sources. But states also have discretion, expressly conferred on them by Congress in CAA section 111(d), to take into account a source's remaining useful life and other factors when establishing a standard of performance of that source, and much of the discussion in this final rule relates to the nature of that discretion and the factors that should influence states' exercise of it. As the EPA described in the proposal and as commenters have verified, the fleet of coal-fired EGUs is diverse and each EGU has been designed and engineered uniquely to fit the need at the time of construction. Because each coal-fired steam boiler subject to this rule has been designed, maintained, utilized, and upgraded uniquely, each designated facility has a unique set of circumstances with a set of source-specific factors governing its use. The outgrowth of the abundance of source-specific factors has led the EPA to determine that a tailored standard of performance (developed by

states) that considers those factors can achieve emission reductions in the fleet without making broad assumptions about the fleet that may not be applicable to a particular unit. The source-specific circumstances at each EGU causes considerable variation in average emission rates across the fleet. If a single standard of performance (*i.e.*, a single degree of emission limitation resulting from a particular technology or fixed set of technologies) were to be applied to the entire fleet, the result could be either that a large portion of the fleet would not be required to achieve any meaningful emission reductions, or a large portion of the fleet would face overly stringent requirements. The goal of these emission guidelines is not to burden or shut down coal-fired EGUs—which could compromise the stability of the power sector and thus energy reliability to consumers, concerns which the EPA expresses, informed by, among other factors, Congress's direction to take into account energy requirements in determining BSER—as coal-fired EGUs still have considerable viability as part of the power sector.

When states apply the BSER's candidate technologies to a designated facility, the application of each technology and the associated degree of emission limitation achievable by such application will entail source-specific determinations. For this reason, in Table 1, the EPA provided the degree of emission limitation achievable through application of the BSER in the form of ranges, which capture the reductions and costs that the EPA expects to approximate the outcome of the application. The degree of emission limitation achievable through application of the BSER (*i.e.*, the ranges of improvements in Table 1) should be

used by the states in establishing a standard of performance; however, the standard of performance calculated for a specific designated facility may ultimately reflect a degree of emission limitation achievable through application of the BSER outside of the EPA's ranges because of consideration of source-specific factors. If a state uses the sequential two-step process to establish a standard of performance, in the first step the EPA expects that the state will use the range of improvements for each candidate technology (and combinations thereof where technically feasible) to develop a standard of performance for a designated facility (the range of costs can be used in the second step which considers the remaining useful life and other factors as discussed in section III.F.1.b.). The ranges of HRI in section III.E are typical of an EGU operating under normal conditions. While a source with typical operating conditions (assuming no consideration of remaining useful life or other factors) will have a standard of performance with an expected improvement in performance within the ranges in Table 1, there may be source-specific conditions that cause the actual HRI of the applied candidate technology to fall outside the range. For example, if a designated facility had installed a new boiler feed pump just prior to a state's evaluation of the designated facility, the application of that candidate technology would yield negligible improvement in the heat rate and thus the value would fall outside the ranges provided by the EPA (*i.e.*, because the technology has already been applied and the baseline emission rate reflects that). As with the application of all the candidate technologies, the state plan submission must identify: (1) The value of HRI (*i.e.*,

the degree of emission limitation achievable through application of the BSER) for the standard of performance established for each designated facility; (2) the calculation/methodology used to derive such value; and (3) any relevant explanation of the calculation that can help the EPA to assess the plan. In explaining the value of HRI that has been calculated, if the value of the HRI falls within the range identified by the EPA for a particular candidate technology, a state may note as such as part of its explanation. If a resulting value of HRI falls outside the range provided by the EPA, the state should in its state plan submission explain why this is the case based on application of the candidate technology to a particular source. In any instance, the state plan submission must identify the value of HRI that has been calculated and the calculation used to derive the value of HRI, and explain both. The states will thus use the information provided by the EPA, but will be expected to conduct source-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies. After a state applies the candidate technologies to a designated facility (*i.e.*, step one), it can consider the remaining useful life and other factors associated with the source and determine whether it is cost-reasonable to actually implement that technology at the source (*i.e.*, step two). This is described in detail below in section III.F.1.b.

The approach to require states to tailor standards of performance for designated facilities is both consistent with the framework of cooperative-federalism envisioned under CAA section 111(d), and the new

implementing regulations for CAA section 111(d).[227] The new implementing regulations at 40 CFR 60.21a(e) and 60.22a(b)(2) and (4) require emission guidelines to reflect, and contain information on, the degree of emission limitation achievable through the application of the BSER. By providing the BSER and the associated level of stringency in the form of HRIs and associated range of heat rate improvements, the EPA is thus meeting applicable statutory and regulatory requirements and is giving states the necessary information and direction to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through application of the BSER.[228]

(1) Variable Emission Performance

The Agency received comments that there is considerable variation in emissions between designated facilities within the industry, as well as considerable variation of emissions for individual units based on the operating conditions. Commenters expressed concern that the degree of emission limitation achievable through the application of the BSER is similar to the magnitude in the variation in the emission rate at a specific EGU due to different

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[227] *See* 83 FR 44746.

[228] By providing the BSER and level of stringency associated with the BSER, ACE meets the applicable requirements of the new implementing regulations at 40 CFR part 60, subpart Ba, regarding the contents of an emission guideline. An "emission guideline" is defined under 40 CFR 60.21a(e) as a "final guideline document" which must contain certain items enumerated under 40 CFR 60.22a. The preamble, regulatory text, and record for ACE comprise the "final guideline document" referenced as the emission guideline.

operating conditions (*e.g.*, the operating load of the EGU). Commenters contend that because of this similarity, a designated facility could fall out of compliance with its standard of performance if its operating conditions change despite the source's having installed/applied all of the candidate technologies.

Commenters further stated that oftentimes the operation of a designated facility is not in the control of the owner/operator when it goes to load and cycling, and because of that the emission rate varies based on circumstances that are outside of the designated facility's control. The commenters further state that they should not be held accountable to standards that are not reflective of this lack of control and variability. The EPA acknowledges commenters' concerns about variability among designated facilities and variability of emission performance at an individual designated facility, and believes the flexibilities provided for states in establishing standards of performance, as described in this section, are sufficient to accommodate these variables. In establishing standards of performance, states can consider the two distinct types of variable emission performance [229] (*i.e.*, variation between different facilities and variation of emissions at one facility at different times) and states can tailor standards of performance accordingly.

First, standards of performance should acknowledge and reflect variability across EGUs due to unit-specific characteristics and factors, including,

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[229] In this context, variable emission performance is a result of underlying variability in heat rate, as emissions of CO_2 from EGUs are proportional to the unit's heat rate performance.

but not limited to, boiler-type, size, *etc.* By allowing states to establish standards of performance for individual designated facilities (in accordance with the statute's text and structure which provides that states in their plans shall establish standards of performance for existing sources), the EPA expects that standards of performance will inherently account for unit-specific characteristics.[230] By applying the BSER to individual designated facilities within the state, standards of performance would account for unit-specific characteristics such as unit design, historical operation and maintenance. As further described in section III.F.1.b, states may also account for anticipated future design and/or operating plans—such as plans to operate as baseload or load following electricity generators.

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[230] Note that for administrative efficiency in developing a state plan, a state may be able to calculate a uniform standard of performance that reflects application of the BSER for a group of designated facilities rather than performing the same calculation multiple times for multiple individual sources if the group of sources has similar characteristics such that application of BSER would be consistent between the EGUs. This final rule does not necessarily require a state to provide a discrete calculation and separate standard of performance for each designated facility within a group of similar designated facilities, but if a state chooses to calculate a uniform rate for such a group of sources the plan submission should explain how the uniform rate reflects application of the BSER for all of the units in the group (*e.g.*, because of similar operating characteristics). Additionally, even if the same emission rate is calculated for designated facilities at different facilities that are included in such a group, such standard is applicable to each individual designated facility, and each source would be required to meet that standard by implementing ACE requirements separately, consistent with the state plan requirements described in section III.F.2 of this rule.

Second, standards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit-level emission performance (*e.g.*, load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words, states could establish standards of performance for an individual EGU that vary (*i.e.*, differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment.

Another possible option to account for variable emissions is to set standards of performance based on a standard set of conditions. A state could establish a baseline of performance of a unit at specific load and operational conditions and then set a standard against those conditions via the application of the BSER. Compliance for the unit could be demonstrated annually (or by another increment of time if appropriate based on the level of stringency of the standard of performance set for the unit) at those same conditions. In the interim, between the demonstration of compliance under standardized conditions, a state could allow for the maintenance and demonstration of fully operational candidate technologies to be a method to demonstrate compliance as the standard of performance must apply at all times.

The Agency believes that these approaches to providing flexibility (and possible others not described here) in establishing standards of performance are reasonable and appropriate by accounting for innate variable emission performance across EGUs and at specific EGUs while also limiting this flexibility to instances in which underlying variable factors are evaluated and linked to variable emission performance.

(2) Compliance Timelines

Additionally, the new implementing regulations require that emission guidelines identify information such as a timeline for compliance with standards of performance that reflect the application of the BSER.[231] However, given the source-specific nature of these emission guidelines and the reasonably anticipated variation between standards established for sources within a state, the EPA believes it more appropriate that a state establish tailored compliance deadlines for its sources based on the standard ultimately determined for each source. Accordingly, the EPA is superseding this aspect of 40 CFR 60.22a for purposes of ACE, as allowed under the applicability provision in the new implementing regulations under 60.20a and allowing for states to include an appropriate compliance deadline for each designated facility based on its standard of performance determined as part of the state plan process. It is important that states consider compliance timelines that are consistent with the application of the BSER to ensure that the compliance timeline does not undermine the BSER determination

[231] *See* 40 CFR 60.22a.

made by the EPA. For most states, the EPA anticipates initial compliance to be achieved by sources within twenty-four months of the state plan submittal. If a state chooses to include a compliance schedule (because of source-specific factors) for a source that extends more than twenty-four months from the submittal of the state plan, the plan must also include legally enforceable increments of progress for that source [232]). The EPA does not envision that most states will be using increments of progress leading up to initial compliance. However, as with the consideration of other source-specific factors, where a state does choose to provide for a source to comply on a longer timeframe than twenty-four months and to employ legally enforceable increments of progress along the way, the state should include in its state plan submission to the EPA an adequate justification for why that approach is warranted. The level of stringency can be compromised if a compliance schedule does not adequately reflect the BSER determination.

Several commenters requested clarity on when standards of performance must become effective (*i.e.*, when must designated facilities comply with their standards of performance) once a state plan has been submitted but not yet approved by the EPA. The contents of a state plan submission, such as standards of performance and related requirements, are not effective or enforceable under federal law until they are approved by the EPA. However, state plan requirements must be fully adopted as a matter of state law, or issued as a permit, order, or consent

[232] *See* 40 CFR 60.24a(d).

agreement, before the plan is submitted to the EPA (and therefore could be enforceable as a matter of state law, depending on when the state has chosen to make such requirements effective).[233] The EPA anticipates that in determining an appropriate compliance schedule (and more specifically the initial compliance) for designated facilities, a state will consider the anticipated timing of review of the state's plan by the EPA and what sources may need to do in the interim in order to assure ultimate compliance with their standards of performance while EPA is in the process of reviewing the plan.

States also have discretion in establishing a compliance schedule for designated facilities, but the Agency urges states to use caution as to not undermine the BSER by the determined schedules. Most programs under CAA section 111 do not have compliance timelines greater than a year and the Agency believes that is a good indicator for states to take into consideration determining compliances schedules. Much of how a compliance schedule is structured can be based on how the standard of performance is structured. In section III.F.1.a.(1) there is a discussion about how a state might account for variable emissions. One of the options is to set a standard of performance under standardized conditions to take into account many of the factors that can lead to variable emissions from a designated facility. The standardized conditions (*e.g.*, load, ambient temperature, humidity etc.) that apply to the standard of performance must also be met when there is a compliance demonstration. Because these

[233] 40 CFR 60.23a, 60.27a(g)(2)(iii).

standardized conditions are not maintained throughout a compliance period, the segmented nature of demonstrating compliance could mirror the compliance schedule. For example, a designated facility could have a monthly demonstration under standardized conditions that mirrors a monthly compliance schedule. This is one example to illustrate how a standard of performance can align with a compliance schedule.

Another consideration for states in establishing standards of performance is the emission averaging time (*e.g.*, the amount of time that a designated facility may average its emission rate). As described above in section III.F.1.a.(1), EGUs may have considerably variable emissions due to numerous operating factors. A method to account for seasonal variability is to average a designated facility's emission rate over the course of multiple seasons.

b. Consideration of Remaining Useful Life and Other Factors

CAA section 111(d) requires, in part, that the EPA "shall permit the State in applying a standard of performance to any particular source under a plan submitted under [CAA section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Consistent with the requirements of this provision, the EPA is permitting states to consider remaining useful life and other factors in establishing a standard of performance for a particular source in this final rule. States may do this in several ways. If a state is following the sequential two-step process, the state would first apply all of the

candidate technologies to a designated facility to derive a standard of performance with consideration to the EGU's historical or projected performance, as previously described in section III.F.1.a. In the second step of this process, the state would consider the "remaining useful life and other factors" for the EGU and develop a standard of performance accordingly. It should be noted that the consideration of remaining useful life and other factors is a discretionary step for states. If a state were to establish a standard of performance for a designated facility based solely on the application of the BSER, it would be reasonable to do so and not precluded under the statute.

The CAA explicitly provided under CAA section 111(d)(1) that states could, under appropriate circumstances, establish standards of performance that are less stringent than the standard that would result from a direct application of the BSER identified by the EPA. CAA section 111(d)(1) achieves this goal by authorizing a state, in applying a standard of performance, to take into account a source's remaining useful life and other source-specific factors. As such, the EPA is promulgating, as part of the new implementing regulations at 40 CFR 60.20a–29a, a provision to permit states to take into account remaining useful life, among other factors, in establishing a standard of performance for a particular designated facility, consistent with CAA section 111(d)(1)(B). The new implementing regulations (also consistent with the previous implementing regulations) give meaning to CAA section 111(d)(1)(B)'s reference to "other factors" by identifying the following as a nonexclusive list of

several factors states may consider in establishing a standard of performances:

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or
- 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.

Given that there are unique attributes and aspects of each designated facility, there are important factors that influence decisions to invest in technologies to meet a potential standard of performance. These include factors not enumerated in the list provided above, including timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other source-specific criteria. The state may find that there are space or other physical barriers to implementing certain HRIs at specific units. Alternatively, the state may find that some HRI options are either not applicable or have already been implemented at certain units. The EPA understands that many of these "other factors" that can affect the application of the BSER candidate technologies distill down to a consideration of cost. Applying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO_2 reductions.

The EPA received comment on the ACE proposal that the EPA should provide more information and guidance for what could be considered "other factors" in addition to the considerations of the remaining

useful life. In addition, commenters also requested more information on the remaining useful life and other source-specific factors that could be considered in developing a standard of performance. The EPA acknowledges that there are a host of things that could be considered "other factors" by states that can be used to develop a standard of performance. While the EPA cannot identify every set of circumstances and factors that a state could consider, the EPA agrees with the commenters that it would be helpful for states if the EPA were to provide a non-exhaustive set of qualitative examples that states could consider in developing standards of performance as described below. The EPA will evaluate each standard of performance and the factors that were considered in the development of the standard of performance on a case by case basis. The state should include all of the factors and how the factors were applied for each standard of performance in the state plan. The EPA received many notable comments that states would like more direction and assistance in developing standards of performance. The examples are intended to help provide this assistance, but the EPA also understands that, because there are so many considerations for each source, states might have further questions while developing plans. States are encouraged to reach out to the Agency during the development of plans for further assistance.

As noted above, the consideration of the remaining useful life and other factors most often is a reflection of cost. When the EPA determines the BSER for a source category, the EPA typically considers factors such as cost relative to assumptions about a typical unit. Because the costs evaluated for the BSER

determination are relative to a typical unit, the source-specific conditions of any particular existing designated facility that a state will evaluate in developing its plan under CAA section 111(d) are not inherently considered. A state's consideration of the remaining useful life and other factors will reflect the costs associated with the source-specific conditions. As part of the BSER determination, the EPA has provided a range of costs associated with each candidate technology (*see* Table 1). These costs are provided to serve as an indicator for states to determine whether it is cost-reasonable for the candidate technology to be installed. These cost ranges are certainly not intended to be presumptive (*i.e.*, the ranges are not an accurate representation for each designated facility and should not be used without a justified analysis by the state), but rather are provided as guide-posts to states. If a state considers the remaining useful life and/or other factors in determining a standard of performance, the state is required to describe, justify, and quantify how the considerations were made in its plan. Because these considerations are discretionary and source-specific, the burden is on the state in its plan to demonstrate and justify how they were taken into account.

