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 III OF IV)
(Pages 867–1444)

ELIZABETH B. PRELOGAR
Solicitor General
Counsel of Record
U.S. DEPARTMENT OF JUSTICE
950 Pennsylvania Avenue, NW
Washington, DC 20530
(202) 514-2217
supremectbriefs@usdoj.gov
Counsel for Federal Respondents

LINDSAY S. SEE
Solicitor General
Counsel of Record
OFFICE OF THE W.V. ATT'Y GEN.
State Capitol Complex
Building 1, Room E-26
Charleston, WV 25305
(304) 558-2021
lindsay.s.see@wvago.gov
Counsel for Petitioners West Virginia, et al.

(additional counsel listed on inside cover)

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

(continued from front cover)

BETH S. BRINKMANN
Counsel of Record
COVINGTON & BURLING LLP
850 Tenth Street, NW
Washington, DC 20001
(202) 662-5312
bbrinkmann@cov.com
Counsel for Power Company Respondents

SEAN H. DONAHUE
Counsel of Record
DONAHUE, GOLDBERG & LITTLETON
1008 Pennsylvania Ave., SE
Washington, DC 20003
(202) 277-7085
sean@donahuegoldberg.com
Counsel for Non-Governmental Organization & Trade Association Respondents

BARBARA D. UNDERWOOD
Solicitor General
Counsel of Record
OFFICE OF THE ATT'Y GEN.
28 Liberty Street
New York, NY 10005
(212) 416-8016
barbara.underwood@ag.ny.gov
Counsel for Respondents New York, States and Municipalities

YAAKOV M. ROTH
Counsel of Record
JONES DAY
51 Louisiana Ave., NW
Washington, DC 20001
(202) 879-3939
yroth@jonesday.com
Counsel for Petitioner North American Coal Corporation

ANDREW M. GROSSMAN
Counsel of Record
BAKER & HOSTETLER LLP
1050 Connecticut Ave., NW
Washington, DC 20036
(202) 861-1697
agrossman@bakerlaw.com
Counsel for Petitioner Westmoreland Mining Holdings LLC

PAUL M. SEBY
Special Assistant Attorney General
Counsel of Record
GREENBERG TRAURIG, LLP
1144 15th Street, Suite 3300
Denver, CO 80202
(303) 572-6500
sebyp@gtlaw.com
Counsel for Petitioner State of North Dakota

(additional counsel listed on next page)

(continued from inside cover)

ELBERT LIN
Counsel of Record
HUNTON ANDREWS KURTH LLP
951 E. Byrd Street, E. Tower
Richmond, VA 23219
(804) 788-7202
elin@huntonak.com

Counsel for Respondent America's Power

EMILY C. SCHILLING
Counsel of Record
HOLLAND & HART LLP
901 K Street NW, Suite 850
Washington, DC 20001
(202) 393-6500
ecschilling@hollandhart.com

Counsel for Respondent Basin Electric Power Cooperative

MISHA TSEYTLIN
Counsel of Record
TROUTMAN PEPPER HAMILTON SANDERS LLP
227 W. Monroe St., Suite 3900
Chicago, IL 60606
(608) 999-1240
misha.tseytlin@troutman.com

Counsel for Respondent National Mining Association

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

Page

VOLUME IV

Accordingly, we have concluded that a well-supported and conservative estimate of the potential heat rate improvements (and accompanying reductions in CO_2 emission rates) that EGUs can achieve on average through best practices and equipment upgrades is a 4.3-percent improvement in the Eastern Interconnection, a 2.1-percent improvement in the Western Interconnection and a 2.3-percent improvement in the Texas Interconnection. The decision to use these values as the building block 1 potential in each region is based on the weight of evidence that these are conservative values; for each region, each of the three analytical approaches in our methodology supports our determination that the heat rate improvement value we selected is achievable. Taken individually, each approach provides an independently reasonable estimate of the potential for heat rate improvement. Furthermore, as described in the GHG Mitigation Measures TSD, these approaches are conservative on even an individual basis because they do not account for the full extent of heat rate improvements available through additional equipment upgrades and best practices. Some EGUs may have faced difficulties achieving significant heat rate improvement in the past and EGU owners may feel they face challenges in the future. Nevertheless, our methodology as a whole indicates that, on average, coal-fired EGUs can at least achieve the percentage heat rate improvement selected for their region through application of best practices and some of the available equipment upgrades. A more detailed discussion of the EPA's analysis in determining the heat rate improvement potential for existing coal-fired

EGUs may be found in the GHG Mitigation Measures TSD supporting the final CPP.

No affected coal-fired EGU is specifically required to improve heat rate by any amount as a result of this rule. Rather, as described in section VI, the potential for heat rate improvement is used to determine a CO_2 emission performance rate. Those affected EGUs that have done the most to reduce their heat rate will tend to be closer to that CO_2 emission rate. In this sense, our approach to determining potential CO_2 reductions through heat rate improvements is similar to the way EPA ordinarily approaches standards of performance.[641]

In this final analysis, we do not delineate what proportion of the potential heat rate improvement can

---

[641] To give an illustrative example, imagine a population of sources that emit Pollutant X. Half of the sources emit Pollutant X at 2500 lbs/hour, while the other half of the sources have scrubbers installed that reduce their emission rates to 1500 lbs/hour. Because the sources are evenly divided between those with and without scrubbers, the average emission rate for the population as a whole is 2000 lbs/hour. In this hypothetical, EPA decides to base requirements on the emission rate achievable through use of a scrubber, meaning that all sources will have to meet an emission rate of 1500 lbs/hour. Because the fleet as a whole has an average emission rate of 2000 lbs/hour, it would be accurate for EPA to say that the fleet as a whole can reduce its emission rate by 25 percent—from 2000 lbs/hour on average (only half the sources with scrubbers), to 1500 lbs/hour on average (all the sources with scrubbers). This description of what is possible *for the fleet as a whole*—a 25-percent reduction in emission rate—should not be misinterpreted as a statement that every *individual* source is capable of further reducing its emissions by 25 percent. The sources that have already installed scrubbers, and which are thus already operating at 1500 lbs/hour, would not be required to further improve their emission rate.

be expected from equipment upgrades versus best practices;[642] only that these heat rate improvements are achievable in the regions through a combination of these methods. As discussed in section V.C.3 below, we believe that a single heat rate improvement goal for each region incorporating both best practices and upgrades, based on the 11 years of hourly heat rate data for 884 coal-fired EGUs available to the EPA, is a reasonable approach that is supported by our analysis, and is particularly conservative given that it does not account for the full range of heat rate

[642] Examples of the many types of best practices and equipment upgrades available to coal-fired EGUs include adopting sliding pressure operation to reduce turbine throttling losses; installing intelligent sootblowing system software; upgrading the combustion control/optimization system; installing heat rate optimization software; installing a production cost optimization program that benchmarks plant thermal performance using historical plant data; establishing centralized remote monitoring centers with thermal performance software for monitoring heat rates systemwide; repairing steam and water leaks; automating steam system drains; performing an on-site performance appraisal to identify potential areas for improved performance; developing heat rate improvement procedures and training O&M staff on their use; aligning the cycle to isolate or capture high-energy fluid leakage from the steam cycle; repairing utility boiler air in-leakage; performing utility boiler chemical cleaning; installing condenser tube cleaning system; retubing condenser; repairing/upgrading flue gas desulfurization systems; cleaning air preheater coils; adjusting/replacing worn air heater seals; replacing corroded air heater baskets; replacing feed pump turbine steam seals; overhauling high pressure feedwater pumps; installing fan and pump variable speed/frequency drives; upgrading turbine steam seals; upgrading all turbine internals; and installing coal drying systems. These and additional heat rate improvement measures are discussed further in the GHG Mitigation Measures TSD for the CPP Final Rule.

improvements achievable through additional equipment upgrades and best practices.

The performance rates quantified in section VI, below, reflect the region-specific values for heat rate improvement. Although the performance rates are based on the least stringent overall performance rate determined to be reasonable for any region, and are thus based in part on the percentage heat rate improvement identified for the region, this rule does not itself require any specific EGU to implement measures resulting in a specific percentage heat rate improvement. Rather, the percentage heat rate improvement value is merely reflected in the CO_2 emission performance rates and corresponding mass-based and rate-based state goals. Each state has the flexibility to develop a plan that achieves those CO_2 performance rates or emission goals by assigning the emission standards the state considers appropriate to its affected coal-fired EGUs. Similarly, depending on the content of the applicable plan, affected EGUs may achieve their emission standards through use of any of the building block measures described in this rule or any other measures permitted under the plan.

b. *Changes from the proposal.*

In the proposed rule, we determined that building block 1 measures could on average achieve a 6-percent heat rate improvement from coal-fired EGUs in the U.S. based on a 4-percent heat rate improvement from implementation of best practices and a 2-percent heat rate improvement from equipment upgrades. Based on comments received and refinements made to our methodology for determining potential heat rate improvement from the hourly gross heat rate dataset of 884 coal-fired EGUs, we have applied this methodology on a regional basis and reduced the overall expected percentage heat rate improvement for coal-fired EGUs to 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection.[643] These values reflect improvements achievable through both best practices and equipment upgrades because, as described above, we also no longer include a separate estimation of the potential heat rate improvement achievable solely through equipment upgrades.

We received comments on our proposed statistical methodology for determining the CO_2 emission reductions opportunities achievable by coal-fired EGUs through heat rate improvements. We have closely reviewed those comments and, for the final rule, have made refinements to our methodology, as described above and explained in more detail in the GHG Mitigation Measures TSD supporting the final CPP.

In the final rule, the EPA extends the implementation deadline from 2020 to 2022. This additional time will be helpful to the states seeking to conduct more targeted analyses of the nature and extent of heat rate improvements that specific coal-fired EGUs can make, considering specific recent improvements or upgrades, planned retirements of older coal-fired EGUs, and other relevant considerations. The extended deadline will also

---

[643] Had the EPA maintained a nationwide approach to analyzing the potential reductions under building block 1, the result would have been 4.0 percent.

provide additional time to accommodate changes to heat rate monitoring methods at EGUs and for the installation of new pollution controls that comply with other rules, as discussed below in the summary of key comments.

2. Costs of Heat Rate Improvements

By definition, any heat rate improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with the percentage heat rate improvements we identified for each region would be sufficient to cover much of the associated costs. Accordingly, the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low. We recognize that this cost analysis will represent the costs for some EGUs better than others because of differences in individual circumstances. We further recognize that reduced generation from coal-fired EGUs due to the implementation of other building block measures would tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that a significant fraction of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from affected EGUs are reasonable. Even if we conservatively estimate that EGUs will largely rely on equipment upgrades rather than cheaper best practices to reduce heat rate, those reductions can generally be achieved at $100 or less per kW, or approximately $23 per ton of CO_2 removed, as described in detail in the GHG Mitigation Measures TSD supporting the final CPP.[644] Depending on the balance between equipment upgrades and best practices, improving heat rate would even result in a net savings for some EGUs.

Based on the analyses of technical potential and cost summarized above and in Chapter 2 of the GHG Mitigation Measures TSD, we find that heat rate improvements of 4.3, 2.1 and 2.3 percent are reasonable and conservative estimates of what coal-fired EGUs in the Eastern, Western and Texas Interconnections, respectively, can achieve at a reasonable cost.

3. Response to Key Comments

Many commenters said that the EPA should have subcategorized by EGU design or operating characteristics for purposes of evaluating potential heat rate improvements under building block 1.

Several studies categorize EGUs broadly by capacity, thermodynamic cycle, fuel rank or other

[644] The $100/kW cost figure from the proposal is now particularly conservative because it included the cost of significant equipment upgrades that improve heat rate, whereas building block 1 is now largely quantified based on low- or no-cost best practices, with a smaller portion of the remainder comprised of equipment upgrades.

characteristics. We considered subcategorizing the EGUs by their design and fuel characteristics under building block 1. Although grouping by categories does not account for all of the factors that may affect heat rate, it can provide a useful way of understanding the operating profile of classes of coal-fired EGUs and the fleet as a whole. However, we have declined to subcategorize among affected coal-fired EGUs for both technical and practical reasons. First, as discussed above, our assessment of heat rate improvement potential uses a unit-specific data methodology that compares each EGU's performance against its own historical performance. By substantially basing our analysis on these unit-specific assessments, we inherently factor in the effect of numerous design conditions. We also conducted a regression analysis that evaluated the effect of numerous factors on heat rate, and found that subcategorizing would generally make little difference in our analysis. Additionally, subdividing the EGUs into subcategories would reduce the quantity of EGUs used to calculate each average, which would increase the influence of random and atypical variations in the data on the overall averages, and would thus decrease our confidence in the results. Furthermore, as a practical matter, states are free to apportion reductions in a way that reflects any subcategories of their choosing when determining the emission standards for individual affected EGUs. Additionally, commenters assert that because building block 1 is calculated on an average basis, some affected EGUs will have greater potential than others to reduce CO_2 emissions through heat rate improvements. If an affected EGU cannot meet its particular emission standard because it has below-average potential to reduce emissions through heat rate improvements, then in instances where the EGU's state plan allows emissions trading, the EGU can acquire credits or allowances from affected EGUs that have above-average potential. For a further discussion of our reasonable decision not to subcategorize among coal-fired EGUs for purposes of determining building block 1, see the GHG Mitigation Measures TSD supporting the final CPP.

Many commenters told the EPA that EGUs already have undertaken significant efforts to operate efficiently to provide reliable electric service at the lowest reasonable cost; that they believe they cannot significantly improve heat rate; that best practice maintenance activities are performed on a daily basis, including during maintenance outages that allow for the inspection, cleaning and repair of all equipment; that extensive capital investments have been made to install state-of-the art equipment and replace equipment that is beyond repair; and that their employees continuously monitor and control operating levels in the combustion process to maintain maximum combustion of fuel and to avoid wasting available heat energy. In summary, these commenters say they have expended considerable effort and resources to maintain peak boiler efficiency at all times and, therefore, the 6-percent heat rate improvement proposed for building block 1 is unreasonable to apply to EGUs across the board; the EPA should develop a rule that allows treatment of affected EGUs on a case-by-case basis.

We commend the efforts of those who strive to operate and maintain EGUs in the best possible manner to minimize heat loss and CO_2 emissions.

This rule does allow for treatment of EGUs on a case-by-case basis. States may believe that individual considerations are appropriate in some cases and, accordingly, we have purposely allowed states to make decisions about how to implement specific CO_2 reductions. Our determinations of 4.3-, 2.1- and 2.3-percent heat rate improvement for EGUs in the Eastern, Western and Texas Interconnection, respectively, are conservatively based on the lowest value identified by any of our reasonable statistical analyses. If states choose to set limits on individual affected EGUs based in part on the availability of heat rate improvements, the states are free to assess heat rate improvements on a more targeted, case-by-case basis that takes into account an EGU's previous heat rate improvement efforts, or lack thereof. The fact that states (or EGUs complying with state requirements) can make case-by-case decisions about how to achieve goals does not contradict our conservative estimates—which are based on millions of hours of operating data reported to the EPA by EGUs—of how much EGUs are capable of improving their heat rate in each region overall. Opportunities to improve heat rate abound for affected EGUs as a whole, as evidenced by the fact that the approaches in our statistical methodology each included a comparison of an EGU's historical heat rate to its 2012 heat rate. Our estimates of the potential heat rate improvement are additionally conservative because they are based purely on comparisons among historical gross heat rate data, and thus do not reflect available, cost-effective opportunities to improve heat rate that affected EGUs never implemented during the study period. Finally, to the extent that an affected EGU was in 2012 fully implementing every possible best practice for improving heat rate, it may still be capable of improving heat rate through equipment upgrades.

Other commenters said that a 6-percent heat rate improvement overall is too high; that the heat rate improvement from upgrades are double-counted within the data used to determine heat rate improvements from best practices; and that the 2-percent heat rate improvement specifically for upgrades was inappropriately based on "conceptual" improvements from only one study.

We have reduced the 6-percent heat rate improvement from the proposed rule to three regionalized figures of 4.3 percent (Eastern), 2.1 percent (Western) and 2.3 percent (Texas), as discussed above and described in detail in the GHG Mitigation Measures TSD supporting the final CPP. We expect that, on average, affected coal-fired EGUs can at a minimum improve heat rate in these amounts by implementing best practices and equipment upgrades identified in the GHG Mitigation Measures TSD. These overall heat rate improvement figures do not include an estimated percentage heat rate improvement attributable specifically to upgrades. Although we are no longer including in our calculation of building block 1 a separate 2-percent heat rate improvement attributable solely to equipment upgrades, this decision is not because we believe that our initial 2-percent assessment of equipment upgrades was incorrect. To the contrary, the information presented in the S&L study was similar to that in other industry reports and studies—many of which were referenced in the proposal TSD—

describing potential heat rate improvements at EGUs from all types of equipment upgrades. However, we recognized that the possibility existed that some limited portion of that 2 percent was also reflected in our statistical analyses of historical gross heat rate data. In order to ensure that our methodology did not double-count an indeterminate amount of heat rate improvement available through equipment upgrades, we conservatively set aside the entire additional 2 percent attributable solely to equipment upgrades. Accordingly, we determined the amount of potential heat rate improvement in the BSER solely from the heat rate analyses described above, which account for improvements through best practices and equipment upgrades that were at some point achieved by an EGU, but not for the full range of best practices and equipment upgrades that are actually available.

Commenters also said that the EPA did not look at important factors that affect heat rate such as coal type, boiler type, cooling water temperature, age, nameplate capacity or the use of post-combustion pollution controls.

Our statistical methodology compared each unit to its own historical performance and, therefore, largely accounts for the effects that a unit's design or fuel characteristics would have on heat rate. As discussed above, our methodology used hourly data from 884 units over an 11-year period (2002–2012) and compared the variability in the heat rate of each individual unit to that unit's own performance. By assessing potential heat rate improvement by first looking at unit-specific data, our methodology inherently factors in the possible effects of design and fuel characteristics (*e.g.*, coal type, boiler type, nameplate capacity, age, cooling water system, air pollution controls) on heat rate and heat rate variability.

Although cooling water temperature likely plays an important role in a coal-fired EGU's heat rate, as stated by commenters, there are no consistent quality-assured hourly cooling water temperature data available to the EPA. However, in an effort to determine the potential effect of cooling water temperature on heat rate, we looked at a sample of 45 coal-fired EGUs at 19 facilities for which we had hourly surface water temperature data (used as a surrogate for cooling water) from monitors located nearby and upstream of cooling water intake points. Our analysis found that surface water temperature did explain some of the variation in heat rate, but that surface water temperature is strongly correlated with ambient air temperature—a variable we did control for in our methodology. Because of the strong correlation between ambient air temperature and surface water temperature, the availability of a comprehensive dataset of nationwide hourly ambient air temperature, and the similar explanatory power of surface water temperature and ambient air temperature, it is unlikely that separately addressing cooling water temperature would significantly change the results. Rather, we are confident that our use of hourly ambient air temperature in our analyses adequately addressed any significant impact of cooling water temperature. See the GHG Mitigation Measures TSD supporting the final CPP for further details about this analysis. As described further in that TSD, the other potentially relevant variables for which we did not directly control are unlikely to significantly affect the average heat rate.

Commenters said that the heat rate improvement attributable to upgrades will degrade over time or require repeated and costly further upgrades.

We are aware that some heat rate improvement measures can degrade over time. Like most power plant components, some heat rate improvement technologies require maintenance in order to sustain their efficacy over time. Therefore, to avoid degradation, personnel at EGUs will need to diligently apply "best practices" on a regular basis, a practice that numerous commenters say is standard operating procedure. The S&L study includes estimates of associated operations and maintenance (O&M) costs for each heat rate improvement method that is discussed. As we explained in the proposal, the related O&M costs of diligently applying best practices are relatively small compared to the associated capital costs and would, therefore, have little effect on the economics of heat rate improvements.

Commenters stated that heat rate improvement should be set on a basis that is narrower than nationwide—for example, state-by-state or unit-by-unit.

The EPA did not propose and is not finalizing a rule that sets heat rate improvement goals for individual states or for individual coal-fired EGUs. Instead, in the approved state plans developed under this rule, each state will set the emission standards for its various coal-fired EGUs. In doing so, the state may take into account its own view of the amount of heat rate improvement needed (if any) at specific EGUs, and may look to the EPA's analysis of heat rate improvement potential in the applicable region as a guide, while keeping in mind the CO_2 emission performance rate. This broad-based approach is consistent with the traditional rules evaluating the potential for emission reductions on a source-category basis, and is consistent with the broader goal-setting purpose of this rule. Furthermore, the final rule establishes a uniform national performance rate based on the least stringent regional performance rate calculated with the building blocks. Accordingly, affected EGUs in regions not setting the national level have emission reduction opportunities beyond those reflected in the applicable performance rate.

The heat rate improvement measures comprising building block 1 would ordinarily be evaluated on a nationwide basis. However, in this instance there are two good reasons to calculate building block 1 on a regionalized basis. First, a regionalized approach is consistent with the EPA's approach to determining the other building blocks. For building block 1, this means that the heat rate improvement should reflect only as much potential for emission reduction from building block 1 as our analyses indicate can be achieved on average by the affected coal-fired EGUs in that region. This ensures that the BSER for each region is representative of the characteristics and opportunities available within that region, rather than a less logical combination of opportunities in the region and opportunities nationwide. Second, a regionalized approach provides a more representative average of the potential heat rate improvement that EGUs in a given region are capable of achieving. The populations of affected coal-fired EGUs in each region differ in some respects, as discussed in the GHG Mitigation Measures TSD, and the more nuanced regionalized approach thus indirectly accounts for some of those systemic differences. For these and other reasons described in Section V.A. of the preamble with respect to the BSER as a whole, we have reasonably based building block 1 on a regionalized approach. Applying this regionalized approach to building block 1 strikes an appropriate balance between the proposed nationwide analysis and commenters' suggested state-specific analysis, which does not fully reflect the interconnected nature of the system within which affected coal-fired EGUs operate.

The practical consequence of calculating building block 1 on a regionalized versus nationwide basis is minimal. This is because the CO_2 emission performance rates are based on the overall performance rate determined to be reasonable for EGUs in the Eastern Interconnection. Our methodology identifies a 4.3 percent potential improvement in the Eastern Interconnection, compared to a 4.0 percent figure across all three interconnections.

We further note, along with some commenters, that site-specific engineering studies or unit-by-unit analyses of heat rate improvement potential for coal-fired EGUs are not available to the EPA; only a small number of site-specific case studies are available in the public literature. We considered that for the EPA to develop a comprehensive, unit-by-unit heat rate improvement study of nearly 900 coal-fired EGUs from scratch, it would likely cost the Agency \$50,000 to \$100,000 to study each EGU (almost \$50 to \$100 million total) and require three to four years to complete. Such a granular analysis would not serve the broader goal-setting purpose of this rulemaking. We agree with commenters who have pointed out that a heat rate improvement-estimating effort of that magnitude and duration would be unnecessarily lengthy and expensive. Nor would such a granular analysis be a necessary predicate for states to develop emission standards, or for EGUs to comply with those emission standards. Rather, our methodology relies on individualized, unit-by-unit hourly performance data from 884 EGUs provides conservative and reasonable regional estimates of heat rate improvement potential. Indeed, given the conservative nature of our methodology, a unit-specific approach that evaluates the full range of best practices and equipment upgrades available at individual EGUs—including upgrades not accounted for here—would be more likely to result in higher overall heat rate improvement figures than we are finalizing for building block 1. Furthermore, site-specific information forms the foundation of the EPA's estimated heat rate improvement potential, and similar data likely would be used in any site-specific heat rate improvement engineering study. Finally, EGU-specific detailed design and operation information is not consistently available for all the factors that influence heat rate. The EPA has used the comprehensive data that are available to reasonably and conservatively estimate potential heat rate improvement in each region.

Commenters also said that shifting electricity generation from coal-fired EGUs to other EGUs because of measures implemented under other building blocks will lower the capacity factors of coal-fired EGUs, and thus increase, not decrease, their heat rates.

We expect that most states will develop plans that optimize the operation of existing coal-fired EGUs while utilizing the other building blocks and other measures to reduce emissions from carbon-intensive generation. From our IPM projections, the average annual capacity factor of existing coal-fired EGUs that are expected to remain in operation in 2030 will actually increase compared to 2012. This projection—which is further described in the GHG Mitigation Measures TSD—incorporates expected retirements of inefficient units and generation shifts away from using coal-fired EGUs as peaking units.

Commenters also noted that the EPA used net heat rate in state goals, but used gross heat rate in its heat rate improvement analysis—potentially ignoring the detrimental effect that parasitic load from air pollution control devices (APCD) and other equipment can have on net heat rate.

The EPA's variability analysis necessarily and reasonably used gross output data for each of the 884 EGUs in the EPA's database because they are the only publicly available, unit-specific, hourly performance data. By definition, improvement in gross heat rate would be reflected in the net heat rate. Gross heat rate is the total heat output from the EGU, in units of Btu/gross kWh, and includes the power used by auxiliary equipment required to operate the EGU itself. By contrast, net heat rate is the remaining Btu/kWh after subtracting the power used by the EGU's own auxiliary equipment from the gross heat rate value, *i.e.*, what the EGU is able to provide to the grid. Improvements in net heat rate alone (*e.g.*, reducing parasitic load of on-site equipment) may be possible on many units. Therefore, our use of gross heat rate to estimate potential heat rate improvement was conservative because of the additional opportunities to achieve the uniform performance rate through improvements in net heat rate alone.

Commenters also raised concerns that the EPA was not taking into account net heat rate increases due to additional add-on pollution controls that may, for some units, be required by other rules.[645]

The results of our statistical analyses are based on gross heat rates and would not change with installation of emission controls for CSAPR, MATS, or other rules because these controls will add parasitic load requirements and thereby have an impact on the net heat rates only. Furthermore, we conservatively consider region-wide net heat rate improvement potential to be the same as that indicated for the region-wide gross heat rate, when in fact it is not. In order to check our assumptions concerning gross versus net heat rate, we used the IPM Power Sector Modeling Platform (version 5.14) and National Electric Energy Data System (NEEDS) (version 5.14) to analyze the anticipated incremental heat input required to operate additional add-on controls to comply with various EPA rules, including CSAPR, MATS, effluent guidelines for EGUs, and coal combustion residuals. From this analysis, we project that between 2012 and 2025, existing coal-fired EGUs are expected to install approximately 18.6 GW of wet flue gas desulphurization (FGD), 16.6 GW of dry FGD,

[645] See above for an explanation of gross versus net heat rate.

24.9 GW of selective catalytic reduction (SCR), and 3.9 GW of selective noncatalytic reduction (SNCR). The resulting impact from new pollution controls on existing coal-fired EGUs' heat rate is expected to be very small, at conservatively less than 31 Btu/kWh, or less than 0.3 percent in 2025.[646] After 2025, this estimate is particularly conservative because the EPA's cost performance models overestimate the parasitic load from individual add-on controls for future years. Furthermore, at some EGUs these newer pollution control devices will replace existing pollution control devices. Accordingly, for these EGUs, the minimal increase in net heat rate due to power required to operate new controls will be at least partially offset by the decrease in net heat rate caused by removal of the control devices currently in place. For more information about this analysis, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters contended that the 11 years of data used to evaluate potential heat rate improvement is too broad, and that the population of domestic coal-fired EGUs has changed significantly over this time period.

The 11-year span for the hourly gross heat rate data is appropriate because it represents a wide variety of economic conditions, market conditions and fleet composition, while also capturing the relatively recent historical performance of affected coal-fired EGUs.

---

[646] When considered on a regional basis, we expect these controls to impact heat rate by approximately 0.3 percent in both the Eastern and Western Interconnections, and by less than 0.1 percent in the Texas Interconnection.

We also noted in the proposal TSD that the population of coal-fired EGUs used in the analytical approaches to determine potential heat rate improvement is made up of coal-fired EGUs that operated in 2012. The gross heat rate data of any coal-fired EGUs that retired prior to 2012 were not included in the dataset.

Commenters stated that many of the changes in heat rate reflected in the 11-year hourly gross heat rate dataset are attributable to changes in monitoring methodology, and thus do not represent heat rate improvements attributable to best practices or equipment upgrades. In addition, commenters are concerned that changes to the monitoring methodology in the future could artificially alter the measured heat rate.

Different stack gas flow monitoring methods can yield more or less accurate measurements of heat input and CO_2 emissions. These differences depend on the characteristics of the stack gas flow where the monitoring and reference method measurements are taken, and which options under the Part 75 emission measurement rules are chosen in the application of the various flow rate reference methods. In general, more accurate stack gas flow monitoring methodologies yield lower values that, when used to calculate emissions or heat input, may lower the heat rate values reported to the EPA.

Some EGUs adopted monitoring methodologies that have the potential to affect the exactness of the data we used for assessing heat rate improvements. However, as discussed in detail in the GHG Mitigation Measures TSD supporting the final CPP, our review of the data shows that a relatively small amount of the data are affected by these changes; we are confident that the values adopted for building block 1 are conservative and reasonable estimates of the potential for heat rate improvement in each region. Some changes in monitoring methodology would have the result of tending to cause us to underestimate the potential for heat rate improvement. Furthermore, because our methodology analyzes percentage heat rate improvement based on 2012 gross heat rate data, our results are unaffected by EGUs that used more accurate monitoring methodologies in 2012 or used the same monitoring methodologies consistently throughout the 11-year study period. For these and other reasons discussed in detail in the GHG Mitigation Measures TSD, we remain confident in our results despite the marginal differences attributable to monitoring methodologies in some of the heat rate data for a subset of EGUs.[647]

In terms of concerns with future methodological changes, the overwhelming majority of the 884 EGUs in the dataset we used to assess heat rate improvement have already changed their stack gas flow monitoring methodology in 2012 or earlier. Furthermore, extension of the compliance date to 2022 for this rule, as discussed above, more than adequately allows enough time for EGUs to determine how to actually improve their heat rates and lower CO_2 emissions while accommodating future changes to

[647] Furthermore, on a fundamental level, our methodology accounts for a certain amount of any residual inexactness because we have conservatively adopted the lowest value identified by any of our reasonable approaches—all three of which are themselves conservative because they do not account for the full extent of heat rate improvements achievable through equipment upgrades.

monitoring methodologies. For a more detailed explanation, see the GHG Mitigation Measures TSD supporting the final CPP.

Commenters said that there is no proof that lowering the heat rate will reduce variability or that reduced variability will reduce heat rate, *i.e.*, correlation does not prove causation.

As an initial matter, it is important to note that for the final rule the EPA used three types of statistical analyses to evaluate and estimate potential heat rate improvements of coal-fired EGUs, and only one of these analyses involved any consideration of heat rate variability. All three types of statistical analyses are described in the GHG Mitigation Measures TSD supporting the final CPP.

These commenters are correct that, in the abstract, reducing heat rate variability only means that heat rate will be more consistent—not necessarily lower or higher. However, our analysis is not an abstract evaluation of the potential to reduce variability, as commenters suggest, but rather is an evaluation of the potential heat rate *improvement* achievable through reducing variability—*i.e.*, reducing variability to achieve a more consistently low heat rate. See the more detailed discussion of the statistical procedures used for the final rule, above. In particular, the application of a "consistency factor" in the analyses performed for both the proposed and final rule demonstrates the potential results if each individual EGU operated slightly more consistently with the lower heat rates that the EGU had itself previously achieved under similar conditions.

The consequence of a reduced heat rate is, of course, a lower rate of CO_2 emissions, which is the purpose of the BSER for building block 1. This way of thinking about reduced variability is consistent with the utility power sector's own efforts to reduce variability, which are aimed at securing the economic benefits of a more consistently *lower* overall heat rate.

Some commenters expressed concern that heat rate improvements could trigger applicability of new source review (NSR) provisions. The relationship of this final rule to other regulatory provisions, including NSR, is discussed in section X of the preamble.

D. Building Block 2—Generation Shifts Among Affected EGUs

The second element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which fossil steam EGUs can shift generation to existing NGCC EGUs. In this section, we define building block 2 as the gradual shifting of generation from existing fossil steam to existing NGCC within each region up to a maximum NGCC utilization of 75 percent on a net summer basis. In each year of the interim period, this 75 percent net summer maximum potential is subject to a regional limit informed by historical growth rates.

This section summarizes the EPA's analysis supporting that definition. We begin by discussing the sector's ability to reduce CO_2 emissions by shifting generation, including selected background information, data on trends toward greater NGCC generation, and various mechanisms for executing or facilitating generation shifts. Next, we describe the amount and timing of generation shift we have determined to be achievable through the building block. We then discuss various elements supporting our quantification of achievable generation shift, including the technical feasibility of NGCC units to increase generation; historical shifts to NGCC generation; considerations related to reliability, natural gas transmission infrastructure, natural gas production, and electricity transmission infrastructure; and regulatory flexibility. A discussion of costs follows. Finally, we respond to certain comments not addressed in the preceding discussions.

1. Demonstration of Ability to Reduce CO_2 Emissions Through Shifting Generation

a. *Background of utility power sector.*

The ability to shift generation from higher- to lower-emitting sources is compatible with the way EGUs are generally dispatched.[648] The standard approach to dispatching generation is through Security Constrained Economic Dispatch (SCED), a well-established practice in the electric power industry.[649] As the name indicates, SCED has two defining components: Economic operation of generating facilities and assurance that the electric

---

[648] See preamble section II.C.1, History of the Power Sector, for background to this discussion.

[649] "Economic Dispatch: Concepts, Practices and Issues", FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch", Palm Springs, California, November 13, 2005. A copy of this presentation is available in the docket for this rule.

system remains reliable and secure.[650] Economic dispatch generally refers to shorter-term planning and operations from a day ahead through real time. During this period, generating units are committed—a process known as "unit commitment," in which units are committed to be ready to provide generation to the system when they will be needed—and then dispatched in real time to meet the electricity demand of the system. Overall changes in the level of generation from different facilities are also planned over time periods longer than this 2-day dispatch period. Over a calendar year, for example, units are planned and scheduled seasonally or monthly to ensure that sufficient capacity and energy will be available to meet expected loads in an area. Over a period of a week, units are committed to be prepared to start up or shut down to meet forecast loads, and dispatch is coordinated within this planning and unit commitment framework. This process enables system operators to respond quickly to short-term changes in demand, and also to shift generation among different generation types to match longer-term requirements and goals.

EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but the magnitude and timing of their output generally depend on wind and sun conditions rather

---

[650] "Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress", Federal Energy Regulatory Commission, July 31, 2006.

than the operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible to operate. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand. Because of these typical characteristics of the various EGU types, the primary opportunities for switching generation among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the short term—that is, over time intervals shorter than the time required to build a new electric generation unit—fossil fuel-fired units consequently tend to compete more with one another than with nuclear and renewable EGUs. The amount of generation shifting from coal-fired EGUs to NGCC units that takes place as a result of this competition is highly relevant to overall power sector GHG emissions, because a typical NGCC unit produces less than half as much CO_2 per MWh of electricity generated as a typical coal-fired EGU.

b. *Trends in generation shifts from coal-fired to natural gas-fired sources.*

Since at least 2000, fossil fuel-fired generation has been shifting from coal- and oil-fired EGUs to NGCC units, both as a result of construction of additional NGCC units, and also as a result of dispatch of pre-existing NGCC units at higher capacity factors. As a result, generation from NGCC EGUs in 2012 reached over four times the level of NGCC generation in 2000, while generation from coal and oil/gas steam EGUs decreased by around one third.[651] As we demonstrate in the GHG Mitigation Measures TSD, NGCC units are capable of operating at higher annual capacity factors than they have historically, so there remains considerable opportunity for increased use of existing NGCC units to replace generation currently supplied by higher-emitting coal and oil/gas steam units. The electric utility industry is thus well-positioned to address the requirements of this building block by increasing use of existing NGCC units and correspondingly decreasing use of steam units. The electric industry has been shifting generation to NGCC units in recent years and is expected to continue to retire coal capacity and add new NGCC capacity. In the reference case without implementation of CO_2 emission limitations, EIA forecasts 40 GW of coal retirements and 53 GW of NGCC capacity additions from 2014 to 2030.[652] An EPA review of state Integrated Resource Plans (IRPs) shows a pattern of shifting away from coal steam capacity to NGCC capacity and, in some cases, conversion of coal steam capacity to natural gas steam capacity. For example, Ameren plans to add 600 MW of NGCC capacity and convert two coal units to natural gas steam units, and Duke plans to add 680 MW of NGCC capacity and convert one coal unit to a natural gas steam unit.[653]

---

[651] Ventyx Electric Power Database.