A state might consider the remaining useful life of a designated facility with a retirement date in the near future by a number of ways in the standard setting process. One way that a state may take into account this circumstance is in applying the BSER (either through the sequential, two-step process or through some other method that reflects application of the BSER), establish a standard that ultimately only applies the less costly BSER technologies in the

development of the standard of performance that the state establishes for the particular designated facility. The shorter life of the designated facility will generally increase the cost of control because the time to amortize capital costs is less. Another outcome of a state's evaluation of a designated facility's remaining useful life may lead to the state setting a "business as usual" standard. This could be an appropriate outcome where the remaining useful life of the designated facility is so short that imposing any costs on the EGU is unreasonable. Because a state plan must establish standards of performance for "any" designated facility under CAA section 111(d), the standard applied to this designated facility would reflect "business as usual" and require the unit to perform at its current level of efficiency during the remainder of its useful life. Under all of these examples and under any other circumstance in which a state considers remaining useful life or other factors in establishing a standard of performance, the state must describe in its state plan submission such consideration and ensure it has established a standard for every designated facility within the state, even one with an anticipated near-term retirement date.

Another consideration for a state in setting standards of performance with consideration to the remaining useful life and other factors is how the different candidate technologies interact with one another and how they interact with the current system at a designated facility. Commenters have expressed, and the EPA agrees, that the application of efficiency upgrades at EGUs are not necessarily additive. Installing HRI technologies in parallel with one another may mitigate the effects of one or more of the

technologies. While states must apply the BSER and the degree of emission limitation achievable through such application in calculating a standard of performance, states may also consider the mitigating effects on the emission reductions that would result from the installation of a particular candidate technology, and may as a result of this consideration determine that installing that particular candidate technology at a particular source is not reasonable. This consideration is authorized as one of the "other factors" that states may consider in establishing a standard of performance under CAA section 111(d)(1) and the new implementing regulations under 40 CFR 60.24a(e).

A prime example of an "other factor" is ruling out the reapplication of a candidate technology. The EPA anticipates this to be a part of many state plans. In this scenario, a designated facility recently applied one of the candidate technologies prior to the time ACE becomes applicable. To require that designated facility to update that candidate technology again, as a result of ACE, would not be reasonable because the costs will be significant with marginal, if any, heat rate improvement.

As described in section III.F.1.c., states are obligated to set rate-based standards of performance. These will generally be in the form of the mass of carbon dioxide emitted per unit of energy (for example pounds of CO_2 per megawatt-hour or lb/MWh). The emission rate can be expressed as either a *net* output-based standard or as a *gross* output-based standard, and states have the discretion to set standards of performance in either form. The difference between net and gross generation is the electricity used at a

plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. The gross generation is the total energy produced, while the net generation is the total energy produced minus the energy needed to operate the auxiliary equipment.

Most of the candidate technologies, when applied, affect the gross generation efficiency. However, some candidate technologies, namely improved or new variable frequency drives and improved or new boiler feed pumps, improve the net generation by reducing the auxiliary power requirement. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, states may want to consider standards expressed in terms of net generation. If a state chooses to set standards in the form of *gross* energy output, it will be up to the state to determine and demonstrate how to account for emission reductions that are achieved through measures that only affect the *net* energy output.

One of the more significant changes between the ACE proposal and this action is that the EPA is not finalizing the NSR reforms that it proposed in the same document that it proposed ACE. While the EPA intends to take final action on the NSR reform at a later time in a separate action, the consequences of that action are no longer considered in parallel with ACE. Two of the candidate technologies, blade path upgrades and a redesigned/replaced economizer, were proposed as part of the BSER considering that NSR would not be a barrier for installation. Under ACE as finalized without parallel NSR reforms, the EPA anticipates that states may take into account costs

associated with NSR as a source-specific factor in considering whether these two technologies are reasonable. While the EPA believes that states are more likely to determine that blade path upgrades and redesigned/ replaced economizers are not as reasonable as anticipated at proposal when these were proposed as elements of BSER alongside proposed NSR reforms, as discussed above, the EPA is still finalizing a determination that these candidate technologies are elements of the BSER because it still expects these technologies to be generally applicable across the fleet of existing EGUs, and because the costs of the technologies themselves are generally economical and reasonable. In any case, under ACE as finalized, states are required to evaluate the applicability of all candidate technologies (*i.e.*, the BSER) to a particular existing source when establishing a standard of performance for that source.

c. Forms of Standards of Performance

While the EPA is allowing broad flexibility for states in establishing standards of performance for designated facilities, the EPA is finalizing a requirement that all standards of performance be in the form of an allowable emission rate (*i.e.*, rate-based standard in, for example, lb CO_2/MWh-gross). As described in the proposal an allowable emission rate is the form that corresponds to the EPA's BSER determination for these emission guidelines. When HRIs are made at an EGU, by definition, the CO_2 emission rate will decrease as described above in section III.E. There is a natural correlation between the BSER and an allowable emission rate as the standard of performance in this action. Also, by the Agency prescribing that only a singular form of

standard (*i.e.*, an allowable emission rate) is acceptable, it will promote continuity among states and power companies, prevent ambiguity, and promote simplicity and ease of administration and avoid undue burden on the states and regulated parties.

The EPA received considerable comment that it should allow mass-based standards of performance. While the EPA understands the appeal of a mass-based standard for some stakeholders, this form of standard is not compatible with the EPA's BSER determination. In fact, the EPA believes that a mass-based standard would undermine the EPA's BSER. If designated facilities were to have mass-based standards, it is likely that many would meet their compliance obligation by reduced utilization. A standard of performance that incentivizes reduced utilization and possibly retirements does not reflect application of the BSER. See section II.B above for a discussion of reduced utilization and CAA section 111.

Additionally, given that the EPA has the obligation under CAA section 111(d)(2) to determine whether state plans are "satisfactory," certain programmatic bounds are appropriate to facilitate the state's submission of, and EPA's review of, the approvability of state plans. Having a uniform type of standard of performance will help streamline the states' development of their plans, as well as the EPA's review of those plans as there will be fewer variables to consider in the development of each standard of performance. While the Agency has experience implementing mass-based programs, the uncertainty associated with projecting a level of generation for

designated facilities is unnecessary when there is a more compatible format, *i.e.*, a rate-based standard.

The EPA also notes that it is not establishing a preference or requirement for whether a rate-based standard of performance be based in gross or net heat rate. The EPA acknowledges that there are ramifications of applying the BSER to establish a standard of performance with the consideration of type of heat rate used. This may be particularly important when considering the effects of part load operations (*i.e.*, net heat rate would include inefficiencies of the air quality control system at a part load whereas gross heat rate would not). This will also be important in recognizing the improved efficiency obtained from upgrades to equipment that reduce the auxiliary power demand. The consideration of this factor is left to the discretion of the state.

2. Compliance Mechanisms

Just as states have broad flexibility and discretion in setting standards of performance for designated facilities, sources have flexibility in how they comply with those standards. To the extent that a state develops a standard of performance based on the application of the BSER for a designated facility within its jurisdiction, sources should be free to meet that standard of performance using either BSER technologies or certain non-BSER technologies or strategies. Thus, a designated facility may have broad discretion in meeting its standard of performance within the requirements of a state's plan. For example, there are technologies, methods, and/or fuels that can be adopted at the designated facility to allow the source to comply with its standard of performance that

were not determined to be the BSER, but which may be applicable and prudent for specific units to use to meet their compliance obligations. Examples of non-BSER technologies and fuels include HRI technologies that were not included as candidate technologies, CCS, and natural gas co-firing. In keeping with past programs that regulated designated facilities using a standard of performance, the EPA takes no position regarding whether there may be other methods or approaches to meeting such a standard, since there are likely various approaches to meeting the standard of performance that the EPA is either unable to include as part of the BSER, or is unable to predict. The EPA is, however, excluding some measures from use as compliance measures: averaging and trading and bio-mass cofiring. These measures do not meet the criteria for compliance measures. Those criteria, which are designed to assure that compliance measures actually reduce the source's emission rate, are two-fold: (1) The compliance measures must be capable of being applied to and at the source, and (2) they must be measurable at the source using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported, and verified at a unit.

With respect to the first criterion, the EPA believes that both legal and practical concerns weigh against the inclusion of measures that cannot qualify as a "system of emission reduction." Allowing those measures would be inconsistent with the EPA's interpretation of the BSER as limited to measures that apply at and to an individual source and reduce emissions from that source. Because state plans must establish standards of performance—which by

definition [234] "reflect[]. . . the application of the [BSER]"—implementation and enforcement of such standards should correspond with the approach used to set the standard in the first place. Applying an implementation approach that differs from standard-setting would result in asymmetrical regulation. Specifically, a state's implementation measures would result in a more or less stringent standard implemented at an EGU than could otherwise be derived from application of the BSER.

There are certainly methods that affected EGUs could use to meet compliance obligations that are not the BSER, but these methods still fit the two criteria: They can be applied to and at the source and can be measured at the source using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be monitored, reported, and verified at a unit. Such examples include CCS and natural gas cofiring.

Commenters also requested that reduced utilization be an available compliance mechanism. While a designated facility reducing its utilization would certainly reduce its mass of CO_2 emissions, it would likely not lead to an improved emission rate. As noted above in section III.F.1., a state can certainly take into account a designated facility's projected decreased utilization in setting a standard of performance, but it cannot make it the means of meeting compliance obligations because the degree of emission limitation achievable through the application of the BSER must still be reflected in setting the standard of

[234] *See* CAA section 111(a)(1)

performance. See section II.B above for a discussion of reduced utilization under CAA section 111.[235]

a. Averaging and Trading

This section discusses the question of whether averaging and trading are permissible means for sources to comply with ACE. For a discussion of averaging EGU-emissions over a compliance period, see section III.F.1.a.(2). In the proposal, the EPA solicited comment on whether CAA section 111(d) authorizes states to include averaging or trading between existing sources in the plans they submit to meet the requirements of final emission guidelines.[236] Specifically, the EPA: (1) Proposed to allow states to incorporate, as part of their plan, emissions averaging among EGUs across a single plant; and (2) solicited comment on whether CAA section 111(d) should be read not to authorize states to include trading and averaging between sources.[237]

The EPA received numerous comments on the topic of averaging and trading for compliance with ACE. With respect to averaging across designated facilities that are located at the same plant—including, but not limited to, EGUs that are served by a common stack—some commenters disapproved of this flexibility while others supported the ability to implement ACE via averaging in state plans. On the topic of averaging and trading between designated facilities located at

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[235] For a discussion of reduced utilization in other CAA contexts, please see ACE RTC Chapter 1, response to comment 76.

[236] *See* 83 FR 44767–768.

[237] *Id.*

different plants, the Agency received mixed support and opposition. Some commenters suggested that the EPA's proposed prohibition on averaging and trading between designated facilities at different plants was necessary given the Agency's construction of the BSER as limited to systems that could be applied to and at the "source" itself. Other commenters suggested that averaging and trading for compliance with ACE is not precluded under CAA section 111(d). Commenters also suggested that the statutory cross-reference under CAA section 111(d)(1) to CAA section 110 suggests that trading could be used for implementation under ACE. Several commenters provided examples of prior CAA section 111(d) regulations in which the agency allowed trading for implementation (*e.g.*, CAMR).

In this final action, the EPA determines that: Neither (1) averaging across designated facilities located at a single plant; nor (2) averaging or trading between designated facilities located at different plants are permissible measures for a state to employ in establishing standards of performance for existing sources or for sources to employ to meet those standards. CAA section 111(d) authorizes states to establish standards of performance for "any existing source," which the CAA defines as "any stationary source other than a new source."[238] "Stationary source," in turn, means "any building, structure, facility, or installation which emits or may emit any air pollutant."[239] In the ACE proposal, the EPA explained that an EGU "subject to regulation upon

[238] 42 U.S.C. 7411(a)(6).

[239] *Id.* at section 7411(a)(3).

finalization of ACE is any fossil fuel-fired electric utility steam generating unit (*i.e.*, utility boilers) that is not an integrated gasification combined cycle (IGCC) unit (*i.e.*, utility boilers, but not IGCC units) that was in operation or had commenced construction as of [January 8, 2014]," and "serves a generator capable of selling greater than 25 MW to a utility power distribution system and has a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel)."[240] The proposal then identified HRI measures as the BSER for such units.[241] This action finalizes the Agency's determination that HRI measures are the BSER for designated facilities. *See* sections III.C & III.E.

Although the D.C. Circuit has recognized that the EPA may have statutory authority under CAA section 111 to allow plant-wide emissions averaging,[242] the Agency's determination that individual EGUs are subject to regulation under ACE precludes the Agency from attempting to change the basic unit from an EGU to a combination of EGUs for purposes of ACE implementation.[243]

In *ASARCO*, the EPA promulgated regulations re-defining "stationary source" as "any . . . *combination of* . . . facilities."[244] By treating a "combination of

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[240] 83 FR 44754.

[241] *Id.* at 44755.

[242] *See U.S. Sugar* v. *EPA*, 830 F.3d 579, 627 n.18 (D.C. Cir. 2016) (pointing to the definition of "stationary source").

[243] *See, e.g.*, *ASARCO* v. *EPA*, 578 F.2d 319, 327 (D.C. Cir. 1978).

[244] *Id.* at 326 (emphasis added).

facilities" as a single source, the EPA intended to adopt a "bubble concept," which would allow a facility to "avoid complying with the applicable NSPS so long as emission decreases from other facilities within the same source cancel out the increases from the affected facility."[245] The Court concluded, however, that the Agency "has no authority to rewrite the statute in this fashion."[246] In a subsequent case, the D.C. Circuit recognized that the EPA has "broad discretion to define the statutory terms for 'source,' [*i.e.*, building, structure, facility or installation], so long as guided by a reasonable application of the statute."[247]

Following these two decisions, the EPA adopted a new regulation defining "building, structure, facility, or installation" for nonattainment-area permitting under the NSR program as "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel."[248] That rulemaking lead to the Supreme Court's decision in *Chevron* v. *NRDC*, 467 U.S. 837 (1984). In *Chevron*, the Court recognized that "it is certainly no affront to common English usage to take a reference to a major facility or a major

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[245] *Id*.

[246] *Id*. at 327.

[247] *Alabama Power Co.* v. *Costle*, 636 F.2d 323, 396 (D.C. Cir. 1979).

[248] 46 FR 50766.

source to connote an entire plant as opposed to its constituent parts."[249]

Here, the EPA does not need to determine whether it would have been reasonable to interpret "building, structure, facility, or installation" as an entire plant for purposes of CAA section 111 (thus, encompassing all EGUs located at a single plant). Because ACE identifies individual EGUs as the designated facility, [250] state plans cannot accommodate any "bubbling" of EGUs for compliance with these emission guidelines.

In addition, as proposed, the EPA is precluding averaging or trading between designated facilities located at different plants for the following reasons.

The EPA believes that averaging or trading across designated facilities (or between designated facilities

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[249] 467 U.S. at 860.

[250] Fossil fuel-fired steam generators (*i.e.*, EGUs) were among the first source categories listed under CAA section 111. *See* 36 FR 5931. Since then, the Agency has promulgated multiple rulemakings specifically regulating EGUs. *See e.g.*, 40 CFR part 60, subparts D, Da, TTTT, and UUUU. In any case, the decision to identify EGUs as the regulated source is made under CAA section 111(b); that is because regulations under CAA section 111(d) are authorized for sources "to which a standard of performance . . . would apply if such existing source were a new source." In this case, new source performance standards have been established for certain "new, modified, and reconstructed" EGUs. 80 FR 64510. While the EPA proposed to revisit several portions of those standards, *see* 83 FR 65424, the Agency did not propose to revise the applicability requirements for them, *id.* at 65429. Accordingly, individual EGUs continue to be the appropriate regulatory target for purposes of ACE (and not, for example, multiple EGUs that may be co-located at a single power plant).

and other power plants, *e.g.*, wind turbines) is inconsistent with CAA section 111 because those options would not necessarily require any emission reductions from designated facilities and may not actually reflect application of the BSER.[251] Because state plans must establish standards of performance—which by definition "reflects . . . the application of the best system of *emission reduction*"— implementation and enforcement of such standards should be based on improving the emissions performance of sources to which a standard of performance applies. Additionally,

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[251] The EPA's interpretation of CAA section 111 on this point has changed since the promulgation of the since-vacated CAMR and does not necessarily extend to other CAA programs and provisions, which can be distinguishable based on the applicable statutory and regulatory requirements and programmatic circumstances. For example, the EPA has implemented several trading programs under the so-called Good Neighbor provision at CAA section 110(a)(2)(D)(i)(I). *See* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (also known as the NO_x SIP Call), 63 FR 57356 (October 27, 1998); Clean Air Interstate Rule (CAIR) Final Rule, 70 FR 25162 (May 12, 2005); Cross State Air Pollution Rule (CSAPR) Final Rule, 76 FR 48208 (August 8, 2011); CSAPR Update Final Rule, 81 FR 74504 (October 26, 2016). Section 110(a)(2)(A), which is applicable to the requirements of the Good Neighbor provision, explicitly authorizes the use of marketable permits and auctions of emission rights. Additionally, the Good Neighbor provision prohibits emissions activity in certain "amounts" with respect to the NAAQS. The affirmative requirement under this provision to reduce certain emissions means it is appropriate to implement measures which will result in the required emission reductions. The EPA has done so previously by implementing trading programs to reduce ozone and particulate matter, the regional-scale nature of which can be effectively regulated under a trading program.

averaging or trading would effectively allow a state to establish standards of performance that do not reflect application of the BSER. For example, under a trading program, a single source could potentially shut down or reduce utilization to such an extent that its reduced or eliminated operation generates adequate compliance instruments for a state's remaining sources to meet their standards of performance without any emission reductions from any other source. This compliance strategy would undermine the EPA's determination of the BSER in this rule, which the EPA has determined as heat rate improvements.

In light of these concerns, as proposed, the EPA concludes that neither averaging nor trading between EGUs at different plants can be used in state plans for ACE implementation. Regarding commenters' assertions that the statutory text of CAA section 111(d) does not preclude averaging or trading, the Agency finds that the statutory text of CAA section 111(d) does not require the EPA to allow averaging or trading as a measure for states in establishing existing-source standards of performance or allow for sources to adopt as a compliance measure, and the interpretation of the limits on the scope of BSER under CAA section 111(a)(1) set forth in section II above as a basis for the repeal of the CPP suggests that those measures are not permissible, as they are not applied to a source.

Regarding commenters' assertions that the cross-reference in CAA section 111(d) to CAA section 110 authorizes averaging or trading for implementation, the Agency disagrees. The cross-reference to CAA section 110 indicates that "[t]he Administrator shall prescribe regulations which shall establish a

procedure similar to that provided by CAA section 110 of this title under which each State shall submit to the Administrator a plan . . . ." (emphasis added). The Agency's interpretation of this cross-reference is that it focuses on the *procedure* under which states shall submit plans to the EPA. It does not imply anything affirmative or negative about implementation mechanisms available under CAA section 111(d). In the absence of definitive instruction under this CAA provision, the Agency uses its best judgment to conclude that the meaning and scope of the BSER in this rule preclude the use of averaging or trading for covered EGUs at different plants in state plans. Commenters also asserted that the EPA has promulgated regulations under CAA section 111(d) that included trading in the past, such as CAMR. As an initial matter, CAMR was vacated by the D.C. Circuit and never implemented. Nonetheless, the Agency notes that the CAMR included trading both in the establishment of the BSER and as an available implementation mechanism. In the ACE rule, by contrast, trading was not factored into the determination of the BSER and so should not be authorized for implementation.

Moreover, it is not clear that trading would qualify as a "system of emission reduction" that can be applied to and at an individual source and would lead to emission reductions from that source. Indeed, the nature of trading as a compliance mechanism is such that some sources would not need to apply any pollution control techniques at all in order to comply with a cap-and-trade scheme. A compliance mechanism under which multiple sources can comply not by any measures applied to those sources

individually, but instead by obtaining credits generated by measures adopted at another source, is not consistent with the interpretation of the limits on the scope of BSER adopted in section II above. Accordingly, trading is not permissible under CAA section 111.

b. Biomass Co-Firing

The ACE proposal solicited comment on the inclusion of forest-derived and non-forest biomass as non-BSER compliance options for affected units to meet state plan standards. The proposal also solicited comment on what value to attribute to biogenic CO_2 associated with non-forest biomass, if included. The EPA received a range of comments both supporting and opposing the use of forest-derived and non-forest biomass feedstocks for compliance under this rule. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion.

Numerous commenters supported the inclusion of biomass as a compliance measure. Some reiterated the EPA's 2018 policy statement regarding biogenic CO_2 emissions, which laid out the Agency's intent to treat biogenic CO_2 emissions from forest biomass from managed forests as carbon neutral in forthcoming Agency actions. Specifically, these commenters stated that the nature of biomass and its role in the natural carbon cycle (*i.e.*, carbon is sequestered during biomass growth that occurs offsite) makes biomass a carbon-neutral fuel, and therefore that biomass should be eligible as a compliance option under this rule. Commenters opposing the inclusion of biomass for compliance asserted that biomass combustion does not

reduce stack GHGs emissions, as it emits more emissions per Btu than fossil fuels, and therefore should not be eligible for compliance. Some comments noted that the scientific rationale underlying the use of biomass as a potential GHG reduction measure at stationary sources relies primarily on terrestrial CO_2 sequestration occurring due to activities offsite (*i.e.*, activities outside of and largely not under the control of a designated facility).

The construct of this final ACE rule necessitates that measures taken to meet compliance obligations for a source actually reduce its emission rate in that: (1) They can be applied to the source itself; and (2) they are measurable at the source of emissions using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported, and verified at a unit (see section III.F.2). While the firing of biomass occurs at a designated facility, biomass firing in and of itself does not reduce emissions of CO_2 emitted from that source. Specifically, when measuring stack emissions, biomass emits more CO_2 per Btu than fossil fuels, thereby increasing the CO_2 emission rate at the source. Accordingly, recognition of any potential CO_2 emissions reductions associated with biomass firing at a designated facility relies on accounting for activities not applied at and largely not under the control of that source (*i.e.*, activities outside of and largely unassociated with a designated facility), including consideration of terrestrial carbon effects during the biomass fuel growth. Therefore, biomass fuels do not meet the compliance obligations and are not eligible for compliance under this rule.

3. Submission of State Plans

CAA section 111(d)(1) provides that states shall submit to the EPA plans that establish standards of performance for existing sources within their jurisdiction and provide for implementation and enforcement of such standards. Under CAA section 111(d)(2), the EPA has the obligation to determine whether such plans are "satisfactory." In light of the statutory text, state plans implementing ACE should include detailed information related to two key aspects of implementation: Establishing standards of performance for covered EGUs and providing measures that implement and enforce such standards.

Generally, the plans submitted by states must adequately document and demonstrate the process and underlying data used to establish standards of performance under ACE. Providing such documentation is required so that the EPA can adequately and appropriately review the plan to determine whether it is satisfactory; the EPA's authority to promulgate a federal plan is triggered in "cases where the State fails to submit a satisfactory plan . . . ."[252] For example, states must include data and documentation sufficient for the EPA to understand and replicate the state's calculations in applying BSER to establish standards of performance. Plans must also adequately document and demonstrate the methods employed to implement and enforce the standards of performance such that EPA can review and identify measures that assure transparent and verifiable implementation. Additionally, state plan submissions must, unless

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

otherwise provided in a particular emissions guideline rule, adhere to the components of the new implementing regulations described in section IV. The following paragraphs discuss several components that states are required to include in their state plans as required under these final emission guidelines.

First, state plans must detail the approach or methods used by the state to apply the BSER and establish standards of performance. The state should include enough detail for the EPA to be able to reproduce the state's methods and calculations. The methodology submitted should clearly identify the approach by which states evaluate all of the HRIs finalized in this action, both alone and in combination with each other where technically feasible. To the extent that HRIs are not feasible to apply at a particular EGU, states must provide a rationale (and supporting data or metrics where relied upon) for why the calculation would be invalid or inappropriate.

Second, state plans must identify EGUs within their borders that meet the applicability requirements and are thereby considered a designated facility under ACE. Plans must also include emissions and operational data relied upon to apply BSER and determine standards of performance. These data must include, at a minimum, an inventory of CO_2 emissions data and EGU operational data (*e.g.*, heat input) for designated EGUs during the most recent calendar year for which data is available at the time of state plan development and/or submission. State plans must also include any future projections data relied upon to establish standards of performance, including future operational assumptions. To the extent that state plans consider an existing source's remaining

useful life in establishing a standard of performance for that source, the state plan must specify the exact date by which the source's remaining useful life will be zero. In other words, the state must establish a standard of performance that specifies the designated facility will retire by a future date certain (*i.e.*, the date by which the EGU will no longer supply electricity to the grid). It is important to note that (as with all aspects of the state plan) the standard of performance and associated retirement date will be federally enforceable upon approval by the EPA. In the event a source's circumstances change so that this retirement date is no longer feasible, states generally have the authority and ability to revise their state plans. Such plan revisions must be adopted by the state and submitted to the EPA pursuant to the requirements of 40 CFR 60.28a.

Third, state plans should submit detailed documentation demonstrating in detail the application of the state's methodology to the state's data. In other words, states should include the calculations relied upon when applying the BSER to establish standards of performance. States should also include detailed documentation demonstrating the relied upon compliance mechanisms, consistent with section III.F.2.

Regarding establishing standards of performance and ensuring verifiable implementation for EGUs with complex stack configurations, states should include approaches (*e.g.*, formulas) that appropriately assign emissions and generation to individual EGUs. For example, if two EGUs share a common stack, the state should provide a methodology for disaggregating monitoring data to the individually covered EGUs.

Another example for states to consider when appropriately assigning emissions and setting standards of performance is apportioning HRI that affect and improve the performance of multiple EGUs at a plant (*e.g.*, apportioning improvement credited to installed variable speed drives that affect multiple designated facilities at a plant).

As part of ensuring that regulatory obligations appropriately meet statutory requirements such as enforceability, the EPA has historically and consistently required that obligations placed on sources be quantifiable, permanent, verifiable, and enforceable. The EPA is similarly requiring that standards of performance placed on designated facilities as part of a state plan to implement ACE be quantifiable, permanent, verifiable, and enforceable. A state plan implementing ACE should include information adequate to support a determination by the EPA that the plan meets these goals.

Additionally, the EPA is finalizing a determination that states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of standards of performance. Each state will have the flexibility to design a compliance monitoring program for assessing compliance with the standards of performance identified in the plan. To the extent that designated facilities or states already monitor and report relevant data to the EPA, states are encouraged to use these existing systems to efficiently monitor and report ACE compliance. For example, most potentially affected coal-fired EGUs already continuously monitor CO_2 emissions, heat input, and gross electric output and

report hourly data to the EPA under 40 CFR part 75. Accordingly, if a state plan establishes a standard of performance for a unit's CO_2 emissions rate (*e.g.*, lb/MWh), states may use data collected by the EPA under 40 CFR part 75 to meet the required monitoring, reporting, and recordkeeping requirements under these emission guidelines.

The EPA is further generally applying the new implementing regulations for timing, process and required components for state plan submissions and implementation for state plans required for designated facilities. The new implementing regulations are described in detail in section IV. In section 40 CFR 60.5740a there is a complete description and list of what a state plan must include.

a. Electronic Submission of State Plans

The EPA will, in the near future, provide states with an electronic means of submitting plans. While the EPA proposed the use of the SPeCS software which has been used by the Agency for SIP submittals, the Agency is still developing the software to be used for ACE submittals. The EPA recommends that states submit state plans electronically as it will provide a more structured process and provide more timely feedback to the submitting state. The Agency also anticipates that many states will choose to submit plans electronically as states have a level of familiarity with EPA software, such as SPeCS. The EPA envisions the electronic submittal system as a user-friendly, web-based system that enables state air agencies to officially submit state plans and associated information electronically for review. Electronic submittal is the EPA's preferred method for receiving

state plan submissions under ACE. However, if a state prefers to submit its state plan outside of this forthcoming system, the state must confer with its EPA Regional Office regarding additional guidance for submitting the plan to the EPA.

b. Approvability of State Plans That Are More Stringent Than Required Under ACE

One issue raised by several commenters is whether the EPA can approve, and thereby render federally enforceable, a state plan that contains requirements for an existing source within a state's jurisdiction that are more stringent than what is required under CAA section 111(d).[253] At proposal, the EPA acknowledged that CAA section 116 allows states to be more stringent than federal requirements as a matter of state law, but also noted that nothing in section 116 provides for such more-stringent requirements to become federally enforceable.[254] Some commenters assert that it is not within the EPA's authority under the CAA to approve such more-stringent requirements

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[253] Requirements under state plans generally become federally enforceable once the EPA determines that they are "satisfactory" per section 111(d)(2). Section 113(a)(3) provides the EPA with the authority, in part, to enforce any requirement of any plan approved under the same subchapter as section 113; section 111(d) is within the same subchapter as section 113. Additionally, section 304(a)(1) grants citizens the authority to bring civil action against any person in violation of an "emission standard" under the CAA. Section 304(f)(1) and (3) respectively define "emission standard" as a standard of performance or any requirement under section 111 without regard to whether such requirement is expressed as an emission standard. Accordingly, citizens with standing could attempt to enforce the requirements of an EPA-approved section 111(d) state plan.

[254] 83 FR 44767 n.37.

as part of the federally enforceable state plan, and the EPA should instead direct states to make such requirements exclusively a matter of state law and enforceability. Other commenters assert that the Supreme Court in *Union Electric Co.* v. *EPA*, 427 U.S. 246, (1976), precluded a reading of section 116 that would functionally require two separate sets of requirements, one at the stricter state level and one at the federally approved level.

In response to the commenters who contend the EPA does not have the authority to approve more stringent state plans, the EPA believes that these comments have merit. However, the EPA does not think it is appropriate at this point to predetermine the outcome of its action on a state plan submission in this regard without going through notice-and-comment rulemaking with regard to the approval or disapproval of that submission.[255]

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[255] In the CPP, the EPA took the position that because "the EPA's action on a 111(d)(1) state plan is structurally identical to the EPA's action on a SIP," the EPA is required to approve a state plan that is more stringent than the BSER because of CAA section 116 as interpreted by *Union Electric.* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 28–30; 80 FR 64840. For the reasons further described in this preamble, the EPA's position on this state plan stringency issue has evolved since the EPA addressed it in the CPP, and the Agency now identifies a potentially salient structural distinction between CAA sections 110 and 111(d). Notably, the BSER aspect of section 111(d) is absent from section 110, as SIP-measures required for attainment or maintenance of the NAAQS are not predicated on application of a specific technology. Under CAA section 109, the EPA establishes a health-protective standard, and CAA section 110 then gives states broad latitude on designing the contents of SIPs intended to meet that standard. By contrast, under CAA section 111, the EPA identifies a

In response to the commenters who contend the EPA has the authority to approve more stringent state plans, as an initial matter, the EPA notes that the Court's decision in *Union Electric* on its face does not apply to state plans under CAA section 111(d). The decision specifically evaluated whether the EPA has the authority to approve a SIP under *section 110* that is more stringent than what is necessary to attain and maintain the NAAQS. The Court specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis, a provision that is wholly separate and distinct from CAA section 111(d). CAA section 110(a)(2)(A) requires SIPs to include any assortment of measures that may be necessary or appropriate to meet the "applicable requirements" of the CAA, which largely relate to the attainment and maintenance of the NAAQS. CAA section 111(d), by contrast, directs state plans to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through the application of the

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particular measure or set of measures, and CAA section 111(d) more narrowly prescribes that the contents of state plans include performance standards based on the application of such measures, and measures that provide for the implementation and enforcement of such standards. Given this key distinction between CAA sections 110 and 111(d), the EPA no longer takes the position it took in the CPP that these two statutory schemes are "structurally identical" and that therefore, under *Union Electric*, it must approve section 111(d) state plans that are more stringent on this basis. See *FCC* v. *Fox Television Stations, Inc.*, 556 U.S. 502 (2009). However, for the reasons discussed in this preamble, the EPA is not at this stage prejudging the approvability of any future plan submission in this regard and will evaluate any plan submission, including one that is more stringent than what the BSER requires, on an individual basis through notice-and-comment rulemaking.

BSER that EPA has determined is adequately demonstrated—and CAA section 111(d) expressly provides that it cannot be used to regulate NAAQS pollutants. Because the Court's holding was in the context of section 110 and not CAA section 111(d), the EPA believes that *Union Electric* does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.