[652] Energy Information Administration, Annual Energy Outlook 2015 reference case, ref2015.d021915a.

[653] For further examples, see the memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

c. *Mechanisms for dispatch shifts from coal-fired to natural gas-fired generation.*

There are a variety of patterns of ownership and operational control of EGUs; these ownership and operational structures influence how EGUs will respond to this building block. However, all owners and operators have the ability to comply by using this building block. In terms of ownership, investor-owned utilities (IOUs) serve about 75 percent of the US population, while consumer-owned utilities serve the remaining 25 percent.[654] In states that have maintained traditional regulation, IOUs are generally vertically integrated (owning generating capacity as well as transmission and distribution infrastructure), and the wholesale sales of these EGUs are regulated by the state; in states that have deregulated their retail service, ownership of the EGU is separated from ownership of transmission, and wholesale sales of generation are regulated by FERC. Consumer-owned utilities comprise municipal utilities, public utility districts of various types owned by government agencies, nonprofit cooperative entities (co-ops), and a number of other entities such as Native American Tribes.

Operational control of the dispatch of power over the electricity grid is superimposed on this pattern of ownership. Prior to electricity restructuring, this dispatch was typically operated by major vertically-integrated utilities or by public power entities. Over

---

[654] Regulatory Assistance Project, Electricity Regulation in the US: A Guide, Page 9, March 2011. Available at *http://www.raponline.org/docs/RAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf.*

the last 15 years, large portions of the power grid are now independently operated by ISOs or RTOs. These entities are regulated by FERC and dispatch power from multiple owners to meet the loads on the bulk power grid.

The combination of multiple ownership and types of operational control adds to the complexity of electricity dispatch, but all affected EGUs, regardless of ownership and type of control, can use this building block to comply with the final rule. The principal difference among the differing entities lies in the types of methods that are available for the affected EGU owner to bring about the shift in generation that will make use of this building block for compliance. There are several alternatives to accomplish this result: The owner of the higher-emitting affected EGU may also own, or have affiliates that own, lower emitting generation and thus reduce its own generation and use its control over these other EGUs to increase their generation; an EGU may be able to reduce its generation and buy replacement power from the market that is lower emitting; or the EGU may be able to reduce its generation and procure generation from a separately-owned lower-emitting EGU. These alternatives will be available in states with either rate or mass-based state plans without any change in their general form. Under a rate-based state plan, an EGU owner may also be able to purchase ERCs and average the ERCs into its emission rate for purposes of demonstrating compliance with its standard of performance. Under standards of performance that incorporate emissions trading, an EGU owner may be able to purchase rate-based emission credits or mass based emission allowances not needed by other EGUs and use those credits or allowances to help achieve its standard of performance.

The potential to shift generation identified for this building block is entirely consistent with the existing economic dispatch protocols described above. State environmental policies can shift generation in two ways. The first is operational restrictions, such as permit limits on the number of hours that an EGU can operate in order to limit emissions. The second is changes in the relative costs of generation among different types of EGUs related to pollution reduction measures. For example, a regulation that necessitates the use of a control technology that requires the application of a reagent in a certain kind of EGU will increase the variable cost of operating that plant, which in turn may reduce the amount of generation it is called upon to deliver to the grid through security-constrained economic dispatch procedures.

In an organized market, where the system operator dispatches units partly based upon costs, an electric power plant that experiences an increase in its variable costs will tend to operate less than it otherwise would have. For example, market-based pollution control programs require units to hold tradable allowances to authorize their emissions of a regulated pollutant. Such an allowance-holding requirement puts a price on the act of emitting the regulated pollutant, which increases the operating costs of units that emit that pollutant, and thus such units will be dispatched less than they otherwise would without such an allowance-holding requirement. The RGGI is an example of a state program that has this effect. In the present rule, although shifts in the mix of generation to address the costs of pollution control can lead to higher electricity generating costs overall, the EPA analysis shows these costs to be modest and well below their associated benefits.[655]

Many of the NGCC units are owned by the same companies or affiliates that also own steam units. In these cases, changes in EGU generation can be planned by the company or affiliate without the need to engage in separate market transactions with outside parties. Where the affected EGU owner is also the dispatch entity, as in most traditional market structures, the EGU owner will generally have operational control over the unit. Environmental conditions, such as compliance costs or limits on generation, can be factored in with fuel costs for purposes of determining when the unit is committed to be available, how the unit can be most efficiently cycled, and at what level the unit is dispatched.

An analysis of generation data from steam and NGCC units in 2012 shows that 77 percent of the steam generation occurred from an EGU that owned, or that had an affiliate that owned, NGCC generation. Eighty percent of the generation shift potential identified in this building block (increasing NGCC generation up to a 75 percent capacity factor on a net basis to replace steam generation) could occur among these entities that own (either directly or through affiliates) both steam and NGCC generation.[656] These data show that most EGU generation relevant for this

---

[655] See the Regulatory Impact Analysis.

[656] SNL Energy. Data used with permission. Accessed May 2015.

building block is produced by entities that own both steam and NGCC generation.

Another alternative available to an affected EGU owner that does not also own NGCC generation is for the higher-emitting affected EGU to reduce its generation and purchase replacement power from the market. In organized markets such as RTOs, it is available through standard practice, because the owner impacts how its EGUs are dispatched based upon how it bids into the RTO market. In this case, the owner can exercise control over the levels of generation across units by when it offers generation to the market operator (the RTO or ISO), and the prices it bids for this generation. As in traditional economic dispatch by a utility, environmental conditions, compliance costs, or limits on generation can be incorporated by the owner into the determination of the cost-effective generation pattern of its EGUs.

In regions with organized electricity markets (including, but not limited to, RTOs or ISOs), the various types of EGU owners of higher-emitting sources can reduce their generation, and any resulting deficit in generation on the system can be supplied from other EGUs in the region; for example, a coal-fired unit can reduce generation that is then replaced through the operation of the market by generation from an NGCC unit, subject to dispatch by a regional operator to ensure the reliable delivery of the generation to loads within the region. To comply with this rule, higher-emitting steam units will need greater emission reductions relative to lower-emitting NGCC units which will, in turn, tend to raise steam unit costs compared to NGCC units. As a result, the bids that a steam unit provides a market operator will rise relative to NGCC units. This process of reducing generation from a higher-emitting unit will lead to substitution of lower-emitting generation.

EGU owners that do not participate in an organized electricity market may nevertheless purchase power from the wholesale power market. Purchases in the wholesale power market can be spot purchases, which are typically general purchases of system power supplied by the EGUs across a region, or contract purchases, which may have more provider-specific characteristics (such as specifying the type of unit that is providing the power). Purchases between EGUs through the wholesale power market will have similar emission-lowering properties as operation of the organized market discussed above, because dispatch in balancing areas outside RTOs and ISOs also follows a similar economic dispatch protocol that is informed by each unit's production costs and environmental limitations.

Under this alternative, the steam generators may, in effect, realize emission reductions from building block 2 simply by reducing their generation. Steam generators do not need to purchase replacement electricity as a prerequisite for realizing emission reductions from reducing their own generation because other generators already have an incentive to provide as much electricity as load-serving entities are willing to buy in order to satisfy electricity demand.[657]

---

[657] Some owners or operators of steam generators may have electricity supply obligations to which they may be applying power from those steam generators. However, such parties may fulfil those supply obligations using the wholesale power market in the exact same way described here that enables any other generator with economically attractive electricity to offer such

As noted above, higher-emitting generation sources will have to incorporate correspondingly higher costs of pollution reduction into their supply bids compared to lower-emitting generation sources, and as a result, load-serving entities will seek to buy a greater share of electricity from the lower-emitting sources because their supply bids will be more economically attractive. Once the steam generators reduce their generation (and associated emissions), the other entities in the electricity system arrange for the replacement electricity. The outcome of this power market process will reduce both the mass and the rate of emissions across sources.

An owner of a source can also reduce the generation of an EGU by substituting generation from a lower-emitting NGCC directly. For an EGU owner without existing NGCC generation, this substitution can take the form of a bilateral contract purchase. In RTOs and ISOs, this alternative often takes the form of a contract for differences, where the replacement source could be an NGCC and the contract specifies a delivery location and the price of the power. In bilateral markets, the contract vehicle could be a Power Purchase Agreement from a replacement source. It is also possible that the owner of a steam unit could directly invest in an existing EGU by purchasing the asset or taking a partial ownership position, thus acquiring the generation from the unit through that means. The acquired generation and its associated

supply. In other words, the ability of a steam generator to reduce its generation is not contingent on an associated purchase to replace that power, notwithstanding the possibility that the owner or operator of that steam unit may choose to make such a purchase to meet an electricity supply obligation.

emissions could be used for compliance by the higher-emitting EGU, in accordance with the plan under which it is operating. The amount of generation that could be shifted using the approaches described in this paragraph will depend on the type and terms of the commercial arrangements, as well as the potential need for regulated entities to obtain approvals for contracts or for changes in asset positions. The wide range of approaches permitted by this rule provides flexibility, both within a year and across multiple years, for EGUs to fashion these arrangements to fit their circumstances.

Where permitted under its state plan, an EGU would also be able to meet its reduction obligations using ERCs or allowances. The particular nature of this alternative will depend on how a state elects to develop its plan. If a state chooses a mass-based approach, the EGU would simply need to hold allowances to cover its emissions. To realize an emission reduction from building block 2 under this approach, a steam generator would only need either to reduce its emissions by reducing its generation, which would lead to that generator needing fewer allowances to cover its emissions under the program, or to purchase surplus allowances not needed by another EGU that had reduced its emissions. In a rate-based state, the state may choose to provide for compliance through the acquisition of tradable ERCs. To realize an emission reduction from building block 2 under this approach, a steam generator would be able to adjust its effective emission rate by purchasing ERCs that are produced by other sources whose emission rates are lower than the applicable rate standard. In this fashion, a steam generator does not need to purchase lower-emitting replacement power per se in order to demonstrate an emission reduction from this building block; instead, the steam generator may purchase any ERCs that were produced from lower-emitting sources (see section VIII for more detail on how state plans can use an ERC approach to facilitate a rate-based compliance demonstration of this type of emission reduction).[658]

The approaches shown here collectively demonstrate that all steam generators—regardless of size, location, form of ownership, or type of market in which they operate—can implement building block 2 through some or all of the mechanisms described.

2. Amount and Timing of Generation Shift

The EPA has determined that for purposes of quantifying the CO_2 emission reductions achievable through building block 2, a reasonable amount of generation shift is the amount of generation shift that would result from existing NGCC units, on average, increasing their annual utilization rates to 75 percent of net summer capacity. However, the building block does not reflect achievement of this average capacity factor at the start of the interim period, but instead reflects a glide path of increases in NGCC utilization over the interim period. Below, we discuss the glide

---

[658] Stakeholders have recognized that ERCs and allowances are an effective tool for EGUs to implement the building blocks and achieve their standards of performance required under this rule. *See* "Clean Power Plan Implementation: Single-State Compliance Approaches with Interstate Elements," Georgetown Climate Center (May 2015), *http://www.georgetownclimate.org/sites/www.georgetownclimate.org/files/GCC_ComplianceApproacheswithInterstateElements_May2015.pdf*.

path, and in the following section we discuss the basis for finding the 75 percent utilization rate, achieved over the period of time consistent with the glide path, to be reasonable.

The EPA received significant public comments expressing concern regarding the proposal's incorporation of the full building block 2 shift in generation by the first year of the interim period. These commenters perceived this approach as requiring states to achieve such a significant portion of the required CO_2 emission reductions early in the interim period that states would lack flexibility in when and how they may achieve the required emission reductions. Other commenters expressed concern that the full extent of building block 2 would be difficult for some states to achieve by the first year of the interim period as a result of technical, engineering, and infrastructure limitations or other considerations; that such timing may crowd out other cost-effective options for emission reductions; and that such timing might have negative implications for reliability.

In the proposal, the EPA determined that emission reductions are feasible and achievable at fossil fuel-fired steam EGUs by shifting from more carbon-intensive EGUs to less carbon-intensive EGUs, as part of the BSER. More specifically, the EPA proposed that generation shifts from fossil fuel-fired steam units (which are primarily coal-fired) to NGCC units, up to a utilization of 70 percent on a nameplate capacity basis, could be achieved by 2020. In contrast, the EPA proposed that reductions in CO_2 emissions from fossil fuel-fired units associated with other measures, such as increased utilization of RE generating capacity and increased demand-side EE, would be achievable on a phased-in basis between 2020 and 2029, reflecting the time needed for deployment.[659] In light of the concerns noted above, in the October 2014 NODA, the EPA solicited comment on potential rationales for phasing in the potential to shift generation under building block 2.[660]

As already noted, in the final rule the EPA has revised the interim period to start in 2022, which itself is a meaningful response regarding the concerns expressed by commenters about the timing of building block 2's generation shift potential. In addition, the EPA has evaluated the feasibility over time of building block 2 within the framework of BSER, and is finalizing a change to building block 2 that gradually phases in the shift from existing fossil steam to existing NGCC over the interim period. This phase-in allows for additional time to complete potential infrastructure improvements (*e.g.*, natural gas pipeline expansion or transmission improvements) that might be needed to support more use of existing natural gas-fired generation, and provides states with the increased ability to coordinate actions taken under building block 2 with actions taken under building block 3 (deployment of new renewable capacity).

The phase-in schedule applies a limit to the maximum building block 2 potential in each year of the interim period based on two parameters. The first parameter defines an amount of generation shift to existing NGCC capacity that is feasible by 2022, and the second parameter defines how quickly that

[659] 79 FR 34866.

[660] 79 FR 64543.

amount could grow until the full amount of NGCC generation could be achieved as part of the BSER. Both of these parameters are determined by examining the extent to which gas-fired generation has increased over historical time periods. The first parameter is based on the single largest annual increase in power sector gas-fired generation since 1990, which occurred between 2011 and 2012 and is equal to 22 percent.[661] We believe that this amount is a conservative estimate of the ability of the sector to increase utilization of NGCC capacity by 2022, given that this increase has already occurred in a single year. The second parameter is based on the average annual growth in gas-fired generation in the power sector between 1990 and 2012, which is approximately 5 percent per year.

In the performance rate calculation methodology, these two parameters constrain the annual rate at which building block 2 shifts generation from fossil steam units to NGCC units. The interim performance rate is an average of annual rates calculated over the 2022–2029 period. The two parameters above limit the extent to which NGCC generation is able to increase and replace fossil steam generation in each year of the interim period. In the first year, NGCC generation is limited to a maximum of a 22 percent increase from 2012 levels in each region. In each subsequent year, regional NGCC generation is limited to a maximum of a 5 percent increase from the

[661] US EIA Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector (2015), *available at http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m*.

previous year. This phase-in continues in the performance rate-setting methodology until the full building block 2 level of shifting from fossil steam generation to NGCC generation is reached. Under this approach, building block 2 is completely phased into the source category calculation of all regions by the end of the interim period.

TABLE 7—BSER MAXIMUM NGCC GENERATION BY REGION AND YEAR (TWH)

Region	NGCC generation (TWh)										
	Maximum potential at 75%	2012 (adjusted)	BSER maximum								
			2022	2023	2024	2025	2026	2027	2028	2029	2030
Limit	....	....	22%	5%	5%	5%	5%	5%	5%	5%	5%
Eastern Interconnection	988	735	896	941	988	988	988	988	988	988	988
Western Interconnection	306	198	242	254	267	280	294	306	306	306	306
Texas Interconnection	204	137	167	176	185	194	203	204	204	204	204

This phase-in, in addition to the flexible nature of the goals, ensures that the overall framework of this final rule includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from the affected units, so that states can develop cost-effective strategies and allow for infrastructure improvements to occur should they prove necessary in some locations.

3. Basis for Magnitude of Generation Shift

a. *Technical feasibility of NGCC units to generate at 75% of their capacity.*

In order to estimate the potential magnitude of the opportunity to reduce power sector CO_2 emissions through shifting generation among existing EGUs, the EPA first examined information on the design capabilities and availability of NGCC units. Availability is defined as the number of hours that generators are available to generate electricity, and it is typically expressed as a percentage of the total number of hours in a year. Since the value of NGCC capacity is related to how much electricity the owner of that capacity can generate and sell, units are typically designed with very high availability ratings. Baseload units have annual average availabilities of approximately 91%–92%, and peaking units are generally available 96% to 98% of peak hours.[662] The EPA also examined information on the historical availability of NGCC units in practice. This examination showed that, although most NGCC units

---

[662] Negotiating Availability Guarantees for Gas Turbine Plants, available at: *http://www.power-eng.com/articles/print/volume-105/issue-3/features/negotiating-availability-guarantees-for-gas-turbine-plants.html.*

have historically been operated in intermediate-duty roles for economic reasons, they are technically capable of operating in baseload roles at much higher annual utilization rates. Average annual availability (that is, the percentage of annual hours when an EGU is not in a forced or maintenance outage) for NGCC units in the U.S. generally exceeds 85 percent, and can exceed 90 percent for some groups.[663]

We also researched historical data to determine the utilization rates that NGCC units have already demonstrated their capability to sustain. Over the last several years, the utilization patterns of fossil fuel-fired units have shifted relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity generated nationwide from coal.[664] These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal. Although the relative fuel prices vary by location, as do the recent generation patterns, this trend holds across broad regions of the U.S. In the aggregate, the historical data provide ample evidence indicating that,

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

[664] *http://www.eia.gov/todayinenergy/detail.cfm?id=6990.*

on average, existing NGCC units can achieve and sustain utilization rates higher than their historical average utilization rates.

Utilization of EGUs is often considered using the metric of a capacity factor, which is the percentage of total production potential that an electric generating unit achieves in a given time period. A capacity factor of 75 percent thus represents a unit producing three-quarters of the electricity it could have produced in that time had it utilized its entire capacity. The EPA received multiple comments regarding the proposed use of nameplate capacity in calculating the potential utilization level of existing NGCCs under building block 2. These comments stated that net summer capacity is a more meaningful and reliable metric than nameplate capacity, because net capacity best reflects the electric output available to serve load. The EPA agrees with these comments. The quantification of building block 2 as well as performance rate and state goal calculations in the final rule are all based on net summer generating capacity. An annual utilization rate of 75 percent on a net summer basis is similar to the proposed rule's consideration of 70 percent utilization on a nameplate basis.[665]

The experience of relatively heavily-used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible.

---

[665] For a given amount of net generation, a net summer capacity factor appears higher compared to a corresponding nameplate capacity factor because net summer capacity reflects a lower amount of total generation potential achievable by the unit in practice.

The EPA reexamined the historical NGCC plant utilization rate data reported to the EIA, and found that in 2012 roughly 15 percent of existing NGCC plants operated at annual utilization rates of 75 percent or higher on a net summer basis.[666] In effect, these plants were providing baseload power. In addition to the 15 percent of NGCC plants that operated approximately at a 75 percent utilization rate on an annual basis, some NGCC plants operated at even higher utilization rates for shorter, but still sustained, periods of time in response to high cyclical demand. For example, on a seasonal basis, a significant number of NGCC plants have achieved utilization rates greater than 90 percent on a net summer basis; during the summer of 2012 (June through August), about 30 percent of NGCC plants operated at utilization rates of 75 percent or more across the entire season. During the spring and fall periods when electricity demand levels are typically lower, these plants were sometimes idled or operated at much lower capacity factors. Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC plants have proven the ability to sustain 75 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the annual average utilization rates of

---

[666] Net summer capacity is defined as: "The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries." (EIA, *http://www.eia.gov/tools/glossary*).

existing NGCC units to 75 percent on a net summer basis would be technically feasible.

The EPA believes that an annual average utilization rate of 75 percent on a net summer basis is a conservative assessment of what existing NGCC plants are capable of sustaining for extended periods of time. In 2012, roughly 10 percent of existing NGCC plants operated at annual utilization rates of 80 percent or higher on a net summer basis. While the EPA believes this level is also technically feasible on average for the existing NGCC fleet, the EPA is quantifying building block 2 assuming an NGCC utilization level of 75% on a net summer basis in order to offer sources additional compliance flexibility, given that the extent to which they realize a utilization level beyond 75 percent will reduce their need to rely on other emission reduction measures or building blocks.

b. *Historical generation shifts to NGCC generation.*

In 2012, total electric generation from existing NGCC units was 966 TWh.[667] After the application of the building block 2 potential (increasing NGCC utilization up to a 75 percent capacity factor on a net summer basis, including generation from NGCC units that were under construction), the total generation from these existing sources is assumed to be 1,498 TWh.[668]

The EPA believes that producing this quantity of generation from this set of NGCC units is feasible. To

---

[667] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

[668] Appendix 1, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule.

put this level of generation into context, NGCC generation increased by approximately 439 TWh (an 83 percent increase) between 2005 and 2012. The EPA calculates that assumed NGCC generation in 2022 through the quantification of building block 2 potential is approximately 44 percent higher than 2014 levels. This reflects a smaller growth rate in potential NGCC generation between 2015 and 2022 than has been observed in practice from 2005 to 2012, a time period of the same duration.

c. *Reliability.*

We also expect that an increase in NGCC generation of this amount would not impair power system reliability. Sources can achieve increases in utilization of existing NGCCs that displace generation from steam sources without impacting reliability because this shift in average annual utilization across existing EGUs does not inhibit the power sector's ability to maintain adequate dispatchable resources to continue to meet reserve margins and maintain reliability. Furthermore, sources are not required to achieve the exact or even the full extent of the building block 2 generation shift itself, which means that sources will have ample flexibility to maintain reliability-relevant operations while achieving emission reductions through a variety of measures.[669]

d. *Natural gas infrastructure.*

The EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability

---

[669] See section VIII for further discussion of electric reliability planning.

of the electricity transmission system to accommodate shifting generation patterns. For several reasons, we conclude that these systems would be capable of supporting the degree of increased NGCC utilization potential in building block 2. First, the natural gas pipeline system is already supporting national average NGCC utilization rates of 60 percent or higher during peak hours, which are the hours when constraints on pipelines or electricity transmission networks are most likely to arise. NGCC unit utilization rates during the range of peak daytime hours from 10 a.m. to 9 p.m. are typically 15 to 20 percentage points above their average utilization rates (which have recently been in the range of 40 to 50 percent). [670] Fleet-wide combined-cycle average monthly utilization rates have reached 65 percent, [671] showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. Furthermore, the NGCC utilization increase assumed in building block 2 could occur without a significant impact on peak demand for natural gas, including winter demand (when the power sector's demand for

---

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

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

natural gas competes with other sectors' demands for natural gas), since increasing annual utilization of NGCCs could focus on non-peak periods when NGCC capacity factors are currently low.

The second consideration supporting a conclusion regarding the adequacy of the gas supply infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity. [672] Natural gas pipeline capacity has regularly been added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity from 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCC units. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities, the pipeline industry projected that increases of up to 30 percent in total deliverability out of the pipeline system would be

---

[672] *See, e.g.*, EIA, Natural Gas Pipeline Additions in 2011, Today in Energy, *available at http://www.eia.gov/todayinenergy/detail.cfm?id=5050*; INGAA Foundation, Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market (2004 update), *available at http://www.ingaa.org/Foundation/Foundation-Reports/Studies/FoundationReports/45.aspx;* INGAA Foundation, North American Midstream Infrastructure Through 2035—A Secure Energy Future Report (2011), *available at http://www.ingaa.org/File.aspx?id=14911*.

possible.[673] There have been notable pipeline capacity expansions over the past five years, and substantial additional pipeline expansions are currently under construction.[674] Further, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance provide time for infrastructure improvements to occur should they prove necessary in some locations. Combining these factors of currently observed average monthly NGCC utilization rates of up to 65 percent, the flexibility of the emission guidelines, the rates of historical growth, and the availability of time to address any existing pipeline infrastructure limitations, it is reasonable to conclude that the natural gas pipeline system can reliably deliver sufficient natural gas supplies to allow NGCC utilization to increase up to an average annual capacity factor of 75 percent on a net summer basis.

e. *Natural gas production.*

We recognize that an increase in NGCC utilization rates at existing units corresponds with an associated increase in natural gas production, consistent with the

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

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

current trends in the natural gas industry. The EPA expects the growth in NGCC generation assumed for building block 2 to be feasible and consistent with the production potential of domestic natural gas supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices. According to EIA, proven natural gas reserves have doubled between 2000 and 2012. Domestic dry gas production has increased by 25 percent over that same timeframe (from 19.2 TCF in 2000 to 24.0 TCF in 2012). EIA's Annual Energy Outlook Reference Case for 2015 projects that production will further increase to 29.5 TCF by 2022 and 33 TCF by 2030, as a result of increased supplies and favorable market conditions. In the AEO 2015 high oil and gas resource case, production is projected to increase to 42.7 TCF in 2030. For comparison, building block 2 assumes NGCC generation growth of 235 TWh from 2012 to reach the level assumed for 2022, and that NGCC generation growth would result in increased gas consumption of less than 2 TCF for the electricity sector, which is less than EIA's projected increase in natural gas production of 5.5 TCF from 2012 to 2022.

The EPA has also assessed the ability of the electricity and natural gas industries to achieve the potential quantified for building block 2 using the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies. To inform its projections of least-cost capacity expansion and electricity dispatch, IPM incorporates representations of constraints related to fuel supply, bulk power transmission capacity, and unit availability. The model includes a detailed representation of the natural gas pipeline network and the capability to project economic expansion of that network based on pipeline load factors. At the EGU level, IPM includes detailed representations of key operational limitations such as turn-down constraints, which are designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units.

As described in more detail below, the EPA used IPM to assess the costs of increasing generation from existing NGCC capacity. IPM was able to meet average NGCC utilization rates of 75 percent on a net summer basis, while observing the market, technical, and regulatory constraints represented in the model. This modeling also demonstrates the ability of domestic natural gas supplies to increase their production levels, and deliver that supply through the pipeline network, to support the level of NGCC generation quantified in building block 2. Such a result is consistent with the EPA's determination that increasing the average utilization rate of existing NGCC units to 75 percent would be technically feasible.

f. *Transmission planning and construction.*

Achieving the generation shift quantified in building block 2 would not impose significant additional burden on the transmission planning process and does not necessitate major construction projects. Two considerations are important for this conclusion:

First, building block 2 applies only to increases in generation at *existing* NGCC facilities and does not contemplate any connection of new capacity to the bulk power grid. Second, regional grids are already supporting operation of the NGCC units for sustained periods of time at the capacity factors quantified in building block 2.[675] Although some upgrades to the grid (including potential, but modest, expansions of transmission capacity) may be necessary to support the extension of the time that these capacity factors are sustained over the course of the annual time period on which building block 2 is based, such upgrades are part of the normal planning process around the increased use of existing facilities. In fact, the electric transmission system is currently undergoing substantial expansion.[676] Consequently, EPA does not believe that achieving the generation shift potential in building block 2 would necessitate any

---

[675] See Greenhouse Gas Mitigation Measures TSD for a discussion of regional NGCC capacity factors.

[676] According to the Edison Electric Institute, member companies are planning over 170 projects through 2024, with costs totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects (over 13,000 line miles) are high voltage (345 kV and higher). Construction of transmission lines of 345KV and above are generally major projects that are particularly effective at carrying power of large distances. *http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.*

significant additional requirements for transmission planning and construction beyond those already being addressed at routine intervals by the power sector. Furthermore, the phasing in of building block 2's potential in the determination of the BSER; the flexible nature of multi-year compliance with the ultimate emission reduction requirements of the rule; and the seven years between finalization of this rule and the first year of compliance all provide time for infrastructure improvements to occur should they prove necessary in some locations.

g. *Regulatory flexibility.*

The final consideration supporting our view that natural gas and electricity system infrastructure would be capable of supporting increased NGCC unit utilization rates at a maximum of 75% on a net summer basis is the substantial unit-level compliance flexibility of the emission guidelines. The final rule does not require any particular NGCC unit to achieve any particular utilization rate in any specific hour or year. Thus, even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours on the order assumed in the generation shift potential quantified for building block 2.

4. Cost

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

To consider the cost implications of building block 2, the EPA expanded upon the proposal's extensive analysis of the magnitude and cost of CO_2 emission reductions through generation shifting within defined areas (consistent with the application of building blocks for performance rate- and state goal-setting), without consideration of the availability of other emission reduction methods ultimately available to units for compliance.

To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to shift generation from more carbon-intensive to less carbon-intensive EGUs, the EPA analyzed a series of scenarios in which the fleet of NGCC units within each of the regions considered for quantifying BSER (*i.e.*, the three interconnections) was directed to achieve a specified average annual utilization rate across that region on a net basis while maintaining a fixed level of aggregate generation in that region across all existing fossil fuel-fired sources. The EPA conducted such scenarios to address average utilization rates of 70 percent, 75 percent and 80 percent on a net basis, allowing for shifting of fossil generation between existing units within the regions described above. This scenario identifies a generation pattern that would meet electricity demand at the lowest total cost, subject to all other specified operating and bulk power transfer constraints for the scenario, including the specified average NGCC unit utilization rate.

The costs of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a base case scenario. For the scenario reflecting a 75 percent NGCC utilization rate on a net basis with regional fossil generation shifting, comparison to the base case indicates that the average cost of the CO_2 reductions achieved over the 2022–2030 period was $24 per short ton of CO_2. We view these estimated costs as reasonable and therefore as supporting the use of a 75 percent net utilization rate target for purposes of quantifying the emission reductions achievable at a reasonable cost through the application of building block 2 in the BSER.

We also conclude from these analyses that potential impacts to fuel prices and electricity prices from achieving the extent of fossil generation shifting quantified for this building block are reasonably within the bounds of power sector experience. For example, in the 75 percent NGCC unit utilization rate scenario where generation shifting is limited to regional boundaries, the delivered natural gas price was projected to increase by an average of 7 percent over the 2022–2030 period, which is well within the range of historical natural gas price variability.[677] Projected wholesale electricity price increases over the same period were less than 4 percent, which similarly is well within the range of historical electric price variability. These projected impacts on prices were captured in the emission reduction costs of these scenarios already described above, which are reasonable and support use of a 75 percent NGCC utilization rate target for purposes of quantifying the emission reductions achievable through application of the BSER.

However, we also note that the costs (and their incorporated price impacts) just described are higher than we would expect to actually occur in real-world compliance with the final rule's compliance requirements for the following reasons. First, this analysis does not capture the building block 2 phase-in, which assumes an average utilization rate over the interim period of less than 75 percent in all three interconnections. Second, the analysis overstates the extent to which building block 2 is ultimately reflected in the source category performance rates. While the performance rate computation procedure assumes a maximum NGCC utilization rate of 75 percent on a net summer basis, the Eastern Interconnection's realization of this level of NGCC utilization yields higher source category performance rates for steam than what would have been calculated for units in the

---

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

Western Interconnection and Texas Interconnection if they realized that maximum NGCC utilization rate in conjunction with the other building blocks. In other words, there is substantial building block 2 potential in the Western Interconnection and Texas Interconnection that is not actually captured in the source category performance rates that are ultimately assigned to steam through this rate- and goal-setting approach (where the performance rates are ultimately determined by the BSER region with the highest rate outcome in the calculation). Therefore, the building block 2 analysis overstates the cost of this component of BSER to the extent that it assumes achievement of this generation shift potential that is not reflected in the source category performance rates ultimately determined. Third, as a practical matter, sources will be able to achieve additional emission reductions through other measures that may prove to be less costly than generation shifting and could substitute for the reductions and costs considered here. These building block 2 analyses were focused on evaluating the potential impacts of fossil generation shifting in isolation, and as a result, they do not consider states' and sources' flexibility to choose among alternative CO_2 reduction strategies that could offer lower-cost reductions, instead of relying on fossil generation shifting to the extent analyzed here.

Based on the analyses summarized above, the EPA concludes that an average annual utilization rate for each region's NGCC units of up to 75 percent is a technically feasible, cost-effective, and adequately demonstrated building block for BSER.

For further information on the analysis discussed in this section, see Chapter 3 of the GHG Mitigation Measures TSD for the CPP Final Rule.

5. Major Comments and Responses

The EPA received numerous comments regarding building block 2. Many of these comments provided helpful information and insights and have resulted in improvements to the rule. This section summarizes some of these comments, and the remainder of the comments are responded to in the Response to Comment document, available in the docket.

The EPA received comment regarding the potential for an increase in upstream methane emissions from increased utilization of natural gas. Our analysis found that the net upstream methane emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the Clean Power Plan. Furthermore, the changes in upstream methane emissions are small relative to the changes in direct emissions from power plants. The technical details supporting this analysis can be found in the Regulatory Impact Analysis.

Commenters also expressed concern that neither a utility nor any state agency controls dispatch in most states. The EPA believes these comments fail to adequately appreciate that the utilities do control the dispatch of units that they own and/or operate, either by being the actual dispatch agent in many cases where there is no RTO or ISO that schedules the dispatch, or by the choice of units and bids they offer into an organized electricity market operated by an RTO or ISO. These entities currently control the dispatch of their units while respecting all existing requirements from environmental rules. This final rule does not change these current circumstances and makes clear that it is the EGU that is responsible for meeting the requirements in the state plan; the state is responsible for the development of that plan, but the state does not need to control the dispatch.

Other comments object to the use of a single capacity factor for all existing NGCCs to quantify building block 2 potential on the grounds that not all units may be able to achieve this utilization level, and that some units may be designed for cycling and so may need upgrades to sustain such utilization. The EPA disagrees with these comments. The 75 percent capacity factor establishes a regional potential for generation from existing NGCC capacity, and it does not establish any individual unit requirements.

Some comments argue that generation limits in permits for some existing NGCC units will limit the amount by which these units can increase their generation and thereby limit the feasibility of building block 2. The EPA disagrees with these comments. Although permit limits can constrain the ability of individual units to operate above certain levels, building block 2 was developed conservatively, with units operating on average at a level below the maximum levels at which some units have demonstrated the capability to operate. No individual unit is required to achieve the average generation levels used to quantify building block 2. Further, permit limits at individual units can be considered when state plans are developed. There are many flexibilities in the final rule, including the opportunity to establish standards of performance that incorporate emissions trading or develop plans that will respect any existing permit limits at individual units.

The EPA also received comments asserting that increasing generation from new renewables would require increased use of natural gas capacity for back-up and ramping, and therefore it is not possible for NGCC units to run at BSER utilization rates and also be available to support the additional variable renewable generation resulting from building block 3. The EPA disagrees with this comment. The 75% net summer utilization rates defined by building block 2 is a conservative assessment and applied on an annual average basis. It is therefore possible for these existing units to both operate at higher annual utilization rates, and also to operate at higher rates during limited periods and still maintain a 75% net summer average annual utilization rate. While variable renewable generation does require additional load following and ramping resources and unit cycling, these requirements are generally a small part of the overall ramping costs of the system (see NREL, Relevant Studies for NERC's Analysis of EPA's Clean Power Plan 111(d) Compliance). Additionally, while existing NGCC units are an efficient source of ramping to support variable renewables, other units running in an intermediate mode can also provide load following and ramping.

E. Building Block 3—New Zero-Emitting Renewable Generating Capacity

The third element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of zero-emitting renewable electricity (RE) generating capacity to produce replacement generation.

In this section we address first the history of and then trends in RE development, as well as the importance of expanding the use of RE. Next we discuss the ability of affected EGUs to access generation from new RE generating capacity, followed by a discussion of renewable energy certificate (REC) markets. We then describe the quantification of the amount of generation from new RE generating capacity achievable through building block 3, including key comments, changes made from the proposal, the method by which RE target generation levels are quantified, and the magnitude and timing of increases in RE generation associated with this building block. Next, we discuss the feasibility of implementing the identified incremental amounts of RE generation. Finally, we address the costs associated with those increases in RE generation.