Thus, *Union Electric* and the SIP issues that it addresses are distinguishable from the CAA section 111(d) context. States have broad discretion under section 110 to select the measures for inclusion in their SIPs to meet the NAAQS, which are health- or welfare-based standards not predicated on the application of any particular technology, whereas state plans under 111(d) must establish standards of performance, which are defined at CAA section 111(a)(1) as reflecting the degree of emission limitation achievable through application of the BSER at a source. However, the EPA is mindful that it does not prejudge the approvability of any state plan submission, but rather must determine whether it is "satisfactory" through undertaking notice-and-comment rulemaking.[256] Further, some issues of approvability are most appropriately handled through the submission, review, and approval or disapproval processes (with approvals and disapprovals then being subject to judicial review). The EPA anticipates that some states may wish to apply additional measures beyond those that the EPA has identified as BSER when setting the standard of performance, which states may believe are better suited to particular

[256] *See* CAA section 111(d)(2), 40 CFR 60.27a(b).

existing sources within their jurisdiction. The EPA notes, as stated above, that the comments suggesting that the EPA does not have the authority to approve a state plan that establishes standards of performance for existing sources more stringent than those that would result from an application of the BSER identified by the EPA have merit. However, the EPA believes that the question of whether it has the authority to approve, and thereby render federally enforceable, a state plan that establishes standards of performance that are more stringent than those that would result from the application of the BSER that the EPA has identified is addressed properly in the context of evaluating an individual state plan.

While the EPA does not prejudge the approvability of a state plan that establishes standards of performance for existing sources within the state's jurisdiction that are more stringent than those that would result from the application of the BSER that the EPA has identified, there are clear principles and limitations imposed by CAA section 111(d) that will apply to the EPA's review of *any* state plan. As a first principle, states must apply the BSER measures, as further described in section III.E. of the preamble, and derive a standard of performance that reflects the degree of emission limitation achievable through application of the candidate technologies, taking into account remaining useful life and other factors as appropriate.

As a second principle, whatever the scope of a state's authority under state law may be to design a scheme to meet the emissions guidelines, the EPA's authority to approve state plans that contain standards of performance for existing sources only extends to

measures that are authorized statutorily. Specifically, the EPA's authority is constrained to approving measures that comport with the statutory interpretations, including interpretations of the limitations on "standards of performance" and the underlying BSER. For example, CAA section 111(d)(1) clearly contemplates that state plans may only contain requirements for existing sources, and not other entities. Therefore, in implementing the ACE rule, the EPA may not approve state plan requirements on entities other than existing EGUs, which are the designated facilities under this rule.[257] Another example that would exceed the EPA's authority is a state plan that includes standards of performance or implementation measures that do not result in emission reductions from an individual designated facility, such as the use of biomass or emissions trading, for the reasons discussed at section III.E.4.C. and III.F.2.a, respectively. Finally, the EPA does not have the authority to approve measures that purport to be standards of performance but that actually do not

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[257] Section 111(d) clearly identifies that the regulated entity under this provision is an existing source that would be of the same source category as a new source regulated under section 111(b), *i.e.*, a designated facility, as defined at 40 CFR 60.21(b). If the EPA were to approve a state plan that contained provisions regulating entities other than designated facilities, that approval would give the EPA (and citizen groups) federal enforcement authority over such entities. The EPA believes such a result would be contrary to statements by the U.S. Supreme Court that caution an agency against interpreting its statutory authority in a way that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization," *Utility Air Regulatory Group* v. *EPA*, 134 S. Ct. 2427, 2444 (2014).

meet the statutory and regulatory terms for such standards. For example, under ACE, the EPA cannot approve a standard that is a requirement for a designated facility shut down. Such a standard is an operational standard rather than a standard of performance.[258] The EPA has not authorized the use of operational standards under CAA section 111(h) because the EPA has determined that it is feasible to prescribe a standard of performance for this source category and pollutant, expressed as an emission rate.[259]

As previously described, the EPA must review state plans, including plans that establish standards of performance for a particular existing source or sources that are more stringent than the standards that would result from application of the BSER, through notice-and-comment rulemaking to determine whether they are "satisfactory". This review includes ensuring that the state plan submission does not contravene the statute by including measures that the EPA has no authority to approve or enforce as a matter of federal

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[258] This example is distinguishable from the one described in section IV.H. where a state chooses to rely on a source's remaining useful life in establishing a less stringent standard of performance for that source than would otherwise result from an application of the BSER. In that instance, a state would include the shutdown date as a measure for implementation of a standard of performance, as required under section 111(d)(1)(B).

[259] The EPA also notes that for purposes of a federal plan, the EPA is limited to promulgating a standard of performance, which, as defined by section 111(a)(1) must reflect the degree of emission limitation achievable by the BSER; in promulgating a standard of performance under a federal plan, the statute directs the EPA to take into account, among other factors, remaining useful life of the source to which the standard applies. *See* section 111(d)(2).

law, and that the state actually has evaluated the BSER in setting a standard. Though the EPA lacks the authority to approve certain measures, thereby rendering them federally enforceable, nothing precludes states from implementing or enforcing such requirements as a matter of state law.[260]

G. Impacts of the Affordable Clean Energy Rule

1. What are the air impacts?

In the RIA for this action, the Agency provides a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models adoption of HRI measures at coal-fired EGUs. This illustrative policy scenario represents one set of potential outcomes of state determinations of standards of performance and compliance with those standards by affected coal-fired EGUs. Throughout the RIA, the illustrative policy scenario is compared against a single baseline that does not include the CPP. As described in Chapter 2 of the RIA, the EPA believes that a single baseline without the CPP represents a reasonable future against which to assess the potential impacts of the ACE rule. The EPA also provides analysis in Chapter 2 of the RIA that satisfies any need for regulatory impact analysis that may be required by statute or executive order for the repeal of the CPP.

The EPA has identified the BSER to be HRI. The EPA is providing states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. The cost, suitability, and potential improvement for any of these HRI technologies is dependent on a range of unit-

[260] *See* CAA section 116; 40 CFR 60.24a(f).

specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. The EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis. Therefore, any analysis of the final rule is illustrative. Nonetheless, the EPA believes that such illustrative analyses can provide important insights.

In the RIA, the EPA evaluated an illustrative policy scenario that assumes HRI potential and costs will differ based on unit size and efficiency. To establish categories and HRI potential for use in the RIA, the EPA developed a methodology that is explained in Chapter 1 of the RIA. Designated facilities were grouped into twelve groups based on three size categories and four efficiency categories. Cost and performance assumptions for the candidate technologies were applied to the groupings to establish representative and illustrative assumptions for use in the RIA. The EPA then assumed these varying levels of HRI potential and costs for the different groups in the power sector and emissions modeling as an illustration of the potential impacts.

The EPA evaluates the potential impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023–2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These specific snapshot years are 2025, 2030, and 2035.

Overall, the impacts of the illustrative policy scenario in terms of change in emissions, compliance costs, and other energy-sector effects are small compared to the recent market-driven changes that have occurred in the power sector. These larger industry trends are discussed in detail in Chapter 2 of the RIA. In evaluating the significance of the illustrative policy scenario, as presented in the RIA and summarized here, it is important for context to understand that these impacts are modest and do not diverge dramatically from baseline expectations.

Emissions are projected to be lower under the illustrative policy scenario than under the baseline. Table 3 shows projected aggregate emission decreases for the illustrative policy scenario, relative to the baseline, for CO_2, SO_2 and NO_X from the electricity sector.

TABLE 3—PROJECTED CO_2, SO_2, AND NO_X ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE
[2025, 2030, and 2035]

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2025	(12)	(4.1)	(7.3)
2030	(11)	(5.7)	(7.1)
2035	(9.3)	(6.4)	(6.0)

Note: All estimates in this table are rounded to two significant figures.

The emissions changes in these tables do not account for changes in HAP that may occur as a result of this rule. For projected impacts on mercury emissions, please see Chapter 3 of the RIA. The EPA was unable to project impacts on other HAP emissions from the illustrative policy scenario due to methodology and resource limitations.

As noted earlier in this section, the illustrative policy scenario is compared against a baseline that does not include the CPP. This is because the ACE action only occurs after the repeal of the CPP. Chapter 2 of the RIA discusses the EPA's analysis of the CPP repeal. It explains how after reviewing the comments and fully considering a number of factors, the EPA ultimately concluded that the most likely result of implementation of the CPP would be no change in emissions and therefore no cost or changes in health benefits. This conclusion (*i.e.*, that repeal of the CPP has little or no effect against a baseline that includes the CPP) is appropriate for several reasons, consistent with OMB's guidance that the baseline for analysis "should be the best assessment of the way the world would look absent the proposed action."[261] It is the EPA's consideration of the weight of the evidence, taking into account the totality of the available information, as presented in Chapter 2 of the RIA, that leads to the finding and conclusion that there is likely to be no difference between a world where the CPP is implemented and one where it is not. As further explained in Chapter 2 of the RIA, the EPA comes to this conclusion not through the use of a single analytical scenario or modeling alone, but rather

[261] OMB circular A-4, at 15.

through the weight of evidence that includes: Several IPM scenarios that explore a range of changes to assumptions about implementation of the CPP; consideration of the ongoing evolution and change of the electric sector; and recent commitments by many utilities that include long-term CO_2 reductions across the EGU fleet.

2. What are the energy impacts?

This final action has energy market implications. Overall, the analysis to support this action indicates that there are important power sector impacts that are worth noting, although they are small relative to recent market-driven changes in the sector or compared to some other EPA air regulatory actions for EGUs. The estimated impacts reflect the EPA's illustrative analysis of the final action. States are afforded considerable flexibility in the final action, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis.

Table 4 presents a variety of energy market impacts for 2025, 2030, and 2035 for the illustrative policy scenario representing ACE, relative to the baseline.

TABLE 4—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE
[Percent change]

	2025 (%)	2030 (%)	2035 (%)
Retail electricity prices	0.1	0.1	0.0
Average price of coal delivered to the power sector	0.1	0.0	(0.1)
Coal production for power sector use	(1.1)	(1.0)	(1.0)
Price of natural gas delivered to power sector	0.0	(0.1)	(0.6)
Price of average Henry Hub (spot)	0.0	0.0	(0.6)
Natural gas use for electricity generation	(0.4)	(0.3)	0.0

Energy market impacts are discussed more extensively in the RIA found in the rulemaking docket.

3. What are the compliance costs?

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenario, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the HRI required by the final action.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative policy scenario is designed to reflect, to the extent possible, the scope and nature of the final guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the final requirements because there are considerable flexibilities afforded to the states in developing their state plans.

Table 5 presents the annualized compliance costs of the illustrative policy scenario.

Table 5—COMPLIANCE COSTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE
[Millions of 2016$]

Year	Cost
2025	290
2030	280
2035	25

Note: Compliance costs equal the projected change in total power sector generating costs plus the costs of monitoring, reporting, and recordkeeping.

More detailed cost estimates are available in the RIA included in the rulemaking docket.

4. What are the economic and employment impacts?

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Market and employment impacts of this final action are discussed more extensively in Chapter 5 of the RIA for this final action.

5. What are the benefits?

The EPA reports the estimated impact on climate benefits from changes in CO_2 and the estimated impact on health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the illustrative policy scenario described previously. The EPA refers to the climate benefits as "targeted pollutant benefits" as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits

derived from reductions in emissions other than CO_2 as "co-benefits" as they are not direct benefits from reducing the targeted pollutant. To estimate the climate benefits associated with changes in CO_2 emissions, the EPA applied a measure of the domestic social cost of carbon (SC-CO_2). The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. The SC-CO_2 estimates used in the RIA for these rulemakings focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

The estimated health co-benefits are the monetized value of the human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. This rule is expected to alter the emissions of SO_2 and NO_X emissions, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, the EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. for the years 2025, 2030, and 2035 for the illustrative policy scenario. The EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition (BENMAP-CE). The EPA quantified effects using concentration-response parameters detailed in the RIA, which are consistent with those employed by the Agency in the PM NAAQS and Ozone NAAQS RIAs (U.S. EPA, 2012; 2015) (Table 6).

TABLE 6—ESTIMATED ECONOMIC VALUE OF AVOIDED $PM_{2.5}$ AND OZONE-ATTRIBUTABLE DEATHS AND ILLNESSES FOR THE ILLUSTRATIVE POLICY SCENARIO USING ALTERNATIVE APPROACHES TO REPRESENTING $PM_{2.5}$ EFFECTS
[95% Confidence interval in parentheses; millions of 2016$][a]

	2025		2030		2035	
Ozone Benefits Summed With $PM_{2.5}$ Benefits						
3% Discount rate						
No-threshold model[b]	$390 ($37 to $1,100)	*to* $970 ($86 to $2,800)	$490 ($47 to $1,300)	*to* $1,200 ($110 to $3,500).	$550 ($52 to $1,500)	*to* $1,400 ($120 to $3,900).
Limited to above LML[c]	$370 ($36 to $1,000)	*to* $480 ($42 to $1,400)	$440 ($42 to $1,200)	*to* $520 ($47 to $1,500)	$480 ($25 to $1,300)	*to* $610 ($16 to $1,800).
Effects above NAAQS[d]	$76 ($8 to $210)	*to* $250 ($23 to $760)	$75 ($8 to $210)	*to* $260 ($23 to $770)	$90 ($10 to $250)	*to* $320 ($28 to $930).
Ozone Benefits Summed With $PM_{2.5}$ Benefits						
7% Discount rate						
No-threshold model[b]	$360 ($34 to $990)	*to* $900 ($80 to $2,600)	$460 ($44 to $1,200)	*to* $1,100 ($100 to $3,200).	$510 ($48 to $1,400)	*to* $1,300 ($110 to $3,600).

Limited to above LML[c] ...	$350 ($33 to $950) ...	*to*	$460 ($41 to $1,300)	$410 ($39 to $1,100)	*to*	$500 ($44 to $1,400)	$450 ($22 to $1,200)	*to*	$590 ($13 to $1,700).
Effects above NAAQS[d] ...	$76 ($8 to $210)....	*to*	$250 ($23 to $760)....	$75 ($8 to $210).....	*to*	$260 ($23 to $770).....	$90 ($10 to $250).....	*to*	$320 ($28 to $930).

[a] Values rounded to two significant figures.

[b] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009). Full range of ozone effects is included, and ozone effects range from 19% to 22% of the estimated values.

[c] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$). Full range of ozone effects is still included, and ozone effects range from 20% to 49% of the estimated values.

[d] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end. Full range of ozone effects is still included, and ozone effects range from 91% to 95% of the estimated values.

To give readers insight to the distribution of estimated benefits displayed in Table 6, the EPA also reports the PM benefits according to alternative concentration cut-points and concentration-response parameters. The percentage of estimated avoided $PM_{2.5}$-related deaths occurring in 2025 below the lowest measured levels (LML) of the two long-term epidemiological studies the EPA uses to estimate risk varies between 5 percent (Krewski et al. 2009)[262] and 69 percent (Lepeule et al. 2012).[263] The percentage of estimated avoided premature deaths occurring in 2025 above the LML and below the NAAQS ranges between 94 percent (Krewski et al. 2009) and 31 percent (Lepeule et al. 2012). Less than 1 percent of the estimated avoided premature deaths occur in 2025 above the annual mean $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$.

Table 7 reports the combined domestic climate benefits and ancillary health co-benefits attributable to changes in SO_2 and NO_X emissions estimated for 3 percent and 7 percent discount rates in the years 2025, 2030, and 2035, in 2016 dollars. This table reports the air pollution effects calculated using $PM_{2.5}$ log-linear no threshold concentration-response functions that

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[262] Krewski, D., Jerrett, M., Burnett, R.T., Ma, R., Hughes, E., Shi, Y., Turner, M.C., Pope, C.A., Thurston, G., Calle, E.E., Thun, M.J., Beckerman, B., DeLuca, P., Finkelstein, N., Ito, K., Moore, D.K., Newbold, K.B., Ramsay, T., Ross, Z., Shin, H., Tempalski, B., 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. Res. Rep. Health. Eff. Inst. 5–114–36.

[263] Lepeule, J., Laden, F., Dockery, D., Schwartz, J., 2012. Chronic exposure to fine particles and mortality: An extended follow-up of the Harvard Six Cities study from 1974 to 2009. Environ. Health Perspect. *https://doi.org/10.1289/ehp.1104660.*

quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population (U.S. EPA, 2009[264]; U.S. EPA, 2011[265]; NRC, 2002[266]).

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[264] U.S. EPA, 2009. Integrated Science Assessment for Particulate Matter. U.S. Environmental Protection Agency, National Center for Environmental Assessment, Research Triangle Park, NC.

[265] U.S. EPA, 2011. Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards. Research Triangle Park, NC.

[266] NRC, 2002. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. National Research Council. Washington, DC.

TABLE 7—MONETIZED BENEFITS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE
[Millions of 2016$]

	Values calculated using 3% discount rate			Values calculated using 7% discount rate		
	Domestic climate benefits	Ancillary health co-benefits	Total benefits	Domestic climate benefits	Ancillary health co-benefits	Total benefits
2025.....	81	390 to 970.....	470 to 1,000.....	13	360 to 900.....	370 to 920.
2030.....	81	490 to 1,200...	570 to 1,300.....	14	460 to 1,100...	470 to 1,100.
2035.....	72	550 to 1,400...	620 to 1,400.....	13	510 to 1,300...	520 to 1,300.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (*e.g.*, from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Jerrett et al. (2009)). The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

In general, the EPA is more confident in the size of the risks estimated 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, the EPA is less confident in the risk the EPA estimates from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[267] Furthermore, when setting the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the "magnitude and significance" of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, "EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration."[268]

Monetized co-benefits estimates shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X, and HAP including

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[267] The **Federal Register** notice for the 2012 PM NAAQS indicates that "[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution." *See* 78 FR 3159 (January 15, 2013).

[268] *See* 78 FR 3154, January 15, 2013.

mercury and hydrogen chloride. Although the EPA does not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for this rule, the EPA includes a qualitative assessment of these unquantified benefits in the RIA. For more information on the benefits analysis, please refer to the RIA for these rules, which is available in the rulemaking docket.

IV. Changes to the Implementing Regulations for CAA Section 111(d) Emission Guidelines

The EPA is finalizing new regulations to implement CAA section 111(d) (implementing regulations) which will be codified at 40 CFR part 60, subpart Ba. The current implementing regulations at 40 CFR part 60, subpart B, were originally promulgated in 1975.[269] Section 111(d)(1) of the CAA explicitly requires that the EPA prescribe regulations establishing a procedure similar to that under section 110 of the CAA for states to submit plans to the EPA establishing standards of performance for existing sources within their jurisdiction. The implementing regulations have not been significantly revised since their original promulgation in 1975. Notably, the implementing regulations do not reflect CAA section 111(d) in its current form as amended by Congress in 1977, and do not reflect CAA section 110 in its current form as amended by Congress in 1990. Accordingly, the EPA believes that certain portions of the implementing regulations do not appropriately align with CAA section 111(d), contrary to that provision's mandate that the EPA's regulations be "similar" in procedure to

[269] *See* 40 FR 53346.

the provisions of section 110. Therefore, the EPA proposed to promulgate new implementing regulations that are in accordance with the statute in its current form (*See* 83 FR 44746–44813). Agencies have the ability to revisit prior decisions, and the EPA believes it is appropriate to do so here in light of the potential mismatch between certain provisions of the implementing regulations and the statute.[270] While the preamble for the final new implementing regulations are part of the same **Federal Register** document as certain other Agency rules (specifically, the repeal of the CPP and the promulgation of the ACE rule), these new implementing regulations are a separate and distinct rulemaking with its own regulatory text and response to comments. The implementing regulations are not dependent on the other final actions contained in this **Federal Register** document.

The EPA proposed to largely carry over the current implementing regulations in 40 CFR part 60, subpart B to a new subpart that will be applicable to emission guidelines that are finalized either concurrently with or subsequently to final promulgation of the new implementing regulations, as well as to state plans or federal plans associated with such emission guidelines. For purposes of regulatory certainty, the EPA believes it is appropriate to apply these new implementing

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[270] The authority to reconsider prior decisions exists in part because the EPA's interpretations of statutes it administers "[are not] instantly carved in stone," but must be evaluated "on a continuing basis." *Chevron U.S.A. Inc.* v. *NRDC, Inc.*, 467 U.S. 837, 863–64 (1984). Indeed, "[a]gencies obviously have broad discretion to reconsider a regulation at any time." *Clean Air Council* v. *Pruitt*, 862 F.3d 1, 8–9 (D.C. Cir. 2017).

regulations prospectively and retain the existing implementing regulations as applicable to CAA section 111(d) emission guidelines and associated state plans or federal plans that were promulgated previously. Additionally, because the original implementing regulations also applied to regulations promulgated under CAA section 129 (a provision enacted in the 1990 Amendments that builds on CAA section 111 but provides specific authority to address facilities that combust waste), which has its own statutory requirements distinct from those of CAA section 111(d), the original implementing regulations under 40 CFR part 60, subpart B continue to apply to EPA-regulations promulgated under CAA section 129, and any associated state plans and federal plans. The new implementing regulations are thus applicable only to CAA section 111(d) regulations and associated state plans issued solely under the authority of CAA section 111(d).

The EPA is aware that there are a number of cases where state plan submittal and review processes are still ongoing for existing CAA section 111(d) emission guidelines. Because the EPA is finalizing new state plan and federal plan timing requirements under the implementing regulations to more closely align CAA section 111(d) with both general CAA section 110 state implementation plan (SIP) and federal implementation plan (FIP) timing requirements, and because of the EPA's understanding from experience of the realities of how long these actions typically take, the EPA is applying the new timing requirements to both emission guidelines published after the new implementing regulations are finalized and to all ongoing emission guidelines already published under

CAA section 111(d). The EPA is finalizing applicability of the timing changes to all ongoing 111(d) regulations for the same reasons that the EPA is changing the timing requirements prospectively. Based on years of experience working with states to develop SIPs under CAA section 110, the EPA believes that given the comparable amount of work, effort, coordination with sources, and the time required to develop state plans, more time is necessary for the process. Giving states three years to develop state plans is more appropriate than the nine months provided for under the existing implementing regulations, considering the workload required for state plan development. These practical considerations regarding the time needed for state plan development are also applicable and true for recent emission guidelines where the state plan submittal and review process are still ongoing.

For those provisions that are being carried over from the existing implementing regulations into the new implementing regulations, the EPA is not intending to substantively change those provisions from their original promulgation and continues to rely on the record under which they were promulgated. Therefore, the following provisions remain substantively the same from their original promulgation: 40 CFR 60.21a(a)–(d), (g)–(j) (Definitions); 60.22a(a), 60.22a(b)(1)–(3), (b)(5), (c) (Publication of emission guidelines); 60.23a(a)–(c), (d)(3)–(5), (e)–(h) (Adoption and submittal of state plans; public hearings); 60.24a(a)–(d), (f) (Standards of performance and compliance schedules); 60.25a (Emission inventories, source surveillance, reports); 60.26a (Legal authority); 60.27a(a), (e)–(f) (Actions by

the Administrator); 60.28a(b) (Plan revisions by the state); and 60.29a (Plan revisions by the Administrator).

As noted at proposal, the EPA is also sensitive to potential confusion over whether these new implementing regulations would apply to emission guidelines previously promulgated or to state plans associated with prior emission guidelines, so the EPA proposed that the new implementing regulations are applicable only to emission guidelines and associated plans developed after promulgation of this regulation, including the emission guidelines being proposed as part of this action for GHGs and existing designated facilities. The EPA is finalizing this proposed applicability of the new implementing regulations.

While the EPA is carrying over a number of requirements from the existing implementing regulations to the new implementing regulations, the EPA is finalizing specific changes to better align the implementing regulations with the statute. These changes are reflected in the regulatory text for the new implementing regulations, and include:

- An explicit provision allowing specific emission guidelines to supersede the requirements of the new implementing regulations;
- Changes to the definition of "emission guidelines";
- Updated timing requirements for the submission of state plans;
- Updated timing requirements for the EPA's action on state plans;
- Updated timing requirements for the EPA's promulgation of a federal plan;

- Updated timing requirement for when increments of progress must be included as part of a state plan;
- Completeness criteria and a process for determining completeness of state plan submissions similar to CAA section 110(k)(1) and (2);
- Updated definition replacing "emission standard" with "standard of performance";
- Usage of the internet to satisfy certain public hearing requirements;
- Elimination of the distinction between public health-based and welfare-based pollutants in emission guidelines; and
- Updated provision allowing for consideration of remaining useful life and other factors to be consistent with CAA section 111(d)(1)(B).

Because the EPA is updating the implementing regulations and many of the provisions from the existing implementing regulations are being carried over, the EPA wants to be clear and transparent with regard to the changes that are being made to the implementing regulations. As such, the EPA is providing Table 8 that summarizes the changes being made.

TABLE 8—SUMMARY OF CHANGES TO THE IMPLEMENTING REGULATIONS

New implementing regulations—Subpart Ba for all future and ongoing CAA section 111(d) emission guidelines	Existing implementing regulations—Subpart B for all previously promulgated CAA section 111(d) emission guidelines
Explicit authority for a new 111(d) emission guidelines requirement to supersede these implementing regulations.	No explicit authority.
Use of term "standard of performance"	Use of term "emission standard".
"Standard of performance" allows states to include design, equipment, work practice, or operational standards when the EPA determines it is not feasible to prescribe or enforce a standard of performance, consistent with the requirements of CAA section 111(h).	"Emission standard" allows states to prescribe equipment specifications when the EPA determines it is clearly impracticable to establish an emission standard.
State submission timing: 3 years from promulgation of final emission guidelines.	State submission timing: 9 months from promulgation of final emission guidelines.
EPA action on state plan submission timing: 12 months after determination of completeness.	EPA action on state plan submission timing: 4 months after submittal deadline.
Timing for EPA promulgation of a federal plan, as appropriate: 2 years after finding of plan	Timing for EPA promulgation of a federal plan, as appropriate: 6 months after submittal deadline.

submission to be incomplete, finding of failure to submit a plan, or disapproval of state plan.	
Increments of progress are required if compliance schedule for a state plan is longer than 24 months after the plan is due.	Increments of progress are required if compliance schedule for a state plan is longer than 12 months after the plan is due.
Completeness criteria and process for state plan submittals	No analogous requirement.
Usage of the internet to satisfy certain public hearing requirements.....	No analogous requirement.
No distinction made in treatment between health-based and welfare-based pollutants; states may consider remaining useful life and other factors regardless of type of pollutant.	Different provisions for health-based and welfare-based pollutants; state plans must be as stringent as the EPA's emission guidelines for health-based pollutants unless variance provision is invoked.

A. Regulatory Background

The Agency also is, in this action, clarifying the respective roles of the states and the EPA under section 111(d), including by finalizing revisions to the regulations implementing that section in 40 CFR part 60 subpart B. CAA section 111(d)(1) states that the EPA "Administrator shall prescribe regulations which shall establish a procedure . . . under which each state shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance."[271] CAA section 111(d)(1) also requires the Administrator to "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[272]

As the statute provides, the EPA's authorized role under CAA section 111(d)(1) is to develop a procedure for states to establish standards of performance for existing sources. Indeed, the Supreme Court has acknowledged the role and authority of states under CAA section 111(d): This provision allows "each State to take the first cut at determining how best to achieve EPA emissions standards within its domain."[273] The

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[271] *See* 42 U.S.C. 7411(d).

[272] *Id.*

[273] *Am. Elec. Power Co.* v. *Connecticut*, 131 S. Ct. 2527, 2539 (2011).

Court addressed the statutory framework as implemented through regulation, under which the EPA promulgates emission guidelines and the states establish performance standards: "For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, [42 U.S.C.] 7411(d)(1)."[274]

As contemplated by CAA section 111(d)(1), states possess the authority and discretion to establish appropriate standards of performance for existing sources. CAA section 111(a)(1) defines "standard of performance" as "a standard of emissions of air pollutants which reflects" what is commonly referred to as the "Best System of Emission Reduction" or "BSER"—*i.e.*, "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 non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[275]

In order to effectuate the Agency's role under CAA section 111(d)(1), the EPA promulgated implementing regulations in 1975 to provide a framework for subsequent EPA rules and state plans under CAA section 111(d).[276] The implementing regulations reflect the EPA's principal task under CAA section

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[274] *Id.* at 2537–38.

[275] 42 U.S.C. 7411(a)(1) (emphasis added).

[276] *See* 40 CFR part 60, subpart B (hereafter referred to as the "implementing regulations").

111(d)(1), which is to develop a procedure for states to establish standards of performance for existing sources through state plans. The EPA is promulgating an updated version of the implementing regulations. Under the revised implementing regulations, the EPA effectuates its role by publishing "emission guidelines"[277] that, among other things, contain the EPA's determination of the BSER for the category of existing sources being regulated.[278] In undertaking this task, the EPA "will specify different emissions guidelines . . . for different sizes, types and classes of . . . facilities when costs of control, physical limitations, geographic location, or similar factors make subcategorization appropriate."[279]

In short, under the EPA's revised regulations implementing CAA section 111(d), which tracks with the existing implementing regulations in this regard, the guideline documents serve to "provide information for the development of state plans."[280] The "emission guidelines," reflecting the degree of emission limitation achievable through application of the BSER determined by the Administrator to be adequately demonstrated, are the principal piece of information

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[277] *See* section IV.B. for the changes to the definition of "emission guidelines" as part of the EPA's new implementing regulations.

[278] *See* 40 CFR 60.22a(b) ("Guideline documents published under this section will provide information for the development of State plans, such as: . . . (4) 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.").

[279] 40 CFR 60.22(b)(5).

[280] 40 CFR 60.22a(b).

states rely on to develop their plans that establish standards of performance for existing sources. Additionally, the Act requires that the EPA permit states to consider, "among other factors, the remaining useful life" of an existing source in applying a standard of performance to such sources.[281]

Additionally, while CAA section 111(d)(1) clearly authorizes states to develop state plans that establish performance standards and provides states with certain discretion in determining appropriate standards, CAA section 111(d)(2) provides the EPA specifically a role with respect to such state plans. This provision authorizes the EPA to prescribe a plan for a state "in cases where the State fails to submit a satisfactory plan."[282] The EPA therefore is charged with determining whether state plans developed and submitted under CAA section 111(d)(1) are "satisfactory," and the new implementing regulations at 40 CFR 60.27a accordingly provide timing and procedural requirements for the EPA to make such a determination. Just as guideline documents may provide information for states in developing plans that establish standards of performance, they may also provide information for the EPA to consider when reviewing and taking action on a submitted state plan, as the new implementing regulations at 40 CFR 60.27a(c) reference the ability of the EPA to find a state plan as "unsatisfactory because the

[281] 42 U.S.C. 7411(d)(1).

[282] *Id.* 7411(d)(2)(A).

requirements of (the implementing regulations) have not been met."[283]

B. Provision for Superseding Implementing Regulations

The EPA proposed to include a provision in the new implementing regulations that expressly allows for any emission guidelines to supersede the applicability of the implementing regulations as appropriate, parallel to a provision contained in the 40 CFR part 63 General Provisions implementing section 112 of the CAA. The EPA cannot foresee all of the unique circumstances and factors associated with particular future emission guidelines, and therefore different requirements may be necessary for a particular 111(d) rulemaking that the EPA cannot envision at this time. The EPA is finalizing this provision as proposed.

C. Changes to the Definition of "Emission Guidelines"

The existing implementation regulations under 40 CFR 60.21(e) contain a definition of "emission guidelines," defining them as guidelines which reflect the degree of emission reduction achievable through the application of the BSER which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities. This definition additionally references that emission guidelines may be set forth in 40 CFR part 60, subpart C, or a "final guideline

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[283] *See also* 40 FR 53343 ("If there is to be substantive review, there must be criteria for the review, and EPA believes it is desirable (if not legally required) that the criteria be made known in advance to the States, to industry, and to the general public. The emission guidelines, each of which will be subjected to public comment before final adoption, will serve this function.").

document" published under 40 CFR 60.22(a). While the implementing regulations do not define the term "final guideline document," 40 CFR 60.22 generally contains a number of requirements pertaining to the contents of guideline documents, which are intended to provide information for the development of state plans.[284] The preambles for both the proposed and final existing implementing regulations suggest that "emission guidelines" would be guidelines provided by the EPA that reflect the degree of emission limitation achievable by the BSER. In the proposal for this action, the EPA described that it is important to provide information on such degree of emission limitation in order to guide states in their establishment of standards of performance as required under CAA section 111(d). However, the EPA also explained that it did not believe anything in CAA section 111(a)(1) or 111(d) compels the EPA to provide a presumptive emission standard that reflects the degree of emission limitation achievable by application of the BSER. Accordingly, as part of the proposed new implementing regulations, the EPA proposed to re-define "emission guidelines" as final guideline documents published under 40 CFR 60.22a(a) that include information on the degree of emission reduction achievable through the application of the BSER which (taking into account the cost of such reduction and any non-air quality health and environmental impact and energy requirements) the EPA has determined has been adequately demonstrated for designated facilities.

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[284] *See* 40 CFR 60.22(b).

The EPA received substantial comments regarding this proposed change to the implementing regulations. Commenters contend that because CAA section 111(a)(1) requires the EPA to identify the BSER, it is also the EPA's statutory responsibility to identify the degree of emission limitation achievable through application of the BSER. According to commenters, the identification of a BSER without an accompanying emission limitation reflecting its application is an incomplete identification of the system of emission reduction itself, as it is the manner and degree of application of a system that often determines the quantity and cost of the emission reductions achieved, as well as any implications for energy requirements—factors that are statutorily a component of the BSER analysis delegated to the EPA.