1. History of RE Development

RE generating technologies are a well-established part of the utility power sector. These technologies generate electricity from renewable resources, such as wind, sun and water. While RE has been used to generate electricity for over a century, the push to commercialize RE more broadly began in the 1970s.[678] Following a series of energy crises, new federal organizations and initiatives were established

---

[678] Nearly all U.S. hydroelectric capacity was built before the mid-1970s. U.S. DOE. History of Hydropower. Accessed March 2015. Available at: *http://energy.gov/eere/water/history-hydropower*.

to coordinate energy policy and promote energy self-sufficiency and security, including solar energy legislation, the Public Utility Regulatory Policies Act of 1978 (PURPA) and the 1980 Energy Security Act.[679]

PURPA was a key step in stimulating RE development. By requiring utilities to purchase generation from qualifying facilities (*i.e.*, certain CHP and RE generators) at avoided costs, PURPA opened electricity markets to more RE generation and gave rise to non-utility generators that were willing to try new RE technologies.[680] In addition, since 1992, federal tax policy has provided important financial support via tax credits for the production of RE and investments in RE.

States have also taken a significant lead in requiring the development of RE resources. In particular, a number of states have adopted renewable portfolio standards (RPS), which are regulatory mandates to increase production of RE. As of 2013, 29 states and the District of Columbia had enforceable RPS or similar laws.[681] These RPS requirements continue to drive robust near-term growth of non-hydropower RE.

---

[679] U.S. DOE Office of Management, Timeline of Events: 1971–1980. Accessed March 2015. Available at: *http://energy.gov/management/office-management/operational-management/history/doe-history-timeline/timeline-events-1*.

[680] "Restructuring or Deregulation?" Smithsonian Museum of American History. Accessed March 2015. Available at: *http://americanhistory.si.edu/powering/dereg/dereg1.htm*.

[681] Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, at LR-5 (2014).

2. Trends in RE Development

Today, RE is tightly integrated with the utility power sector in multiple ways: States have set RE targets for electrical load serving entities; utilities themselves are diversifying their portfolios by contracting with RE generators; and new RE generators are being developed to provide more electrical power grid support services beyond just energy (*e.g.*, modern electronics allow wind turbines to provide voltage and reactive power control at all times).[682] [683]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE technologies, including conventional hydropower, represented 12 percent of total U.S. electricity, up from 8 percent in 2005.[684] In 2013, U.S. non-hydro RE capacity for the total electric power industry exceeded 80,000 megawatts, reflecting a fivefold increase in just 15 years.[685] In particular, there has been substantial

---

[682] IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: *http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.*

[683] American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. p. 107.

[684] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b. Available at: *http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[685] Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts in 1998. Energy Information Administration, 1990–2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State

growth in the wind and solar photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twentyfold.[686]

The global market for RE is projected to grow to $460 billion per year by 2030.[687] RE growth is further spurred by the significant amount of existing natural resources that can support RE production in the U.S.[688] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in the reference case and all alternative cases.[689] In the reference case, RE generation increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[690]

(EIA-860). Available at: *http://www.eia.gov/electricity/data/state/*.

[686] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b. Available at: *http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf*.

[687] "Global Renewable Energy Market Outlook." Bloomberg New Energy Finance, November 16, 2011. Available at *http://bnef.com/WhitePapers/download/53*.

[688] Lopez et al., NREL, "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," (July 2012). Available at *http://www.nrel.gov/docs/fy12osti/51946.pdf*.

[689] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040 (2015), p. 25. Available at *http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf*.

[690] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040 (2015), p. ES-6–7. Available at *http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf*.

The recent and projected growth of RE is in part a reflection of its increasing economic competitiveness. Numerous studies have tracked capital cost reductions and performance improvements for RE, particularly for solar and wind. For instance, Lazard's analysis of wind and utility-scale solar PV levelized costs of energy (LCOE), on an unsubsidized basis, over the last five years found the average percentage decrease of high and low of LCOE ranges were 58 percent and 78 percent, respectively.[691] Analyses of wind's competitiveness found falling wind turbine LCOE while the wind industry developed projects at lower wind speed sites using new turbine designs (*e.g.*, increased turbine hub heights and rotor diameters). Performance improvements have come from novel deployments of new turbines designed for lower quality wind sites that are deployed at higher quality wind sites, which have resulted in capacity factor increases for these locations.[692] [693] For utility-scale solar, cost and performance have also improved significantly. Analysis has shown that the installed price of solar photovoltaics (PV) systems, prior to any incentives, has declined substantially since 1998. Capacity-weighted average prices of solar PV in utility-scale deployments were 40 percent lower in

---

[691] Lazard, *Levelized Cost of Energy Analysis-Version 8.0*, September 2014, p. 9, Available at: *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf*.

[692] "2013 Wind Technologies Market Report," LBNL, August 2014. Available at *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf*.

[693] "2013 Cost of Wind Energy Review," NREL, Feb 2015. Available at: *http://www.nrel.gov/docs/fy15osti/63267.pdf*.

2013 than five years earlier.[694] [695] Initially, price declines were partially driven by oversupply and manufacturers' thin margins, but, in 2014, prices have remained low due to reductions in manufacturing costs.[696] The capacity factors of new utility-scale installations have increased as systems are optimized to maximize energy production. For example, a growing number of utility-scale PV systems are increasing the direct current capacity of the solar array relative to the alternating current rating of the array's inverter to increase energy production and improve project economics.[697] The cost and performance improvements for wind and solar are driven by increased scale of production, improved technologies, and advancements in system deployments.

3. Importance of Increasing Use of RE

Currently, the utility power sector accounts for 40 percent of total annual energy consumption in the U.S.[698] Introducing more zero-emitting RE generation

---

[694] "Tracking the Sun VII" LBNL, Sept 2014. Available at: *http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20*.

[695] "Photovoltaic System Pricing Trends," NREL, 22 Sept 2014. Available at: *http://www.nrel.gov/docs/fy14osti/62558.pdf*.

[696] "Revolution Now—The Future Arrives for Four Clean Energy Technologies—2014 Update," DOE, Oct 2014. Available at: *http://energy.gov/sites/prod/files/2014/10/f18/revolution_now_updated_charts_and_text_october_2014_1.pdf*.

[697] "Utility-Scale Solar 2013," LBNL, Sept 2014. Available at: *http://emp.lbl.gov/publications/utility-scale-solar-2013-empirical-analysis-project-cost-performance-and-pricing-trends*.

[698] U.S. Energy Information Administration Annual Energy Review, 2011. Accessed March 2015. Available at:

over the long term could significantly reduce CO_2 emissions, as production of RE predominantly replaces fossil fuel-fired generation and thereby avoids the emissions from that replaced generation.

A number of studies and recent policy developments have acknowledged RE as an important means of achieving CO_2 reductions. California cited the reduction of CO_2 emissions from electrical generations as one of the reasons for increasing its RE target from 20 percent to 33 percent by 2020 (and potentially 50 percent by 2030).[699] A recent IPCC report also concluded that RE has large potential to mitigate CO_2 emissions.[700]

Increased use of RE provides numerous benefits in addition to lower CO_2 emissions. RE typically consumes less water than fossil fuel-fired EGUs. Wind power and solar PV systems do not require the use of any water to generate electricity; water is only needed for cleaning to ensure efficient operation. In contrast, utility boilers, in particular, require large

---

http://www.eia.gov/totalenergy/data/monthly/pdf/flow/primary_energy.pdf.

[699] California S.B. 2 (1X), 2011. Accessed March 2015. Available at: *http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf.*

[700] IPCC, Renewable Energy Sources and Climate Change Mitigation, 2012. Accessed March 2015. Available at: *http://www.ipcc.ch/pdf/special-reports/srren/SRREN_Full_Report.pdf.*

quantities of water for steam generation and cooling.[701]

Increasing RE use will also continue to lower other air pollutants (*e.g.*, fine particles, ground-level ozone, etc.). In addition, the RIA notes that increasing RE will diversify energy supply, hedge against fossil fuel price increases and create economic development and jobs in manufacturing, installation, and other sectors of the economy.

4. Access to RE by Owners of Affected EGUs

The ability of affected EGUs to co-locate or obtain incremental RE to reduce CO_2 emissions is well-demonstrated, whether it is through direct ownership, bilateral contracts, or procurement of the environmental attributes associated with RE generation.[702] Consequently, the EPA believes that an increase in RE is a proven way to reduce CO_2 emissions at affected EGUs of all types at a reasonable cost.

Owners and operators of affected EGUs across the U.S. already have substantial opportunities to procure RE regardless of their organizational structure and/or business model. In many parts of the country, EGUs are owned and operated by vertically integrated utilities. These utilities can be investor-owned utilities that operate under traditional electricity regulation, municipal utilities (munis), or electric

---

[701] EPA, Water Resource Use. Accessed on March 2015. Available at: *http://www.epa.gov/cleanenergy/energy-and-you/affect/water-resource.html*.

[702] Refer to the GHG Mitigation Measures TSD for additional information on RE ownership and co-location.

cooperatives (co-ops). These utilities have significant control over the types of generating capacity they develop or acquire, and over the electricity mix used to meet demand within their service territories.

Even when EGU owners participating in organized markets do not directly determine dispatch among energy sources, such EGU owners make decisions about what types of capacity they choose to develop and thus what generation mix they can ultimately supply into that market's dispatch choices. Because zero-emitting RE technologies have relatively low variable costs, an EGU owner's decision to install (or to finance the installation of) RE capacity will yield lower-cost electricity generation that, when available, a system dispatcher will prefer over higher-variable-cost generation from fossil fuel-fired capacity. Therefore, all owners of affected EGUs have a direct path for replacing higher-emitting generation with RE regardless of their organizational type and regardless of whether they operate in a cost-of-service framework or in a competitive, organized market.

Many affected EGUs have already directly invested in RE. Of the 404 entities that owned part of at least one affected EGU under this rule, 178 also owned RE (biomass, geothermal, solar, water or wind). These 178 owners owned 82 percent of affected EGU capacity. As a whole, these entities' share of RE capacity was equal to 25 percent of the total of their affected EGU capacity.[703]

---

[703] SNL Energy. Data used with permission. Accessed on June 9, 2015.

Some of the largest owners of affected EGUs also owned RE (see Table 8). For example, NRG Energy, Inc. owns more than 3,000 megawatts of RE capacity, over 20 percent of which (nearly 800 megawatts) is solar, and almost 80 percent of which (over 2,500 megawatts) is wind. Duke Energy Corporation owns 175 megawatts of solar and over 1,500 megawatts of wind. NextEra Energy, Inc.'s share of RE capacity approaches 40 percent of their total affected EGU capacity.[704] Table 8 lists a sampling of affected EGUs that have large amounts of fossil fuel-fired capacity and RE capacity:

[704] Ibid.

TABLE 8—SAMPLE OF OWNERS OF AFFECTED EGUS AND RE CAPACITY [705] [706]

Ultimate parent	Affected EGU capacity (MW)	Renewable capacity (MW)
NRG Energy, Inc.	48,787	3,149
Duke Energy Corporation	39,028	5,526
Southern Company	37,168	3,245
American Electric Power Company, Inc.	34,940	1,142
NextEra Energy, Inc.	29,471	11,626
Calpine Corporation	23,878	1,509
Tennessee Valley Authority	21,717	5,427
Berkshire Hathaway Inc.	18,899	6,650
FirstEnergy Corp.	16,175	1,371
Exelon Corporation	10,283	3,361
Nebraska Public Power District	2,003	90
Basin Electric Power Cooperative	1,526	275
American Municipal Power, Inc.	1,112	53
Sacramento Municipal Utility District	925	834
Golden Spread Electric Cooperative, Inc.	521	78

[705] SNL Energy. Data used with permission. Accessed on June 9, 2015.

[706] eGRID, EPA. 2012 Unit-Level Data Using the eGRID Methodology.

Large vertically integrated utilities generally have multiple options for investing in RE, including building their own RE capacity or procuring RE under a long-term power purchase agreement. Municipal utilities and rural cooperatives that own generating asset portfolios, particularly generation and transmission cooperatives and larger municipal utilities, have also used RE to reduce carbon emissions. Large generation and transmission cooperatives also purchase significant quantities of RE for their members. Federal power authorities own or contract for significant amounts of RE.[707] [708]

The list of ten electric utilities with the largest amounts of wind power capacity on the system (owned or under contract) includes a variety of affected EGU organizational structures, including vertically integrated investor-owned utilities, municipal utilities, and federal power authorities. Xcel Energy and Berkshire Hathaway Energy rank first and second with 5,736 megawatts and 4,992 megawatts of wind capacity, respectively. Tennessee Valley Authority, a federal power authority, had 1,572 megawatts and CPS Energy, a public utility, had 1,059 megawatts of wind power capacity. [709] Basin Electric Power

---

[707] American Wind Energy Association. AWEA Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources and Supplemental Proposed Rule. pp. 88–91.

[708] Solar Energy Industries Association. Comments to the EPA and States on the Proposed Clean Power Plan Regulating Existing Power Plants Under Section 111(d) of the Clean Air Act. pp. 98–147.

[709] American Wind Energy Association. U.S. Wind Industry Annual Market Report (2014 data). Accessed July 2015.

Cooperative had 716 megawatts and was the top ranked cooperative utility, but is not on the top ten utilities with wind power capacity list.

Many affected EGUs are already planning on deploying significant amounts of RE according to their integrated resource plans (IRPs). Electric utilities use IRPs to plan operations and investments over long time horizons. These plans typically cover 10 to 20 years and are mandated by public utility commissions (PUCs). A recent study of IRPs, included in the docket for this rulemaking, shows this trend.[710] For instance, Dominion plans for over 800 megawatts of wind and solar in their 2015 to 2029 planning period.[711] Duke Energy Carolinas' IRP has no plans for new coal, but describes plans for roughly 1,250 megawatts of additional RE by 2021, and approximately 2,150 megawatts by 2029. A significant portion (1,670 megawatts) of the planned RE is solar.[712] Ameren is

---

Available at *http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=7422&RDtoken=64560&userID=*. The ten largest electric utilities with wind power capacity on the system (owner or under contract) includes: Xcel Energy; Berkshire Hathaway Energy; Southern California Edison; American Electric Power; Pacific Gas & Electric; Tennessee Valley Authority; San Diego Gas & Electric; CPS Energy; Los Angeles Department of Water & Power; and Alliant Energy.

[710] See memo entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015).

[711] Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan, August 2014. Available at: *https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/nc-irp-2014.pdf*.

[712] Duke Energy Carolinas' 2014 Integrated Resource Plan, September 2014. Available at: *http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c3c5cbb5-51f2-423a-9dfc-a43ec559d307*.

planning to retire one-third of the coal generating capacity, as well as installing an additional 400 megawatts of wind, 445 megawatts of solar, and 28 megawatts of hydroelectric generating capacity.[713]

Independent power producers (IPPs) also can and do own both RE and fossil generation. For example, NRG is a diversified IPP that operates substantial coal, natural gas, wind, solar, and nuclear capacity. NRG demonstrates the ability of IPPs to reduce utilization of fossil fuel-fired EGUs and replace that generation with RE. NRG announced a goal to cut CO_2 emissions from its fleet by 50 percent by 2030 (from a 2014 baseline).[714] NRG has already reduced CO_2 emissions from its fleet by 40 percent since 2005. This achievement demonstrates that when an IPP commits to shifting its generation portfolio, it can do so at reasonable cost and without reliability impacts. The NRG example shows that reduced utilization of fossil fuel-fired EGUs that is replaced by RE also owned by the EGU owner is adequately demonstrated.

EGU owners can also replace fossil fuel-fired generation with RE through bilateral contracts and REC purchases, as described below. Both the bilateral market for RE contracts and REC markets are well-developed. There are no legal or technical obstacles to a fossil fuel-fired EGU owner acting as the

---

[713] Integrated Resource Plan Update, October 2014. Available at: *https://www.ameren.com/missouri/environment/renewables/ameren-missouri-irp*.

[714] NRG, "NRG Energy Sets Long-Term Sustainability Goals at Groundbreaking of 'Ultra-Green' New Headquarters" (Nov. 20, 2014). Available at *http://investors.nrg.com/phoenix.zhtml?c=121544&p=irolnewsArticle&ID=1991552*.

counterparty of a bilateral contract for purchase of energy from a RE facility. Any type of EGU owner (utility or otherwise) can purchase and retire RECs. The fact that RECs are purchased by a diverse set of market participants—including residential consumers, commercial businesses, and industrial facilities—demonstrates that such a purchase for all EGU owners is adequately demonstrated.

5. REC Markets

Affected EGU owners do not need to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure. RECs are used to demonstrate compliance with state RE targets, such as state RPS, and also to substantiate claims stemming from RE use. RECs are tradable instruments that are associated with the generation of one megawatt-hour of RE and represent certain information or characteristics of the generation, called attributes.[715] RECs may be traded and transferred regardless of the actual energy flow.

The legal basis for RECs is established by state statutes and administrative rules. Nearly all states with a mandatory RPS have established RECs as a means of compliance. The Federal Energy Regulatory Commission (FERC) has observed that states created RECs to facilitate programs designed to promote increased use of RE, and that "attributes associated

[715] EPA Green Power Partnership, Renewable Energy Certificates July 2008). Available at *http://www.epa.gov/greenpower/documents/gpp_basics-recs.pdf*.

with the [RE] facilities are separate from, and may be sold separately from, the capacity and energy."[716]

In complying with states' RPS requirements, utilities have contracted for RECs from in-state and out-of-state resources in accordance with RPS requirements. Utilities may have sourced RECs from out-of-state to reduce the cost of compliance, to source RECs from specific generation types, or for other reasons.[717]

The development of REC markets to facilitate RPS compliance provides evidence that markets can develop to facilitate compliance with rate-based state plans. These markets will afford affected EGU owners an alternative to directly invest in, or own, renewable generating capacity in order to replace fossil fuel-fired generation with RE as an emission reduction measure.

6. Quantification of RE Generation Potential for BSER and Major Comments

The methodology for quantifying RE generation levels under building block 3 is a modified version of the alternative RE approach from proposal, with adjustments that reflect the data and information the

---

[716] FERC Docket No. EL03-133-000, Petition for Declaratory Order and Request for Expedited Consideration, American Ref-Fuel Company, Covanta Energy Group, Montenay Power Corporation, and Wheelabrator Technologies, Inc. June 16, 2003, *Order Granting Petition for Declaratory Ruling*, October 1, 2003. *American Ref-Fuel Co. et al.*, 105 FERC ¶ 61,004 (2003); and *Order Denying Rehearing*. April 15, 2004. 107 FERC ¶ 61,016 (2004). Available online at: *http://www.ferc.gov/whats-new/comm-meet/041404/E-28.pdf* (accessed 11/7/2014).

[717] Heeter, J. Quantifying the Level of Cross-State Renewable Energy Transactions. NREL 2015. Available at *http://www.nrel.gov/docs/fy15osti/63458.pdf*.

EPA collected through stakeholder comments and the EPA's additional analysis and information collection. In evaluating the proposed and alternative RE approaches commenters observed that RPS, as the basis for quantifying RE generation levels under the proposed approach, are policy instruments that states may choose to implement for a variety of reasons not related to CO_2 emission reductions. Additionally, differences across RPS policies in eligible resources, crediting mechanisms, deliverability requirements, alternative compliance payments, and other policy elements made the regional averaging of state-level RPS requirements challenging. Finally, commenters provided data demonstrating that RE resource potential can vary significantly within the regions identified under the proposed approach, producing state-level RE generation levels that may not be aligned with the opportunity to deploy incremental RE resources at reasonable cost. In contrast, commenters argued that a methodology similar to the alternative RE approach, which is based on economic potential, represents a more technically sound basis for quantifying building block 3 target generation levels that accounts for regional differences in RE resources and power market conditions, such as projected fuel prices, load growth and wholesale power prices. The EPA agrees with these comments.

Within the framework of the alternative RE approach, the EPA received significant comments on a number of issues, including the use of historical deployment rates, the interstate nature of RE and the power system, merits of total versus incremental RE generation as the metric by which building block 3 generation levels are quantified, types of RE technologies that contribute to those generation levels, cost and performance estimates associated with those RE technologies, magnitude of the reduced cost applied to new RE capacity as an incentive to deploy, and application of a nationally uniform benchmark development rate to modeled projections of economic deployment. Based on commenter data and information, as well as further analysis and information collection, the primary adjustments the EPA made to the alternative RE approach are:

- The basis for quantifying building block 3 generation has been modified to incorporate historical deployment patterns for RE technologies as well as the economic potential identified through modeling projections. The introduction of historical capacity additions to the final methodology further grounds building block 3 generation in demonstrated levels of RE deployment that have been successfully incorporated into the power system. This adjustment also serves to harmonize the approach across all three building blocks in which historical data is the primary basis for identifying emission reduction opportunities under the BSER.

- The RE technologies used to quantify building block 3 generation levels are onshore wind, utility-scale solar PV, concentrating solar power (CSP), geothermal and hydropower. Each of these technologies is a utility-scale, zero-emitting resource that was included under the alternative RE approach at proposal. Additionally, the EPA received significant comments on the opportunities and challenges associated with distributed RE technologies. Distributed technologies, as a demand-side resource, present unique data and technical challenges (such as the role of evaluation, measurement and verification (EM&V) procedures in verifying their production, the diverse economic incentives of different parties involved in their deployment, and the variety of grid integration policies and conditions across potential deployment sites) that complicate identifying a technically feasible and cost-effective level of generation. Consequently, the EPA is, at this time, choosing not to include distributed technologies as part of the BSER (although, as explained in section VIII.K of this preamble, distributed RE technologies that meets eligibility criteria may be used for compliance). Finally, any RE technology that has not been deployed in the U.S., including demonstrated RE technologies for which there is clear evidence of technical feasibility and cost-effectiveness (*e.g.*, offshore wind), contributes no generation to building block 3 under this historically-based methodology. These RE technologies are consequently reserved for compliance, which offers affected EGUs additional flexibility and will reduce their need to rely on other emission reduction measures or building blocks.

- Building block 3 generation levels are expressed in terms of incremental, rather than total, RE generation. As a metric, incremental generation is better aligned with quantifying an amount of expanded RE to replace generation at affected EGUs.[718] Specifically, the generation levels under

[718] Consistent with the October 2014 NODA, the final goal-setting methodology assumes replacement of affected EGU generation by incremental building block 3 generation in calculating source-specific CO_2 emission performance rates. For

building block 3 include generation from capacity that commenced operation subsequent to 2012 (the data year on which the BSER is evaluated). Commenters remarked that it is unnecessary to include generation from RE capacity that was already in operation by 2012 in building block 3 because the impact of that generation on fossil fuel-fired EGUs is already reflected in the observed 2012 emissions and generation data of those EGUs.

- Due to the interstate nature of RE and the power system, and consistent with the rationale provided in the October 2014 Notice of Data Availability (NODA), building block 3 generation levels are quantified for each of the three BSER regions—the Eastern Interconnection, Western Interconnection, and Texas Interconnection—rather than at the state-level. This regionalized approach, as described in the NODA, takes into account the opportunity to develop regional RE resources and thus better aligns building block 3 generation levels with the rule's approach to allowing the use of qualifying out-of-state renewable generation for compliance.

- Commenters observed that the cost and performance estimates the EPA relied on at proposal from the Energy Information Administration's Annual Energy Outlook 2013 do not reflect the decline in cost and increase in performance that have been demonstrated by current projects, particularly in regards to wind and solar technologies. Commenters provided data from a variety of sources to support these claims, including Lawrence Berkeley National

---

additional information on the goal-setting methodology, refer to Section VI.

Laboratory (LBNL), the Department of Energy (DOE) and Lazard. Each of these sources supported the contention that RE technologies, particularly wind and solar, have realized gains in cost and efficiency at a scale that has altered the competitive dynamic between RE and conventional resources. As a result, it has become increasingly necessary for any long-term outlook of the utility power sector to continually assess the development of RE technology cost and performance trends. In performing this task, the EPA revised its data for onshore wind and solar technologies to reflect the mid-case estimates from the National Renewable Energy Laboratory's (NREL's) 2015 Annual Technology Baseline. The EPA selected the NREL 2015 Annual Technology Baseline (ATB) estimates based on the quality of its data as well as NREL's demonstrated success in both reflecting and anticipating RE cost and performance trends. In addition to wind and solar technologies, the EPA evaluated hydropower deployment potential based on the latest cost and performance data from NREL's Renewable Energy Economic Potential study.[719]

- The benchmark development rate that constrained cost-effective RE deployment under the alternative RE approach in the proposal has been removed from the final methodology.[720] Commenters detailed several issues with applying the benchmark

---

[719] For additional information on the updated RE cost and performance assumptions used to quantify building block 3 generation, refer to the GHG Mitigation Measures TSD.

[720] The technical potential limiter was a nationally uniform, technology-specific limit on cost-effective RE deployment based on the amount of 2012 generation in a state as a share of that state's total technical potential.

development rate, including that it does not factor in the total size of the RE resource in a given state and is inconsistent with a regional approach to quantifying target generation levels. EPA agrees with these comments and the benchmark development rate has been eliminated.

In addition to the comments described above, the EPA received significant comments on a wide variety of topics related to building block 3. Many of these comments provided helpful information and insights, and have resulted in improvements to the final rule. These comments, as well as the EPA responses, are available in the Response to Comment document.

The final methodology for quantifying incremental RE target generation levels contains seven steps. Each step is described below.[721]

First, the EPA collected data for each RE technology (onshore wind, utility-scale solar PV, CSP, geothermal and hydropower) to determine the annual change in capacity over the most recent five-year period. From these data, the EPA calculated the five-year annual average change in capacity and the five-year maximum annual change in capacity for each technology.

Second, the EPA determined an appropriate capacity factor to apply to each RE technology that would be representative of expected future performance from 2022 through 2030. For this purpose the EPA relied on NREL's ATB.

---

[721] For supporting data, documentation, and examples for each step of the quantification methodology, refer to the GHG Mitigation Measures TSD.

Third, the EPA calculated two generation levels for each RE technology. The first generation level is the product of each technology's five-year average capacity change and the assumed future capacity factor. The second generation level is the product of each technology's five-year maximum annual capacity deployment and the assumed future capacity factor. Table 9 below shows the data and assumptions used for these calculations.

TABLE 9—HISTORICAL CAPACITY CHANGES AND ASSOCIATED GENERATION LEVELS

	Assumed future capacity factor (percent)	Five-Year average capacity change (MW)	Generation associated with five year-average capacity change (MWh)	Maximum annual capacity change (MW)	Generation associated with maximum annual capacity change (MWh)
Utility-Scale Solar PV[722]	*20.7*	*1,927*	*3,494,268*	*3,934*	*7,133,601*
CSP	*34.3*	*251*	*754,175*	*767*	*2,304,590*
Onshore Wind	*41.8*	*6,200*	*22,702,416*	*13,131*	*48,081,520*
Geothermal	*85.0*	*142*	*1,057,332*	*407*	*3,030,522*
Hydropower	*63.8*	*141*	*788,032*	*294*	*1,643,131*
Total Generation	*N/A*	*N/A*	*28,796,222*	*N/A*	*62,193,363*

[722] Capacity values for utility-scale solar PV are expressed in terms of MW_{DC}. The assumed future capacity factor for this utility-scale solar PV includes a DC-to-AC conversion, enabling the generation totals to be combined across all RE technologies.

Fourth, the EPA quantified the RE generation from capacity commencing operation after 2012 that can be expected in 2021 (the year before this rule's first compliance period) without the imposition of this rule. Because building block 3 is focused on the ability of fossil fuel-fired EGUs to reduce their emissions by deploying incremental RE, it is reasonable to take into account the considerable amount of RE deployment that is already taking place and is projected to continue doing so before considering the additional deployment that would be motivated by this rule's mandate to reduce emissions from affected EGUs. The EPA considered its base case power sector modeling projections using IPM to quantify this component of future-year RE generation, which the EPA assumes to be 213,084,125 megawatt-hours in 2021.

Fifth, the EPA applied the generation associated with the five-year average capacity change to the first two years of the interim period. Combining the projected 2021 RE generation from capacity starting operation after 2012 with the generation increment associated with the five-year average change in capacity produces 241,880,347 megawatt-hours in 2022 and 270,676,570 megawatt-hours in 2023. The EPA believes it is appropriate to apply the generation associated with the five-year average capacity change for the first two years of the interim period to ensure adequate opportunity to plan for and implement any necessary RE integration strategies and investments in advance of the higher RE deployment levels assumed for later years.

Sixth, for all years subsequent to 2023 the EPA applied the generation associated with the maximum annual capacity change from the historical data analysis. In 2024, this produces a building block 3 generation level of 332,869,933 megawatt-hours (aggregated across all three BSER regions); by 2030, that generation level is 706,030,112 megawatt-hours.

Seventh, to further evaluate the technical feasibility and cost-effectiveness of the building block 3 generation levels (aggregated across all three BSER regions), as well as to produce interconnection-specific levels of building block 3 generation from the national totals described in steps 5 and 6, the EPA conducted analysis using IPM of a scenario directing the power sector to achieve those RE generation levels. IPM modeling projections assess opportunities for RE deployment in an integrated framework across power, fuel, and emission markets. The modeling framework incorporates a host of constraints on the deployment of RE resources, including resource constraints such as resource quality, land use exclusions, terrain variability, distance to existing transmission, and population density; system constraints such as interregional transmission limits, partial reserve margin credit for intermittent RE installations, minimum turndown constraints for fossil fuel-fired EGUs, and short-term capital cost adders to reflect the potential added cost due to competition for scarce labor and materials; and technology constraints such as construction lead times and hourly generation profiles for non-dispatchable resources by season.[723] Additionally, the EPA assumes in this analysis that deployment of variable, non-dispatchable RE resources is limited to 20 percent of

[723] Refer to GHG Mitigation Measures TSD for more detail on modeling methodology.

net energy for load by technology type and 30 percent of net energy for load in total at each of IPM's 64 U.S. sub-regions.[724] The 30 percent constraint applied to variable, non-dispatchable RE resources reflects levels commonly modeled in grid integration studies at the level of the interconnection. These studies have demonstrated that impacts to the grid in reaching levels as high as 30 percent of net energy for load are relatively minor.[725] For example, the Western Wind and Solar Study Phase 2 found cycling costs ranged from $0.14 to $0.67 per megawatt-hour of added wind and solar generation. These integration cost levels are not impactful in determining cost-effectiveness. As such, applying the 30 percent constraints at the IPM sub-region level is very conservative and provides a high degree of assurance that the RE capacity

---

[724] Regions that have already exceeded these limits are held at historical percent of net energy for load.

[725] 2013 Wind Technologies Market Report. LBNL. August 2014. Available at *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf*.

Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy. NREL. Cochran et al., April 2015. *http://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20%20Grid%20Integration%20and%20the%20Carrying%20Capacity%20of%20the%20US%20Grid%20to%20Incorporate%20Variable%20Renewable%20Energy_1.pdf*.

The Western Wind and Solar Integration Study Phase 2. NREL. Lew et al., 2013. Available at *http://www.nrel.gov/docs/fy13osti/55588.pdf*. Refer to GHG Mitigation Measures TSD for further analysis.

deployment pattern projected by the model would not incur significant grid integration costs.[726]

In addition to facilitating the EPA's assessment of the feasibility and cost of reaching the aggregate building block 3 generation levels across all three BSER regions, the IPM projections also provide the EPA with a basis for apportioning those generation levels to each interconnection. The EPA considered the projected regional location of the evaluated RE deployment in this analysis, which shows the majority of such deployment occurring in the Eastern Interconnection. The GHG Mitigation Measures TSD describes in greater detail the process by which the EPA calculated the apportionment of building block 3 generation levels to each of the BSER regions, taking these modeling projections into account. Table 10 describes the annual building block 3 generation levels for each interconnection from 2022 through 2030.

[726] Refer to the GHG Mitigation Measures TSD for additional information on constraints related to deployment of non-dispatchable RE.

TABLE 10—BUILDING BLOCK 3 GENERATION LEVELS (MWH).

Year	Eastern interconnection	Western interconnection	Texas interconnection
2022	*166,253,134*	*56,663,541*	*18,963,672*
2023	*181,542,775*	*60,956,363*	*28,177,431*
2024	*218,243,050*	*75,244,721*	*39,382,162*
2025	*254,943,325*	*89,533,078*	*50,586,893*
2026	*291,643,600*	*103,821,436*	*61,791,623*
2027	*328,343,875*	*118,109,793*	*72,996,354*
2028	*365,044,150*	*132,398,151*	*84,201,085*
2029	*401,744,425*	*146,686,508*	*95,405,816*
2030	*438,444,700*	*160,974,866*	*106,610,547*

Through the quantification methodology detailed above, the EPA has identified amounts of incremental RE generation that are reasonable, rather than the maximum amounts that could be achieved while preserving the cost-effectiveness of the building block. For example, assuming gradual improvement in RE technology capacity factors consistent with historical trends, expanding the portfolio of RE technologies that contribute to the building block 3 generation level, and applying the five-year maximum capacity change values to all years of the interim period are adjustments that would produce higher building block 3 generation levels and maintain the primacy of historical data in quantifying RE generation potential. External analysis and studies of RE penetration levels strongly support the technical feasibility and cost-reasonableness of RE deployment well in excess of the levels established by building block 3, as detailed in section V.E.7. By identifying reasonable rather than maximum achievable amounts, we are increasing the assurance that the identified amounts are achievable by the source category and providing greater flexibility to individual affected EGUs to choose among alternative measures for achieving compliance with the standards of performance established for them in their states' section 111(d) plans.

7. Feasibility of RE Deployment

The 2030 level of RE deployment and the rate of progress during the interim period in getting to that level are well supported by comments received, DOE and NREL analysis, and external studies evaluating the costs of and potential for RE penetration. The EPA has assessed the feasibility of RE in terms of deployment potential, system integration, reliability, backup capacity, transmission investments, and RE supply chains.

Historical RE deployment rates are a strong indication of the feasibility of the 2030 level of deployment and interim period pathway. The use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from RE, including conventional hydropower, represented 12 percent of total U.S. electricity, up from 8 percent in 2005. In particular, there has been substantial growth in the wind and solar markets in the past decade. Since 2009, wind energy has tripled and solar has grown tenfold.

The expected future capacity installations in 2022–2030 needed to reach the 2030 level of incremental RE generation are consistent with historical deployment patterns. Forecasts by Cambridge Energy Research Associates (CERA) of 17 gigawatts in 2015 and historical deployment of 16 gigawatts in 2012 are significant. The average deployment of wind over the past five years was 6,200 megawatts per year; 2014 deployment of solar PV, both distributed and utility-scale, was 6,201 megawatts. This contribution from solar PV is consistent with the rapid reduction in costs that is currently being observed and is expected to continue.

Grid operators are reliably integrating large amounts of RE, including variable, non-dispatchable RE today. For example, Iowa and South Dakota produced more than 25 percent of their electricity from wind in 2013, with a total of nine states above 12 percent and 17 states at more than 5 percent. California served nearly 19 percent of total load in 2013 with RE resources, not including behind-the-meter distributed solar resources, and approximately 25 percent of total load with RE in 2014. On an instantaneous basis, California is regularly serving above 25 percent of load with RE resources, recently began seeing over 5,000 megawatt-hours of solar energy, and is on track for 33 percent of load with no serious reliability or grid integration issues. Germany exceeded 28 percent non-hydro RE as a percentage of total energy in first half of 2014. Other recent examples include: ERCOT met 40 percent of demand on March 31, 2014 with wind power; SPP met 33 percent of demand on April 6, 2013 with wind power; and, Xcel Energy Colorado met 60 percent of demand on May 2, 2013 with wind power. Operational and technical upgrades to the power system may be required to accommodate high levels of variable, non-dispatchable RE like wind and solar over longer time periods; however, the penetration levels cited above have been achieved without negative impacts to reliability due in large part to low-cost measures such as expanded operational flexibility and effective coordination with other regional markets.

RE can contribute to reliable system operation. The abundance and diversity of RE resources in the U.S. can support multiple combinations of RE in much higher penetrations. When California, the Midwest, PJM, New York, and New England experienced record winter demand and prices during the polar vortex, wind generation played a key role in maintaining system reliability.

Wind and solar PV are increasingly productive and capable of being accurately forecast, which improves grid reliability. Increasing capacity factors mean less variability and more generation. While the wind industry develops more projects at lower wind speed sites, wind turbine design changes are driving capacity factors higher among projects located in a given wind resource regime.[727] Average capacity factors have risen from the low 30 percent range to high 30 percent range and continue to improve. One key recent advancement is the increasing use of turbines designed for low to medium wind speed sites (with higher hub-heights and larger rotors, relative to nameplate capacity) at higher wind-speed sites with low turbulence.

New variable RE generators can provide more electrical power grid support services beyond just energy. Modern wind turbine power electronics allow turbines to provide voltage and reactive power control at all times. Wind plants meet a higher standard and far exceed the ability of conventional power plants to "ride-through" power system disturbances, which is essential for maintaining reliability when large conventional power plants break down. Xcel Energy sometimes uses its wind plants' exceedingly fast response to meet system need for frequency response and dispatchable resources. Utility-scale PV can incorporate control systems that enable solar PV to contribute to grid reliability and stability, such as voltage regulation, active power controls, ramp-rate controls, fault ride through, and frequency control. Solar generation is capable of providing many ancillary services that the grid needs but, like other

---

[727] LBNL, Wind Technologies Market Report 2013, August 2014, p. 43, Available at: *http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.*

generators, needs the proper market signals to trade energy generation for ancillary service provision.

The transmission network can connect distant high-quality RE to load centers and improve reliability by increasing system flexibility. Investments in transmission and distribution upgrades also enable improvements in system-wide environmental performance at lower cost.

The potential range of new transmission construction is within historical investment magnitudes. Under nearly all scenarios analyzed for the DOE's Quadrennial Energy Review, circuit-miles of transmission added through 2030 are roughly equal to those needed under the base case, and while those base case transmission needs are significant, they do not appear to exceed historical annual build rates. DOE's Wind Vision findings project 11.5 gigawatts of wind per year from 2021–2030. This deployment level would require 890 circuit miles per year of new transmission; 870 miles per year have been added on average between 1991 and 2013. 11.5 gigawatts per year is consistent with building block 3 deployment levels for wind capacity over the compliance period. DOE's SunShot scenario, which increases utility-scale PV to 180 gigawatts by 2030, required spending of $60 billion on transmission through 2050. On an average annual basis, this expenditure is within the historical range of annual transmission investments made by IOUs in recent decades.

Incremental grid infrastructure needs can be minimized by repurposing existing transmission resources. Transmission formerly used to deliver fossil-fired power to distant loads can—and is—being used to deliver RE without new infrastructure. First Solar's Moapa project uses transmission built to deliver coal-fired power from Navajo to Los Angeles. NV Energy's retirement of Reid-Gardner will free up additional transmission capacity. The Milford wind projects in Utah already utilize transmission that was built to deliver coal power to Los Angeles.

Storage can be helpful but is not essential for the feasibility of RE deployment because there are many sources of flexibility on the grid. DOE's Wind Vision and many other studies have found an array of integration options (*e.g.*, large balancing areas, geographically dispersed RE, weather forecasting used in system operations, sub-hourly energy markets, access to neighboring markets) for RE beyond storage. Storage is a system resource, as its value for renewables is a small share of its total value.

Increasing regional coordination between balancing areas will increase operational flexibility. The Energy Imbalance Market (EIM) recently implemented by the California ISO and Pacificorp is a good example of the increased coordination that will be helpful in ensuring that resources across the West are being utilized in an efficient way.

Significant wind and solar supply chains have developed in the past decade to serve the fast-growing US RE market. For wind, domestic production capability would likely have to increase to accommodate projected builds under the CPP in the 2022–2030 time period; however, the global supply chain has expanded significantly to serve multiple markets and can augment production from the domestic supply chain, if necessary. At the start of

2014, the U.S. domestic supply chain could produce 10,000 blades (6.2 gigawatts) and 4300 towers (8 gigawatts) annually. It is not anticipated that expanded domestic manufacturing will be constrained by raw materials availability or manufacturing capability. For solar technologies, the global supply chain has a capacity that has significantly expanded over the past few years from 1.4 gigawatts per year in 2004 to 22.5 gigawatts per year in 2011. Current capacity exceeds these levels and is expected to grow. For PV systems, raw materials like tellurium and indium are at highest risk of supply shortage, but these materials are not used in the PV technologies currently being deployed at large-scale.

8. Cost of CO_2 Emission Reductions from RE Generation

The EPA believes that RE generation at the levels represented in building block 3 can be achieved at reasonable costs. In the EPA's modeling of the building block 3 generation level, the projected cost of achieving CO_2 reductions through this expansion of RE generation is $37 per ton on average from 2022 through 2030.[728] There are a number of reasons why the EPA believes that the cost of CO_2 emission reductions from RE generation will be lower than this analysis suggests. First, modeling constraints that restrict variable, non-dispatchable RE technologies to 30 percent of net energy for load at each of the 64 U.S. IPM regions is a conservative limit intended to eliminate significant grid integration costs at increased levels of RE penetration. In fact, many

---

[728] Refer to the GHG Mitigation Measures TSD for further analysis and IPM run results.

regions have already demonstrated levels of RE penetration that exceed the constraints, and in practice intermittency can be managed across larger regions than the 64. Consequently, the extent to which these regions could, in practice, achieve higher levels of RE deployment without facing substantial grid integration costs would lead to a lower-cost RE outcome than is estimated by this analysis. Second, there are multiple RE technologies not quantified under building block 3 that affected EGUs may use to demonstrate compliance (distributed generation technologies, offshore wind, etc.). Based on preliminary analysis from DOE and NREL, cost-effective opportunities for distributed generation alone could satisfy one-third to over one-half of the stringency associated with building block 3.[729] Third, as discussed in section V and VI of the preamble, the BSER reflects the degree of emission limitation achieved through the application of the building blocks in the least stringent region. By definition, in the other two regions the BSER is less stringent than the simple combination of the three building blocks, rendering a portion of the emission reduction potential quantified by the building blocks unnecessary to achieving the interim and final CO_2 emission performance rates. For example, the EPA has calculated that in excess of 160,000,000 megawatt-hours of building block 3 potential is not required to achieve the final CO_2 emission performance rates in 2030—and would be accessible to affected EGUs for

[729] See Section VIII.K. for a description of qualifying RE technologies for compliance.

compliance.[730] Therefore, it is reasonable to expect that it would cost less to achieve the component of building block 3 potential that is reflected in the calculation of the final CO_2 emission performance rates, as compared to the results of this analysis which assumed achievement of the entire quantified building block 3 potential. The EPA believes that these factors provide significant opportunities for achievement of the building block 3 generation levels at lower costs than estimated in this analysis.

VI. Subcategory-Specific CO_2 Emission Performance Rates

A. Overview

In this section, the EPA sets out subcategory-specific CO_2 emission performance rates to guide states in development of their state plans. The emission performance rates reflect the emission rates for two generating subcategories affected by the rule (fossil steam generation and gas-fired combustion turbines).[731] These final emission performance rates reflect the EPA's quantification of the BSER based on the three building blocks described in section V above.

---

[730] For additional discussion on how this concept impacts building block 3 generation levels, refer to the GHG Mitigation Measures TSD and the CO_2 Emission Performance Rate and Goal Computation TSD for Final CPP.

[731] The only natural gas fired EGUs currently considered affected units under the 111(d) applicability criteria are NGCC units capable of supplying more than 25 MW of electrical output to the grid. The data and rates for these units represent all emissions and MWh output associated with both the combustion turbines as well as all associated heat recovery steam generating units. The remainder of the section will use the term "NGCC" to collectively refer to these natural gas fired EGUs.

This procedure follows a similar logic to BSER quantification at proposal, but it keeps the emission performance rates separate for fossil steam and NGCC subcategories instead of immediately blending them together into a single value for all affected EGUs. Commenters noted that the proposed rule established guidelines that were based on the aggregation of units, and their reduction potential, in a state rather than providing technology-specific guidelines. While many commenters appreciated the flexibility this state-focused structure provided, some noted two concerns with this approach: (1) It would potentially create different incentives for the same generating technology class depending on the state in which that generator was located, and (2) it deviated from the EPA's previous interpretation of the 111(d) regulatory guidelines by not providing technology-specific standards of performance. In response to these comments and our further consideration, the final rule establishes subcategory-specific emission performance rates that are identical across units within a subcategory regardless of where a unit is located within the contiguous U.S. These subcategory-specific emission performance rates are then translated into state-specific goals which, as in the proposal, reflect the particular energy mix present in each state. That translation is presented in section VII.

These performance rates reflect the average emission rate requirement for each subcategory. Similar to the proposal, they are presented as adjusted average emission rates that reflect other generation components of BSER (*e.g.*, renewable) in addition to the fossil component. These performance rates must be achieved by 2030 and sustained thereafter. The interim performance rates apply over a 2022–2029 interim period and would be achieved on average through reasonable implementation of the best system of emission reduction (based on all three building blocks) described above. In other words, the interim performance rates are consistent with a reasonable deployment schedule of BSER technologies as they scale up to their full BSER potential by 2030. The performance rates are meant to reflect emission performance required across all affected EGUs when averaged together and inclusive of lower-emitting BSER components.

The performance rates are expressed in the form of adjusted [732] output-weighted-average CO_2 emission rates for affected EGUs. However, states are authorized to use a converted statewide rate-based or mass-based goal as discussed in the next section. The EPA has determined that the statewide rate-based and mass-based CO_2 goals are expressions of the emission performance rates equivalent to application of the emission performance rates to affected EGUs within a state.

The EPA is finalizing the performance rates in a manner consistent with the proposal, with appropriate adjustments based on comments. Stakeholders had the opportunity to demonstrate during the comment

[732] As described below, the emission performance rates include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO_2 emissions primarily by reducing the amount of electricity produced at a state's affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generation rather than by reducing their CO_2 emission rates per unit of energy output produced).

period that application of one or more of the building blocks would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA. The EPA has considered all of this input in setting final performance rates.

The remainder of this section addresses two sets of topics. First, we discuss several issues related to the form of the performance rates. Second, we describe the performance rates, computation procedure, and adjustments made between proposal and final based on stakeholder feedback in the comment period.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the docket for this rulemaking, including the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and the Greenhouse Gas Mitigation Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Emission Performance Rate Requirements

The EPA has developed a single performance rate requirement for existing fossil steam units in the contiguous U.S., and a single rate for existing gas turbines in the contiguous U.S., reflecting application of the BSER, based on all three building blocks described earlier, to pertinent data. The rates are intended to represent CO_2 emission rates achievable by 2030 after a 2022–2029 interim period on an output-weighted-average basis by all affected EGUs, with certain computation adjustments described below to reflect the potential to achieve mass emission reductions by avoiding fossil fuel-fired generation.

1. Final Emission Performance Rate Requirements

The emission performance rates are set forth in Table 11 below, followed by a description of the computation methodology.

TABLE 11—EMISSION PERFORMANCE RATES
[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

Subcategory	Interim rate	Final rate
Fossil Fuel-Fired Electric Steam Generating Units..........	1,534	1,305
Stationary Combustion Turbines	832	771

The emission performance rates are expressed as adjusted output-weighted-average emission rates for each subcategory. As discussed later in this section, the emission rate computation includes an adjustment designed to reflect mass emission reductions associated with lower-emitting BSER components. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying incremental lower-carbon and zero-carbon generation and substituting those MWhs for the baseline electricity generation and CO_2 emissions from the higher-emitting affected EGUs. Under the final rule approach, regionally identified building block 3 potential generation replaces fossil steam and NGCC generation on a pro-rata basis corresponding to the baseline mix of fossil generation in each region.

2. Interim Emission Performance Rates

Some commenters suggested that the interim period starting in 2020 provided too little time for implementation of measures required to demonstrate compliance during the interim period. As discussed in section V.A.3.g of this preamble, the EPA has determined that an interim period beginning in 2022 provides sufficient time for states to undertake necessary planning exercises and for the implementation of measures towards achieving the performance rates. The EPA determined the interim rates in a manner similar to proposal, with an adaptation to address the revised timing of the interim compliance period (beginning in 2022 rather than in 2020 as proposed). They reflect the averaging of estimated emission performance rates for each year in the interim period (*i.e.*, 2022–2029).

The interim performance rates are less stringent than the final 2030 emission performance rates because the amount of emission reduction potential identified for the BSER increases over time, as explained in section V.

C. Form of the Emission Performance Rates

1. Rate-Based Guidelines

The interim and final emission performance rates for fossil steam and NGCC units are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected fossil fuel-fired units could achieve, through application of the measures comprising the BSER (or alternative control methods). Several aspects of this form of emission rate are worth noting at the outset: The use of emission rates expressed in terms of net rather than gross energy output; the use of output-weighted-average emission rates for all affected EGUs; the use of adjustments to accommodate incremental NGCC generation and RE measures that reduce CO_2 emissions by reducing the quantity of fossil fuel-fired generation and associated emissions; and the adjustability of the goals based on the severability of the underlying building blocks.

a. *Rationale for rate-based guidelines.*

First, the EPA sets an emission rate requirement for each subcategory by identifying the technology-specific reductions available under the building blocks. We then give each state the choice to apply the emission performance rates directly to the affected EGUs within the state or provides the opportunity to use the statewide rate-based goal or the equivalent mass-based form translated from the emission performance rates for state plan purposes. The emission performance rates reflect the BSER, and the statewide rate-based goal and statewide mass-based goal are alternative metrics for realizing the emission performance rates at the aggregate affected fleet level for a state.

Stakeholders have expressed support for having the flexibility to choose from among the multiple options for crafting an implementation plan to realize the BSER. The EPA is providing emission performance rate-based guidelines that apply uniformly to technology subcategories nationwide, and the EPA is providing corresponding state emission rate goals and state mass goals to further enhance compliance flexibility for each state. This approach allows each state to adopt a plan that it considers optimal and is consistent with the state flexibility principle that is central to the EPA's development of this program.

b. *Net vs. gross MWh.*

The second aspect noted above concerns the expression of the goals in terms of net energy output [733]—that is, energy output encompassing net MWh of generation measured at the point of delivery to the transmission grid rather than gross MWh of generation measured at the EGU's generator. The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, goals are expressed in terms of net generation. As noted by commenters, EGUs have familiarity and in some places already have in place equipment necessary to collect and report hourly net generation.[734]

c. *Output-weighted performance rates for all affected EGUs.*

This final rule provides an expression of the BSER as subcategory-specific emission performance rates

---

[733] As discussed below in Section VIII on state plans, we are similarly determining that states choosing a rate-based form of emission performance level for their plans should establish a requirement for affected EGUs to report hourly net energy output.

[734] Specifically, commenters noted that while net generation is not reported to the EPA under 40 CFR part 75, affected EGUs are generally required to report gross and net generation on a monthly basis to EIA through form 923 submittal.

rather than the state goals provided at proposal. Whereas the proposal also estimated the BSER impact on fossil steam and NGCC emissions and generation, it went one step further by averaging these two technology rates into a single rate for each state. Under this final rule, the EPA is identifying the fossil steam rate and the NGCC rate separately instead of only presenting them in a blended fashion at the state level.[735] These two emission performance rates are the expression of the BSER for the final rule for affected EGUs located within the contiguous U.S.

The modification from a blended emission rate in the proposed rule to a subcategory-specific emission performance rate for affected EGU categories in the final rule was made in response to comments that technology subcategory-specific emission rates were more analogous to prior 111(d) efforts and more consistent with the statute. The EPA received significant comments suggesting a technology subcategory-specific rate is consistent with past section 111(d) regulations. However, many commenters also supported the flexibility provided to states through a state goal metric provided at proposal. Therefore, the EPA does provide alternative statewide rate-based and mass-based goals in the next section.

---

[735] However, as discussed in the next section, in order to provide maximum flexibility to states, the EPA averages these two emission rates together for each state using their adjusted 2012 baseline generation share to arrive at a single statewide emission performance goal. The state has the option to comply with this statewide goal through a compliance pathway of its choice. This compliance pathway may or may not involve requiring its affected units to meet the emission performance rates.

The EPA's main consideration has been to ensure that the expression of the BSER reflects opportunities to manage CO_2 emissions by shifting generation among different types of affected EGUs. Both the performance rates in this final rule and the state goals at proposal rely on the adjusted emission rate metric to reflect that potential shifting. Specifically, because CO_2 emission rates differ widely across the fleet of affected EGUs, and because transmission interconnections typically provide system operators with choices as to which EGU should be called upon to produce the next MWh of generation needed to meet demand, opportunities exist to manage utilization of high carbon-intensity EGUs based on the availability of less carbon-intensive generating capacity. For states and generators, this means that CO_2 emission reductions can be achieved by shifting generation from EGUs with higher CO_2 emission rates, such as coal-fired EGUs, to EGUs with lower CO_2 emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs offers opportunities to achieve large amounts of CO_2 emission reductions at reasonable costs. The realization of these opportunities can be reflected in an emission rate established in the form of an output-weighted-average emission rate where the weighting reflects the varying levels of replacement generation technologies.

d. *Severability of building blocks.*

Section V above discusses the severability of the three building blocks upon which the CO_2 emission performance rates are based. Because the building blocks can be implemented independently of one another and the emission performance rates reflect the sum of the emission reductions from all of the building blocks, if any of the building blocks is found to be an invalid basis for the "best system of emission reduction . . . adequately demonstrated," the rates would be adjusted to reflect the emissions reductions from the remaining building blocks. The sole exception, as described above, is the application of building block 1 in isolation, which would not be implemented independently. The performance rates and statewide goals that would result from any combination of the building blocks could be computed using the formulas and data included in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule and its appendices using the methodology described below and elaborated on in that TSD.

D. Emission Performance Rate-Setting Equation and Computation Procedure

The methodology used to compute the performance rates is summarized on a step-by-step basis below in section 3. The methodology is described in more detail in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which includes a numerical example illustrating the full procedure. The quantification of the building blocks used in the computation procedure is discussed in Section V above and in the Greenhouse Gas Mitigation Measures TSD.

1. Inventory of Likely Affected EGUs

In order to calculate the subcategory-specific emission performance rates reflecting the BSER, the EPA first needed to develop a baseline inventory of likely affected EGUs in order to estimate the impact of the BSER. The EPA developed an inventory of likely affected units that were operating in 2012 or that began construction prior to January 8, 2014 and that appeared to meet the final rule's applicability criteria.[736] This inventory does not constitute a final applicability determination, but best reflects the EPA's estimate of units subject to the 111(d) applicability criteria as laid out in Section IV. The EPA identified a list of likely affected units at proposal comprised of approximately 3,000 EGUs. The agency took comment on this list and has made a number of updates to the inventory in response to those comments and in regards to applicability criteria changes resulting from comments. However, the inventory does not reflect a final applicability determination, and where a unit's status was unclear, the EPA generally treated the unit's status in a manner consistent with the proposal and publically available reported data.[737]

Since the final rule's applicability includes under construction units, the EPA also identified units that had not yet commenced operation by the 2012 baseline period, but that commenced construction before

---

[736] The EPA's responsibility is to determine the BSER for all affected EGUs. Some of these under construction units may not enter operation until 2015 or later, but they are likely affected units and therefore appropriate to reflect in the baseline and corresponding subcategory-specific emission performance rates and state goals.

[737] The EPA notes that in some cases, it may not yet be possible to determine the status of an EGU as affected or unaffected without additional data. There are potentially some units excluded or included in the baseline that will ultimately have a different status following an applicability determination. However, these cases are limited, and the effect of any collective changes to the affected fleet inventory will not yield a bias in the BSER computation at the regional level.

January 8, 2014. The EPA received significant comment on the proposal's sole use of the National Electric Energy Data System (NEEDS) to identify these under construction units. Commenters suggested that the EPA also utilize EIA and 2012 proposed unit-level files to help better identify under construction units. In some cases, NEEDS did not reflect units that had commenced construction. Therefore, the EPA updated its approach to identifying units that had commenced construction prior to January 8, 2014, but that had not commenced operation in 2012. In the final rule, the EPA uses EIA data, comments, as well as NEEDS data to identify these under construction units.[738] [739] [740]

These units that were operating by 2012 along with those that had not commenced operation by 2012 but had commenced construction by January 8, 2014, reflect the EPA baseline inventory of likely affected EGUs. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule explains the prime mover, capacity, and fuel criteria used to identify the likely affected EGUs.[741]

---

[738] The NEEDS database was also updated to reflect the latest data and commenter input on under construction units.

[739] For purposes of determining emission performance rates, the EPA classifies any unit that had begun construction prior to Jan. 8, 2014, but had not commenced operation by Dec. 31, 2011 as "under construction". Many of these "under construction" units have commenced operation at some point during 2012 or prior to signature of this final rule.

[740] "Commence" and "construction" are defined in 40 CFR 60.2.

[741] The baseline inventory relies on historical data and does not incorporate anticipated future retirements. Most commenters supported this treatment as they viewed those scheduled

The EPA received significant comment that units that came online during the baseline year (*e.g.*, 2012) should be treated as under construction rather than operating units in 2012 for purposes of estimating baseline values, because their 2012 operation may be misrepresentative of anticipated future-year operation due to partial year operation in 2012. The EPA has made an adjustment to flag these units as having commenced operation during 2012 and treat them as under construction units, consistent with commenters' suggestion; for BSER computational purposes, generation and emissions for these units are estimated based on a representative first full year of operation for that technology class.

2. Data Year

In the proposed rule, the EPA considered using a historical-year data set or a projected-year data set as a starting point for applying the technology assumptions identified under BSER. The EPA proposed using 2012 data as it was the most recent data year for which complete data were available when the EPA undertook analysis for the proposed rule and it reflected actual performance at the state level. The EPA took comment on alternative data sets. In particular, the EPA issued a NODA on October 30, 2014 (79 FR 64543) in which we provided 2010 and 2011 historic data for consideration.

The EPA received a significant number of comments supporting the use of historical data as the basis from which to quantify performance rates reflecting BSER.

---

retirements (and corresponding emission reductions) as an alternative compliance flexibility.

Some commenters supported the 2012 data year as the best reflection of the power fleet, and some suggested that the EPA use a different year or a historical average to control for data anomalies in 2012. Moreover, some commenters pointed out that using 2010, 2011, 2012 data, or an average of the three would not address their concerns about recent year anomalies in hydro generation due to high snow pack. Some commenters also suggested the EPA use a baseline including years prior to 2012, not to increase representativeness of the power sector, but as a means of recognizing early action.

In this final rule, the EPA is taking an approach to the baseline year where we still largely rely on reported 2012 data as the best and most recent available data representing the power sector from which to apply the BSER, but also including targeted baseline adjustments to address commenter concerns with 2012 data.[742] Below, we explain why—at the nationwide level—2012 data are preferable, more objective, and more accurate than a prior year, or an average of years, for informing the baseline. Then, we explain the adjustments that we are making to the 2012 data along with our rationale for such adjustments, in response to comments we received.

Some commenters supported the EPA's use of 2012 data to inform performance rates, and the EPA agrees that 2012 data with targeted adjustments, relative to other historical years, best reflects the power sector

[742] The EPA recognizes that more recent emissions and generation data have become available since 2012, but 2012 data constituted the most recent year for which full data was available at the time the EPA began its analysis for proposal.

and best informs the performance rates that pertain to the BSER. The EPA believes that starting with 2012 data is more accurate and better informs the BSER than an earlier historical year or historical multi-year average for the following reasons:

(1) Of the historical data fully available at the time the proposal analysis began, 2012 was the most recent and best reflects the power fleet. Approximately 43 GW of new capacity came online in 2010 and 2011. In other words, there was 43 GW of capacity online as of 2012 that had not been in service at some point during the 2010–2011 period. Likewise, approximately 17 GW of capacity that were operable in 2010 and/or 2011 were retired prior to 2012.[743] Using state-level, prior year data, either on its own, or as part of a multi-year baseline, is not as representative of the current power fleet as the 2012 data, which better reflects significant changes in power sector infrastructure.

(2) A three-year baseline would not address some of the substantive concerns raised by commenters. Many commenters pointed out that using a three-year baseline would not address their critical concern about variation in the hydrological cycle due to snow pack (particularly in the Northwest), because the snow pack was significantly above average in both 2011 and 2012. The EPA agrees with commenters that we can better address their baseline data concerns regarding an average hydro year by identifying those states with a significant share of hydro generation and variation in that hydro generation, and making targeted adjustments to those states' affected fossil generation levels in order to reflect a more typical snow-pack year.

[743] EIA Form 860, 2012.

This procedure is described in more detail below and in the TSDs.

(3) In addition to being, in the EPA's view, a less representative baseline of the existing power fleet, a multi-year baseline would also likely entail complexity when determining how to average together yearly fleet data while appropriately accounting for fleet changes occurring during those years. The 2012 baseline starting point maximizes the EPA's reliance on latest reported operating data and minimizes the need for fleet capacity adjustments. For instance, because of year-to-year fleet turnover, the averaging of multiple baseline years would require additional assumptions in regards to which generation to consider from a fleet that is changing in a given state or region (or even where units are switching fuel sources such as a coal-to-gas conversion).

(4) Due to the region-based approach to quantify building blocks and the BSER as subcategory-specific emission performance rates, variations in unit-level data do not significantly impact the calculation of emission performance rates. For instance, if one fossil unit is operating less in a given year due to an outage, another fossil unit in the same region is generally operating more. Therefore, at the regional level, fossil generation and emissions do not vary to the same degree that unit-level data varies. Moreover, the variation at the regional level that does exist in 2012 relative to previous years is not necessarily unrepresentative variation, but illustrates trends in the power sector infrastructure that are desirable to capture for purposes of determining a representative year from which further improvements in CO_2 emissions performance can be made. Because the EPA

is moving from a state approach at proposal to a regional approach for calculating the expression of the BSER in this final rule, unit-level operational variation from year to year becomes even less relevant to the calculation of regional emission performance rates.

(5) Some commenters suggested the EPA use an earlier baseline year as a means of recognizing early action. They noted that an earlier baseline would reflect a higher-emitting fleet and therefore when the same level of building block MWhs are applied, they would result in a higher (*i.e.*, less stringent) state goal. The EPA disagrees with this view for several reasons. First, the objective of selecting a baseline to inform BSER is to have one that best reflects the power sector and consequently the best system of emission reductions of which the power fleet is capable. Using an earlier baseline that "inflates" the starting point would undermine this objective, not serve it. Second, the EPA disagrees with the premise of this comment—that the baseline would change and building block potentials would stay the same. For instance, building block 2 functions based on incremental generation potential (incremental generation = potential generation–baseline generation). This incremental value would increase if an earlier baseline period was used that had less existing NGCC generation.

(6) Some commenters pointed out that the EPA relied on multi-year historical data in allowance allocation in previous rulemakings (*e.g.*, CAIR and/or CSAPR allocations). However, that comparison is not relevant to the quantification of emission reduction potential under 111(d). In those previous instances, the EPA was considering typical unit-level behavior

for allowance allocation purposes—not for determining the emission reduction requirements of the program. Those allowance allocation determinations were independent of and subsequent to the determination of emission reduction requirements in those rulemakings.

(7) The EPA received significant comment that 2012 was not a representative year for natural gas prices, and thus the EPA should use another year. The EPA disagrees with this comment, and does not view it as grounds for a change to the baseline period. While the EPA does recognize that Henry Hub natural gas prices were lower in 2012 relative to previous years, this does not invalidate the suitability of the data year selection. The EPA's objective in selecting a baseline is to identify potential reductions when BSER technologies are applied; year-to-year variation in market prices for natural gas does not frustrate this effort. For instance, a region may have generated only 5 MWh of NGCC generation in 2011 when gas prices were higher, and 10 MWh of NGCC generation in 2012 when gas prices dropped. However, this does not change the outcome of the quantification of the BSER, because the building block is based on the emission reduction *potential* of the fleet. That potential (*e.g.*, a fuller realization of the existing NGCC generation potential equivalent to 15 MWh) does not change regardless of the year used for baseline NGCC generation. Therefore, a different data year may change a baseline data point, but it would not change the total potential NGCC generation for quantifying the emission performance rates in these circumstances.

In summary, the EPA believes that continuing to rely on 2012 data while incorporating select data adjustments as detailed below is not only a reasonable choice and adequately supported, but a more reliable and preferable starting point for determining the BSER requirements.

3. Adjustments That the EPA Made to the 2012 Data

The EPA made corrections to unit-level 2012 data based on commenter feedback. In addition, we also made some adjustments to 2012 data, not to address a correction, but to address a concern about the representativeness of the data. Although the EPA determined that the 2012 data year better informed its BSER determination than a preceding year or a multi-year average, commenters did identify some limitations that we are addressing through targeted adjustments. These are discussed below:

(1) Adjustments to state-level data to account for annual variation in the hydrologic cycle as it relates to fossil generation.

Hydropower plays a unique role in a handful of states in that (1) it is a significant portion of their generation portfolio, (2) it varies on an annual basis, and (3) 2012 was an outlier year for snow-pack (meaning hydropower was above and fossil generation was below its historical average). The EPA notes that these three conditions are not present in other weather-based RE technologies like solar or wind.[744]

[744] While solar and wind generation may vary on an hourly or daily basis, their annual generation profiles are subject to notably less variation compared to hydropower. The EPA's calculation of the BSER relies on annual generation data, not on hourly or daily generation data.

Therefore, no similar adjustment was needed to account for weather patterns with these technologies.

Unlike market conditions (*e.g.*, changes in natural gas prices) that may produce different generation profiles year-to-year but that do not change the overall generating potential of the state's power fleet, variation in the hydrologic cycle does fundamentally change the generating potential of the state's power fleet in hydro-intensive states as they no longer have the same generating potential in an average year as they had in a "high hydro" year. The CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule provides analysis and explains the adjustment that the EPA made to the state-level 2012 data for Idaho, Maine, Montana, Oregon, South Dakota, and Washington to better reflect fossil generation levels when hydro generation performed at its average level as observed over a 1990–2012 timeframe. The EPA agrees with commenters that using a 2010–2012 baseline would not address the concern as 2011 was also an outlier year relative to historical snow-pack and hydro generation.

(2) Extended unit outages due to maintenance.

Generally, because of the regional-level approach to calculate performance rates, the EPA does not believe that unit-level variations in operation influence the subcategory-specific performance rates reflecting BSER. For instance, as some units ramp down, and others ramp up to replace their load at the regional level, total fossil generation changes little due to these fossil-for-fossil substitutions. Unit-level variation does not inherently entail region-wide variation.

However, the EPA did receive comment that in limited cases, this could have a substantial impact on an individual state if it chooses to use a rate-based or mass-based statewide goal. Even though the EPA is calculating subcategory-specific performance rates that it believes are not affected by this type of unit-level variation, it still evaluated the possible impacts it may have when converting to state goals in the next section. The EPA examined units nationwide with 2012 outages to determine where an individual unit-level outage might yield a significant difference in state goal computation. When applying this test to all of the units informing the computation of the BSER, emission performance rates, and statewide goals, the EPA determined that the only unit with a 2012 outage that (1) decreased its output relative to preceding and subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's goal as it constituted more than 10 percent of the state's generation was the Sherburne County Unit 3 in Minnesota. The EPA therefore adjusted this state's baseline coal steam generation upwards to reflect a more representative year for the state in which this 900 MW unit operates.

(3) Many commenters also noted that because the EPA uses annual data, 2012 was not representative for units coming online part way through the year. The EPA relies on annual data, so if a unit is underrepresented in a certain part of the year because it is not yet online, then another unit is likely over-represented as it is operating more than it otherwise would when the second unit commences operation. Therefore, the resulting state-level and regional-level aggregate annual generation level used in

determining the BSER may be considered to be representative and there is not necessarily a need for any adjustment.

However, the EPA recognizes that the over-represented and under-represented units do not necessarily fall within the same state, and therefore this potential difference in the state location of the affected units could have an impact when estimating appropriate statewide goals. To address this comment, the EPA adjusted the 2012 generation data for fossil units coming online during 2012 to a more representative annual operating level for that type of unit reflecting its incremental impact on generation and emissions. This effectively resulted in increased baseline emissions and generation assumed for those units beyond their reported partial-year operations in 2012. Conceptually, the assumption of full-year operation at units that came online partway through 2012 could pair with an assumed reduction in the operation of other units somewhere in the same region. However, the EPA made no corresponding deduction to represent this likely decreased utilization at other affected units because it was impossible to project the state location of such units with certainty and the assumed utilization level was meant to reflect the incremental impact on the baseline. As a result, this data adjustment increases the total generation and emissions for units reporting in the 2012 baseline beyond the 2012 reported levels.

Additionally, as done in proposal, the EPA continued to identify under construction units that did not begin operation in 2012, but had commenced construction prior to January 8, 2014 and would commence operation sometime after 2012. As described in the next section, the EPA estimated baseline generation and emissions for these units as they had no 2012 reported data.

In summary, this final rule continues to rely on the latest reported 2012 data as the foundation for quantifying the BSER. However, the EPA has made limited adjustments, in addition to corrections identified by commenters, to the 2012 data to address some of the relevant concerns raised by commenters. Therefore, the baseline is informed by 2012 data, but not limited to 2012 data.[745]

4. Equations

In this section we describe how we develop the equations used to determine the emission performance rates for fossil steam and NGCC units that express and implement BSER. More detailed information regarding rate computation, including example calculations, can be found in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket for this action. Here we first present the general principles we follow when developing equations to express the BSER; then, we summarize the steps taken to assemble baseline data to reflect 2012 baseline emissions and generation, and apply the building blocks that constitute the BSER to derive performance rates that will be used by states to implement BSER. Section VII

[745] Updated unit-level data reflecting corrections identified by commenters to the underlying 2012 file are provided in Appendix 1 of the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule. The adjustments made to the aggregate data to address representativeness concerns are provided in Appendix 3.

then explains how these nationwide performance rates are reconstituted into a statewide goal metric similar to the proposal in order to allow a state (at its discretion) to use a statewide goal as a mechanism for demonstrating compliance at the aggregate state level in a state plan, as an alternative to applying the emission performance rates to its affected EGUs directly.

When developing equations to implement BSER, we adhere to a number of basic principles. First, we ensure that the equations are consistent with the BSER itself, and in particular, reflect the redistribution of generation among fossil steam, NGCC and renewables embodied in building blocks 2 and 3. In doing this, we account for the interactions between building blocks in a way that is consistent with the assessment of incremental building block generation potential and the compliance framework for Emission Reduction Credits (ERCs). In particular, we must ensure that each increment of building block 3 emission reduction potential is applied to either fossil steam or NGCC units but not both. The equations we develop must also take account of the dual status of existing NGCC units, which are simultaneously affected units and provide generation that is an element of the BSER itself.

In addition, we are applying the BSER, as we have done in calculating other section 111(d) standards, to a defined population of existing affected sources, represented in this case by the generation of the source category in the 2012 adjusted baseline. This provides an empirical historical baseline against which we define the performance rates and their state goal equivalents. In doing so, we must account for any offsetting increases in emissions that result from applying the BSER control measures, as we have done in setting other standards. For example, when determining BSER for particulate matter control, a number of pollution control devices (such as sorbent injection technologies) themselves create particulate matter. If the particulate matter created by these control devices were not appropriately accounted for when developing the standard intended to address the primary emissions of particulate, this could create an unreasonably stringent PM standard. In the current context, this means recognizing that increasing NGCC capacity utilization in accordance with building block 2 both offsets higher emitting steam generation and increases emissions at the NGCC units themselves, which are also affected entities that must demonstrate compliance with the BSER. Thus, it is essential that we apply the building blocks in a way that avoids creating a level of stringency in the performance standards for affected EGUs that goes beyond what we have determined to be the BSER—while at the same time ensuring that equations apply the building blocks to generate performance standards that represent the full application of the BSER to the affected EGUs.

Under section 111, the EPA adopts emission performance standards that are based on the BSER. The emission performance rates reflect our recognition of the value of giving sources the flexibility to adopt equivalent emissions reduction strategies and measures that for them may be preferable (in a specific circumstance) to the technologies and measures that we define as the BSER. An important function of the emission performance rates representing the BSER is to provide the flexibility needed to allow alternative compliance options, including the development of new technologies or the deployment of effective technologies outside of the BSER technologies. In the guidelines we issued under section 111(d) for landfill gas, for example, we adopted the primary standard based on flaring of any captured landfill gas, but we also developed equations that led to an expression of the BSER that allowed for the alternative of capturing the gas and combusting it in an electrical generating unit.