The EPA has considered carefully these comments and is not finalizing the proposed changes to the definition of "emission guidelines" regarding the aspect of such guidelines reflecting the degree of emission limitation achievable through application of the BSER. The EPA is finalizing a definition of "emission guidelines" that requires them to reflect the degree of emission limitation of emission achievable through application of the BSER, as well as updates to the definition consistent with CAA section 111(a)(1) (*e.g.*, including a reference to "energy requirements" which was not present in the original definition). Relatedly, the EPA is not finalizing changes to proposed 40 CFR 60.21a(e) requiring the EPA in emission guidelines to provide *information* on the degree of emission limitation achievable through application of the BSER rather than such degree of emission limitation itself. While the statute is

ambiguous as to whose role (*i.e.*, the EPA's or the states') it is to determine the degree of emission limitation achievable through application of the BSER in the context of standards of performance for existing sources, the EPA believes it is reasonable to construe this aspect of CAA section 111 as included within the EPA's obligation to determine the BSER. While states are better positioned to evaluate source-specific factors and circumstances in establishing standards of performance, the EPA agrees with commenters that because the EPA evaluates components such as cost of emission reductions and environmental impacts on a broader, systemwide scale when determining the BSER, if a state instead were to determine the degree of emission limitation achievable for the sources within its borders, these factors will naturally be re-balanced on a smaller scale than the EPA's calculation and likely re-define the BSER in the process. Under the cooperative federalism structure of CAA section 111, the EPA determines the BSER and the associated level of stringency (*i.e.*, the degree of emission limitation achievable through application of the BSER), but states may where appropriate relax this level of stringency when establishing standards of performance by accounting for source-specific factors such as remaining useful life. Accordingly, given the EPA's role in determining the BSER, the EPA is retaining the requirement from the original implementing regulations that emission guidelines reflect the degree of emission limitation achievable through application of the BSER, rather than finalizing the proposed change that emission guidelines provide information on such degree of emission limitation achievable.

D. Updates to Timing Requirements

The timing requirements in the existing implementing regulations for state plan submissions, the EPA's action on state plan submissions, and the EPA's promulgation of federal plans generally track the timing requirements for SIPs and federal implementation plans (FIPs) under the 1970 version of the CAA. The existing implementing regulations at 60.23(a)(1) require state plans to be submitted to the EPA within nine months after publication of final emission guidelines, unless otherwise specified in emission guidelines. Congress subsequently revised the SIP and FIP timing requirements in section 110 as part of the 1990 CAA Amendments. The EPA proposed to update accordingly the timing requirements regarding state and federal plans under CAA section 111(d) to be consistent with the current timing requirements for SIPs and FIPs under section 110.[285]

Commenters contend that premising the proposed longer timelines for state plans based on the timelines for SIPs and FIPs is inappropriate because CAA section 111(d) state plans are narrower in scope and less complex than section 110 SIPs for a number of reasons. According to commenters, these reasons include: (1) Because state plans cover one source category, whereas SIPs cover the different types of sources whose emissions must be reduced to meet an ambient air quality standard; (2) because sources under state plans are required to meet an emission standard expressed as a rate or mass limitation, whereas SIPs are required to assure that ambient air

[285] *See* 84 FR 44746–813.

within a state stay below the NAAQS, which requires monitoring, modeling, and other complicated considerations; and (3) EPA already does a substantial percentage of the work for states in the first instance by determining the BSER and the degree of emission limitation achievable through application of the BSER.

While it is correct that the main requirement under CAA section 111(d) is for state plans to establish standards of performance for designated facilities, and that these existing-source performance standards are informed by the degree of emission limitation achievable through application of the BSER that EPA identifies, CAA section 111(d)(1)(B) also requires state plans to include measures that provide for the implementation and enforcement of such standards. The implementing regulations further clarify what those measures may be, such as monitoring, reporting, and recordkeeping requirements, but the regulations do not specify the types of measures that may satisfy those requirements (*e.g.*, what type of monitoring is adequate to measure compliance for a particular source category). Nor do the implementing regulations contain an exhaustive list of implementation and enforcement measures given that the nature of a specific state plan, or individual source subject to a state plan, may necessitate tailored implementation and enforcement measures that the EPA has not, or cannot, prescribe.

Establishment of standards of performance under CAA section 111(d) state plans also may not be as straightforward as commenters suggest, as states have the authority to consider remaining useful life and other factors in applying a standard to a designated facility. While the EPA defines the degree

of emission limitation achievable through application of the BSER, it is the state that must evaluate whether there are source-specific considerations which necessitate development of a different standard than the degree of emission limitation that the EPA identifies. Commenters do not provide any information suggesting development of such standards, or development of appropriate implementation and enforcement measures generally, would take some shorter period of time to formulate and adopt for submission of a state plan than the three years the EPA proposed. Therefore, for these reasons, commenters fail to recognize that while CAA section 111(d) is not the same as CAA section 110 in the scope of its requirements, state plans under CAA section 111(d) have their own complexities and realities that take time to address in the development of state plans.

To the contrary, it has been the EPA's experience over decades in the SIP context that states often do need and take much, if not all, of the three-year period under section 110 for the process of developing and adopting SIPs, even if a required SIP submission is relatively narrow in scope and nature. To the extent the EPA determines a shorter timeline is appropriate for the submission of state plans under CAA section 111(d), for example based on the nature of the pollution problem involved, the EPA has authority under the implementing regulations to impose a shorter deadline in specific emission guidelines. Relatedly, the EPA also proposed that it would be required to propose a federal plan "within" two years, and nothing in this provision precludes the EPA from promulgating a federal plan at any period within that span of two years if it deems appropriate.

For all of these reasons and based on its experience, the EPA believes it is at least reasonable to construe Congress's direction that it establish a procedure "similar" under that of CAA section 110 to authorize it to provide the same timing requirements for state and federal plans under CAA section 111(d) as Congress provided under CAA section 110, and indeed that this direction may indicate Congress's specific intention that the EPA adopt those same timing requirements. The EPA is finalizing, as part of new implementing regulations, a requirement that states adopt and submit a state plan to the EPA within three years after the notice of the availability of the final emission guidelines. Because of the amount of work, effort, and time required for developing state plans that include unit-specific standards, and implementation and enforcement measures for such standards, the EPA believes that extending the submission date of state plans from nine months to three years is appropriate. Because states have considerable flexibility in implementing CAA section 111(d), this timing also allows states to interact and work with the Agency in the development of their state plans and to minimize the chances of unexpected issues arising that could slow down eventual approval of state plans. The EPA notes that nothing in CAA section 111(d) or the implementing regulations preclude states from submitting state plans earlier than the applicable deadline. The EPA also is finalizing to give itself discretion to determine, in specific emission guidelines, that a shorter time period for the submission of state plans particular to that emission guidelines is appropriate. Such authority is consistent with CAA section 110(a)(1)'s grant of authority to the

Administrator to determine that a period shorter than three years is appropriate for the submission of particular SIPs implementing the NAAQS.

Following submission of state plans, the EPA will review plan submittals to determine whether they are "satisfactory" pursuant to CAA section 111(d)(2)(A). Given the flexibilities CAA section 111(d) and emission guidelines generally accord to states, and the EPA's prior experience on reviewing and acting on SIPs under section 110, the EPA is extending the period for EPA review and approval or disapproval of plans from the four-month period provided in the 1975 implementing regulations to a twelve-month period after a determination of completeness (either affirmatively by the EPA or by operation of law, see section IV.F. for the new implementing regulations' treatment of completeness) as part of the new implanting regulations. This timeline will provide adequate time for the EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment on the EPA's proposed action on a state plan.

The EPA additionally is extending the timing for the EPA to promulgate a federal plan from six months in the existing implementing regulations to two years, as part of the new implementing regulations. This two-year timeline is consistent with the FIP deadline under section 110(c) of the CAA. The EPA is finalizing provisions in the new implementing regulations [286] that provide that it has the authority to promulgate a federal plan within two years if it:

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[286] 40 CFR 60.27a(c).

- Finds that a state failed to submit a plan required by emission guidelines and CAA section 111(d);
- Makes a finding that a state plan submission is incomplete, as described under the new completeness requirements and criteria in 40 CFR 60.27a(g); or
- Disapproves a state plan submission.

E. Compliance Deadlines

The previous implementing regulations required that any compliance schedule for state plans extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities.[287] However, as described in section IV.D, the EPA is finalizing updates to the timing requirements for the submission of, and action on, state plans. Consequently, it follows that the requirement for increments of progress also should be updated in order to align with the new timelines. Given that the EPA is finalizing a period of up to 18 months for its action on state plans (*i.e.*, 12 months from the determination that a state plan submission is complete, which could occur up to six months after receipt of the state plan), the EPA believes it is appropriate that the requirement for increments of progress should attach to plans that contain compliance periods that are longer than the period provided for the EPA's review of such plans. This way, sources subject to a plan will have more certainty that their regulatory compliance obligations would not

[287] 40 CFR 60.24(e)(1).

change between the period when a state plan is due and when the EPA acts on a plan. Accordingly, the EPA is requiring that states include provisions for increments of progress where their state plans contain compliance schedules longer than 24 months from the date when state plans are due for particular emission guidelines.

F. Completeness Criteria

Similar to requirements regarding determinations of completeness under CAA section 110(k)(1), the EPA is finalizing completeness criteria that provide the Agency with a means to determine whether a state plan submission includes the minimum elements necessary for the EPA to act on the submission. The EPA determines completeness simply by comparing the state's submission against these completeness criteria. In the case of SIPs under CAA section 110(k)(1), the EPA promulgated completeness criteria in 1990 at appendix V to 40 CFR part 51.[288] The EPA is adopting criteria similar to the criteria set out at section 2.0 of appendix V for determining the completeness of submissions under CAA section 111(d).

The EPA notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under any applicable emission guidelines. The completeness criteria in this action are those that would generally apply to all plan submissions under CAA section 111(d), but specific emission guidelines

[288] 55 FR 5830; February 16, 1990.

may supplement these general criteria with additional requirements.

The completeness criteria that the EPA is finalizing in this action can be grouped into administrative materials and technical support. For administrative materials, the completeness criteria mirror criteria for SIP submissions because the two programs have similar administrative processes. Under these criteria, the submittal must include the following:

(1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof;

(2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter "document") in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan;

(4) A copy of the official state regulation(s) or document(s) submitted for approval and incorporated by reference into the plan, signed, stamped, and dated by the appropriate state official indicating that they are fully adopted and enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submission must indicate the changes made to the approved plan by redline/strikethrough;

(5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan;

(6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice;

(7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23.; and

(8) Compilation of public comments and the state's response thereto.

In addition, the technical support required for all plans must include each of the following:

(1) Description of the plan approach and geographic scope;

(2) Identification of each designated facility; identification of emission standards for each designated facility; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility;

(3) Identification of compliance schedules and/or increments of progress;

(4) Demonstration that the state plan submission is projected to achieve emissions performance under the applicable emission guidelines;

(5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(6) Demonstration that each emission standard is quantifiable, permanent, verifiable, and enforceable.

The EPA intends that these criteria generally be applicable to all CAA section 111(d) plans submitted on or after the date on which final new implementing regulations are promulgated, with the proviso that specific emission guidelines may provide otherwise.

Consistent with the requirements of CAA section 110(k)(1)(B) for SIPs, the EPA is finalizing that the EPA will determine whether a state plan is complete (*i.e.*, meets the completeness criteria) by no later than 6 months after the date, if any, by which a state is required to submit the plan. The EPA requires that any plan or plan revision that a state submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum completeness criteria, shall on that date be deemed by operation of law to be a complete state plan. Then, as previously discussed, the EPA relatedly is finalizing that the EPA will act on a state plan submission through notice-and-comment rulemaking within 12 months after determining a plan is complete either through an affirmative determination or by operation of law.

When plan submissions do not contain the minimum elements, the EPA will find that a state has failed to submit a complete plan through the same process as finding a state has made no submission at all. Specifically, the EPA will notify the state that its submission is incomplete and that it therefore has not submitted a required plan, and the EPA will also publish a finding of failure to submit in the **Federal Register,** which triggers the EPA's obligation to

promulgate a federal plan for the state. This determination that a submission is incomplete and that the state has failed to submit a plan is ministerial in nature and requires no exercise of discretion or judgment on the Agency's part, nor does it reflect a judgment on the eventual approvability of the submitted portions of the plan.

G. Standard of Performance

As previously described, the implementing regulations were promulgated in 1975 and effectuated the 1970 version of the CAA as it existed at that time. The 1970 version of CAA section 111(d) required state plans to include "emission standards" for existing sources, and consequently the implementing regulations refer to this term. However, as part of the 1977 amendments to the CAA, Congress replaced the term "emission standard" in section 111(d) with "standard of performance." The EPA has not since revised the implementing regulations to reflect this change in terminology. For clarity's sake and to better track with statutory requirements, the EPA is determining to include a definition of "standard of performance" as part of the new implementing regulations, and to consistently refer to this term as appropriate within those regulations in lieu of referring to an "emission standard." In any event, the current definition of "emission standard" in the implementing regulations is incomplete and would need to be revised. For example, the definition encompasses equipment standards, which is an alternative form of standard provided for in CAA section 111(h) under certain circumstances. However, CAA section 111(h) provides for other forms of alternative standards, such as work practice

standards, which are not covered by the existing regulatory definition of "emission standard." Furthermore, the definition of "emission standard" encompasses allowance systems, a reference that was added as part of the EPA's CAMR.[289] This rule was vacated by the D.C. Circuit, and therefore this added component to the definition of "emission standard" had no legal effect because of the Court's vacatur. Consistent with the Court's opinion, the EPA signaled its intent to remove this reference as part of its MATS rule.[290] However, in the final regulatory text of that rulemaking, the EPA did not take action removing this reference, and it remains as a vestigial artifact.

For these reasons, the EPA is replacing the existing definition of "emission standard" with a definition of "standard of performance" that tracks with the definition provided for under CAA section 111(a)(1). This means a standard of performance for existing sources would be defined as a standard for emissions of air pollutants that reflects the degree of emission limitation achievable through the application by the state of the BSER which (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. Several commenters expressed concern that the proposed definition of "standard of performance" in conjunction with the proposal to strike the reference to allowance-based systems precluded states from including mass-based standards of performance. Commenters

[289] 70 FR 28605.

[290] 77 FR 9304.

misunderstand the EPA's proposal, which did not propose that the new definition of "standard of performance" itself would specify either rate-based or mass-based standards. As explained at proposal, the new definition is intended to track the definition of the same term in CAA section 111(a)(1), which does not specify that standards of performance must be rate or mass-based. Rather, the EPA may determine in particular emission guidelines the appropriate form of the standard that a state plan must include, based on considerations specific to those emission guidelines, such as the BSER determination, the nature of the pollutant and affected source-category being regulated, and other relevant factors. The EPA believes the term "standard of performance" alone does not require or preclude that the standard be in rate or mass-based form, whereas the prior definition of "emission standard" was actually more restrictive in that it specified rate-based standards and allowance-based systems, but it did not identify other mass-based standards (such as limits) as permissible.

Similarly, other commenters stated that the definition in the implementing regulations should be clarified to encompass unambiguously rates of any kind (*e.g.*, input-based or output-based), quantities, concentrations, or percentage reductions, consistent with statutory language. However, as previously described, the term "standard of performance" alone does not specify which form the standard must take, and such specification is appropriately made in a particular emission guideline depending on considerations such as the nature of the BSER, source category, and pollutant for that rule. Therefore, the EPA is finalizing the definition of "standard of

performance" as proposed and clarifying that the definition alone does not preclude any form of rate or mass-based standards, but particular emission guidelines may specify the appropriate form of standards that a state plan under such guidelines can or cannot include.

The EPA is further finalizing a definition of standard of performance that incorporates CAA section 111(h)'s allowance for design, equipment, work practice, or operational standards as alternative standards of performance under the statutorily prescribed circumstances. The previous implementing regulations allowed for state plans to prescribe equipment specifications when emission rates are "clearly impracticable" as determined by the EPA. CAA section 111(h)(1), by contrast, allows for alternative standards such as equipment standards to be promulgated when standards of performance are "not feasible to prescribe or enforce," as those terms are defined under CAA section 111(h)(2). Given the potential discrepancy between the conditions under which alternative standards may be established based on the different terminology used by the statute and existing implementing regulations, the EPA is establishing in the new implementing regulations the "not feasible to prescribe or enforce" language as the condition under which alternative standards may be established.

H. Remaining Useful Life and Other Factors Provisions

The EPA believes that the previous implementing regulations' distinction between public health-based and welfare-based pollutants is not a distinction

unambiguously required under CAA section 111(d) or any other applicable provision of the statute. The EPA does not believe the nature of the pollutant in terms of its impacts on health and/or welfare impact the manner in which it is regulated under this provision. Particularly, 60.24(c) requires that for health-based pollutants, a state's standards of performance must be of equivalent stringency to the EPA's emission guidelines. However, CAA section 111(d)(1)(B) states that the EPA's regulations "shall" permit states to take into account, among other factors, a designated facility's remaining useful life when establishing an appropriate standard of performance. In other words, Congress explicitly envisioned under CAA section 111(d)(1)(B) that states could implement standards of performance that vary from the EPA's emission guidelines under appropriate circumstances. Notably, the pre-existing implementing regulations at § 60.24(f) contain a provision that allows for states to also apply less stringent standards on sources under certain circumstances.[291] However, this provision attaches to the distinction between health-based and welfare-based pollutants and is available to the states only under the EPA's discretion. This provision was also promulgated prior to Congress's addition of the requirement in CAA section 111(d)(1)(B) that the EPA

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[291] The EPA is hereafter no longer referring to 40 CFR 60.24(f) or its corollary under the new implementing regulations as the "variance provision." The EPA is instead using the phrase "remaining useful life and other factors" when referring to this provision, as this phrase is consistent with the terminology used in CAA section 111(d)(1) and better reflects the states' role and authority in establishing standards of performance under CAA section 111(d) generally.

permit states to take into account remaining useful life and other factors, and the terms of the regulatory provision and statutory provision do not match one another, meaning that this provision may not account for all of the factors envisioned under CAA section 111(d)(1)(B). Given all of these considerations, the EPA is finalizing in the new implanting regulations provisions that remove the distinction between health-based and welfare-based pollutants and associated requirements contingent upon this distinction. The EPA is also finalizing a new provision to permit states to take into account remaining useful life, among other factors, in establishing a standard of performance for a particular designated facility, consistent with CAA section 111(d)(1)(B).

Under this new "remaining useful life and other factors" provision, these following factors may be considered, among others:

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or
- 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.

Given that there are unique attributes and aspects of each designated facility, it is not possible for the EPA to define each and every circumstance that states may consider when applying a standard of performance under CAA section 111(d); accordingly, this list is not intended to be exclusive of other source-specific factors that a state may permissibly take into account in developing a satisfactory plan establishing

standards of performance for existing sources within its jurisdiction. Such "other factors" referred to under the remaining useful life and other factors provision may be ones that influence decisions to invest in technologies to meet a potential performance standard. Such other factors may include timing considerations like payback period for investments, the timing of regulatory requirements, and other unit-specific criteria. A state may account for remaining useful life and other factors as it determines appropriate for a specific source, so long as the state adopts a reasonable approach and adequately explains that approach in its submission to the EPA.

V. Statutory and Executive Order Reviews

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

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

This final action is an economically significant action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the compliance cost, benefit, and net benefit impacts associated with this action in the analytical timeframe of 2023 to 2037. This analysis, which is contained in the Regulatory Impact Analysis (RIA) for this final action, is consistent with Executive Order 12866 and is available in the docket for this action.

In the RIA for this final action, the Agency provides a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models HRI at coal-fired EGUs. This illustrative policy scenario, described in greater detail in section III.F above, represents potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. Throughout the RIA, the illustrative policy scenario is compared against a single baseline. As described in Chapter 2 of the RIA, the EPA believes that a single baseline without the CPP represents a reasonable future against which to assess the potential impacts of the ACE rule. The EPA also provides analysis in Chapter 2 of the RIA that satisfies any need for regulatory impact analysis that may be required by statute or executive order for the repeal of the CPP.

The EPA evaluates the potential regulatory impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the timeframe of 2023–2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These specific snapshot years are 2025, 2030, and 2035.

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenario, including the cost of monitoring, reporting, and recordkeeping. The EPA also reports the impact on climate benefits from changes in CO_2 and the impact on health benefits

attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions. More detailed descriptions of the cost and benefit impacts of these rulemakings are presented in section III.F above.

Table 9 presents the PV and equivalent annualized value (EAV) of the estimated costs, domestic climate benefits, ancillary health co-benefits, and net benefits of the illustrative policy scenario for the timeframe of 2023–2037, relative to the baseline. The EAV represents an even-flow of figures over the timeframe of 2023–2037 that would yield an equivalent present value. The EAV is identical for each year of the analysis, in contrast to the year-specific estimates presented earlier for the snapshot years of 2025, 2030, and 2035. Table 10 presents the estimates for the specific snapshot years of 2025, 2030, and 2035.

TABLE 9—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, DOMESTIC CLIMATE BENEFITS, ANCILLARY HEALTH CO-BENEFITS, AND NET BENEFITS, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037
[Millions of 2016$]

	Costs		Domestic climate benefits		Ancillary health co-benefits		Net benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
Present Value.....	1,600	970	640	62	4,000 to 9,800..	2,000 to 5,000..	3,000 to 8,800..	1,100 to 4,100.
Equivalent Annualized Value..	140	110	53	6.9	330 to 820.....	220 to 550.....	250 to 730	120 to 450.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity

sector SO_2 and NO_X emissions and reflect the range based on adult mortality functions (*e.g.*, from Krewski et al. (2009) with Smith et al. (2009)[292] to Lepeule et al. (2012) with Jerrett et al. (2009)).[293]

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[292] Smith, R.L., Xu, B., Switzer, P., 2009. Reassessing the relationship between ozone and short-term mortality in U.S. urban communities. Inhal. Toxicol. 21 Suppl 2, 37–61. *https://doi.org/10.1080/08958370903161612*.

[293] Jerrett, M., Burnett, R.T., Pope, C.A., Ito, K., Thurston, G., Krewski, D., Shi, Y., Calle, E., Thun, M., 2009. Long-term ozone exposure and mortality. N. Engl. J. Med. 360, 1085–95. *https://doi.org/10.1056/NEJMoa0803894*.

TABLE 10—COMPLIANCE COSTS, DOMESTIC CLIMATE BENEFITS, ANCILLARY HEALTH CO-BENEFITS, AND NET BENEFITS IN 2025, 2030, AND 2035, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES
[Millions of 2016$]

	Costs		Domestic climate benefits		Ancillary health co-benefits		Net benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
2025	290	290	81	13	390 to 970	360 to 900	180 to 760	84 to 630.
2030	280	280	81	14	490 to 1,200	460 to 1,100	300 to 1,000	200 to 860.
2035	25	25	72	13	550 to 1,400	510 to 1,300	600 to 1,400	500 to 1,200.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2 and NO_X emissions and reflect the range based on adult mortality functions (*e.g.*, from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Jerrett et al. (2009)).

In the decision-making process it is useful to consider the change in benefits due to the targeted pollutant relative to the costs. Therefore, in Chapter 6 of the RIA for this final action the Agency presents a comparison of the benefits from the targeted pollutant—CO_2—with the compliance costs. Excluded from this comparison are the benefits from changes in $PM_{2.5}$ and ozone concentrations from changes in SO_2, NO_X, and $PM_{2.5}$ emissions that are projected to accompany changes in CO_2 emissions.

Table 11 presents the PV and EAV of the estimated costs, benefits, and net benefits associated with the targeted pollutant, CO_2, for the timeframe of 2023–2037, relative to the baseline. In Table 11 and Table 12, negative net benefits are indicated with parenthesis.

TABLE 11—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2), ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037
[Millions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value	1,600	970	640	62	(980)	(910)
Equivalent Annualized Value	140	110	53	6.9	(82)	(100)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Table 12 presents the costs, benefits, and net benefits associated with the targeted pollutant for specific years, rather than as a PV or EAV as found in Table 11.

TABLE 12—COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2) IN 2025, 2030, AND 2035, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES
[Millions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
2025	290	290	81	13	(210)	(280)
2030	280	280	81	14	(200)	(260)
2035	25	25	72	13	47	(11)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Throughout the RIA for this action, the EPA considers a number of sources of uncertainty, both quantitatively and qualitatively. The RIA also summarizes other potential sources of benefits and costs that may result from these rules that have not been quantified or monetized.

B. Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned the EPA ICR number 2503.04. A copy of the ICR can be found in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

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 Ba.

Respondents/affected entities: 48—the 48 contiguous states;

Respondent's obligation to respond: The EPA expects state plan submissions from 43 of the 48 contiguous states and negative declarations from Vermont, California, Maine, Idaho, and Rhode Island.

Frequency of response: Yearly.

Total estimated burden: 192,640 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $21,500 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce the approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

D. Regulatory Flexibility Act (RFA)

After considering the economic impacts of this rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final 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 develop and submit to the EPA plans that establish performance standards for existing sources within their jurisdiction, and it is those state requirements that could potentially impact small entities. Our analysis in the accompanying RIA 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 with the description in the RIA, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans.[294]

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

This action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the three-year period following

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[294] *See American Trucking Ass'n* v. *EPA*, 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

promulgation of the rule was estimated and is listed in section IV.A. above, but this burden is estimated to be below $100 million in any one year. Thus, this rule is not subject to the requirements of section 203 or section 205 of the Unfunded Mandates Reform Act (UMRA).

This rule is also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, it contains no regulatory requirements that might significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

The EPA has concluded that this action may have federalism implications because it might impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. The development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal. The Agency understands the burden that these actions will have on states and is committing to providing aid and guidance to states through the plan development process. The EPA will be available at the states initiative to provide clarity for developing plans, including standard of performance setting and compliance initiatives.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It would not impose substantial direct compliance costs on tribal governments that have designated facilities located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for designated facilities. The EPA notes that this final rule does not directly impose specific requirements on EGU sources, including those located in Indian country; before developing any standards of performance for existing sources on tribal land, the EPA would consult with leaders from affected tribes. This action also will not have substantial direct costs or impacts on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the action.

Executive Order 13175 requires the EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." The EPA has concluded that this action does not have tribal implications as specified in E.O. 13175. It would not impose substantial direct compliance costs on tribal governments that have designated facilities located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for designated facilities. This action also will not have substantial direct cost or impacts on the relationship between the federal

government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175.

Consistent with EPA Policy on Consultation and Coordination with Indian Tribes, the EPA consulted with tribal officials during the development of this action to provide an opportunity to have meaningful and timely input. On August 24, 2018, consultation letters were sent to 584 tribal leaders that provided information and offered consultation regarding the EPA's development of this rule. On August 30, 2018, the EPA provided a presentation overview on the Proposal: Affordable Clean Energy (Rule) on the monthly National Tribal Air Association/EPA Air Policy call. At the request of the tribes, two consultation meetings were held: One with the Navajo Nation on October 11, 2018, and one with the Samish Indian Nation on October 16, 2018. The Samish Indian Nation opened their consultation to other tribes—also participating in this meeting for informational purposes only were seven tribes (Blue Lake Rancheria, Cherokee Nation Environmental Program, La Jolla Band of Luiseno Indians, Leech Lake Band of Ojibwe, Muscogee (Creek) Nation Office of Environmental Services, Nez Perce Tribe, The Quapaw Tribe) and the National Tribal Air Association. In the meetings, the tribes were presented information from the proposal. The tribes asked general clarifying questions and indicated that they would submit formal comments. Comments on the proposal were received from the Navajo Nation, the Samish Indian Nation, Blue Lake Rancheria, Leech Lake Band of Ojibwe, Nez Perce Tribe, and the

National Tribal Air Association, in addition to the Keweenaw Bay Indian Community, the Fond du Lac Band, the 1854 Treaty Authority, and the Sac and Fox Nation. Tribal commenters insisted on meaningful government-to-government consultation with potentially impacted tribes, and that the final rule require states to consult with indigenous and vulnerable communities as they develop state plans. More specific comments can be found in the docket.

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

This action is subject to Executive Order 13045 because it is an economically significant regulatory action as defined by Executive Order 12866. The EPA believes that this action will achieve CO_2 emission reductions resulting from implementation of these emission guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve children's health.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This action does not affect applicable local, state, or federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

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

This action, which is a significant regulatory energy action under Executive Order 12866, is likely to have a significant effect on the supply, distribution, or use of energy. Specifically, the EPA estimated in the RIA that the rule could result in more than a one percent decrease in coal production in 2025 (or a reduction of more than a 5 million tons per year) and less than a one percent reduction in natural gas use in the power sector (or more than a 25 million MCF reduction in production on an annual basis). The energy impacts the EPA estimates from these rules may be under- or over-estimates of the true energy impacts associated with this action. For more information on the estimated energy effects, please refer to the RIA for these rulemakings, which is in the public docket.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The EPA believes that this action will achieve CO_2 emission reductions resulting from implementation of these final guidelines, as well as

ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve environmental justice communities' health as discussed in the RIA.

With regards to the repeal, Chapter 2 of the RIA explains why the EPA believes that the power sector is already on path to achieve the CO_2 reductions required by the CPP, therefore the EPA does not believe it would have any significant impact on EJ effected communities.

With regards to ACE, as described in Chapter 4 of the RIA, the EPA finds that most of the eastern U.S. will experience PM and ozone-related benefits as a result of this action. While the EPA expects areas in the southeastern U.S. to experience a modest increase in fine particle levels, areas including the Midwest will experience reduced levels of PM, yielding significant benefits in the form of fewer premature deaths and illnesses. On balance, the positive benefits of this action significantly outweigh the estimated disbenefits.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a "major rule" as defined by 5 U.S.C. 804(2).

VI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, and 307(d)(1)(V) of the CAA, as

amended (42 U.S.C. 7411, 7601, 7607(d)(1)(V)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

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

Dated: June 19, 2019.

Andrew R. Wheeler,

Administrator.

Therefore, 40 CFR chapter I is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ **1.** The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Add subpart Ba to read as follows:

Subpart Ba—Adoption and Submittal of State Plans for Designated Facilities

Sec.

§ 60.20a Applicability.

(a) The provisions of this subpart apply upon publication of a final emission guideline under § 60.22a(a) if implementation of such final guideline is ongoing as of July 8, 2019 or if the final guideline is published after July 8, 2019.

(1) Each emission guideline promulgated under this part is subject to the requirements of this subpart, except that each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart. Each emission guideline must identify explicitly any provision of this subpart that is superseded.

(2) Terms used throughout this part are defined in § 60.21a or in the Clean Air Act (Act) as amended in 1990, except that emission guidelines promulgated as individual subparts of this part may include specific definitions in addition to or that supersede definitions in § 60.21a.

(b) No standard of performance or other requirement established under this part shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 112, Part C or D, or any other

authority of this Act), or a standard issued under State authority.

§ 60.21a Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A of this part:

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) *Designated facility* means any existing facility (see § 60.2) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2).

(c) *Plan* means a plan under section 111(d) of the Act which establishes standards of performance for designated pollutants from designated facilities and provides for the implementation and enforcement of such standards of performance.

(d) *Applicable plan* means the plan, or most recent revision thereof, which has been approved under § 60.27a(b) or promulgated under § 60.27a(d).

(e) *Emission guideline* means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22a(a), 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 such reduction and any non-air quality health and

environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) *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, including, but not limited to a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof.

(g) *Compliance schedule* means a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific standards of performance contained in a plan or with any increments of progress to achieve such compliance.

(h) *Increments of progress* means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification;

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) *Region* means an air quality control region designated under section 107 of the Act and described in part 81 of this chapter.

(j) *Local agency* means any local governmental agency.

§ 60.22a Publication of emission guidelines.

(a) Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft emission guideline containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft emission guideline will be published in the **Federal Register** and public comments on its contents will be invited. After consideration of public comments and upon or after promulgation of standards of performance for control of a designated pollutant from affected facilities, a final emission guideline will be published and notice of its availability will be published in the **Federal Register.**

(b) Emission guidelines published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission limitation which is achievable with each system, together with information on the costs, nonair quality health environmental effects, and energy requirements of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) The degree of emission limitation achievable through the application of the best system of emission reduction (considering the cost of such achieving reduction and any nonair quality health and environmental impact and energy requirements) that has been adequately demonstrated for designated facilities, and the time within which compliance with standards of performance can be achieved. The Administrator may specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) The emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in subpart C of this part with such modifications as may be appropriate.

§ 60.23a Adoption and submittal of State plans; public hearings.

(a)(1) Unless otherwise specified in the applicable subpart, within three years after notice of the availability of a final emission guideline is published under § 60.22a(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the emission guideline applies.

(2) At any time, each State may adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart or an applicable subpart of this part.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c) The State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision in accordance with the provisions under this section.