Finally, in deriving the emission performance rates, there are a number of considerations we took into account. First, it is important that the baseline from which the rates are derived be transparent and based on observable, historical data. Second, the emission performance rates must reflect the emission reductions achievable through the best system of emission reduction. Because the BSER includes shifting of emissions from higher-emitting to lower-emitting sources, state compliance frameworks will likely involve a combination of physical measures at the plant (where either rate or generation may be reduced) and some form of credit for lower-emitting generation (or demand side measures) outside of the plant. In this context, the emission performance rates must provide appropriate incentives for affected entities to achieve the emission reductions encompassed in the BSER, including through state plans that provide crediting for lower-emitting generation. Third, and as set forth below, we must account for the EPA's determination that pro rata implementation of building block 3 is the best reflection of the potential for RE to displace both fossil steam and NGCC, and the dual role of NGCC units as both affected sources and a BSER compliance technology.

This set of considerations was central to the development of the BSER equations that the EPA describes next. They were particularly important for steps five through seven below which address building blocks 2 and 3, building blocks that have both significant overlap with each other and which impact steam and NGCC units in an integrated way.

Step-by-Step Discussion of Equations

Step one (compilation of baseline data). On a unit-level basis, the EPA obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for likely affected EGUs that had commenced operation prior to 2012.[746] The EPA made changes to the historical unit-level

[746] EGUs whose capacity or fossil fuel combustion were insufficient to qualify them as likely affected EGUs were not included in the subcategory-specific rate and goal computations. Most simple cycle combustion turbines (CTs) were excluded on this basis at proposal, and all simple cycle CTs were excluded at final reflecting changes to the applicability language. IGCC's were designated as "other" generation at proposal, but they are grouped with coal units for purposes the final rule category-specific rates. Useful thermal output (UTO) was also translated to a MWh equivalent and included in state goals at proposal, resulting in more stringent rates for states with more cogeneration sources, but UTO is not included in this final rule emission performance rate or state goal calculations as a result of comments regarding potentially adverse impacts on cogeneration units and uncertainty of thermal load outputs. As described in the state plan section of the preamble, units may still quantify and convert UTO (*i.e.*, taking credit for waste heat capture) when demonstrating compliance. See the applicability criteria described in Section IV.D above.

data based on comments received at proposal. For each state and region, the agency aggregated the 2012 operating data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. The EPA adjusted these state values upwards in a limited number of instances to reflect the hydropower and unit outage concerns raised in comments and described above. As discussed above, the EPA first only aggregated the reported data for units that commenced operation prior to 2012. For those likely affected units that commenced operation during 2012, the EPA treated that capacity consistent with its framework for under construction affected units, which were added next. This was done in response to comments recognizing the fact that the year during which a unit commences operation may not have been representative of its potential generation and emissions.

For the under construction units (*i.e.*, those under construction prior to January 8, 2014 but which had not commenced operation by December 31, 2011), the EPA estimated their incremental impact on the baseline generation and emissions using their capacity. The EPA assumed a 55 percent capacity factor for under construction NGCC units and a 60 percent capacity factor for under construction fossil steam units, which are consistent with the values and methodology the EPA proposed for under construction units.[747] These values are informed by the 2012

[747] The EPA notes that we did not identify any under construction coal units at proposal, but we are using a methodology in this final rule for newly categorized under

capacity factors for other units in these technology classes that recently commenced operation.[748] Using these capacity factors along with the capacity for the units, the EPA estimated an annual baseline generation value for these units. The agency then estimated annual baseline CO_2 emissions for these under construction units using the average emission rate of generating units of the same technology in the state where the under construction unit is located. Where no generators of the same technology existed in a given state, the EPA used the national baseline average for that technology. This is similar to the adjustment made at proposal for under construction units, with the main difference being units that commenced operation in 2012 are now also treated as under construction for baseline data purposes in the final rule.

---

construction coal units similar to our under construction assessment of NGCC at proposal.

[748] The EPA received comment on the assumed 55 percent capacity factor for under construction NGCC EGUs. Some comments suggested the value was too large of an estimation for incremental generation as some of that 55 percent utilization would have a replacement impact on 2012 operating generation. Others suggested it should be larger as a particular planned under construction unit was anticipated to have a higher utilization rate. The EPA reviewed operating patterns of EGUs that came online, and determined a 55 percent and 60 percent capacity factor assumption for under construction NGCC and coal EGUs respectively are a reasonable estimate for informing the incremental emissions and generation from under construction units. It recognizes that some of these units may indeed operate at a higher utilization level, but also recognizes that some of the generation may have a replacement effect instead of an incremental one.

The estimated emissions and generation for under construction units were added to the 2012 reported emissions and generation data for the affected units that had already commenced operation prior to 2012 to derive an adjusted historical baseline total for each state that was reflective of all likely affected 111(d) sources.[749]

Step two (aggregation to the regional level). The EPA took comment on applying building blocks at the regional level, and received significant comment supporting such an approach. Therefore, whereas the proposal aggregated the baseline data to the state level, the final rule further aggregated it to the regional level prior to building block application. The regions reflect the Eastern, Western, and Texas Interconnections. The shift to a regional framework was based on comments suggesting that the EPA would better capture the interstate impacts of the building blocks and reflect the interconnected nature of the electric grid under a regional structure. The basis for the regions is defined and discussed in Section V.A.3.

Step three (identification of source category baseline emission rates). As discussed in the beginning of this section, the EPA took a technology-specific approach to quantifying guidelines. Therefore, whereas the proposal first averaged the fossil steam rate and

---

[749] The EPA received some comments suggesting that under construction units should not be included in the quantification of BSER and/or rate calculations, and other comments supporting their inclusion. The EPA determined that including it was consistent with our responsibility under the 111(d) statute to define a Best System of Emission Reduction for existing units.

NGCC rate together before applying the building blocks and defining state goals, the final rule applied the building blocks at the regional level to give a separate fossil steam rate and NGCC rate for each region. The starting point for calculating the subcategory-specific emission performance rates was the baseline regional emission rates for both fossil steam and NGCC in the year 2012 with the modifications discussed above.

Step four (application of building block 1). The baseline CO_2 emissions amount for the coal-fired steam EGU fleet in each region was reduced by 2.1, 2.3, and 4.3 percent in the Western, Texas, and Eastern Interconnections respectively, while the coal generation level was held constant, reflecting the EPA's assessment of the average opportunities in each region to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that are technically achievable at a reasonable cost. The EPA then averaged together the region's baseline oil- and natural gas-fired steam rate with its building block 1 adjusted coal steam rate to get a fossil steam rate post-building block 1.[750] [751]

Step five (application of building block 3). At proposal, the EPA incorporated incremental RE

---

[750] Building block 1 analysis acknowledges some variation in heat rate improvement potential at different units. The implementation of this building block reflects a heat rate improvement on average across a region's coal fleet, not necessarily a heat rate improvement at every unit.

[751] Baseline OG steam emissions are added to adjusted coal emissions and divided by baseline OG steam generation and baseline coal generation.

MWhs (where incremental means the amount above the adjusted 2012 baseline) by adding them to the denominator of the emission rate goal. In response to comments on this approach, the EPA issued a NODA discussing an alternative methodology of incorporating building block 3 in a manner more analogous to building block 2 treatment, where the incremental MWhs identified for the building block replace baseline fossil MWhs on a one-to-one basis. The EPA is adopting this replacement methodology for building block 3 in the final rule consistent with comments noting that such a computational procedure better reflects the reduction potential of that building block.

Under this methodology, all of building block 2 incremental NGCC potential and part of building block 3 incremental RE potential were ultimately applied to replace higher-emitting fossil steam generation and emissions, while the remaining building block 3 potential was applied to replace NGCC generation and emissions. Commenters noted that under this approach building block 3 should be applied first, or the EPA would understate the potential of building block 2 by subtracting out some NGCC generation after the 75 percent utilization level of NGCC had been applied to replace fossil steam. The EPA agrees and calculated the building block 3 impacts first in developing the emission performance rates.

To implement this, first, building block 3 replacement potential was identified for each region to arrive at a total amount of incremental zero-emitting generation hours available to replace fossil generation in the region. Because renewable generation can replace both fossil steam and NGCC on the grid, the EPA determined that it was appropriate to apply these incremental zero-emitting generation hours to replace generation and associated emissions from each of the fossil steam and NGCC fleets in the region on a pro-rata basis in the following manner.[752] The EPA determined the percent of fossil steam generation and the percent of NGCC generation of total affected fossil generation in each region's baseline. We then assigned those percentages of the incremental zero-emitting MWhs to each of those technology source categories.[753] The incremental zero-emitting generation assigned to each technology replaced the same amount of fossil generation from that technology's baseline value.

Step six (application of building block 2). If the remaining generation level for the NGCC fleet in a region, taking into account the previous step's replacement of NGCC generation, was less than 75 percent of the fleet's potential summertime generating capacity (the potential capacity factor the EPA

[752] The EPA took comment on a pro-rata or an intensity-based replacement approach. In this final rule, the EPA agrees with commenters that a pro-rata approach is a better reflection of the BSER. Incremental RE generation has, and is likely to continue, to replace both steam and gas turbine generation and the BSER captures this through a pro-rata distribution of identified building block 3 potential.

[753] For example, if 100 MWh of incremental zero emitting generation is available in a given region and that region had 70 percent of its affected fossil generation coming from fossil steam units in the baseline and 30 percent from NGCC units—then 70 MWhs of the incremental zero-emitting generation are applied to baseline fossil steam generation and 30 MWhs are applied to baseline NGCC generation.

determined to represent the BSER), then the NGCC generation in the region was assumed to increase to levels equal to the lesser of (1) its potential at a 75 percent capacity factor [754] or (2) a generation level above which there is no longer fossil steam generation remaining within the same region to replace. In other words, the regional NGCC capacity factor was only assumed to reach 75 percent if there was sufficient higher-emitting fossil steam generation that it could replace after step five. The increase in NGCC generation at this step compared to the post-building block 3 level was matched by an equal decrease in fossil steam generation reflecting the 1 for 1 MWh hour replacement. At this point, the generation for both steam and NGCC reflect the final distribution of generation between the subcategories after application of the building blocks. But the emission performance rates must account for CO_2 emissions and generation from incremental gas and renewable generation that comprise building blocks 2 and 3, to reflect and enable the emission reductions achievable under the best system of emission reduction, and ensure that the shared implementation of the BSER by steam and NGCC generation is reflected in the rates.

Step seven (accounting for and facilitating the emission reductions achievable through the implementation of the best system of emission reduction).

This step quantifies the aggregate emission changes associated with the emission rate improvement and

[754] In early years, will be less than 75 percent due to building block 2 gradual deployment.

generation replacement patterns described in steps four, five, and six to arrive at an adjusted fossil steam emission rate and an adjusted NGCC emission rate for each region that will, as discussed above, (1) enable the implementation of all three building blocks, (2) be based on observable, concrete baselines, and (3) reflect the BSER.

First, in developing the emission performance rates, the EPA had to answer the question of how to reflect the building blocks in the equations defining the rates in a manner that would enable the generation shifts that are essential components of the BSER. In the case of building block 3, the EPA accomplished this by incorporating the pro rata share of incremental (above baseline) zero emitting generation into the emission rates for each group of affected EGUs, thus ensuring that these EGUs would have to include a corresponding amount of zero-emitting generation in their compliance calculations, either through the acquisition of credits or through some other mechanism as determined by their state in its implementation plan.

For building block 2, a similar mechanism is needed. Accordingly, a portion of the NGCC generation and emissions used to replace fossil steam must be averaged into the steam rate, analogous to what was done with building block 3. The EPA considered two approaches to define the quantity of NGCC generation and emissions to be averaged into the steam rate: (1) Incremental NGCC generation after the implementation of building block 3 and (2) incremental NGCC generation from baseline levels. For the reasons below, the EPA has determined that the second approach better reflects the considerations discussed above.

As discussed above, it is beneficial that the baseline from which emission performance rates are derived be transparent and based on observable historical data. The first approach, however, depends on the level of incremental NGCC generation relative to what is available after the implementation of building block 3. This level of NGCC generation (obtained after replacing baseline levels of generation with NGCC's pro rata share of incremental RE generation) only exists as an intermediate step in the BSER calculation. It is not based on an observable or concrete level of generation.

In Section VIII we discuss methods for creating ERCs for implementing shifting of generation from steam to NGCC, and this discussion illustrates the value of relying on an observable and concrete baseline. In that section we suggest that incentivizing and facilitating the purchase of ERCs as a compliance option for steam units could be implemented through the use of a factor that creates a fraction of an allowable credit for each hour that an NGCC operates. This factor is derived from the incremental generation of NGCC post-building block 2, relative to the baseline. While a different factor could be derived from the hypothetical intermediate level resulting from the pro rata application of zero emitting generation to NGCC in building block 3 (by transferring the full amount of NGCC emissions and generation replacing steam generation in building block 2), the EPA believes that grounding baselines in historical data (such as those used to derive the 2012 baseline) is both more transparent and easier to understand in a way that is more useful to states and utilities, in contrast to the practical challenges of relying on a calculated level that corresponds to an interim step within the emission performance rate calculation. As long as the crediting framework for creating ERCs is consistent with the amount of gas emissions and generation that is transferred to the coal rate, either the chosen option or the option of transferring the entire quantity of gas emissions and generation that occurred in step six to the coal rate would provide an incentive for the power market to implement the shift in generation from coal to gas.[755]

Also as discussed above, it is important that the compliance equations reflect the BSER pro rata allocation of RE to fossil steam and NGCC generation. The first approach to define the quantity of NGCC generation and emission to be averaged into the steam rate would require the steam rate to take into account the total additional NGCC generation that results from the application of building block 3 before building block 2 has been applied. This approach would reflect in the compliance rate for steam units a greater share of the implementation of building block 3. Ensuring that emission performance rates for both steam and gas units reflect the emission reduction potential of

---

[755] The EPA recognizes that real world market dynamics will necessarily differ from the BSER assumptions, and has designed the emission guidelines to provide flexibility beyond the emission reduction opportunities identified in the BSER. The essential criteria, however, are that the emission rates and crediting framework are consistent with the BSER and provide the incentives needed to facilitate the emission reduction measures reflected in the BSER and together produce an achievable compliance framework for sources.

building block 3 is integral to the building block 3 methodology and also recognizes that application of building block 3 on a pro-rata basis was intended to achieve emission reductions from both NGCC and fossil steam commensurate with their emissions reduction opportunities.

If the EPA were to use the increment of NGCC emissions and generation derived at the intermediary step after the application of building block 3, rather than the increment relative to the 2012 baseline, the effect would be to largely assign to fossil steam the building block 3 generation shift apportioned to NGCC. That, in turn, would have undermined the fact that building block 3 was determined to be a BSER measure applicable to the entire source category, comprising NGCC as well as fossil steam, and would have conflicted with the preceding steps we are taking to develop the equations. Instead, by using only the incremental NGCC generation relative to the baseline, the EPA has ensured that the logic behind the pro rata displacement of fossil generation by RE generation is reflected in the emission rates. Having established the appropriate way to measure the amount of incremental gas generation placed in the fossil steam rate, the EPA is able to calculate the subcategory-specific emission performance rates. For the numerator of the fossil steam rate, the EPA multiplied the remaining fossil steam generation (post-step six) by the fossil steam rate reflecting the heat rate improvement from building block 1 (step four). We then added in the emissions associated with the incremental NGCC generation from step six by multiplying the incremental NGCC generation as discussed above (difference between the baseline

NGCC generation level and post-step six NGCC generation) by the baseline NGCC rate for that region.[756] This constitutes the numerator of the fossil steam emission rate.

For the fossil steam denominator, the EPA added the remaining fossil steam generation (post-step six), the incremental NGCC generation defined above, and the amount of zero emitting building block 3 MWhs apportioned to fossil steam generation in the region (step five). Dividing the fossil steam numerator described above by this fossil steam denominator resulted in a regional adjusted fossil steam rate reflecting the three building blocks.

For the NGCC performance rate, the EPA calculated a numerator in a similar manner. First, we took the remaining NGCC generation (post step six) and multiplied it by the regional baseline NGCC rate to calculate the total emissions in the numerator. For the denominator, the EPA added the remaining NGCC generation (post step six) to the amount of zero-emitting building block 3 generation assigned to that technology in step five. Dividing the emissions by this total generation value (inclusive of the RE generation apportioned to NGCC) provided a regional adjusted NGCC rate.[757]

---

[756] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. The EPA defined the "incremental NGCC generation" in this step in a manner consistent with its measurement and use described in section VIII of this preamble.

[757] See CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule for an illustration of this step. We note that the entire NGCC generation level (inclusive of the amount assigned to the fossil steam rate) expected post

Step eight (determining the nationwide subcategory-specific emission performance rate).

Following step seven, we evaluated the resulting adjusted fossil steam rates and NGCC rates for each region and identified the highest (least stringent) emission rate among the three regions for each technology category. This becomes the nationwide emission performance rate for that technology class. This ensures that the same rates are applied to facilities in each region and that these rates are achievable by facilities in all three regions.

Finally, the EPA repeated steps four through eight for each year 2022–2030.[758] The resulting annual rates vary because the amount of building block 2 and 3 potential in each year varies. The rates for years 2022–2029 were averaged together to calculate an interim rate, and the 2030 value becomes the final emission performance rate for that year forward. As

building block application is included in the NGCC rate calculation. Including the entire NGCC generation in the NGCC rate recognizes the simultaneous compliance responsibility of affected NGCC units while the fossil steam rate recognizes its mitigation potential through incorporation of the incremental NGCC generation component. Failing to do so would result in a NGCC rate lower than that expected after full implementation of the building blocks and create a compliance inconsistency when reporting all generation.

[758] At proposal, the EPA repeated this step over a 10 year period. The building blocks and corresponding BSER emission rates increased for ten consecutive years (2020–2029) in the EPA's rate calculation. In this final rule, the EPA has maintained the same 2030 compliance period for final rates but adjusted the start date to 2022 based on comments. Therefore, the deployment of building blocks is spread over a nine year period (2022–2030) instead of the proposed 10 year period.

described in the corresponding TSD, the EPA rounded the interim and final subcategory-specific emission performance rates up to the nearest integer to ensure that they did not slightly overstate BSER potential through use of conventional rounding. Unless otherwise stated, conventional rounding is used elsewhere during the calculation process.

It bears emphasis that the procedure described above was used only to determine emission performance rates, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state, would be based on the emission standards established through that state's plan. The details of how states could demonstrate compliance with the emission performance rates or statewide goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in section VIII on state plans.

Finally, the procedures and assumptions in the equation to calculate emission performance rates are not intended to reflect a compliance scenario in a future year, but rather reflect a representative year in which the building blocks are applied. The power sector fleet will continue to turn over, and in some cases has already experienced turnover beyond the baseline period. However, while the system's fleet may change, the EPA believes this turnover will only further promote the feasibility of the emission performance rates. Fleet turnover has trended towards, and is expected to continue to trend towards, lower-emitting generation sources that will make reductions more readily available.

VII. State-Specific CO_2 Goals

A. Overview

In section VI of this preamble, the EPA provides the methodology for computing subcategory-specific CO_2 emission performance rates, based on the BSER. The subcategory-specific CO_2 emission performance rates are the quantitative expression of the BSER as determined by the EPA. In this section, we provide state rate-based goals and mass-based goals that can be used in the alternative, by states, as an equivalent quantitative expression of the BSER in establishing standards of performance for affected EGUs in state plans. In this section, the EPA also describes reasons for providing state-specific rate-based goals and mass-based goals equivalent to the emission performance rates, supported by the many requests from commenters for the provision of these alternative expressions of the BSER established by the EPA. We further ensure this equivalence, and therefore reflection of the BSER, by requiring that rate-based state goals and mass-based state goals fully implement the BSER, including by ensuring that affected EGUs operating under mass-based emission standards are not incented by dint of the mass-emissions constraint to shift generation to unaffected fossil fuel-fired sources to an extent that deviates from, or negates, the implementation of the BSER.

The EPA is reconstituting the emission performance rates discussed in section VI into statewide CO_2 emission performance goals for each state for the purpose of facilitating states' development of state plans encompassing maximum flexibilities in implementing the BSER. This state-specific goal is not a compliance requirement, but rather an alternative yet equivalent expression of the BSER that the state may choose to use to establish emission standards for its affected EGUs. The state goal is the equivalent of the technology-specific CO_2 emission performance rates and represents the equivalent of the state's applying the emission performance rates directly to its affected EGUs in the form of standards of performance. As discussed further in section VIII on state plans, the states are charged with setting emission standards for the affected EGUs in their respective jurisdictions such that the affected EGUs operating under those standards together satisfy the requirements of the final emission guidelines and statute by meeting the emission performance rates or equivalent statewide emission performance goals, and thereby meet emission standards that reflect the BSER.

In the June 2014 proposal, the EPA proposed a set of state-specific emission rate-based CO_2 goals (in lbs of CO_2 per MWh of electricity generated). In addition, the EPA proposed emission rate-based CO_2 goals for areas of Indian country and U.S. territories with affected EGUs in a supplemental proposal on November 4, 2014. To provide flexibility to states, territories, tribes and implementing authorities, the proposals authorized each implementing authority to translate the form of the goal to a mass-based form (*i.e.*, goals expressed in terms of total tons of CO_2 per year from affected EGUs), as long as the translated goal was equivalent to the rate-based goal. Upon issuance of the proposed rule, the EPA continued the extensive outreach effort to stakeholders and members of the public that the EPA had engaged in for many months preceding the proposal. We also issued a notice of data availability (79 FR 67406, November 13, 2014) and technical support document (Docket ID: EPA-HQ-OAR-2013-0602-22187) to further clarify potential methods for the translation to a mass-based equivalent. The outreach provided additional opportunities for all jurisdictions with affected EGUs—both individually and in regional groups—as well as numerous industry groups and non-governmental organizations, to meet with the EPA and ask clarifying questions about, and give initial reactions to, the proposed components, requirements and timing of the rulemaking. As a result of the outreach and notice of data availability, the EPA received informed substantive comments for the EPA to consider for the final rule.

Numerous commenters encouraged and supported the EPA's efforts to allow states the maximum possible degree of flexibility in developing plans for their affected EGUs, either as a mass-based or rate-based CO_2 goal. States and other stakeholders supported the option to translate rate-based goals to mass-based goals for state plans and requested a simple and transparent method for determining mass-based statewide CO_2 goals that are equivalent to statewide rate-based CO_2 goals and thus reflective of the BSER. We received substantial comments on the potential methodologies for the translation of rate-based goals to mass-based goals. Several commenters requested that the EPA provide the translation to a statewide mass-based goals directly while others requested flexibility to translate to mass using a variety of methodologies and tools. In the context of these comments, the EPA has considered the appropriateness of rate-based and mass-based goals as an expression of BSER and their equivalence to the quantitative expression of BSER through the two CO_2 emission performance rates.

Based on the comments received, the EPA is providing a straightforward translation methodology from the CO_2 emission performance rates to yield statewide rate-based and mass-based CO_2 emission performance goals described in this section. The EPA is providing state mass-based goals in this final rule in place of having states determine the mass themselves. The mass-based goals are the result of a mathematical derivation that provides goals that are an equivalent expression of the BSER. Section VIII below discusses mechanisms for states to plan for and demonstrate achievement of the statewide CO_2 emission performance goals.

CAA section 111(d) requires states to submit a plan that establishes standards of performance for affected EGUs that implement the BSER. States meet the statutory requirements of CAA section 111(d) and the requirements of the final emission guidelines by submitting emission standards for affected EGUs that meet the performance rates, which reflect the application of the BSER as determined by the EPA. Therefore, as a first step for states that choose to submit plans that meet the rate-based or mass-based goals, the goals must be determined to have equivalence as an application of the BSER. For the rate-based and mass-based state goals provided here, this equivalence is evident in the mathematical derivation of the goals, as is described in sections VII.B and VII.C below.

Further (as described in section VIII.J), the state plan must demonstrate that it has measures in place to ensure that any alternative to the performance rates (*i.e.*, rate-based or mass-based state goals that it uses to establish standards of performance) does not result in affected EGUs' failing to implement either the BSER measure themselves or alternative methods of compliance with emission standards that achieve equivalent reductions in emissions or carbon intensity. The EPA has identified one way in which affected EGUs could fail to meet, at a minimum, of the emission performance levels that would result from implementing the BSER, which state plans must do.

Specifically, the EPA has determined that the three building blocks are the BSER, including shifting generation from an affected EGU to a lower-emitting affected EGU or to a non-emitting EGU and that states are required to establish standards of performance that require affected EGUs to achieve, at a minimum, the emission performance levels that reflect the BSER (recognizing that affected sources may choose from a range of equivalent actions (*e.g.*, undertaking the measures included in the building blocks, shifting generation to low-emitting or zero-emitting resources not included in the building blocks or achieving demand-side EE or transmission efficiency—either through operational undertakings, direct investment or emissions trading). Substantial shifting of generation from affected EGUs to new fossil fuel-fired EGUs, such as new NGCC units, represents a deviation from implementing the BSER or its compliance equivalent.

Since the two subcategory-specific emission performance rates represent the BSER, states that established standards of performance at or below those rates, by definition, would be implementing state plans that created no risk that affected EGUs would shift generation to new fossil-fired EGUs to an extent that would deviate from the BSER. Similarly, the EPA has determined that states using rate-based goals as the foundation for plans implementing the BSER are unlikely to foster generation shifts to new fossil fuel-fired sources to an extent that would deviate from the BSER. In contrast, however, EPA analysis has identified a concern that a mass-based state plan that failed to include appropriate measures to address leakage could result in failure to achieve emission performance levels consistent with the BSER.[759] Section VII.B describes how the form of the rate-based state goals minimizes the risk of generation shifts to new fossil fuel-fired sources, or "leakage," by providing affected EGUs with a sufficient incentive to run, similar to the performance rates. Section VII.D. discusses how there is a potential for leakage under mass-based state goals because affected EGUs are incented to operate in a manner—in particular, by shifting generation to new NGCC units (as opposed to shifting generation as contemplated by the BSER or undertaking equivalent alternative compliance actions)—that would result in negating the equivalence with the emission performance rates and thus the BSER, and specifies that requirements are

[759] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.

needed in mass-based implementation to assure those incentives are realigned.[760]

B. Reconstituting Statewide Rate-Based CO_2 Emission Performance Goals From the Subcategory-Specific Emission Performance Rates

In order to provide states flexibility for planning purposes, the EPA is providing a state-specific averaging of the subcategory-specific emission performance rates to determine a statewide goal. While the emission performance rates reflect the quantification of performance based on the BSER and embody the reductions estimated under building blocks 1, 2, and 3, the state goals reflect an equivalent approach through which states may choose to adopt and implement those subcategory-specific performance rates.

The EPA quantified the potential reductions of the BSER in the subcategory-specific emission performance rates established in section VI. These rates themselves reflect the reduction potential expected in emission rates under the BSER for each year from 2022 to 2030. To establish state goals, the EPA applied these rates to the baseline generation levels to estimate the affected fleet emission rate that would occur if all affected EGUs in the fleet met the subcategory-specific rates. This step respects the flexibility of sources to meet the rates in any manner that they see fit (*e.g.*, on-site abatement technology, fuel switching, co-firing, credit purchase, etc.), and does not limit them to their building block

[760] The specific mass-based plan requirements are explained in detail in section VIII.J.

assumptions. For example, the EPA derived the statewide rate-based CO_2 emission performance goals for 2030 by multiplying the fossil steam emission performance rate for 2030 by the baseline fossil steam generation in a state and multiplying the NGCC emission performance rate for 2030 by the baseline NGCC generation in a state. The resulting emissions for fossil steam and NGCC are then added together for each state. This emission total is divided by that state's baseline generation values from the likely affected EGUs in order to develop a state's rate-based CO_2 emission performance goal for 2030. This blended rate reflects the collective emission rate a state may expect to achieve when its baseline fleet of likely affected EGUs continues to operate at baseline levels while meeting its subcategory-specific emission performance rates reflecting the BSER. The EPA believes that using the adjusted 2012 baseline is the most appropriate way to combine the rates. First, as explained in Section VI, the EPA believes there are significant advantages to using real world data to set a baseline rather than using projected data. The adjusted 2012 data is the logical starting point because it is the data that all of the emission performance rates (discussed in Section VI) are based upon. Furthermore, it is clear that generation shifts as projected under the BSER are not the appropriate baseline. The emission performance rates already factor in the BSER assumptions about changes in generation (*e.g.*, implementation of building block 2 significantly lowers the emission performance rate for fossil-steam units). If, on top of that, changes in generation were factored into the calculation of a combined rate, those changes in generation would be factored into the combined rate twice (once when calculating the individual emission performance rates and a second time, when incorporating those rates into a combined state rate).

This step is repeated for each year from 2022–2029 using the emission performance rates calculated for each of those years in the previous section. The EPA also repeats this step for the interim state goal using the interim subcategory rates. The EPA then averages together the annual amounts in increments of 3 years, 3 years, and 2 years for 2022–2024, 2025–2027, and 2028–2029 to estimate emission rate averages for those periods that can provide one illustrative pathway for states to consider in meeting their interim goals. These 3- and 2-year increment are not regulatory guidelines or equivalents for interim goals, but rather benchmarks for demonstrating plan performance as discussed in Section VIII.F illustrative of a potential gradual reduction compliance strategy that states may use to reach their interim and final state goals.

As described in the steps above, the statewide goals represent an equivalent arithmetic combination of the subcategory-specific emission performance rates, weighted by the historical baseline generation levels upon which the BSER is premised. In particular, as discussed above, the method for deriving these goals assures equivalent flexibility by applying the CO_2 emission performance rates to the baseline levels, which respects the flexibility of affected EGUs to meet the rates in whatever way they wish. This corresponding treatment of affected EGUs based on the adjusted 2012 baseline ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates (this is further discussed in section VII.D below). Consequently, the statewide goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. The rate-based statewide goals are provided below in Table 12.

C. Quantifying Mass-Based CO_2 Emission Performance Goals from the Statewide Rate-Based CO_2 Emission Performance Goals

The EPA is also establishing mass-based statewide CO_2 emission performance goals for each state, which are provided below in Table 13. For state plans choosing to meet a mass-based goal, such a goal must be equivalent to the CO_2 emission performance rates in their application of the BSER, as required by the statute and the final emission guidelines. In the following discussion we describe the mathematical calculations that provide an equivalent expression of the BSER. In evaluating the equivalence of the form of mass goals, the EPA must also recognize the impact that the form of the standard has on the relative incentives that the implementation of these goals provides to affected and unaffected EGUs. This section specifies how we have established a quantitative basis for mass goals that is equivalent to CO_2 emission performance rates. The next section (section VII.D) specifies how we require state plans to ensure equivalence to the CO_2 emission performance rates through certain requirements that realign the potential difference in incentives provided to affected and unaffected EGUs to generate under a mass-based implementation compared to a rate-based implementation that could result in leakage.

The starting place for quantifying mass-based statewide CO_2 emission performance goals is the emission amounts directly represented in the numerator of the statewide rate-based CO_2 emission performance goals. Each state-specific emission amount is the product of the fossil steam emission performance rate and historical fossil steam generation, added to the product of the NGCC emission performance rate and historical NGCC generation. The resulting emission amounts for each state represent the emissions associated with rate-based compliance at historical generation levels.

However, under a rate-based state plan, all affected EGUs have the opportunity to increase utilization, provided that sufficient emission reduction measures are available to maintain the necessary ratio of emissions to generation as quantified by the subcategory-specific emission performance rates. Due to the nature of the emission performance rate methodology, which selects the highest of the three interconnection-based values for each source category as the CO_2 emission performance rate, there are cost-effective lower-emitting generation opportunities quantified under the building blocks that are not necessary for affected EGUs in the Western and Texas interconnections to demonstrate compliance at historical generation levels. The EPA recognizes that these lower-emitting generation opportunities are available to affected EGUs at a national level as a means to increase their own output (and, as a result, their own emissions) while maintaining the relevant emission performance rate. To afford affected EGUs subject to a mass-based goal similar compliance flexibility as EGUs subject to a rate-based goal, the

EPA has quantified the emissions associated with the potential realization of these lower-emitting generation opportunities and incorporated those additional tons into each state's mass-based goal.[761] Because the derivation of these mass-based goals respects the arithmetic of the subcategory-specific emission performance rates and the flexibility of affected EGUs to achieve those rates while utilizing up to the full potential quantified in the building blocks, the derivation of these mass-based state goals offers an equivalent expression of BSER in mass form.

The mass goals for existing sources are presented in Table 13. Although their derivation is equivalent to the subcategory-specific emission performance rates, in order to maintain this equivalence in the establishment of emission standards in state plans mass goals must be implemented in combination with requirements that align the incentives provided to affected and unaffected EGUs, specifically in order to prevent leakage.

D. Addressing Potential Leakage in Determining the Equivalence of State-Specific CO_2 Emission Performance Goals

As described in section VI, the subcategory-specific emission performance rates reflect the BSER as determined by the EPA. This final rule allows states to establish emission standards that meet either rate-based or mass-based state goals. As stated above, rate-based state goals were published in the proposed rule, and commenters not only supported having the

---

[761] For more detail on this methodology, please refer to the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule, which is available in the docket.

flexibility to use rate-based goals or mass-based goals as part of state plans, but also requested that the EPA include mass-based goals in this final rule. But to ensure the equivalence of mass-based state goals, we must consider how the form of the goal affects its implementation and how the incentives it provides to affected EGUs on the interstate grid affect whether or not the BSER is fully implemented.

Because of the integrated nature of the utility power sector, the form of the emission performance requirements for existing sources may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether a given set of standards of performance is, at a minimum, consistent with the BSER, in the context of overall emissions from the sector. In this context, we, again, define as "leakage" the potential of an alternative form of implementation of the BSER (*e.g.*, the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. In the proposal, the EPA recognized that the statutory construction regarding the BSER is to reduce emissions, which can be achieved through shifts of generation. Movement of generation between and among sources is needed to produce overall reductions, particularly movement from higher-emitting affected EGUs to lower-emitting affected EGUs, and from all affected EGUs to zero-emitting RE. In all of these cases, the fossil sources involved in these generation shifts are subject to obligations under this final rule.[762]

However, leakage, where shifts in generation to unaffected fossil fuel-fired sources result in increased emissions, relative to what would have happened had generation shifts consistent with the BSER occurred, is contrary to this construction. Therefore, if the form of the standard does not address leakage or incents the kinds of generation shifts that we identify as leakage, the states must otherwise address leakage in order to ensure that the standards of performance applied to the affected EGUs are, in the aggregate, at least equivalent with the emission performance rates, and therefore appropriately reflect the BSER as required by the statute. Commenters noted that shifting generation and emissions from existing sources to new sources undermined the intent of this rule and the overall emission reduction goals, and that requiring states to address leakage is consistent with the obligation that states establish standards of performance that, in the aggregate, at a minimum, reflect the BSER for affected EGUs operating in the interconnected electricity sector.

---

[762] The final rule includes state plan conditions to prevent perverse incentives that could otherwise result in greater overall emissions when generation shifts across affected EGUs. For example, states that wish to engage in rate-based trading through an emission standards plan type must adopt plans designed to achieve either a common rate-based state goal or the subcategory-specific emission performance rates (see section VIII.L). Such a state plan condition avoids encouraging generation to shift from a state with a relatively lower state goal to a state with a relatively higher state goal solely as a response to the form of CPP implementation.

This section specifically addresses the need for state plans designed to achieve either rate- or mass-based state goals to ensure that their plans succeed in implementing standards of performance that reflect the BSER by minimizing the difference in incentives provided to affected EGUs and new sources to generate in order to maintain equivalent emission performance with the CO_2 emission performance rates.

Rate-based goals do not in our view implicate leakage to an extent that would negate or limit the implementation of the BSER because under a rate-based state goal, similar to the subcategory-specific emission performance rates, existing lower-emitting affected EGUs, primarily NGCC units, are incentivized to increase their utilization in order to improve the average emission rates of affected EGUs overall. New units that are not subject to the rate-based state goal, and that are not an allowable measure for adjusting an EGU's CO_2 emission rate, will not have this incentive to increase utilization, and as a result, the imposition of a rate-based goal on affected EGUs is unlikely to encourage increased generation and emissions from unaffected new EGUs. The form of the rate-based state goals provides an equivalent or greater incentive to affected existing EGUs as they are provided in the CO_2 emission performance rates, and similarly avoid the potential for leakage. Under both approaches, existing NGCC units can generate ERCs. These ERCs provide an economic incentive to utilize existing NGCC units rather than new NGCC units. Further, ERCs from incremental RE incentivize new renewable generation over new NGCC generation. Both of these features, which exist in the context of implementation with a state rate-based goal or CO_2 emission performance rates, provide significant incentives to ensure that, consistent with the BSER, shifting of generation does not occur between existing fossil fuel-fired units and new NGCC units.