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected. This requirement may be satisfied by advertisement on the internet;

(2) Availability, at the time of public announcement, of each proposed plan or revision thereof for public inspection in at least one location in each region to which it will apply. This requirement may be satisfied by posting each proposed plan or revision on the internet;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State may cancel the public hearing through a method it identifies if no request for a public hearing is received during the 30 day notification period under paragraph (d) of this section and the original notice announcing the 30 day notification period states that if no request for a public hearing is received the hearing will be cancelled; identifies the method and time for announcing that the hearing has been cancelled; and provides a contact phone number for the public to call to find out if the hearing has been cancelled.

(f) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(g) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) 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.

(h) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24a Standards of performance and compliance schedules.

(a) Each plan shall include standards of performance and compliance schedules.

(b) Standards of performance shall either be based on allowable rate or limit of emissions, except when it is not feasible to prescribe or enforce a standard of performance. The EPA shall identify such cases in the emission guidelines issued under § 60.22a. Where standards of performance prescribing design,

equipment, work practice, or operational standard, or combination thereof are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(1) Test methods and procedures for determining compliance with the standards of performance shall be specified in the plan. Methods other than those specified in appendix A to this part or an applicable subpart of this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2.

(2) Standards of performance shall apply to all designated facilities within the State. A plan may contain standards of performance adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (e) of this section, standards of performance shall be no less stringent than the corresponding emission guideline(s) specified in subpart C of this part, and final compliance shall be required as expeditiously as practicable, but no later than the compliance times specified in an applicable subpart of this part.

(d) Any compliance schedule extending more than 24 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Unless otherwise specified in the applicable subpart, increments of progress must include, where practicable, each

increment of progress specified in § 60.21a(h) and must include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(e) In applying a standard of performance to a particular source, the State may take into consideration factors, such as the remaining useful life of such source, provided that the State demonstrates with respect to each such facility (or class of such 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.

(f) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing:

(1) Standards of performance more stringent than emission guidelines specified in subpart C of this part or in applicable emission guidelines; or

(2) Compliance schedules requiring final compliance at earlier times than those specified in subpart C of this part or in applicable emission guidelines.

§ 60.25a Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the

designated pollutants and information related to emissions as specified in appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. As used in this subpart, "correlated" means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable standards of performance.

(b) Each plan shall provide for monitoring the status of compliance with applicable standards of performance. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan. Submission of electronic documents shall comply with the requirements of 40 CFR part 3 (Electronic reporting).

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable standards of performance (see § 60.25a(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified.

Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act; and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26a are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by §51.321 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any standard of performance or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the

time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26a Legal authority.

(a) Each plan or plan revision shall show that the State has legal authority to carry out the plan or plan revision, including authority to:

(1) Adopt standards of performance and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable standards of performance.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act; and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27a Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, shorten the period for submission of any plan or plan revision or portion thereof.

(b) After determination that a plan or plan revision is complete per the requirements of § 60.27a(g), the Administrator will take action on the plan or revision. The Administrator will, within twelve months of finding that a plan or plan revision is complete, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will promulgate, through notice-and-comment rulemaking, a federal plan, or portion thereof, at any time within two years after the Administrator:

(1) Finds that a State fails to submit a required plan or plan revision or finds that the plan or plan revision does not satisfy the minimum criteria under paragraph (g) of this section; or

(2) Disapproves the required State plan or plan revision or any portion thereof, as unsatisfactory because the applicable requirements of this subpart or an applicable subpart under this part have not been met.

(d) The Administrator will promulgate a final federal plan as described in paragraph (c) of this section unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such federal plan.

(e)(1) Except as provided in paragraph (e)(2) of this section, a federal plan promulgated by the Administrator under this section will prescribe standards of performance of the same stringency as the corresponding emission guideline(s) specified in the final emission guideline published under § 60.22a(a) and will require compliance with such standards as expeditiously as practicable but no later than the times specified in the emission guideline.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent standards of performance or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in §60.24a(e).

(f) Prior to promulgation of a federal plan under paragraph (d) of this section, the Administrator will provide the opportunity for at least one public hearing in either:

(1) Each State that failed to submit a required complete plan or plan revision, or whose required plan or plan revision is disapproved by the Administrator; or

(2) Washington, DC or an alternate location specified in the **Federal Register.**

(g) Each plan or plan revision that is submitted to the Administrator shall be reviewed for completeness as described in paragraphs (g)(1) through (3) of this section.

(1) *General.* Within 60 days of the Administrator's receipt of a state submission, but no later than 6

months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph, the State will be treated as not having made the submission and the requirements of § 60.27a regarding promulgation of a federal plan shall apply.

(2) *Administrative criteria.* In order to be deemed complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations; or issued the permit, order, consent agreement (hereafter "document") in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference

into the plan, including indication of the changes made (such as redline/strikethrough) to the existing approved plan, where applicable. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. If the regulation/document provided by the State for approval and incorporation by reference into the plan is a copy of an existing publication, the State submission should, whenever possible, include a copy of the publication cover page and table of contents;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23a, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23a;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) *Technical criteria.* In order to be deemed complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each designated facility, identification of standards of performance for the designated facilities, and monitoring, recordkeeping and reporting requirements that will determine compliance by each designated facility;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

§ 60.28a Plan revisions by the State.

(a) Any revision to a state plan shall be adopted by such State after reasonable notice and public hearing. For plan revisions required in response to a revised emission guideline, such plan revisions shall be submitted to the Administrator within three years, or shorter if required by the Administrator, after notice of the availability of a final revised emission guideline is published under § 60.22a. All plan revisions must be submitted in accordance with the procedures and

requirements applicable to development and submission of the original plan.

(b) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29a Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable federal plan if:

(a) The provision was promulgated by the Administrator; and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

Subpart UUUU [Removed]

■ 3. Remove subpart UUUU.

■ 4. Add subpart UUUUa to read as follows:

Subpart UUUUa—Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units

Introduction

Sec.

State Plan Requirements

Applicablity of Plans to Designated Facilities

Introduction

§ 60.5700a What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit for the purposes of this subpart, is referred to as a designated facility. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subpart A or Ba of this part, the requirements of this subpart will apply.

§ 60.5705a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are heat rate improvements which target achieving lower carbon dioxide (CO_2) emission rates at designated facilities.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from facilities regulated in the plan, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

§ 60.5710a Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more designated facilities that commenced construction on or before January 8, 2014, you are subject to this action and you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no designated facilities for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715a What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720a What if I do not submit a plan, my plan is incomplete, or my plan is not approvable?

(a) If you do not submit a complete or an approvable plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of designated facilities not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a plan.

§ 60.5725a In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan submittal or a negative declaration letter (if applicable).

§ 60.5730a Is there an approval process for a negative declaration letter?

The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register.** If, at a later date, a designated facility for which construction commenced on or before January 8, 2014 is found in your State, you will be found to have failed to submit a plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that designated facility until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5735a What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (4) of this section in your plan submittal. The final plan must meet the requirements of, and include the information required under, § 60.5740a.

(1) *Identification of designated facilities.* Consistent with § 60.25a(a), you must identify the designated facilities covered by your plan and all designated facilities in your State that meet the

applicability criteria in § 60.5775a. In addition, you must include an inventory of CO_2 emissions from the designated facilities during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Standards of performance.* You must provide a standard of performance for each designated facility according to § 60.5755a and compliance periods for each standard of performance according to § 60.5750a. Each standard of performance must reflect the degree of emission limitation achievable through application of the heat rate improvements described in § 60.5740a. In applying the heat rate improvements described in § 60.5740a, a state may consider remaining useful life and other factors, as provided for in § 60.24a(e).

(3) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each designated facility.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each designated facility and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5785a.

(4) *State reporting.* Your plan must include a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under § 60.5795a.

(b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

§ 60.5740a What must I include in my plan submittal?

(a) In addition to the components of the plan listed in § 60.5735a, a state plan submittal to the EPA must include the information in paragraphs (a)(1) through (8) of this section. This information must be submitted to the EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a summary of how you determined each standard of performance for each designated facility according to § 60.5755a(a). You must include in the summary an evaluation of the applicability of each of the following heat rate improvements to each designated facility:

(1) Neural network/intelligent sootblowers;

(ii) Boiler feed pumps;

(iii) Air heater and duct leakage control;

(iv) Variable frequency drives;

(v) Blade path upgrades for steam turbines;

(vi) Redesign or replacement of economizer; and

(vii) Improved operating and maintenance practices.

(2)(i) As part of the summary under paragraph (a)(1) of this section regarding the applicability of each heat rate improvement to each designated facility, you must include an evaluation of the following degree of emission limitation achievable through application of the heat rate improvements:

TABLE 1 TO PARAGRAPH (A)(2)(I)—MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI Measure	< 200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to > 2.0% depending on the unit's historical O&M practices.					

(ii) In applying a standard of performance, if you consider remaining useful life and other factors for a designated facility as provided in § 60.24a(e), you must include a summary of the application of the relevant factors in deriving a standard of performance.

(3) You must include a demonstration that each designated facility's standard of performance is quantifiable, permanent, verifiable, and enforceable according to § 60.5755a.

(4) Your plan demonstration must include the information listed in paragraphs (a)(4)(i) through (v) of this section as applicable.

(i) A summary of each designated facility's anticipated future operation characteristics, including:

(A) Annual generation;

(B) CO_2 emissions;

(C) Fuel use, fuel prices, fuel carbon content;

(D) Fixed and variable operations and maintenance costs;

(E) Heat rates; and

(F) Electric generation capacity and capacity factors.

(ii) A timeline for implementation.

(iii) All wholesale electricity prices.

(iv) A time period of analysis, which must extend through at least 2035.

(v) A demonstration that each standard of performance included in your plan meets the requirements of § 60.5755a.

(5) Your plan submittal must include certification that a hearing required under § 60.23a(c) 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 § 60.23a(g).

(6) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority to implement and enforce each component of its plan, including standards of performance, pursuant to the requirements of §§ 60.26a and 60.5740a(a)(6);

(ii) Materials supporting calculations for designated facility's standards of performance according to § 60.5755a; and

(iii) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA according to § 60.5800a.

§ 60.5745a What are the timing requirements for submitting my plan?

You must submit a plan with the information required under § 60.5740a by July 8, 2022.

§ 60.5750a What schedules and compliance periods must I include in my plan?

The EPA is superseding the requirement at § 60.22a(b)(5) for EPA to provide compliance timelines in the emission guidelines. Each standard of performance for designated facilities regulated under the plan must include a compliance period that ensures the standard of performance reflects the

degree of emission limitation achievable though application of the heat rate improvements used to calculate the standard. The schedules and compliance periods included in a plan must follow the requirements of §60.24a.

§ 60.5755a What standards of performance must I include in my plan?

(a) You must set a standard of performance for each designated facility within the state.

(1) The standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh).

(2) In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements and associated degree of emission limitation achievable included in § 60.5740a(a)(1) and (2) to the designated facility. You must include a demonstration in your plan submission for how you considered each heat rate improvement and associated degree of emission limitation achievable in calculating each standard of performance.

(i) In applying a standard of performance to any designated facility, you may consider the source-specific factors included in § 60.24a(e).

(ii) If you consider source-specific factors to apply a standard of performance, you must include a demonstration in your plan submission for how you considered such factors.

(b) Standards of performance for designated facilities included under your plan must be demonstrated to be quantifiable, verifiable,

permanent, and enforceable with respect to each designated facility. The plan submittal must include the methods by which each standard of performance meets each of the requirements in paragraphs (c) through (f) of this section.

(c) A designated facility's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(d) A designated facility's 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 the standard of performance.

(e) A designated facility's standard of performance is permanent if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision.

(f) A designated facility's standard of performance is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The designated facility 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, the State, and third parties maintain the ability to enforce against violations (including if a designated facility does not meet its

standard of performance based on its emissions) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a) through (h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§ 60.5760a What is the procedure for revising my plan?

EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart Ba of this part, including the requirements in § 60.5740a. If one (or more) of the elements of the plan set in § 60.5735a require revision, a request must be submitted to the Administrator indicating the proposed revisions to the plan.

§ 60.5765a What must I do to meet my plan obligations?

To meet your plan obligations, you must demonstrate that your designated facilities are complying with their standards of performance as specified in § 60.5755a.

Applicability of Plans to Designated Facilities

§ 60.5770a Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, designated facility owners or operators must comply with the plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a plan to implement and enforce the emission guidelines contained in this subpart by July 8, 2022, or the date that EPA disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in § 60.27a(c), applicable to each designated facility within the State that commenced construction on or before January 8, 2014.

§ 60.5775a What designated facilities must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any designated facility that commenced construction on or before January 8, 2014.

(b) A designated facility is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (3) of this section, as applicable, of this section except as provided in § 60.5780a.

(1) Serves a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.*, capable of selling greater than 25 MW of electricity).

(2) Has a base load rating (*i.e.*, design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

(3) Is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years.

§ 60.5780a What EGUs are excluded from being designated facilities?

(a) An EGU that is excluded from being a designated facility is:

(1) An EGU that is subject to subpart TTTT of this part as a result of commencing construction, reconstruction or modification after the subpart TTTT applicability date;

(2) A steam generating unit that is subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) A stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine;

(4) An IGCC unit;

(5) A non-fossil unit (*i.e.*, a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(6) An EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(7) An EGU that is a municipal waste combustor unit that is subject to subpart Eb of this part;

(8) An EGU that is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part; or

(9) A steam generating unit that fires more than 50 percent non-fossil fuels.

(b) [Reserved]

§ 60.5785a What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for designated facilities?

(a) Your plan must include monitoring, recordkeeping, and reporting requirements for designated facilities. To satisfy this requirement, you have the option of either:

(1) Specifying that sources must report emission and electricity generation data according to part 75 of this chapter; or

(2) Including an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:

(i) Monitoring plans that specify the monitoring methods, systems, and formulas that will be used to measure CO_2 emissions;

(ii) Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;

(iii) Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;

(iv) Recordkeeping requirements;

(v) Electronic reporting procedures and systems; and

(vi) Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

(b) [Reserved]

Recordkeeping and Reporting Requirements

§ 60.5790a What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan. After the effective date of the plan, States must keep records of all information relied upon in support of any continued demonstration that the final standards of performance are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each designated facility that is used to determine compliance with each designated facility emissions standard or requirements in an approved State plan, consistent with the designated facility requirements listed in § 60.5785a.

(c) If your State has a requirement for all hourly CO_2 emissions and generation information to be used to calculate compliance with an annual emissions standard for designated facilities, any information that is submitted by the owners or operators of designated facilities to the EPA electronically

pursuant to requirements in part 75 of this chapter meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 5 years from the date the record is used to determine compliance with a standard of performance or plan requirement. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5795a What are my reporting and notification requirements?

You must submit an annual report as required under § 60.25a(e) and (f).

§ 60.5800a How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section unless you submit through the procedure described in paragraph (f) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan may be reported through EPA's electronic reporting system to be named and made available at a later date.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible

official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the July 8, 2022, deadline for plan submittal so that the official will have the ability to submit a plan in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to the EPA electronic reporting system. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(f) If, in lieu of the requirements described in paragraphs (b) through (e) of this section, you choose to submit a paper copy or an electronic version by other means you must confer with your EPA Regional Office regarding the additional guidelines for submitting your plan.

Definitions

§ 60.5805a 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 TTTT, A, and Ba of this part.

Air Heater means a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air and potentially for other uses such as coal drying.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions.

Boiler feed pump (or *boiler feedwater pump*) means a device used to pump feedwater into a steam boiler at an EGU. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler.

CO_2 emission rate means for a designated facility, the reported CO_2 emission rate of a designated facility

used by a designated facility to demonstrate compliance with its CO_2 standard of performance.

Combined cycle unit 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 unit or *CHP unit* (also known as "cogeneration") means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means a discrete time period for a designated facility to comply with a standard of performance.

Designated facility means a steam generating unit that meets the relevant applicability conditions in section § 60.5775a, except as provided in § 60.5780a.

Economizer means a heat exchange device used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material to create useful heat.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The

Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Intelligent sootblower means an automated system that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup at a steam generating unit.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross

calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous State under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.*, steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output

and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the designated facility divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.*, steam delivered to an industrial process for a heating application).

Neural network means a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution at steam generating unit.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine

based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the designated facility, to directly enhance the performance of the designated facility (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the designated facility. Useful thermal output for designated facility(s) with no condensate return (or other thermal energy input to the designated facility(s)) or where measuring the energy in the condensate (or other thermal energy input to the designated facility(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Designated facility(s) with

meaningful energy in the condensate return (or other thermal energy input to the designated facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Variable frequency drive means an adjustable-speed drive used on induced draft fans and boiler feed pumps to control motor speed and torque by varying motor input frequency and voltage.

[FR Doc. 2019-13507 Filed 7-5-19; 8:45 am]

BILLING CODE 6560-50-P