Mass-based goals for existing sources, however, incur a leakage risk to the extent that they incent generation shifts from affected EGUs to unaffected fossil fuel-fired sources in a way that negates the reliance on the BSER. In contrast to various forms of rate-based implementation, mass-based implementation in a state plan can unintentionally incentivize increased generation from unaffected new EGUs as a substitute action for reducing emissions at units subject to the existing source mass goal in ways that would negate the implementation of the BSER and would result in increased emissions. This occurs because, unlike in a rate-based system where rate-based averaging lowers the cost of generation from existing NGCC units relative to generation from new NGCC units, in a mass-based system the allowance price increases the cost of generation from existing NGCC units relative to generation from new NGCC units. The extent to which electricity providers opt to rely on this increase in unaffected new source utilization as a substitute for improving the emissions performance across existing sources would be fundamentally inconsistent with relying on the BSER to reduce emissions as the basis of the subcategory-specific emission performance rates.

As a result, notwithstanding the fact that mass goals for existing sources are quantified in a way that is an equivalent expression of the BSER, the form of mass goals is only equivalent if leakage is satisfactorily addressed in the state plan's establishment of emission standards and implementation measures. The EPA is therefore requiring that states adopting a mass-based state plan include requirements that address leakage, or otherwise provide additional justification that leakage would not occur under the state's implementation of mass-based emission standards. This requirement enables states to establish standards of performance that meet a mass-based goal equivalent to the performance rates and therefore reflect the BSER, as required by section 111(d). The required demonstration and options for state plans to minimize leakage are discussed in detail in section VIII.J of this preamble.

Further supporting the need for this requirement, the EPA has evaluated the mass goals in concert with some of the options to minimize leakage described in that section. As mentioned above, the EPA analysis identified a concern regarding leakage in a mass-based approach, namely that the mass-based implementation without measures to address leakage produced higher generation from new NGCC units and lower emission performance when compared to a rate-based implementation. Further analysis where implementation of the mass-based goals was coupled with measures to address leakage produce utility power sector emissions performance that is similar to emissions performance under the rate goals.[763]

[763] See Chapter 3 of the Regulatory Impact Analysis for more information on this analysis, which is available in the docket.

E. State Plan Adjustments of State Goals

The EPA notes that it is the emission performance rates in section VI that constitute the application of the BSER to the affected EGUs and serve as the chief regulatory requirement of this rulemaking. The statewide CO_2 rate-based and mass-based emission performance goals provided here are metrics that states may choose to adopt when demonstrating compliance at the state level, and states may consider these goals when determining how to set unit-level compliance requirements. The EPA believes that the regional nature of determining the emission performance rates encompasses a large population size and makes it robust against unit-level variation and unit-level inventory discrepancies. The EPA does acknowledge that state-level rate-based goals or mass-based goals may be sensitive to applicability changes within a state's affected population. In the proposal, the EPA used a baseline that aggregated data for what it believed to be affected units and asked states, companies and other stakeholders to provide corrections in their comments. We received input from many commenters and have corrected information as appropriate. Therefore, we believe the baseline to be accurate. However, if subsequent applicability review or formal applicability determinations change the status of units in regards to being affected or unaffected by this rulemaking, states can, via state plan submittal or revision, adjust their statewide rate or mass goal to reflect this change of status.

This adjustment flexibility provision is based on comments received at proposal. For example, some stakeholders noted that the affected status of particular units was unclear. The EPA recognizes that all the necessary data to determine the affected status of some units may not be available at this time. As stated above, the EPA does not believe unit-level variation or inclusion/exclusion disparities between baseline inventory and affected units will impact the regionally determined emission performance rates discussed in the previous section. However, variations in baseline data or inventory may have an impact on the *state-level* rate-based or mass-based goals provided in this section. Therefore, the EPA is allowing the flexibility for states to demonstrate the need for this type of adjustment under the justifications above and utilize an adjusted value for compliance purposes when submitting or revising its state plan. The EPA will evaluate the appropriateness of such an adjusted value based on the state's demonstration and evaluate the approvability of a plan or plan revision accordingly.

Rate-based statewide CO_2 emission performance goals are listed below in Table 12. Mass-based statewide CO_2 emission performance goals are found in Table 13.

TABLE 12—STATEWIDE[764] RATE-BASED CO_2 EMISSION PERFORMANCE GOALS
[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State name	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Alabama	1,244	1,133	1,060	1,157	1,018
Arizona*	1,263	1,149	1,074	1,173	1,031
Arkansas	1,411	1,276	1,185	1,304	1,130
California	961	890	848	907	828
Colorado	1,476	1,332	1,233	1,362	1,174
Connecticut	899	836	801	852	786
Delaware	1,093	1,003	946	1,023	916
Florida	1,097	1,006	949	1,026	919
Georgia	1,290	1,173	1,094	1,198	1,049
Idaho	877	817	784	832	771
Illinois	1,582	1,423	1,313	1,456	1,245
Indiana	1,578	1,419	1,309	1,451	1,242
Iowa	1,638	1,472	1,355	1,505	1,283

[764] The EPA has not developed statewide rate-based or mass-based CO_2 emission performance goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs.

State name	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Kansas	1,654	1,485	1,366	1,519	1,293
Kentucky	1,643	1,476	1,358	1,509	1,286
Lands of the Fort Mojave Tribe	877	817	784	832	771
Lands of the Navajo Nation	1,671	1,500	1,380	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,671	1,500	1,380	1,534	1,305
Louisiana	1,398	1,265	1,175	1,293	1,121
Maine	888	827	793	842	779
Maryland	1,644	1,476	1,359	1,510	1,287
Massachusetts	956	885	844	902	824
Michigan	1,468	1,325	1,228	1,355	1,169
Minnesota	1,535	1,383	1,277	1,414	1,213
Mississippi	1,136	1,040	978	1,061	945
Missouri	1,621	1,457	1,342	1,490	1,272
Montana	1,671	1,500	1,380	1,534	1,305
Nebraska	1,658	1,488	1,369	1,522	1,296
Nevada	1,001	924	877	942	855
New Hampshire	1,006	929	881	947	858
New Jersey	937	869	829	885	812
New Mexico*	1,435	1,297	1,203	1,325	1,146

State name	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
New York	1,095	1,005	948	1,025	918
North Carolina	1,419	1,283	1,191	1,311	1,136
North Dakota	1,671	1,500	1,380	1,534	1,305
Ohio	1,501	1,353	1,252	1,383	1,190
Oklahoma	1,319	1,197	1,116	1,223	1,068
Oregon	1,026	945	896	964	871
Pennsylvania	1,359	1,232	1,146	1,258	1,095
Rhode Island	877	817	784	832	771
South Carolina	1,449	1,309	1,213	1,338	1,156
South Dakota	1,465	1,323	1,225	1,352	1,167
Tennessee	1,531	1,380	1,275	1,411	1,211
Texas	1,279	1,163	1,086	1,188	1,042
Utah*	1,483	1,339	1,239	1,368	1,179
Virginia	1,120	1,026	966	1,047	934
Washington	1,192	1,088	1,021	1,111	983
West Virginia	1,671	1,500	1,380	1,534	1,305
Wisconsin	1,479	1,335	1,236	1,364	1,176
Wyoming	1,662	1,492	1,373	1,526	1,299

* Excludes EGUs located in Indian country within the state.

TABLE 13—STATEWIDE MASS-BASED CO_2 EMISSION PERFORMANCE GOALS
[Adjusted output-weighted-average tons of CO_2 from all affected fossil fuel-fired EGUs]

State	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Alabama	66,164,470	60,918,973	58,215,989	62,210,288	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	33,061,997	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	33,683,258	30,322,632
California	53,500,107	50,080,840	48,736,877	51,027,075	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	33,387,883	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	7,237,865	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	5,062,869	4,711,825
Florida	119,380,477	110,754,683	106,736,177	112,984,729	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	50,926,084	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,550,142	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	74,800,876	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	28,254,411	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	24,859,333	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	71,312,802	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	611,103	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	24,557,793	21,700,587

State	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Lands of the Ute Tribe of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,561,445	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	39,310,314	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,158,184	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	16,209,396	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,747,677	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	53,057,150	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	25,433,592	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	27,338,313	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	62,569,433	55,462,884
Montana	13,776,601	12,500,563	11,749,574	12,791,330	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	20,661,516	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	14,344,092	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	4,243,492	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	17,426,381	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	13,815,561	12,412,602
New York	35,493,488	32,932,763	31,741,940	33,595,329	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	56,986,025	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	23,632,821	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806

State	Interim goal—Step 1	Interim goal—Step 2	Interim goal—Step 3	Interim goal	Final goal
Oklahoma	47,577,611	43,665,021	41,577,379	44,610,332	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,643,164	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	99,330,827	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,657,385	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	28,969,623	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,948,950	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	31,784,860	28,348,396
Texas	221,613,296	203,728,060	194,351,330	208,090,841	189,588,842
Utah*	28,479,805	25,981,970	24,572,858	26,566,380	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
Washington	12,395,697	11,441,137	10,963,576	11,679,707	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	31,258,356	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	35,780,052	31,634,412

* Excludes EGUs located in Indian country within the state.

F. Geographically Isolated States and Territories With Affected EGUs

Alaska, Hawaii, Guam, and Puerto Rico constitute a small set of states and U.S. territories representing about one percent of total U.S. EGU GHG emissions. Based on the current record, the EPA does not possess all of the information or the analytic tools needed to quantify the application of the BSER for these states and territories, particularly data regarding RE costs and performance characteristics needed for building block 3 of the BSER. The NREL data for RE that the EPA is relying upon for building block 3 does not cover the non-contiguous states and territories.

The EPA acknowledges that NREL has collaborated with the state of Hawaii to provide technical expertise in support of the state's aggressive goals for clean energy, including analyses of the grid integration and transmission of solar and wind resources.[765] The EPA also recognizes that there are studies and data for some renewable resources in some of the other non-contiguous jurisdictions. However, taken as a whole, the data we currently possess do not allow us to quantify the emissions reductions available from building block 3 using the same methodology used for the contiguous states encompassed by the three interconnections. Lastly, the IPM model used to support the EPA's analysis is geographically limited to the contiguous U.S. As a result of these factors, the EPA currently lacks the necessary analytic resources to set emission performance goals for these areas.

---

[765] Hawaii Solar Integration Study, NREL Technical Report NREL/TP-5500-57215, June 2013. Available at *http://www.nrel.gov/docs/fy13osti/57215.pdf*.

Because of the lack of suitable data and analytic tools needed to develop area-appropriate building block targets as defined in section V, the EPA is not setting CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in this final rule at this time. The EPA believes it is within its authority to address performance goals only for the contiguous U.S. states in this final rule. Under section 111(d), the EPA is not required, at the time that the EPA promulgates section 111(b) requirements for new sources, to promulgate emission guidelines for all of the sources that, if they were new sources, would be subject to the section 111(b) requirements if there is a reasonable basis for deferring certain groups of sources. As discussed, in this rule, the EPA has a reasonable basis for deferring setting goals for these four jurisdictions. In addition, the Courts have recognized the authority of agencies to develop regulatory programs in step-by-step fashion. As the U.S. Supreme Court noted in *Massachusetts* v. *EPA*, 549 U.S. 497, 524 (2007): "Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;" and instead they may permissibly implement such regulatory programs over time, "refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed." [766]

[766] *See, e.g.*, *Grand Canyon Air Tour Coalition* v. *F.A.A.*, 154 F.3d 455, 471 (D.C. Cir. 1998) (ordinarily, agencies have wide latitude to attack a regulatory problem in phases and that a phased attack often has substantial benefits); *National Association of Broadcasters* v. *FCC*, 740 F.2d 1190, 121–11 (D.C. Cir. 1984) ("We have therefore recognized the reasonableness of

The EPA recognizes, however, that EGUs in Alaska, Hawaii, Puerto Rico, and Guam emit CO_2 and that there are opportunities to reduce the carbon intensity of generation in those areas over time. We recognize further that there are efforts underway to increase the use of RE in these jurisdictions. In particular, we recognize that Hawaii has tremendous opportunities for RE and has adopted very ambitious goals: 40 percent clean energy by 2030 and 100 percent by 2045. Since 2008, Alaska has apportioned in excess of $1.34 billion pursuing its aspirational goal of 50 percent of the state's total yearly electric load from renewable and alternative energy sources by 2025. Puerto Rico's goal is to achieve 20 percent RE sales by 2035, and the territory is working hard to meet the requirements of the Mercury and Air Toxics Standards, which will reduce emissions from its power plants substantially. Guam's RPS is to achieve 25 percent RE sales by 2035.

The agency intends to continue to consider these issues and determine what the appropriate BSER is for these areas. As part of that effort, the agency will investigate sources of information and types of analysis appropriate to devise the appropriate levels for building block 3 and BSER performance levels. Because we recognize that these areas face some of the most urgent climate change challenges, severe public health problems from air pollution and some of the highest electricity rates in the U.S., the EPA is committed to obtaining the right information to quantify the emission reductions that are achievable in these four areas and putting goals in place soon.

[an agency's] decision to engage in incremental rulemaking and to defer resolution of issues raised in a rulemaking. . . .").

VIII. State Plans

A. Overview

After the EPA establishes the emission guidelines that set forth the BSER, each state with one or more affected EGUs[767] shall then develop, adopt and submit a state plan under CAA section 111(d) that establishes standards of performance for the affected EGUs in its jurisdiction in order to implement the BSER. Starting from the foundation of CAA section 111(d) and the EPA's implementing regulations (40 CFR part 60 subpart B), the EPA's proposal laid out a number of options, variations and flexibilities that were intended to provide states and affected EGUs the ability to design state plans that accorded with states' specific situations and policies (now and in the future), and to ensure reliability and affordability of electricity across the system and for all ratepayers. The proposal has prompted numerous discussions between and among stakeholders, especially states and groups of states, including state environmental and energy regulators and policy officials. The EPA has received many comments from a wide range of stakeholders seeking a final rule that afforded freedom and flexibility to consider a wide range of standards of performance to implement the BSER, but also providing significant

---

[767] As stated previously, states with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan.

feedback on the elements and options in the proposal and constructive suggestions for alternative approaches. The EPA has carefully considered all of this input, and is finalizing emission guidelines that continue to provide a variety of options for states to fashion their plans in ways legally supportable by the CAA, while also making certain adjustments to address key comments.

The next few paragraphs present an overview of the main features of the final emission guidelines, highlighting key changes from proposal. In the rest of this section, we describe in detail the various elements of the final emission guidelines' requirements for state plans.

The proposal contained rate-based goals for each state, reflecting a blended reduction target for that state's fossil fired EGUs, and provided that states could either meet that rate-based goal or convert it to a mass-based equivalent goal. Reflecting the final BSER described in section V and in response to many comments desirous that the EPA establish mass-based goals in the final rule, these final guidelines include three approaches that states may adopt for purposes of implementing the BSER, any one of which a state may use in its plan. These are: (1) Establishing standards of performance that apply the subcategory-specific CO_2 emission performance rates to their affected EGUs, (2) adopting a combination of standards and/or other measures that achieve state-specific rate-based goals that represent the weighted aggregate of the CO_2 emission performance rates applied to the affected EGUs in each state, and (3) adopting a program to meet mass-based CO_2 emission goals that represent the equivalent of the rate-based goal for each state. These alternatives, as well as the other options we are finalizing, ensure that both states and affected EGUs enjoy the maximum flexibility and latitude in meeting the requirements of the emission guidelines and that the BSER is fully implemented by each state.

In the proposal, we provided two designs for state plans: One where all the reduction obligations are placed directly on the affected EGUs and one, which we called the "portfolio approach," that could include measures to be implemented, in whole or in part, by parties other than the affected EGUs. In the final guidelines, we retain that basic choice, but with some modifications to respond to comments we received, especially on the portfolio approach. In their plans, states will be able to choose either to impose federally enforceable emission standards that fully meet the emission guidelines directly on affected EGUs (the "emission standards" approach) or to use a "state measures" approach, which would be composed, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan but result in the affected EGUs meeting the requirements of the emission guidelines. A state measures type plan must include a backstop of federally enforceable standards on affected EGUs that fully meet the emission guidelines and that would be triggered if the state measures fail to result in the affected EGUs achieving on schedule the required emission reductions.

States that choose an emission standards plan may establish as standards of performance for their affected EGUs the subcategory-specific CO_2 emission performance rates, which express the BSER.[768] This would satisfy the requirement described in section VIII.D.2.a.3 that a state demonstrate its plan would achieve the CO_2 emission performance rates; in this case, no further demonstration would be necessary. Alternatively, a state may establish emission standards for affected EGUs at different levels from the uniform subcategory-specific emission performance rates, provided that when implemented, the emission standards achieve the CO_2 emission performance rates or state rate- or mass-based CO_2 emission goal set forth by the EPA for the state. States that adopt differential standards of performance among their affected EGUs must demonstrate that, in the aggregate, the differential standards of performance will result in their affected EGUs meeting the CO_2 emission performance rates, the state's rate-based CO_2 emission goal or its mass-based CO_2 emission goal.

In the proposal, we proposed that states could use the portfolio approach to meet either a rate- or mass-based goal. In these final emission guidelines, the state measures approach is available only for a state choosing a mass-based CO_2 emission goal, to provide certainty that the state measures are achieving the required emission reductions. Similar to emission standards plans with differential standards of performance, states that adopt state measures plans must demonstrate that the state measures, alone or in conjunction with any federally enforceable emission standards on affected EGUs also included in the state

---

[768] Rate-based and mass-based emission standards may incorporate the use of emission trading.

plan, will result in the affected EGUs in the state meeting the state's mass-based CO_2 emission goal. A "state measures" type plan must also include a backstop provision—triggered if, during the interim period, the state plan fails to achieve the emission reduction trajectory identified in the plan or if, during the final phase, the state plan fails to meet the final state mass-based CO_2 emission goal—that would impose federally enforceable emission standards on the affected EGUs adequate to meet the emission guidelines when fully implemented.

The final guidelines reflect the changes to the timing of the reductions within the interim period, which is laid out in section V as part of the determination of the BSER. States may adopt in their plans emission reduction trajectories different from the illustrative three-step trajectory included in these guidelines for purposes of creating a "glide path" between 2022 and 2029, provided that the interim and final CO_2 emission performance rates or state CO_2 emission goals are met.

We recognize that while we are establishing 2022 as the date by which the period for mandatory reductions must start as part of our BSER determination, utilities and other parties are moving forward with projects that reduce emissions of CO_2 from affected EGUs. We received numerous comments urging us to allow credit for these early actions. The final guidelines encourage those early reductions, by making clear that states may, in their plans, allow EGUs to use allowances or ERCs generated through the CEIP. The final guidelines also require that states include in their final plans a schedule of the actions they will be taking to ensure that the period for mandatory reductions will begin as required starting in 2022, and submit a progress report on those actions.

For all types of plans, the final guidelines make clear that states may adopt programs that allow trading among affected EGUs. The final guidelines retain the flexibility for states to do individual plans, or to join with other states in a multi-state plan. In addition, and in response to comments from many states and other stakeholders, the guidelines provide that states may design their programs so that they are "ready for interstate trading," that is, that they contain features necessary and suitable for their affected EGUs to engage in trading with affected EGUs in other "trading ready" states without the need for formal arrangements between individual states.

We have been mindful of the concerns raised by stakeholders about reliability. The final BSER, especially the changes in the timing of the interim period, substantially address these concerns. The flexibilities provided for the design of state plans, including the ability to use trading programs, further enhance system reliability. We have included, as an additional assurance, a reliability safety valve for use where the built-in flexibilities are not sufficient to address an immediate, unexpected reliability situation.

The EPA believes that all the flexibilities provided in the final rule are not only appropriate, but will enhance the success of the program. CO_2 is a global pollutant, and where and when the reductions occur is not as significant to the environmental outcome as compared to many other pollutants. The flexibilities provided in the final guidelines will better reflect the unique interconnectedness of the electricity system, and will allow states and EGUs to reduce CO_2 emissions while maintaining reliability and affordability for all consumers.

In developing the plan, the state rulemaking process must meet the minimum public participation requirements of the implementing regulations as applicable to these guidelines, including a public hearing and meaningful engagement with all members of the public, including vulnerable communities. In the community and environmental justice considerations section, section IX of this preamble, the EPA addresses the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rule. These actions include conducting a proximity analysis, setting expectations for states to engage meaningfully with vulnerable communities and requiring that they describe their plans for doing so as they develop their state plans, providing communities with access to additional resources, providing communities with information on federal programs and resources available to them, recommending that states take a multi-pollutant planning approach that examines the potential impacts of co-pollutants on overburdened communities, and conducting an assessment to determine if any localized air quality impacts need to be further addressed. Additionally, the EPA outlines the continued engagement that it will be conducting with states and communities throughout the state plan development process.

As discussed in more detail in section VIII.E, commenters, particularly states, provided compelling information establishing that for some, and perhaps many, states it will take longer than the agency initially anticipated to develop and submit their required plans. In response to those comments, we are finalizing a plan submittal process that provides additional time for states that need it to submit a final plan submittal to the EPA after September 6, 2016. Within the time period specified in the emission guidelines (from as early as September 6, 2016, to as late as September 6, 2018, depending on whether the state receives an extension), the state must submit its final state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA disapproves a state's plan, then the EPA has the express authority under CAA section 111(d) to establish a federal plan for the state.[769] During and following implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements.

This section is organized as follows. First, we discuss the timeline for state plan performance and provisions to encourage early action. Second, we describe the types of plans that states can submit. Third, we summarize the components of an approvable state plan submittal. Fourth, we address the process and timing for submittal of state plans and plan

[769] A federal plan may be withdrawn if the state submits, and the EPA approves, a state plan that meets the requirements of this final rule and section 111(d) of the CAA. More details regarding the federal plan are addressed in the EPA's proposed federal plan rulemaking.

revisions. Fifth, we address plan implementation and achievement of CO_2 emission performance rates or state CO_2 emission goals for affected EGUs, and the consequences if they are not met. Sixth, we discuss general considerations for states in developing and implementing plans, including consideration of a facility's "remaining useful life" and "other factors" and electric reliability. Seventh, we note certain resources that are available to facilitate state plan development and implementation. Finally, we discuss additional considerations for inclusion of CO_2 emission reduction measures in state plans, including: Accounting for emission reduction measures in state plans; requirements for mass-based and rate-based emission trading approaches; EM&V requirements for RE and demand-side EE resources and other measures used to adjust a CO_2 rate; and treatment of interstate effects.

B. Timeline for State Plan Performance and Provisions To Encourage Early Action

This section describes state plan requirements related to the timing of achieving the emission reductions required in the guidelines and the state plan performance periods. This section also describes the CEIP the EPA is establishing to encourage early investment in certain types of RE projects, as well as in demand-side EE projects implemented in low-income communities.

1. Timeline for State Plan Performance

The final guidelines establish three types of performance periods: (1) A final deadline by which and after which affected EGUs must be in compliance with the final reduction requirements, (2) an interim period, and (3) within that interim period, three multi-year interim step periods. As discussed below and in section V, these performance periods are consistent with our determination of the BSER and are also responsive to the key comments we received on this aspect of the state plans.

A performance period is a period for which the final plan submittal must demonstrate that the required CO_2 emission performance rates or state CO_2 emission goal will be met. The final guidelines establish 2030 as the deadline for compliance by affected EGUs with the final CO_2 emission performance rates or CO_2 rate or mass emission goal; 2030 is the beginning of the final performance period. The interim performance period is 2022 to 2029, and there are three interim step periods—2022–2024, 2025–2027, and 2028–2029—where increasingly stringent emission performance rates or state emission goals must be met. The state may submit a plan that incorporates alternative interim step emission performance rates or state emission goals to those provided by EPA, as long as on average or cumulatively, as appropriate, they result in the equivalent of the interim emission performance rates or state emission goals in the emission guidelines. These timelines are based on careful consideration of the substantial comments we received on both the timing of the interim period and the trajectory of compliance by affected EGUs over the interim period and our determination of the BSER, discussed in section V above. The modifications we have made to the timelines included in the proposal respond to these comments and to concerns about, among other things, reliability, feasibility, and cost.

As previously discussed, the EPA has determined that the BSER includes implementation of reduction measures over the period of 2022 through 2029, with final compliance by affected EGUs in 2030. Therefore, the final rule requires that interim CO_2 emission performance rates or state CO_2 emission goals be met for the interim period of 2022–2029. Many commenters expressed a desire that the EPA designate steps during the interim period to create an interim goal that offered states and utilities greater flexibility and choice in determining their own emission reduction trajectories over the course of the interim period. Since our intent at proposal was to provide such flexibility and choice, and since it remains our intent to do so in this final rule, we are addressing these comments by including in the 2022–2029 interim period three interim step periods (2022–2024, 2025–2027, 2028–2029), which correspond roughly to the phasing in of the BSER. We note, however, that the final rule also allows states the flexibility to define an alternate trajectory of emission performance between 2022 and 2029, provided that (1) the state plan specifies its own interim step CO_2 emission performance rates or state CO_2 emission goals, (2) meeting the alternative interim step CO_2 emission performance rates or state CO_2 emission goals will result in the interim emission performance rates or state CO_2 emission goal being met on an 8-year average or cumulative basis, and, (3) the final CO_2 emission performance rates or state CO_2 emission goal is achieved. To be approvable, a state plan submittal must demonstrate that the emission performance of affected EGUs will meet the interim step CO_2 emission performance rates or interim step state CO_2 emission goals over the 2022–2024, 2025–2027, and 2028–2029 periods and the final CO_2 emission performance rates or state CO_2 emission goal no later than 2030.[770]

This relatively long period—first for planning, then for implementation and achievement of the interim and final CO_2 emission performance rates or state CO_2 emission goals—provides states and utilities with substantial flexibility regarding methods and timing of achieving emission reductions from affected EGUs. The EPA believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help achieve a number of goals, including, but not limited to: Reducing cost, addressing reliability concerns, addressing concerns about stranded assets, and facilitating the integration of meeting the emission guidelines and compliance by affected EGUs with other air quality and pollution control obligations on the part of both states and affected EGUs. Moreover, we note that over the course of time between submittal of final plans and 2030, circumstances may change such that states may need or wish to modify their plans. The relatively lengthy performance periods provided in the final rule should help keep those situations to a minimum but will also accommodate

[770] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022–2029 finalized in this action.

them if necessary.[771] The EPA envisions that the agency, states and affected EGUs will have an ongoing relationship in the course of implementing this program. Since the record also indicates a high degree of interest on the part of states and stakeholders in pursuing banking and trading programs, the timing and level of stringency of the interim CO_2 performance rates or state CO_2 emission goals we are finalizing should provide states and affected EGUs with ample capacity to accommodate such changes without necessitating changes in state plans in many instances.

The timelines established in the final rule respond to the issues raised in numerous comments regarding the concept of the interim period, including comments supporting the flexibility afforded states in developing their plans and the timing necessary to meet the 2030 emission requirements. Some commenters supported beginning the interim goal plan period at 2020. Others stated that the investments necessary to meet the proposed interim emission performance goals beginning in 2020 are unachievable in that timeframe or would place too great a burden on affected EGUs, states, and ratepayers. Some suggested that the 2020 interim goal step should be eliminated in favor of later start dates, including 2022, 2025, or other years. Some commenters urged the EPA to establish phased interim steps creating a steady downward trajectory that allowed several years for each step, compatible with the "chunkiness" of utility planning processes. Yet other commenters provided input suggesting that states be allowed to establish their own set of emission

[771] Modifications to state plans are addressed more specifically in section VIII.E.7 below.

performance steps during the interim plan performance period and thereby control their own emission reduction trajectory or "glide path" for achievement of the interim goal and the 2030 goal, or that the EPA not establish any interim standards at all. Commenters also noted that for some states, there was not a significant difference between the interim and final goal, and, therefore, no glide path for those states. As discussed in previous sections, based on this input and our final determination of the BSER, the EPA has adjusted the interim period to include 2022–2029, is establishing three interim performance periods creating a reasonable trajectory from 2022 to 2030, and is also retaining the flexibility for states to establish their own emission reduction trajectory during the interim period.

As noted, the EPA has determined that the period for mandated reductions should begin in 2022, instead of 2020 as we proposed, because of the substantial amount of comment and data we received indicating that states and utilities reasonably needed that additional time to take the steps necessary to start achieving reductions. In order to assure the EPA and the public that states are making progress in implementing the plan between the time of the state plan submittal and the beginning of the interim period, and as discussed in further detail in section VIII.D, the final rule requires that the state plan submittal include a timeline with all the programmatic plan milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022.

2. Provisions To Encourage Early Action

Many 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. In the proposal, the EPA requested comment on an approach that would recognize emission reductions that existing programs provide prior to the initial plan performance period starting from a specified date. We also requested comment on options for that specified date and on conditions that should apply to counting those pre-compliance emission reductions toward a state goal. The EPA received many comments requesting that the agency recognize early actions for the emission reductions they provide prior to the performance period, that the EPA allow those pre-compliance impacts to be counted toward meeting requirements under the rule, and that certain conditions should be applied to recognition of early reductions so as to ensure the emission reductions required in the rule. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program—called the Clean Energy Incentive Program (CEIP)—in which states may choose to participate. This section describes this program.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction in the case of RE, or commence operation in the case of EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional; the EPA is establishing this program as an additional flexibility to facilitate achievement of the CO_2 emission reductions required by this final rule, regardless of the type of state plan a state chooses to implement.

Under the CEIP, a state may set aside allowances from the CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. A state implementing a mass-based plan approach, as described in section VIII.C, may issue early action allowances; a state implementing a rate-based plan approach, also described in section VIII.C, may issue early action ERCs. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs, as outlined below, for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions. The EPA intends that a portion of this pool will be reserved for eligible wind and solar projects, and a portion will be reserved for low-income EE projects. In the proposed federal plan, the EPA is taking comment on the size of each reserve, and is proposing provisions to provide that any unallocated amounts would be redistributed among participating states.

The EPA has determined that the size of this 300 million short ton CO_2-equivalent matching pool is an appropriate reflection of the CO_2 emission reductions that could be achieved by the additional early investment in RE and demand-side EE the agency expects will be incentivized by the CEIP. For example, in 2012, 13 GW of utility scale wind were deployed,[772] and, in 2014, 3.4 GW of utility-scale solar [773] plus 2–3 GW of distributed solar were deployed,[774] according to industry estimates. Assuming 19 GW per year of RE from 2017–2020 based on these historic maximums yields an installed base of 76 GW of RE potentially eligible for CEIP incentives in 2020 and/or 2021. Assuming an average capacity factor of 30 percent, this would translate into approximately 200 TWh/year of generation, which would be eligible for approximately 300 million short tons of matching allowances over the 2-year period, if the RE MWh were converted to allowances based on the 2012 carbon intensity of 0.8 short tons per MWh. This would leave the remaining half of the pool of matching federal

---

[772] U.S. Energy Information Administration Electric Power Annual 2013. *http://www.eia.gov/electricity/annual*. Table 4.6: Capacity additions, retirements and changes by energy source. March 2015.

[773] U.S. Energy Information Administration Electric Power Monthly. *http://www.eia.gov/electricity/monthly*. Table 6.3: New Utility Scale Generating Units by Operating Company, Plant, Month, and Year.

[774] GTM Research/Solar Energy Industries Association: U.S. Solar Market Insight Q1 2015.

allowances available for EE projects implemented in low-income communities, and additional growth in RE deployment beyond these historic maximums as potentially enabled by reductions in cost and improvements in performance.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to eligible projects. These are projects that:

- Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;
- Are implemented 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 complete state plan by that date;
- For RE: Generate metered MWh from any type of wind or solar resources;
- For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and
- Generate or save MWh in 2020 and/or 2021.

The following provisions outline how a state may award early action ERCs or allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

- For RE projects that generate metered MWh from any type of 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.

- 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.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule, and will address design and implementation details of the CEIP, including the appropriate factor for determining equivalence between allowances and MWh and the definition of a low-income community for project eligibility purposes, in a subsequent action. Before doing so, the EPA will engage states and stakeholders to gather additional information concerning implementation topics, and to solicit information about the concerns, interests and priorities of states, stakeholders and the public.

In order for a state that chooses to participate in the CEIP to be eligible for a future award of allowances or ERCs from the EPA, a state must include in its initial submittal a non-binding statement of intent to participate in the program. In the case of a state submitting a final plan by September 6, 2016, the state plan would either include requirements establishing the necessary infrastructure to implement such a program and authorizing its affected EGUs to use early action allowances or ERCs as appropriate, or would include a non-binding statement of intent as part of its supporting documentation and revise its plan to include those requirements at a later date.

Following approval of a final state plan that includes requirements for implementing the CEIP, the agency will create an account of matching allowances or ERCs for the state that reflects the pro rata share—based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states—of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal matching pool upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021.

Any matching allowances or ERCs that remain undistributed after September 6, 2018,[775] will be distributed to those states with approved state plans that include requirements for CEIP participation. These ERCs and allowances will be distributed according to the pro rata method outlined above. Unused matching allowances or ERCs that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA.

---

[775] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

For purposes of establishing a state plan program eligible for an award of matching allowances or ERCs from the EPA, such a program must include a mechanism for awarding early action emission allowances or ERCs for eligible actions that reduce or avoid CO_2 emissions in 2020 and/or 2021, and that is implemented in a way such that the early action allowances or ERCs allocated by the state would maintain the stringency of the state's goal for emission performance from affected EGUs in the performance periods established in this rule. Specifically, the state must demonstrate in its plan that it has a mechanism in place that enables issuance of ERCs or allowances from the state to parties effectuating reductions in 2020 and/or 2021 in a manner that would have no impact on the aggregate emission performance of affected EGUs required to meet rate-based or mass-based CO_2 emission standards during the compliance periods.[776] This demonstration is not required to

[776] For example, under a mass-based implementation, the state plan could include a set-aside of early action allowances from an emissions budget that itself reflects the state goals. Allocation of those early action allowances to parties effectuating reductions in 2020 and 2021 would have no impact on the total emissions budget, which sets the total allowable emissions in the compliance periods. Alternatively, under a rate-based implementation, the state plan could require that early action ERCs issued to parties effectuating reductions in 2020 and 2021 would be "borrowed" from a pool of ERCs created by the state during the interim plan performance period. States could limit the size of the "borrowed" pool of ERCs to be equivalent to the size of the federal matching pool, or could take into consideration the potential for each state's federal matching pool to expand after a redistribution of unused credits. For every early action ERC awarded for actions in 2020 and 2021, the state would retire

account for matching ERCs or allowances that may be issued to the state by the EPA. Participation in this program is entirely voluntary, and nothing in these provisions would have the effect of requiring any particular affected EGU to achieve reductions prior to 2022, or requiring states to offer incentives for emission reductions achieved prior to 2022.[777] These and other details will be developed in the subsequent action.

The EPA is providing the CEIP as an option for states implementing plans—and is including a similar program for the federal plan proposal being issued concurrently—for several reasons. Chief among them is that offered by commenters to the effect that the overall cost of achievement of the emission performance rates or state goals could be reduced by an approach that granted some form of beneficial recognition to emissions reduction investments that both occur and yield reductions prior to the first date on which the program of the interim plan performance period. Other commenters pointed out that to the extent that states and utilities would benefit from the availability of low-cost RE and other zero-emitting generation options during the interim and final plan performance periods, the EPA should include in the final emission guidelines provisions that accelerate

---

one ERC from the pool of ERCs created as a result of reductions achieved from 2022 onward.

[777] In addition to the CEIP, states may also offer credit for early investments in RE and demand-side EE according to the provisions of section VIII.K.1 of this final rule: A state may award ERCs to qualified providers that implement projects from 2013 onward that realize quantified and verified MWh results in 2022 and subsequent years.

deployment of RE resources, since in so doing the final emission guidelines would speed achievement of expected reductions in the cost of those technologies commensurate with their accelerated deployment. In addition, the incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the start date 2 years later than at proposal.

The specific criteria the EPA is establishing for eligible RE projects reflect a variety of considerations. First, the EPA seeks to preserve the incentive for project developers to execute on planned investments in all types of solar and wind technologies. Commenters raised concerns that the fast pace of reductions underlying the emission targets in the proposed rule could potentially shift investment from RE to natural gas, thus dampening the incentive to develop wind and solar projects, in particular. Second, the EPA, consistent with the CAA's design that incentivizes technology and accelerates the decline in the costs of technology, seeks to drive the widespread development and deployment of wind and solar, as these broad categories of renewable technology are essential to longer term climate strategies. Finally, in contrast to other CO_2-reducing technologies—including other zero-emitting or RE technologies—solar and wind projects often require lead times of shorter duration, which would allow them to generate MWh beginning in 2020.

The specific criterion the EPA is establishing for eligible EE projects—namely that these projects be implemented in low-income communities—is also consistent with the technology-forcing and development design of CAA section 111. The EPA believes it is appropriate to offer an additional incentive to remove current barriers to implementing demand-side EE programs in low-income communities. While the EPA acknowledges that a number of states have demand-side EE programs focused on these communities,[778] the agency also recognizes that there have been historic economic, logistical, and information barriers to implementing programs in these communities. As a result, the costs of implementing demand-side EE programs in these communities are typically higher than in other communities and stand as barrier to harvesting potentially cost effective reductions and advancing these technologies. The EPA intends for the CEIP to help incentivize increased deployment of projects that will deliver demand-side EE benefits to these communities, which will in turn lower the costs of these approaches. These lower costs will help new technologies and delivery mechanisms penetrate in the future, thus improving the cost of implementation of the emission guidelines overall, consistent with Congress' design in the New Source Performance Standard provisions of the CAA. Further, reducing barriers to demand-side EE in low-income communities will help ensure that the benefits of the final rule are shared broadly across society and that potential adverse impacts on low-income ratepayers are avoided. It complements other steps the federal

[778] Several of these programs are discussed in section IX of this preamble, including, for example, Maryland's EmPOWER Low Income Energy Efficiency Program (LIEEP) and New York's EmPower New York program.

government is taking to bring clean energy technologies to these communities, as we discuss in section IX of this preamble.

More broadly, the CEIP responds to the urgency of meeting the challenge of climate change in two key ways. First, of course, it fosters reductions before 2022. Second, in targeting investments in wind, solar and low-income EE, it focuses on the kinds of measures and technologies that are the essential foundation of longer-term climate strategies, strategies that inevitably depend on the further development and widespread deployment of highly adaptable zero-emitting technologies.

We are not requiring that projects demonstrate to states that they are "additional" or surplus relative to a business-as-usual or state goal-related baseline in order to be eligible. At the same time, we believe that including an incentive to develop projects that benefit low-income communities will increase the likelihood of investments being made that would not have been made otherwise.

In order to be awarded matching ERCs or allowances by the EPA for projects that meet the eligibility criteria, a final state plan must have requirements establishing the appropriate infrastructure to issue early action ERCs or allowances to eligible project providers by 2020. The state must require that the state or its agent will, in accordance with state plan requirements approved as meeting the ERC issuance and EM&V requirements included in section VIII.K: (1) Evaluate project proposals from eligible RE and demand-side EE project providers, including the EM&V plans that must accompany such proposals; (2) evaluate monitoring and verification reports submitted by eligible providers following project implementation, which contain the quantified and verified MWh of RE generation or energy savings achieved by the project in 2020 and/or 2021; (3) issue ERCs or allowances to eligible providers for these MWh results; (4) ensure that no MWh of renewable generation or energy savings receives early action or matching ERCs or allowances more than once.[779]

The CEIP will provide a number of benefits. First, the program will provide incentives designed to reduce energy bills early in the implementation of the guidelines through earlier and broader application of energy saving technologies, and help ensure that these benefits are fully shared by low-income communities. Second, the EPA believes that stimulating or supporting early investment in RE generation technologies could accelerate the rate at which the costs of these technologies fall over the course of the interim performance period. Third, the CEIP will provide affected EGUs and states with additional emission reduction resources to help them achieve their state plan obligations. Finally, the program will

---

[779] For a state plan incorporating the use of ERCs or allowances to be approvable by the EPA, such a plan must use an EPA-approved or EPA-administered tracking system for ERCs or allowances. The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

improve the liquidity, in the early years of the program, of the ERC and allowance markets we expect to emerge for compliance with the requirements of these guidelines.[780]

The EPA is establishing this program as an option for states that wish to drive investments in RE and low-income EE that will result in actual, early reductions in CO_2 emissions from affected EGUs. States are also authorized to set their own glide path, or interim step performance rates or goals, so long as the interim and final performance rates or goals are met, and could do so in a way that takes into account the availability of the CEIP to assist affected EGUs in meeting the applicable glide path and performance rates or goals. While the EPA is not requiring states to take advantage of this program, its availability simply enhances these already-existing implementation and compliance flexibilities while at the same time delivering meaningful benefits, particularly for low-income communities. The EPA looks forward to an upcoming public dialogue about the implementation details of the CEIP.

[780] The CEIP is expected to provide states and affected EGUs additional flexibility in meeting the guidelines, and bears similarity in both design and purpose to the Compliance Supplement Pool, which the agency established as a part of the NO_X SIP Call. *See* 63 FR 57356, 57428–30 (Oct. 27, 1998). Certain aspects of the Compliance Supplement Pool were challenged in litigation and upheld by the D.C. Circuit Court of Appeals. *See* *Michigan v. EPA*, 213 F.3d 663, 694 (D.C. Cir. 2000).

C. State Plan Approaches

1. Overview

Under the final emission guidelines, states may adopt and submit either of two different types of state plans. The first would apply all requirements for meeting the emission guidelines to affected EGUs in the form of federally enforceable emission standards.[781] We refer to this as an "emission

[781] 40 CFR 60.21(f) defines "emission standard" as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions." This definition is promulgated and effective, and we note that it authorizes the use of allowance systems as a form of emission standard. To resolve any doubt that allowance systems are an acceptable form of emission standard in the final rule, we are including regulatory text in the final subpart UUUU regulations authorizing the use of allowance systems as a form of emission standard under section 111(d). Section 60.21(f) was originally amended in 2005 to include recognition of allowance systems as a form of emission standard in the Clean Air Mercury Rule (CAMR) (70 FR 28606, 28649; May 18, 2005). CAMR was vacated in its entirety in *New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008). However, the reason for vacatur was wholly unrelated to the question of whether an allowance system could be a form of emission standard. In response to the *New Jersey* decision, the agency removed CAMR provisions from the Code of Federal Regulations. The agency chose to retain the language of 60.21(f) and 60.24(b)(1) generally recognizing allowance systems. This language is broader than CAMR and unrelated to the reasons for its vacatur. The EPA re-promulgated these provisions in February of 2012 (77 FR 9304, 9447; Feb. 16, 2012). Even if this were not the case, the agency would not concede that simply because "allowance systems" were not provided for in the framework regulations of subpart B, they could not be relied upon in specific emission guidelines, such as these for CO_2. The implementing regulations generally serve a gap-filling role where there are not more specific provisions laid out in the relevant

standards" state plan type. The second, which we refer to as a "state measures" plan type, would allow the state mass CO_2 emission goals to be achieved by affected EGUs in part, or entirely, through state measures [782] that apply to affected EGUs, other entities, or some combination thereof. The state measures plan type also includes a mandatory contingent backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of emission performance as specified in the state plan during the period that the state is relying on state measures. The inclusion of a backstop of federally enforceable emission standards in a state measures plan type is legally necessary for a state plan to meet the terms of 111(d), which specifically require a state to submit standards of performance.

These two types of state plans and their respective approaches, either of which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of CAA section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. Further, as described in detail below, both types of plans are

---

emission guidelines. In order to resolve any question whether allowance systems are authorized under the final rule, we are including regulatory text in subpart UUUU to make this authorization explicit.

[782] "State measures" refer to 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.

responsive to comments we received from states and other stakeholders. In addition to providing states the option of developing an emission standards or state measures type plan, the final rule makes clear that states that choose an emission standards plan can adopt a plan that meets either the CO_2 emission performance rates, a rate-based CO_2 emission goal, or a mass-based CO_2 emission goal.

Under these two basic plan types, the final emission guidelines provide states with a number of potential plan pathways for meeting the emission guidelines. A plan pathway represents a specific plan design approach used to meet the emission guidelines. These plan pathways are discussed in section VIII.C.2 through C.5 below, and further elaborated in sections VIII.J (for mass-based emission standards) and VIII.K (for rate-based emission standards).

The final emission guidelines provide four streamlined plan pathways. These streamlined plan pathways represent straightforward plan approaches for meeting the emission guidelines, and avoid the need to meet additional plan requirements and include additional elements in a plan submittal. The streamlined plan pathways include the following:

- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs, complemented by state-enforceable mass-based CO_2 emission standards for new fossil fuel-fired EGUs.[783] This approach could involve an emission budget trading program that includes affected EGUs as well

---

[783] New source CO_2 emission complements are discussed in section VIII.J.2.b, which also provides EPA-derived new source CO_2 emission complements for states.

as new fossil fuel-fired EGUs. This approach facilitates interstate emission trading, through either a single-state "ready-for-interstate-trading" plan approach or through a multi-state plan. Under a "ready-for-interstate-trading" plan, interstate emission trading may occur without the need for a multi-state plan.[784]

- Establishing federally enforceable, mass-based CO_2 emission standards for affected EGUs.[785] his approach facilitates interstate emission trading, through either a single-state "ready-for-interstate-trading" plan approach or through a multi-state plan. In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.[786]

- Establishing federally enforceable, subcategory-specific rate-based CO_2 emission standards for affected EGUs, consistent with the CO_2 emission performance rates in the emission guidelines. This approach provides for interstate emission trading, through either a single-state "ready-for-interstate-

[784] Mass-based trading-ready plans are addressed in section VIII.J.3. Multi-state plans, where a group of states are meeting a joint CO_2 goal for affected EGUs, are addressed in section VIII.C.5.

[785] This plan approach would meet a state mass-based CO_2 goal for affected EGUs, or a joint multi-state mass-based CO_2 goal for affected EGUs. These plan approaches are discussed in sections VIII.J.2 and VIII.C.5, respectively.

[786] Submission of a state plan based on the EPA's finalized model rule for a mass-based emission trading program could be considered presumptively approvable. The EPA would evaluate the approvability of such submission through an independent notice and comment rulemaking.

trading" plan approach or through a multi-state plan.[787] In a separate concurrent action, the EPA is proposing a model rule for states that could be used in a plan implementing this approach.

- Establishing federally enforceable rate-based CO_2 emission standards at a single level that applies for all affected EGUs, consistent with the state rate-based CO_2 goal for affected EGUs in the emission guidelines.[788] This approach provides for interstate emission trading, through a multi-state plan that meets a single weighted average multi-state rate-based CO_2 goal.[789]

The final emission guidelines also provide for a range of additional custom plan approaches that a state may pursue, if it chooses, to address specific circumstances or policy objectives in a state. The custom plan pathways, while viable options for meeting the emission guidelines, come with additional plan requirements and plan submittal elements. These additional plan requirements and plan submittal elements are necessary to ensure that the emission guidelines are met and that the necessary level of CO_2 emission performance is achieved by affected EGUs.

Based on this overall approach, the final emission guidelines provide for a range of state options—both easily implementable approaches that can be used to

---

[787] Rate-based trading-ready plans are addressed in section VIII.K.4.

[788] This plan approach is addressed in section VIII.C.2.a.

[789] This multi-state plan approach is addressed in section VIII.C.5.

meet the emission guidelines, and more customizable approaches that can be used, if a state chooses, to address special circumstances or state policy objectives.

2. "Emission Standards" State Plan Type

The emission standards type of state plan imposes requirements solely on affected EGUs in the form of federally enforceable emission standards. This type of state plan, as described below, may consist of rate-based emission standards for affected EGUs or mass-based emission standards for affected EGUs.

The state plan submittal for an emission standards type plan must demonstrate that these federally enforceable emission standards for affected EGUs will achieve the CO_2 emission performance rates or the applicable state rate-based or mass-based CO_2 emission goal for affected EGUs.

Both rate-based and mass-based emission standards included in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Rate-based and mass-based emission standards may incorporate the use of emission trading, as described below. The EPA anticipates the use of emission trading in state plans, given the advantages of this approach and comments suggesting a high degree of interest on the part of states, utilities, and independent power producers in the inclusion of emission trading in state plans.[790]

---

[790] The legal basis for authorizing trading in emission standards is discussed in section VIII.C.6.

The EPA notes it is proposing model rules for both mass-based and rate-based emission trading programs. States could adopt and submit the finalized model rules for either emission trading program to meet the requirements of CAA section 111(d) and these emission guidelines. The EPA will evaluate the approvability of such submission, as with any state plan submission, through independent notice-and-comment rulemaking. The EPA notes that state plan submittals that adopt the finalized model rule may be administratively and technically more straightforward for the EPA in evaluating approvability, as the EPA will have determined that the model rule meets the applicable requirements of the emission guidelines through the process of finalization of such rule.

a. *Rate-based approach.* The first type of "emission standards" plan approach a state may choose is one that uses rate-based emission standards. Under this plan approach, the plan would include federally enforceable emission standards for affected EGUs, in the form of lb CO_2/MWh emission standards.

A rate-based "emission standards" plan may be designed to either meet the CO_2 emission performance rates for affected EGUs or achieve the state's rate-based CO_2 emission goal for affected EGUs. A plan could be designed such that compliance by affected EGUs would assure achievement of either the CO_2 emission performance rates for affected EGUs or the state rate-based CO_2 emission goal. To meet the CO_2 emission performance rates for affected EGUs, a plan would establish separate rate-based emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines. To meet a state rate-based CO_2 goal, a plan would establish a uniform rate-based emission standard (in lb CO_2/MWh) that applies to all affected EGUs in the state. This uniform emission rate would be equal to or lower than the applicable state rate-based CO_2 goal specified in the final emission guidelines.

Under these two approaches, compliance by affected EGUs with the rate-based emission standards in a plan would ensure that affected EGUs meet the CO_2 emission performance rates in the emission guidelines or the state rate-based CO_2 goal for affected EGUs. No further demonstration would be necessary by the state to demonstrate that its plan would achieve the CO_2 emission performance rates or the state's rate-based CO_2 goal.

Alternatively, if a state chooses, it could apply rate-based emission standards to individual affected EGUs, or to categories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal. In this case, compliance by affected EGUs with their emission standards would not necessarily ensure that the collective, weighted average CO_2 emission rate for these affected EGUs meets the CO_2 emission performance rates or the state's rate-based CO_2 goal.[791]

---

[791] The weighted average CO_2 emission rate that will be achieved by the fleet of affected EGUs in a state that applies different rate-based emission standards to individual affected EGUs or groups of affected EGUs will depend upon the mix of

Under this type of approach, therefore, the state would be required to include a demonstration,[792] in the state plan submittal, that its plan would achieve the CO_2 emission performance rates or applicable state rate-based CO_2 goal. This demonstration would include a projection of the collective, weighted average CO_2 emission rate the fleet of affected EGUs would achieve as a result of compliance with the emission standards in the plan. Once the plan is implemented, if the CO_2 emission performance rates or applicable state rate-based CO_2 goal are not achieved, corrective measures would need to be implemented, as described in section VIII.F.3.

Under a rate-based approach, a state may include in its plan a number of provisions to facilitate affected EGU compliance with the emission standards. First, a state may encourage (or require) EGUs to undertake actions to reduce CO_2 emissions at the affected EGU level, such as heat rate improvements or fuel switching. These measures are discussed in section VIII.I. Second, a state may implement a market-based emission trading program, which enables EGUs to generate and procure ERCs, a tradable compliance unit representing one MWh of electric generation (or

---

electric generation from affected EGUs subject to different emission standards. For example, if a state applies higher emission standards for affected steam generating units and lower emission standards for affected NGCC units, the greater the projected amount of electric generation from steam generating units, the higher the projected weighted average emission rate that will be achieved for all affected EGUs.

[792] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 emission goal is one of the required plan components, as described in section VIII.D.2.

reduced electricity use) with zero associated CO_2 emissions. Considerations and requirements for rate-based trading programs are discussed in section VIII.K.

ERCs would be issued by the administering state regulatory body. The state may issue ERCs to affected EGUs that emit below a specified CO_2 emission rate, as well as for measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. These ERCs may then be used to adjust the reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each submitted ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Eligible measures that may generate ERCs, as well as the accounting method for adjusting a CO_2 emission rate, are discussed in section VIII.K.1. Requirements for rate-based emission trading approaches are discussed in section VIII.K.2. Quantification and verification requirements for measures eligible to generate ERCs are discussed in section VIII.K.3.

(1) *Rate-based emission standards based on operational or other standards.*

As discussed in further detail in section VIII.D.2.d.3, regarding the legal considerations and statutory language of CAA section 111(h), the EPA is finalizing that design, equipment, work practice, and operational standards cannot be considered to be "standards of performance" for this final rule. However, a state may elect to use emission standards for affected EGUs that result in a reduced CO_2

lb/MWh emission rate for affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the rate standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 CO_2 lb/MWh as of a certain date. The state would thus include in the state plan an emission standard of 0 CO_2 lb/MWh for that affected EGU that applies after a specified date.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any rate-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in CO_2 lb/MWh. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other rate-based emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 CO_2 lb/MWh reflecting a retirement mandate for one or more affected EGUs in a state and apply a rate-based emission standard equal to the CO_2 emission performance rates or a state's rate-based CO_2 emission goal to the remainder of affected EGUs.

As with all emission standards, emission standards based on design, equipment, work practice, and operational standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

(2) *Additional considerations for rate-based approach.*

Additional considerations and requirements for rate-based emission standards state plans are addressed in section VIII.K. This includes the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, as well as requirements for the use of measures to adjust a CO_2 emission rate, both of which are discussed in sections VIII.K.1 through 3. Such requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. Section VIII.K.4 addresses multi-state coordination among rate-based emission trading programs.

b. *Mass-based approach.*

The second "emission standards" approach a state may elect to use is mass-based emission standards applied to affected EGUs. Under this approach, the plan would include federally enforceable emission standards for mass CO_2 emissions from affected EGUs. The plan would be designed to achieve the mass-based CO_2 goal for a state's affected EGUs (see section VII) or a level of CO_2 emissions equal to or less than the mass-based CO_2 goal plus the new source complement CO_2 emissions (see section VIII.J.2.b, Table 14).[793]

---

[793] For example, a state plan designed to meet a state mass-based CO_2 goal for affected EGUs plus a new source complement could involve a mass-based emission budget trading program that, under state law, applies to both affected EGUs, as well as new

Under a mass-based approach, a state could require that individual affected EGUs meet a specified mass emission standard. Alternatively, a state could choose to implement a market-based emission budget trading program. The EPA envisions that the latter option is most likely to be exercised by states seeking to implement a mass-based emission standard approach, as it would maximize compliance flexibility for affected EGUs and enable the state to meet its mass goal in the most economically efficient manner possible.

(1) *Mass-based emission standard applied to individual affected EGUs.*

One pathway a state could take to achieve its mass-based CO_2 goal would be to apply mass-based emission standards to individual affected EGUs, in the form of a limit on total allowable CO_2 emissions. These emission standards would be designed such that total allowable CO_2 emissions from all affected EGUs in a state are equal to or less than the state's mass-based CO_2 goal, or a state's mass-based CO_2 goal plus the new source complement CO_2 emissions specified in section VIII.J.2.b, Table 14. The individual affected EGUs would be required to emit at or below their mass-based standard to demonstrate compliance. Under this approach, individual affected EGUs would be required to undertake source-specific measures to assure their CO_2 emissions do not exceed their

---

fossil fuel-fired EGUs. The program requirements for affected EGUs would be federally enforceable, while the program requirements for other fossil fuel-fired EGUs would be state-enforceable. This approach is described further in section VIII.J.2.

assigned emission standard. Affected EGU compliance with the emission standards prescribed under this type of mass-based approach would ensure that the affected EGUs in a state achieve the state's mass-based CO_2 goal, or mass-based CO_2 goal plus new source complement.

(2) *Mass-based emission standard with a market-based emission budget trading program.*

A second pathway a state could take to achieve its mass-based CO_2 goal would be to implement a market-based emission budget trading program. This type of program provides maximum compliance flexibility to affected EGUs, and as a result, may be attractive to states that choose to implement a mass-based approach in their state plan.

An emission budget trading program establishes a combined emission standard for a group of emission sources in the form of an emission budget. Emission allowances are issued in an amount up to the established emission budget.[794] Allowances may be distributed to affected emission sources (as well as to other parties) through a number of different methods, including direct allocation to affected sources or auction. These allowances can be traded among affected sources and other parties. The emission standard applied to individual emission sources is a requirement to surrender emission allowances equal to reported emissions, with each allowance representing one ton of CO_2.

[794] An emission allowance represents a limited authorization to emit, typically denominated in one short ton or metric ton of emissions.

The EPA views an emission budget trading program as a highly efficient, market-based approach for reducing CO_2 emissions from affected EGUs. Such programs include a limit on mass CO_2 emissions while providing both short-term and long-term price signals that encourage the owners or operators of affected EGUs, as well as other entities, to determine the most efficient means of achieving the mass emission standard. Notably, such an approach incentivizes actions taken at affected EGUs to reduce CO_2 emissions, as well as the use of strategies such as RE and demand-side EE as complementary measures that reduce CO_2 emissions. However, unlike under a rate-based approach, for this latter set of measures there is no need to address and describe these state measures in a state plan submission or quantify and verify the RE and EE MWh of generation and savings. As a result, a mass-based emission budget trading program incentivizes and recognizes a wide range of emission reduction actions while being relatively simple for a state to implement and administer. Furthermore, the EPA notes that such an approach still allows for a state to address electricity load growth, as load growth can be met through low- and zero-emitting generating resources, as well as avoided through demand-side EE and demand-side management (DSM) measures.

Additional considerations and requirements for mass-based emission standards state plans are addressed in section VIII.J. This includes use of emission budget trading programs in a state plan, including provisions required for such programs (section VIII.J.2.a) and the design of such programs in the context of a state plan. Section VIII.J addresses program design approaches that ensure achievement of a state mass-based CO_2 emission goal (section VIII.J.2.c), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.d). Section VIII.J.2.e addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

(3) *Mass-based emission standards based on operational or other standards.*

As discussed in section VIII.C.2.a.(1) above, a state may elect to use mass-based emission standards for affected EGUs that result in a reduced total tonnage of CO_2 emissions from affected EGUs because of operational or other standards. The state would include in its state plan an emission standard that is the mass standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 total tons of CO_2, as of a certain date. The state would thus include in the state plan an emission standard of 0 total tons of CO_2 for that affected EGU that applies after a specified date. Under a mass-based approach, the state could also include an emission standard (*e.g.*, a mass limit) that reflects the result of a limit on an affected EGU's total operating hours over a specified period. Such an emission standard would be based on an affected EGU's potential to emit given a specified number of operating hours.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any mass-based plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in total tons of CO_2. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying other emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 tons of CO_2 for one or more affected EGUs, reflecting a retirement mandate for one or more affected EGUs in a state, and include the remainder of affected EGUs in an emission budget trading program.

3. "State Measures" State Plan Type

The second type of state plan is what we refer to as a "state measures" plan. As previously discussed, the EPA believes states will be able to submit state plans under the emission standards plan type, and its respective approaches, and achieve the CO_2 emission performance rates or state rate-based or mass-based CO_2 goals by imposing federally enforceable requirements on affected EGUs. Upon further consideration of the requirements of CAA section 111(d), in consideration of the comments we received on the proposed portfolio approach and the state commitments approach, and in order to provide flexibility and choice to states that may wish to adopt a plan that does not place all the obligations on affected EGUs, the EPA is finalizing the state measures plan type in addition to the emission standards plan type. The EPA believes the state measures plan type will provide states with additional latitude in accommodating existing or planned programs that involve measures implemented by the state, or by entities other than affected EGUs, that result in avoided generation and CO_2 emission reductions at affected EGUs. This includes market-based emission budget trading programs that apply, in part, to affected EGUs, such as the programs implemented by California and the RGGI participating states in the Northeast and Mid-Atlantic, as well as RE and demand-side EE requirements and programs, such as renewable portfolio standards (RPS), EERS, and utility- and state-administered incentive programs for the deployment of RE and demand-side EE technologies and practices. The EPA believes this second state plan type will afford states with appropriate flexibility while meeting the statutory requirements of CAA section 111(d).

Measures implemented under the state measures plan type could include RE and demand-side EE requirements and deployment programs. This type of plan could align with existing state resource planning in the electricity sector, including RE and demand-side EE investments by state-regulated electric utilities. The state measures plan type also can accommodate emission budget trading programs that address a broader set of emission sources than just affected EGUs subject to CAA section 111(d), such as the programs currently implemented by California and the RGGI participating states. The EPA also notes that the state measures plan type could accommodate imposition by a state of a fee for CO_2

emissions from affected EGUs, an approach suggested by a number of commenters.

This plan type would allow the state to implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures in achieving the required level of CO_2 emission performance from affected EGUs. The state measures under this plan type could be measures involving entities other than affected EGUs, or a combination of such measures with emission standards for affected EGUs, so long as the state demonstrates that such measures will result in achievement of a state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), as discussed below. The EPA notes that under this plan type, a state could also choose to include any emission standards for affected EGUs, which are required to be included in the plan as federally enforceable measures, to be implemented alongside or in conjunction with state measures the state would implement and enforce.

For a state measures plan to be approvable, it must include a demonstration of how the measures, whether state measures alone or state measures in conjunction with any federally enforceable emission standards for affected EGUs, will achieve the state mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source complement). However, because the state measures would not be federally enforceable emission standards, the plan must also include a backstop of federally enforceable emission standards for all affected EGUs, in order for the state measures plan type to satisfy the requirement of CAA section 111(d) that a state establish standards of performance for affected EGUs. This backstop would impose federally enforceable emission standards on the state's affected EGUs in the case that the state measures fail to achieve the state mass-based CO_2 goal. The backstop, discussed further below, would assure that the state CO_2 emission goal or CO_2 emission performance rates are fully achieved by affected EGUs in the form of federally enforceable emission standards.

a. *Requirements for state measures under a state measures type plan.*

Under the state measures plan type, state measures must be satisfactorily described in the supporting material for a state plan submittal. The supporting material would need to demonstrate that the state measures meet the same integrity elements that would apply to federally enforceable emission standards. Specifically, the state plan submittal must demonstrate that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2. Under the state measures plan, if a state chooses to impose emission standards on affected EGUs, such emission standards must be included in the federally enforceable plan as they would be under an emission standards plan.

The EPA would assess the overall approvability of a state measures plan based, in part, on the state's satisfactory demonstration that the state measures, in conjunction with any federally enforceable emission standards on the affected EGUs that might be included in the plan, would result in the state plan's achievement of the mass-based CO_2 goal for the state's affected EGUs (or mass-based CO_2 goal plus new source complement). This includes a demonstration of adequate legal authority and funding to implement the state plan and any associated measures. The EPA's determination that such a plan is satisfactory would be based in part on whether the state measures are adequately described in the supporting documentation and the plan submittal demonstrates that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent as described above. This is necessary for the EPA to ensure that the results achieved through the plan are quantifiable and verifiable, and to assess whether the state measures are anticipated to achieve the state mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source complement).

The EPA's evaluation of the approvability of a state measures plan would also include an assessment of whether the backstop consisting of federally enforceable emission standards for the state's affected EGUs would ensure that the required emission performance level is fully achieved by affected EGUs, in the case that the state measures fail to achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source complement), or the state does not meet programmatic state measures milestones during the interim period. The trigger for the backstop must also satisfactorily provide for the implementation of the backstop emission standards.

b. *Considerations for the backstop included in a state measures type plan.*

As further discussed in section VIII.C.6.c, the EPA believes a backstop, composed of federally enforceable emission standards for the affected EGUs that are sufficient to achieve the state CO_2 emission goal or the CO_2 emission performance rates in the event that state measures do not result in the required CO_2 emission performance, is necessary for the state measures plan type to meet the requirements of CAA section 111(d). The state plan must specify the backstop that would apply federally enforceable emission standards to the affected EGUs if the state measures plan does not achieve the anticipated level of CO_2 emission performance by affected EGUs, or a state does not meet programmatic state measures milestones during the interim period. The state plan must include promulgated regulations (or other requirements) that fully specify these emission standard requirements, which must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

These federally enforceable emission standards must be designed such that compliance by affected EGUs with the emission standards would achieve the CO_2 emission performance rates or state's rate- or mass-based interim and final goals for affected EGUs. The backstop emission standards must specify CO_2 emission performance levels that would apply for the interim plan performance period (including specifying levels for each of the interim step 1 through step 3 periods) and the final two-year plan performance periods.[795] If a state chose, these backstop emission

[795] This includes the level of emission performance during the interim plan periods 2022–2024, 2025–2027 and 2028–2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030–2031, and subsequent 2-year periods).

standards could be based on a model rule or federal plan promulgated by the EPA.

The state measures plan must specify the trigger and conditions under which the backstop federally enforceable emission standards would apply that is consistent with the requirements in the emission guidelines. The trigger and attendant conditions for deployment of the backstop would address the CAA section 111(d) requirement that states submit a program that provides for the implementation of standards of performance. The state measures plan must specify the level of emission performance that will be achieved by affected EGUs as a result of implementation of the state measures plan during the interim and final plan performance periods. This includes the level of emission performance during the interim plan periods 2022–2024, 2025–2027 and 2028–2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030–2031, and subsequent 2-year periods). If actual CO_2 emission performance by affected EGUs fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029) or for any 2-year final goal performance period, the state measures plan must require that the backstop federally enforceable emission standards would take effect and be applied to affected EGUs. Similarly, the plan must require that the backstop standards take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in the plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027). The backstop standards are also triggered if, at the time of the state's annual reports to the EPA during the interim period, the state has not met the programmatic state measures milestones for the reporting period. The state measures plan must provide that, in the event the backstop is triggered, such emission standards would be effective within 18 months of the deadline for the state's submission of its periodic report to the EPA on state plan implementation and performance, as described in section VIII.D.2.c.[796] [797]

The backstop emission standards must make up for the shortfall in CO_2 emission performance. The shortfall must be made up as expeditiously as practicable. The state may address the requirement to make up for the shortfall in CO_2 emission performance by submitting, as part of the final plan, backstop emission standards that assure affected EGUs would achieve the state's interim and final CO_2 emission goals or the CO_2 emission performance rates for affected EGUs, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the state plan revision process. The state may alternately effectuate this by submitting, along with the backstop emission standards, provisions to adjust the emission standards

---

[796] States may choose to establish an effective date for backstop emission standards that is sooner than 18 months.

[797] In the event a state does not implement the backstop as required if actual emission performance triggers the backstop, the EPA will take appropriate action. The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

to account for any prior emission performance shortfall, such that no modification of the emission standards is necessary in order to address the emission performance shortfall.

For example, assume a state measures plan identified a mass-based CO_2 standard for affected EGUs of 100 million tons during the interim step 1 performance period (2022–2024), 90 million tons during the interim step 2 performance period (2025–2027), and 80 million tons during the interim step 3 performance period (2028–2029). Over the entire interim plan performance period (2022–2029), the interim mass-based CO_2 goal is cumulative emissions of 270 million tons. Assume that CO_2 emissions from affected EGUs in the interim step 1 period were actually 115 million tons, triggering implementation of the backstop. In this instance, the mass-based standard for affected EGUs implemented as part of the backstop during subsequent plan performance periods would need to ensure that cumulative CO_2 emissions during the 2022–2029 interim period do not exceed 270 million tons. This could be achieved, for example, by implementing a mass standard of 75 million tons during the interim step 2 performance period (rather than the 90 million tons originally specified in the plan), or some other combination during the remaining interim step 2 and 3 performance periods.[798] The emission standards included as the

[798] In this example, states could elect to implement different combinations of mass-based standards during the remaining interim step 2 and 3 plan performance periods, provided that cumulative CO_2 emissions during the full interim plan performance period (2022–2029) do not exceed 270 million tons.

backstop in the plan must specify calculations for how such adjustments will be made.

4. Summary of Comments on State Plan Approaches

The EPA received a wide range of comments on the basic plan approaches in the proposal. Numerous commenters supported providing states with the option of implementing a rate-based or mass-based approach. Some commenters expressed concern that a rate-based approach would not reduce overall emissions, and could actually lead to increased emissions. The EPA does not agree with this latter comment, because both approaches would result in adequate and appropriate constraints on CO_2 emissions. As documented in the RIA, a rate-based approach would result in a substantial reduction in CO_2 emissions relative to emissions under a business-as-usual case.

Numerous commenters supported allowing states to implement a rate-based emission standard approach applied to affected EGUs. There was also broad support in comments for allowing states to pursue a mass-based approach in the form of mass emission standards on affected EGUs. The EPA is finalizing both of these approaches.

The EPA received a mix of comments for and against the proposed portfolio approach, in which state requirements and other measures that apply to non-EGU entities would be part of a state's federally enforceable state plan. Multiple commenters supported the portfolio approach because it would align with existing state and utility planning processes in the electric power sector, and would maximize state discretion and flexibility in developing plans. Commenters mentioned the range of state requirements and utility programs overseen by states that could be used under a portfolio approach and result in achieving the CO_2 emission goal for affected EGUs, including state RPS, EERS and utility-administered EE programs. Commenters noted that the portfolio approach would provide states maximum flexibility to take local circumstances, economics and state policy into account when developing their plans.

By contrast, multiple commenters opposed the portfolio approach. Some commenters questioned how a portfolio approach would work, and whether the EPA had provided sufficient detail explaining how such a plan approach could be implemented by a state. In particular, multiple commenters questioned how different state programs, such as utility-administered EE programs, could be made federally enforceable in practice under CAA section 111(d). [799] Multiple commenters expressed concern about making state requirements and utility programs for RE and demand-side EE enforceable under the CAA. Some of these commenters supported the state commitments plan approach that the EPA took comment on in the proposal, which was a variant of the portfolio approach. Under the state commitment variant, measures that applied to entities other than affected EGUs would not be federally enforceable under the CAA, but state commitments to implement those measures would be federally enforceable elements of a state plan under the CAA.

---

[799] Legal considerations with the proposed portfolio approach are explored in section VIII.C.6.d.

After considering these comments, the EPA is not finalizing the portfolio approach or the state commitment variant. However, the EPA is finalizing the state measures plan type, as described above, which would accommodate state choices and allow states to rely upon a variety of measures, as was envisioned under the portfolio approach, in a way that meets the statutory requirements of CAA section 111(d).

5. Multi-State Plans and Multi-State Coordination

The EPA views the ability of a state to implement an individual plan or a multi-state plan as a significant flexibility that allows a state to tailor implementation of its plan to state policy objectives and circumstances. The EPA sees particular value in multi-state plans and multi-state coordination, which allow states to implement a plan in a coordinated fashion with other states. Such approaches can lead to more efficient implementation, lower compliance costs for affected EGUs and lower impacts on electricity ratepayers. Coordinated approaches also will help states identify and address any potential electric reliability impacts when developing plans.

The EPA received broad support in comments for allowing states to implement multi-state plan approaches, and has made multiple changes in the final rule to address many suggestions outlining different approaches states may want to take. These changes are intended to provide streamlined approaches for multi-state coordination while maintaining transparency and assuring that the CO_2 emission performance rates or state CO_2 emission goals are achieved.

The EPA is finalizing two approaches that allow states to coordinate implementation in order to meet the emission guidelines.[800]

First, states may meet the requirements of the emission guidelines and CAA section 111(d) by submitting multi-state plans that address the affected EGUs in a group of states. The EPA is finalizing the proposed approach by which multiple states aggregate their rate or mass CO_2 goals and submit a multi-state plan that will achieve a joint CO_2 emission goal for the fleet of affected EGUs located within those states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[801]

Second, the EPA is also finalizing another approach, in response to comments received on the proposed rule. This approach enables states to retain their individual state goals for affected EGUs and submit individual plans, but to coordinate plan implementation with other states through the interstate transfer of ERCs or emission allowances.[802] This approach facilitates

[800] The EPA notes that in addition to these approved approaches, other types of multi-state approaches may be acceptable in an approvable plan, provided the obligations of each state under the multi-state plan are clear and the submitted plan(s) meets applicable emission guideline requirements.

[801] The concept of a new source CO_2 emission complement is addressed in section VIII.J.2.b. Table 14 provides individual state new source CO_2 emission complements. For a multi-state plan, a joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in Table 14 for the states participating in the multi-state plan.

[802] This approach also applies where a state plan is designed to meet a state mass-based CO_2 goal plus a state's new source CO_2 emission complement.

interstate emission trading without requiring states to submit joint plans.[803] The EPA considers these to be individual state plans, not multi-state plans.

States have the option to implement this second approach in different ways, as discussed in section VIII.C.5.c. These different implementation options allow states to tailor their implementation of linked emission trading programs, based on state policy preferences, as well as economic and other considerations. These different options provide varying levels of state control over emission trading system partners and require varying levels of coordination in the course of state plan development.

In response to comments, the EPA is also further clarifying how multi-state plans with a joint goal for affected EGUs may be implemented. The EPA is clarifying that states may participate in more than one multi-state plan, if necessary, for example, to address affected EGUs in states that are served by more than one ISO or RTO. The EPA is further clarifying that a subset of affected EGUs in a state may participate in a multi-state plan. These clarifications are discussed in section VIII.C.5.d.

a. *Summary of comments on multi-state plans.*

Multiple commenters supported the EPA's proposed approach that would allow states to implement a multi-state plan to meet a joint CO_2 emission goal. However, a number of states commented that states should also be allowed to coordinate without

---

[803] States may submit individual plans with such linkages, or if they choose, provide a joint submittal. Forms of joint submittals are described at section VIII.E.

aggregating multiple individual state goals into a single joint goal. Many states questioned the incentives that a state would have to aggregate its goal with other states that have different goals, and also noted the administrative complexities presented by states seeking to formally coordinate state plans with one another.

The EPA notes that there are multiple incentives for states to collaborate by implementing a multi-state plan to meet an aggregated joint goal, regardless of the specific level of their individual goals, because states share grid regions and impacts from plan implementation will be regional in nature. Further, multiple analyses, including those by ISOs and RTOs, indicate that regional approaches could achieve state goals at lesser cost than individual state plan approaches. However, the EPA also recognizes the value in allowing for collaboration where states retain individual goals. These approaches could provide some of the benefits of a joint goal while reducing the negotiations among states necessary to develop a multi-state plan with a joint goal. As a result, the EPA has finalized the additional approaches described in section VIII.C.5 to provide for coordination while maintaining individual goals. These approaches would allow for interstate transfer of ERCs or emission allowances while retaining individual state goals.

Many commenters suggested that states should be encouraged to join or form regional market-based programs. Many commenters touted the economic efficiency benefits of such approaches, and noted that such programs have features that support electric reliability.

The EPA agrees with these comments, and notes that it encouraged such approaches in the proposal. While the EPA is not requiring states to join and/or form regional market-based programs, we note that such programs can be helpful for many reasons, including features that support reliability. Market-based programs allow greater flexibility for affected EGUs both in the short-term and long-term. Under a market-based program, affected EGUs have the ability to obtain sufficient allowances or credits to cover their emissions in order to comply with their emission standards. Additionally, we continue to encourage states to cooperate regionally. Regional cooperation in planning and reliability assessments is an important tool to meeting system needs in the most cost-effective, efficient, and reliable way.

b. *Multi-state coordination through a joint emission goal.*

Multiple states may submit a multi-state plan that achieves an aggregated joint CO_2 emission goal for the affected EGUs in the participating states (or a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement).[804] The joint emission goal

[804] As a conceptual and legal matter, the relationship between states coordinating to meet a joint CO_2 emission goal under this rule is similar to the relationship between states coordinating SIP submissions to attain the NAAQS in an interstate nonattainment area. In both cases, the states coordinate their actions in a way that, cumulatively, the measures applicable in each state will lead to achievement of a common interstate goal (with the EPA evaluating the sufficiency and success of the plans on a holistic, interstate basis). Despite the shared goal, in both cases, the mere fact of coordination has no effect on each state's sovereign legal authority. For example, the legally applicable rules in a given state are adopted by that state individually, not

approach is acceptable for both types of state plans, the "emission standards" plan type and the "state measures" plan type. However, the EPA is requiring that a joint goal may apply only to states implementing the same type of plan, either an "emission standards" plan or a "state measures" plan.[805]

Under this approach, a rate-based multi-state plan would include a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. A mass-based multi-state plan would include an aggregated mass-based CO_2 emission goal for the participating states, in cumulative tons of CO_2, derived by summing the

---

by a joint entity or other interstate mechanism. Similarly, the fact that the states coordinate their rules does not grant them the authority to directly enforce each other's rules, or to take direct legal action against a state that is failing to implement its own rules. Although some states may jointly submit their coordinated rules to the EPA as a matter of administrative convenience, the state rules within such a plan are nothing more than reciprocal laws of the sort that states routinely enact in voluntary coordination with each other.

[805] This is necessary because if the joint goal is not achieved during a plan performance period, different remedies would apply under an emission standards plan and a state measures plan. Under an emission standards plan, corrective measures would be triggered. Under a state measures plan, the federally enforceable backstop emission standards would be triggered. See section VIII.F.3.

individual mass-based CO_2 emission goals of the participating states.[806]

Such plans could include emission standards in the form of a multi-state rate-based or mass-based emission trading program.[807] Alternatively, states could submit a multi-state plan using a state measures approach.[808] Both approaches could provide for implementation of a multi-state emission trading program.

c. *Multi-state coordination among states retaining individual state goals.*

States that do not wish to pursue a joint CO_2 emission goal with other states may pursue a second pathway to multi-state collaboration. States may submit individual plans that will meet the CO_2

---

[806] Where a multi-state plan is designed to meet a joint mass-based CO_2 goal plus a joint new source CO_2 emission complement, the joint new source CO_2 emission complement would be the sum of the individual new source CO_2 emission complements in section VIII.J.2.b, Table 14, for the states participating in the multi-state plan.

[807] A potential example of this approach is the method by which the states participating in RGGI have implemented individual CO_2 Budget Trading Program regulations in a linked manner using a shared emission and allowance tracking system. Each state's regulations implementing RGGI stand alone on a legal basis, but provide for the use of CO_2 allowances issued in other participating states for compliance under the state regulations. These states are not listed by name in state regulations, which instead refer to participating states that have established a corresponding CO_2 Budget Trading Program regulation. More information is available at *http://www.rggi.org*.

[808] Under this approach, a state measure could include, if a state chose, a multi-state emission trading program that is enforceable at the state level.

emission performance rates or a state mass CO_2 goal for affected EGUs (or mass-based CO_2 goal plus the new source CO_2 emission complement), but include implementation in coordination with other state plans by providing for the interstate transfer of ERCs or CO_2 allowances, depending on whether the state is implementing a rate-based or mass-based emission trading program. This form of coordinated implementation may occur under both an "emission standards" type of plan and a "state measures" type of plan, where states are implementing emission trading programs.[809] For rate-based plans, this type of coordinated approach is limited to state plans with rate-based emission standards that are equal to the CO_2 emission performance rates in the emission guidelines.

Under this approach, a state plan could indicate that ERCs or CO_2 allowances issued by other states with an EPA-approved state plan could be used by affected EGUs for compliance with the state's rate-based or mass-based emission standard, respectively. Such plans must indicate how ERCs or emission allowances will be tracked from issuance through use by affected EGUs for compliance,[810] through either a

[809] ERCs may only be transferred among states implementing rate-based emission limits. Likewise, emission allowances may only be transferred among states implementing mass-based emission limits.

[810] Referred to in different programs as "surrender," "retirement," or "cancellation."

joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[811]

The EPA would assess the approvability of each state's plan individually—the use of ERCs or emission allowances issued in another state would not impact the approvability of the components of the individual state plan.[812] However, the EPA would also assess linkages with other state plans, to ensure that the joint tracking system or interoperable tracking systems used to implement rate-based or mass-based emission trading programs across states are properly designed with necessary components, systems, and procedures to maintain the integrity of the linked emission trading programs.

Coordinated state plan implementation among states that retain individual state mass-based CO_2 goals (or that implement individual state plans with rate-based emission standards consistent with the CO_2 emission performance rates in the emission

---

[811] The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

[812] Note that for mass-based plans, the approvability requirements for a state plan would differ, depending on the structure of the emission budget trading program included in the state plan. For example, approvability requirements and basic accounting with regard to whether a plan achieves a state's mass CO_2 goal would differ for emission budget trading programs that cover only affected EGUs subject to CAA section 111(d) vs. programs that apply to a broader set of emission sources. These considerations are addressed in section VIII.J.

guidelines) is discussed in more detail in sections VIII.J and K. Section VIII.J discusses coordinated implementation among states implementing individual mass-based emission budget trading programs and section VIII.K discusses coordinated implementation among states implementing individual rate-based emission trading programs.

d. *Multi-state plans that address a subset of EGUs in a state.*

The EPA is clarifying in the final emission guidelines that a state may participate in more than one multi-state plan. Under this approach, the state would identify in its submittal the subset of affected EGUs in the state that are subject to the multi-state plan or plans. This could involve a subset of affected EGUs that are subject to a multi-state plan, with the remainder of affected EGUs subject to a state's individual plan. Alternatively, different affected EGUs in a state may be subject to different multi-state plans. In all cases, the state would need to identify in each specific plan which affected EGUs are subject to such plan, with each affected EGU subject to only one multi-state plan or subject only to the state's individual plan (if relevant).

These scenarios may occur where a state chooses to cover affected EGUs in different ISOs or RTOs in different multi-state plans. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs in a respective grid region, in the case where state borders cross grid regions.

These scenarios may also occur where a state is served by multiple vertically integrated electric utilities with service territories that cross state lines.

This will provide states with flexibility to participate in multi-state plans that address the affected EGUs owned and operated by a utility with a multi-state service territory.

6. Legal Bases and Considerations for State Plan Types And Approaches

a. *Legal basis for emission standards approach.*

The emission standards approach is consistent with the requirements of CAA section 111(d). If a state simply adopts the CO_2 emission performance rates, then the corresponding rate-based emission standards in the state plan establish standards of performance for affected EGUs as required under section 111(d)(1)(A). Similarly, if a state chooses to achieve the rate-based CO_2 emission goal through rate-based emission standards applicable only to affected EGUs, or to achieve the mass-based CO_2 emission goal through mass-based emission standards applicable only to affected EGUs (or, alternatively, to achieve the mass CO_2 goal and a new source CO_2 emission complement through federally enforceable mass-based emission standards in conjunction with state enforceable emission standards on new sources), then the set of rate-based emission standards or the set of mass-based emission standards in the state plan establishes standards of performance for affected EGUs as required under section 111(d)(1)(A). The EPA has the authority to approve emission standards for affected EGUs as part of a state plan under all three cases (as long as such emission standards meet the requirements of CAA section 111(d) and the final emission guidelines), thereby making such emission standards federally enforceable upon approval by the

EPA. In all three cases, the emission standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent; this ensures that the plan provides for implementation and enforcement of the standards of performance (*i.e.* the emission standards) as required by section 111(d)(1)(B). Finally, as described in section VIII.B.7.b below, standards of performance may include emission trading. Thus, the credit and allowance trading that is allowed under the emission standards approach is consistent with the statutory requirement that the plan establish standards of performance.

We note that the standard the statute provides for the EPA's review of a state plan is whether it is "satisfactory." We interpret a "satisfactory" plan as one that meets all applicable requirements of the CAA, including applicable requirements of these guidelines. Some commenters suggested that "satisfactory" should be taken to mean something less (such as mostly or substantially meeting requirements) but the structure of 111(d) shows otherwise. When a state plan is unsatisfactory, section 111(d)(2) gives the EPA the "same" authority to promulgate a federal plan as the EPA has under section 110(c). Under section 110(c), the EPA has authority to promulgate a federal implementation plan if a SIP does not comply with all CAA requirements (see sections 110(k)(3) and 110(l)).

For example, if an emission standards type plan includes an emission standard that is unenforceable due to defective rule language, then the plan is not satisfactory because it does not comply with the guideline requirement that emission standards must be enforceable. On the other hand, if a state plan complies with all applicable requirements of the CAA (including these guidelines), then the EPA must approve it as satisfactory. This is true even if the emission standards in the state plan are more stringent than the minimum requirements of these guidelines, or the state plan achieves more emission reductions than required by these guidelines. This follows from section 116 of the CAA as interpreted by the U.S. Supreme Court in *Union Elec. Co.* v. *EPA*, 427 U.S. 246, 263–64 (1976).

b. *Legal basis for emissions trading in state plans.*

There are three legal considerations with respect to emissions trading in state plans. First, we explain how the definition of "standard of performance" in section 111(a)(1) allows section 111(d) plans to include standards of performance that authorize emissions trading. Second, we explain how the EPA interprets the phrase "provides for implementation and enforcement of [the] standards of performance" in the context of a rate-based ERC trading program. Third, we give a similar explanation of the EPA's interpretation of the same phrase in the context of a mass-based allowance trading program.

(1). In the proposal, the EPA proposed that CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading. 79 FR 34830, 34927/1 (June 18, 2014). We are finalizing that states may include the use of emission trading in approvable state plans.

For purposes of this legal discussion, in the case of an emission limitation expressed as an emission rate, trading takes the form of buying or selling ERCs that an affected EGU may generate if its actual emission rate is lower than its allowed emission rate or that an eligible resource may generate. In the case of an emission limitation expressed as a mass-based limit, trading takes the form of buying or selling allowances.

As quoted in full above, the definition of "standard of performance" under CAA section 111(a)(1) is 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 . . . the Administrator determines has been adequately demonstrated."

Both an emission rate that may be met through tradable ERCs, and a mass limit requirement that emissions not exceed the number of tradable allowances surrendered by an affected source, qualify as a "standard for emissions." The term "standard" is not defined, but its everyday meaning is a rule or requirement,[813] which, under the only (or at least a permissible) reading of the provision, would include an emission rate that may be met through tradable ERCs and a requirement to retire tradable allowances.

Treating a tradable emission rate or mass limit requirement as a "standard of performance" is consistent with past EPA practice. In the Clean Air Mercury Rule, promulgated in 2005, the EPA established tradable mass limits as the emission guidelines for certain air pollutants from fossil fuel-fired EGUs, and explained that a tradable mass limit

---

[813] E.g., "Something that is set up and established by authority as a rule for the measure of quantity, weight, value, or quality." Webster's Third New International Dictionary 2223 (1967); see also The American College Dictionary (C.L. Barnhart, ed. 1970) ("an authoritative model or measure").

qualifies as a "standard for emissions." [814] In addition, in the 1995 Municipal Solid Waste (MSW) Combustor rule the EPA authorized emission trading by sources.[815]

It should be noted that CAA section 302(l) includes another definition of "standard of performance," which is "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." As described above, section 111(d) contains its own, more specific definition of "standard of performance," which a tradable emission rate or mass limit satisfies. Whether or not section 302(l) applies in light of section 111(d)'s more specific definition, a tradable emission rate or mass limit also meets section 302(l)'s requirements. A tradable emission rate applies continuously in that the source is under a continuous obligation to meet its emission rate, and that is so regardless of the averaging time, *e.g.*, a rate that must be met on an annual basis. Similarly, a mass limit requirement implemented through the use of allowances applies continuously in that the source is continuously under an obligation to assure that at the appropriate time, its emissions will not exceed the allowances it will surrender. In this respect, a tradable emission rate or mass limit requirement is similar to a non-tradable emission rate that must be met over a specified period, such as one year. In all of these cases, a source is continuously subject to its requirement although it may be able to emit at different levels at different points in time. It

---

[814] 70 FR 28606, 28616–17 (May 18, 2005).

[815] 60 FR 65387, 6540/2 (Dec. 19, 1995).

should also be noted that a tradable emission rate or mass limit requirement is appropriate for CO_2 emissions, the air pollutant covered by this rule, because the environmental effects of CO_2 emissions are not dependent on the location of the emissions.

(2). In our final rule, we are prescribing certain specific requirements for trading systems for ERCs in a rate-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic components for state plans) and are intended to ensure the integrity of the ERC trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance, as required by section 111(d)(1)(B). Requirements relating to ERCs in a rate-based trading system, and allowances in a mass-based system, must also be submitted as federally enforceable components of the state plan, as such requirements provide for the implementation and enforcement of a tradable emission rate or mass limit for an affected EGU.

However, as described in section VIII.C.6.d, the EPA has legal concerns regarding whether federally enforceable requirements under a CAA section 111(d) state plan can be imposed on entities other than affected EGUs. It is important to note that the use of ERCs and inclusion of state plan requirements regarding a rate-based trading system, and the use of allowances and inclusion of state plan requirements regarding a mass-based trading system, does not run afoul of these legal concerns, as neither the requirements of section 111(d) nor of the federally enforceable state plan in either case extend to non-EGU generators or third-party verifiers of such compliance units.

(3). In our final rule, we are prescribing certain specific requirements for trading systems for allowances in a mass-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic requirements for state plans) and are intended to ensure the integrity of the allowance trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance.

c. *Legal basis for state measures plan type.*

The EPA believes the state measures plan type is consistent with CAA section 111(d). Section 111(d)(1) requires a state to submit a plan that "(A) establishes standards of performance for any existing source for [certain] air pollutant[s] . . . and (B) provides for the implementation and enforcement of such standards of performance." Section 111(d)(2)(A) indicates that the EPA must approve the state plan if it is "satisfactory."

For states that choose to adopt and submit a state measures plan, such state must submit a state plan that includes standards of performance for CO_2 emissions from affected EGUs in the form of a federally enforceable backstop in order to meet the requirements of section 111(d). Section 111(d) unambiguously requires a state to submit a plan that establishes standards of performance for certain sources, but does not mandate when such standards of performance must be in effect or implemented in order to meet applicable compliance deadlines. Instead, Congress has delegated to the EPA the determination of the appropriate effective date of standards of performance submitted under state plans to meet the requirements of section 111(d). In other words, where the statute is silent, the EPA has authority to provide a reasonable interpretation. The EPA's interpretation is that for states that submit state plans establishing standards of performance under section 111(d), the effective date of such standards of performance may be later in time, perhaps indefinitely, for a number of reasons and under certain conditions. A key condition is that the state plan provides for the achievement of the required reduction by means other than the standards of performance on the timetable required by the BSER, with provision for federally enforceable standards of performance to be implemented if those other means fall short. The EPA believes it is reasonable to defer the effective date for standards of performance for affected EGUs as long as affected EGU CO_2 emissions are projected to achieve, and do achieve, the requisite state goal.

Additionally, under the state measures plan type, if a state chooses to impose emission standards for the affected EGUs in conjunction with state measures that apply to other entities for any period prior to the triggering of the backstop, this final rule requires such emission standards to be submitted as federally enforceable measures included in the state plan. The EPA believes this is appropriate to help ensure the performance of a state measures plan will meet the requirements of this final rule. Section 111(d) clearly authorizes states to impose, and the EPA to approve, federally enforceable emission standards for affected

EGUs. Though federally enforceable emission standards for affected EGUs in a state measures plan themselves would not necessarily achieve the requisite state goals, the EPA is authorized to approve state plans when they satisfactorily meet applicable requirements. The EPA can evaluate whether a state measures plan is satisfactory by determining whether any federally enforceable emission standards for affected EGUs in conjunction with state measures on other entities will result in the achievement of the requisite emissions performance level. As previously explained in this final rule, the performance rates and the state goals are the arithmetic expression of BSER as applied across affected EGUs in a state as a source category. In a state measures plan, the evaluation of whether a state measures plan is satisfactory goes to evaluating both the state measures and any federally enforceable emission standards on the affected EGUs to determine whether the plan as a whole will result in the affected EGUs achieving the applicable goals that reflect BSER.

Section 111(d)(1)(B) also requires a state to submit a program that provides for the implementation and enforcement of the applicable standards of performance. Under the state measures approach, this requirement regarding implementation is satisfied in part by the submission of an approvable trigger mechanism for the backstop and appropriate monitoring, reporting and recordkeeping requirements. The trigger mechanism provides for the "implementation" of the backstop, *i.e.*, the standards of performance, by putting the backstop into effect once the associated trigger is deployed. In other words, when the CO_2 performance level under a state plan exceeds the trigger as described in section VIII.C.4.b, the emission standards that were submitted as the federally enforceable backstop and any attendant requirements must be implemented and in effect. The statutory requirement under CAA section 111(d)(2) regarding enforcement is also satisfied under the state measures plan type by the state submitting standards of performance sufficient to meet the requisite emission performance rates or state goal, in the form of the backstop, for inclusion as part of the federally enforceable state plan.

Additionally, by requiring states that choose to impose emission standards on affected EGUs under the state measures approach to submit such emission standards for inclusion in the federally enforceable plan, this requirement further provides for implementation and enforcement as required by the statute. Regulating the affected EGUs through federally enforceable emission standards themselves in conjunction with any state measures the state chooses to rely upon further assures the likelihood of the affected EGUs achieving the state goals as required under this rule and section 111(d).

The state measures plan is a variation of the proposed portfolio approach in that both plan types allow the state to rely upon measures that impose requirements on sources other than affected EGUs in meeting the requisite state CO_2 emission goal. The state measures plan type is also a variation of the proposed state commitment approach in that the measures involving entities other than affected EGUs are not included as part of the federally enforceable 111(d) state plan, but the state may rely upon such measures that have the effect of reducing CO_2

emissions from affected EGUs as a matter of state law. The EPA took comment on the proposed portfolio approach and state commitment approach, and on the utilization of measures on entities other than affected EGUs in meeting the requirements of the emission guidelines and CAA section 111(d). With respect to the proposed state commitment approach, the EPA received comments recommending that the EPA require a federally enforceable backstop with emission standards sufficient to achieve the requisite CO_2 emission performance. The backstop component the EPA is finalizing as part of the state measures plan type is consistent with the EPA's statements in the proposal regarding states' obligations under section 111(d) to establish emission standards for affected EGUs, as the backstop contains federally enforceable emission standards for affected EGUs that will achieve the requisite CO_2 emission performance, and is consistent with comments received regarding the proposed state commitment approach.

The state measures plan type the EPA is finalizing is also a logical outgrowth of the comments received on the proposed portfolio approach. As further explained below, legal questions remain as to whether state plans under section 111(d) can include federally enforceable measures that impose requirements on sources other than affected EGUs. However, a number of commenters and stakeholders expressed robust support for the ability to rely on measures and programs that do not impose requirements on affected EGUs themselves through plan types such as the proposed portfolio and state commitment approaches. The EPA is reasonably interpreting 111(d) as authorizing the state measures plan type, and believes this plan type is also responsive to, and accommodating of, states and stakeholders who have expressed the importance of being able to rely upon various measures that have the effect of reducing CO_2 emissions from affected EGUs. The EPA is finalizing the state measures plan type upon careful consideration of statutory requirements and comments received based on the proposed portfolio approach and state commitment approach.

The EPA additionally notes that the state measures plan type is not precluded by the recent Ninth Circuit Court of Appeals' decision in *Committee for a Better Arvin et al.* v. *US EPA et al.*, Nos. 11-73924 and 12-71332 (May 20, 2015). The court held that the EPA violated the CAA by approving a California SIP which relied on emission reductions from state-only mobile source standards ("waiver measures") without including those standards in the SIP. The court first looked at the plain language of section 110(a)(2)(A) of the CAA, which states that SIPs "shall include" the emission limitations and other control measures on which a state relies to comply with the CAA. The court then stated that the EPA's action was also inconsistent with the structure of the CAA. The EPA has the primary responsibility to protect the nation's air quality, but in the court's view, the EPA itself would be unable to enforce the state-only standards. In addition, the court stated that the EPA's action was inconsistent with citizens' right to enforce SIP provisions under section 304.

There are a number of reasons why this decision does not preclude the state measures plan type. The Ninth Circuit's textual analysis does not apply here, as the language of section 110(a)(2)(A) does not control for 111(d) state plans. Section 111(d)(1) requires state plans to "establish standards of performance" and to "provide for implementation and enforcement" of the standards of performance, but, unlike section 110(a)(2)(A), section 111(d) does not specifically say that every emission reduction measure must be "included" in the state plan and be made federally enforceable. Even if section 111(d) did impose such requirements, the state measures approach satisfies them because the trigger is included in the plan as a federally enforceable implementation measure, and the backstop included in the plan also contains standards of performance that reflect the BSER and are federally enforceable once they are triggered.

The Ninth Circuit's structural analysis also does not apply. The availability of the trigger and backstop gives the EPA and citizens a federally enforceable route to ensure that all necessary emission reductions take place in order to achieve the standards of performance. This is markedly different than the state-only standards, where according to the Ninth Circuit, the EPA and citizens had no route to ensure that all necessary emission reductions took place in order to attain the NAAQS. In addition, case law suggests that federal enforceability for every requirement may not be necessary when there are sufficient federally enforceable requirements to satisfy the statute, see *National Mining Ass'n* v. *United States EPA*, 59 F.3d 1351 (D.C. Cir. 1995); in this case federal enforceability for the state-only measures is not necessary to meet the statutory requirements of section 111(d)(1) as the federally enforceable trigger and backstop are sufficient.

d. *Legal considerations with proposed portfolio approach.*

The EPA is not finalizing the portfolio approach that was included in the proposed rulemaking, 79 FR 34830, 34902 (June 18, 2014). In the proposal, the EPA noted that the portfolio approach raised legal questions. 79 FR 34830, 34902–03. A number of commenters stated that the portfolio approach is unlawful because it exceeds the limitations that section 111(d)(1) places on state plans. Upon further review, we agree with these comments.

Section 111(d)(1) provides that state plans shall "establish[] "standards of performance for any existing source" and "provide[] for the implementation and enforcement of . . . standards of performance" under CAA section 111(d)(1). Although in the proposal we identified possible interpretations of section 111(d)(1) that could justify the proposed portfolio approach, after reviewing the comments, we are not adopting those interpretations. Because section 111(d)(1) specifically requires state plans to include only (A) standards for emissions imposed on affected sources and (B) measures that implement and enforce such standards,[816] we interpret it as allowing federal enforceability only of requirements or measures that are in those two specifically required provisions. We therefore do not interpret the term "implementation of . . . such standards of performance" to authorize the EPA to approve state plans with obligations enforceable against the broad array of non-emitting entities that would have been implicated by the

[816] Such measures include, for example, in this rule, requirements for ERCs.

portfolio approach. Thus, the EPA is not finalizing the portfolio approach, and in the event that states submit such measures to the EPA for inclusion in the state plan, the EPA would not approve them into the state plan and therefore would not make them federally enforceable.

We note that section 111(d) limits on federal enforceability of requirements against non-affected sources do not imply that the BSER cannot be based on actions by non-affected sources. As discussed in section V, the BSER may be based on the ability of owners/operators of affected sources to engage in commercial relationships with a wide range of other entities, from the vendors, installers, and operators of air pollution control equipment to, in this rulemaking, owners/operators of RE.

The EPA notes it is also not finalizing the proposed state commitment approach or state crediting approach. The EPA believes the finalized state measures plan type provides states with the same flexibilities as would have been allowed under these two proposed approaches, and does so in a way that is legally supportable by the CAA. Therefore, the EPA does not believe it necessary to finalize the state commitment approach or state crediting approach.

e. *Legal basis for multi-state plans.*

While nothing in section 111(d)(1) explicitly authorizes either states to adopt and submit multi-state plans, or the EPA to approve them as satisfactory, nothing in section 111(d)(1) explicitly prohibits it, either. In addition, nothing in section 111(d)(2)(A)'s standard of "satisfactory" prohibits the EPA from considering multi-state plans as satisfactory. There is thus a gap that the EPA may reasonably fill.

In light of the purpose of these emission guidelines, to reduce emissions of a pollutant that globally mixes in the stratosphere, and the mechanisms to reduce those emissions, which may have beneficial effects across state lines, it is reasonable to allow for multi-state plans. Thus, our gap-filling interpretation of section 111(d) in this context is reasonable.

D. State Plan Components and Approvability Criteria

1. Approvability Criteria

In the "Criteria for Approving State Plans" section of the preamble to the June 2014 proposal (section VIII.C), the EPA proposed the following as necessary components of an approvable state plan:

1. The plan must contain enforceable measures that reduce EGU CO_2 emissions;

2. The projected CO_2 emission performance by affected EGUs must be equivalent to or better than the required CO_2 emission performance level in the state plan;

3. The EGU CO_2 emission performance must be quantifiable and verifiable;

4. The plan must include a process for state reporting of plan implementation, CO_2 emission performance outcomes, and implementation of corrective measures, if necessary.

After reviewing the comments we received concerning the approvability criteria, the EPA has decided against maintaining the four proposed approvability criteria separately from the list of components required for an approvable plan, which may be confusing and potentially redundant. The EPA has determined that a satisfactory state plan that meets the required plan components discussed below will inevitably meet the proposed approvability criteria. The EPA, therefore, has incorporated the proposed approvability criteria into the section titled "Components of a state plan submittal" (section VIII.D.2 below). There is no functional change in the approvability criteria or the components of a state plan addressed in the proposal; they are simply combined and this change does not have a substantive effect on state plan development or approval.

Under the proposed "Enforceable Measures" criterion (section VIII.C.1 of the proposal preamble), the EPA specifically requested comment on the appropriateness of applying existing EPA guidance on enforceability to state plans under CAA section 111(d), considering the types of entities that might be included in a state plan.[817]

The EPA also requested comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs, and if so, what types of entities. Comments received strongly

[817] The existing guidance documents referenced were: (1) September 23, 1987 memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004 "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

suggested that the EPA provide guidance on enforceability considerations for non-EGU affected entities, particularly for RE and EE. Comments also requested additional guidance specific to this rulemaking, including examples of enforceable measures for specific activities, such as solar thermal technologies, waste heat recovery, net-metering energy savings and state RPS.

These enforcement considerations arose primarily under the proposed portfolio approach for state plans, which would have allowed state plans to include federally enforceable measures that apply to entities that are not affected EGUs. In this action, the EPA is finalizing the state measures approach instead of the portfolio approach, under which a state can rely upon measures that are not federally enforceable as long as the plan also includes a backstop of federally enforceable emission standards that apply to affected EGUs. As explained in depth in section VIII.C, if the state is adopting the state measures approach, the state plan submittal will need to specify, in the supporting materials, the state-enforceable measures that the state is relying upon, in conjunction with any federally enforceable emission standards for affected EGUs, to meet the emission guidelines. As part of the state measures approach, the EPA is finalizing a requirement for a federally enforceable backstop, which requires the affected EGUs to meet emission standards that fully achieve the CO_2 emission performance rates or the state's CO_2 emission goal if the state measures do not meet the state's mass-based CO_2 emission goal. Because the EPA is not finalizing the portfolio approach, which would have allowed states to include federally enforceable measures in a state plan that apply to entities that are not affected EGUs, the agency is not providing additional guidance on federal enforceability of measures that might apply to such entities. As proposed, we are requiring that state plans include a demonstration that plan measures are enforceable, which for emission standards plan types is discussed in section VIII.D.2.b.3 below and for state measures plan types is discussed in section VIII.D.2.c.6 below.

Commenters also requested that the EPA allow states to rely on provisions with flexible compliance mechanisms in state plans and clarify how to address flexible compliance mechanisms when demonstrating achievement of a state CO_2 emission goal. Additionally, a commenter requested that the enforceability mechanisms that the EPA requires in state plans should support existing programs, as well as new programs in other states, by minimizing program changes required purely to conform with federal requirements, while still providing enough additional program review and accounting to ensure that CO_2 emission reductions are achieved. These and related comments contributed to the EPA's decision to finalize the option for states to submit a state measures plan, which would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, with a backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the CO_2 emission performance levels specified in the plan on schedule. For more information on the state measures plan approach, see section VIII.C.3 of this preamble above.

2. Components of a State Plan Submittal

In this action, the EPA is finalizing that a state plan submittal must include the components described below. As a result of constructive comments received from many commenters and additional considerations, the EPA is finalizing state plan components that are responsive to that input and are appropriate for the types of state plans allowed in the final emission guidelines. A state plan submittal must also be consistent with additional specific requirements elsewhere in this final rule and with the EPA implementing regulations at 40 CFR 60.23–60.29, except as otherwise specified by this final rule. These requirements apply to both individual state plan submittals and multi-state plan submittals. When a state plan submittal is approved by the EPA, the EPA will codify the approved CAA section 111(d) state plan in 40 CFR part 62. Section VIII.D.3 discusses the components of a state plan submittal that would be codified as the state CAA section 111(d) plan when the state plan submittal is approved by the EPA.

The EPA is finalizing that states can choose to meet the emission guidelines through one of two types of state plans: an emission standards plan type or a state measures plan type. A state pursuing the emission standards plan type may opt to submit a plan that meets the CO_2 emission performance rates for affected EGUs or meets the state rate-based or mass-based CO_2 emission goal for affected EGUs. A state implementing a state measures approach plan type must submit a plan where the state measures, in conjunction with any emission standards on the affected EGUs, result in achievement of the state mass-based CO_2 goal for affected EGUs. The backstop required to be submitted as part of a state measures plan may achieve the CO_2 emission performance rates for affected EGUs or the state rate-based or mass-based CO_2 emission goal. The content of the state plan submittal will vary depending on which plan type the state decides to adopt. States that choose to participate in multi-state plans must adequately address plan components that apply to all participating states in the multi-state plan.

The rest of this section covers components that are required for all types of plans, as well as components specific to each specific type of plans. Section VIII.D.2.a addresses the components required for all plan submittals. Section VIII.D.2.b addresses the additional components required for submittals under the emission standards plan type. Section VIII.D.2.c addresses additional components required for submittals under the state measures plan type.

a. *Components required for all state plan submittals.*

The EPA is finalizing requirements that a final plan submittal must contain the following components, in addition to those in either section VIII.D.2.b (for the emission standards plan type) or VIII.D.2.c (for the state measures plan type) of this section.

(1) *Description of the plan approach and geographic scope.*

The description of the plan type must indicate whether the state will meet the emission guidelines on an individual state basis or jointly through a multi-state plan, and whether the state is adopting an emission standards plan type or a state measures plan type. For multi-state plans this component must identify all participating states and geographic boundaries applicable to each component in the plan submittal. If a state intends to implement its individual plan in coordination with other states by allowing for the interstate transfer of ERCs or emission allowances, such links must also be identified.[818]

(2) *Applicability of state plans to affected EGUs.*

The state plan submittal must list the individual affected EGUs that meet the applicability criteria of 40 CFR 60.5845 and provide an inventory of CO_2 emissions from those affected EGUs for the most recent calendar year prior to plan submission for which data are available.

(3) *Demonstration that a state plan will achieve the CO_2 emission performance rates or state CO_2 emission goal.*

A state plan submittal must demonstrate that the federally enforceable emission standards for affected EGUs and/or state measures are sufficient to meet either the CO_2 emission performance rates or the state's CO_2 emission goal for affected EGUs in the emission guidelines for the interim and final plan performance periods. This includes during the interim period of 2022–2029, including the interim step 1 period (2022–2024); interim step 2 period (2025–2027); and interim step 3 period (2028–2029) period, as well as during the final period of 2030–2031 and

[818] If applicable, this plan component must also identify if the plan is being submitted as a "ready-for-interstate-trading" plan, as discussed in section VIII.J.3 and VIII.K.4.

subsequent 2-year periods.[819] A demonstration of CO_2 emission performance is required through 2031. For the post-2031 period, the demonstration requirement may be satisfied by showing that emission standards or state measures on which the demonstration through 2031 is based are permanent and will remain in place. As discussed in more detail in section VIII.J, states adopting a plan based upon a mass-based state CO_2 emission goal must demonstrate that they have addressed the risk of potential emission leakage in their mass-based state plan.

The type of demonstration of CO_2 emission performance and documentation required for such a demonstration in a state plan submittal will vary depending on how the CO_2 emission standards for affected EGUs and/or state measures in a state plan are applied across the fleet of affected EGUs in a state, as discussed below.[820]

---

[819] State plans may meet the CO_2 emission performance rates in the emission guidelines during the interim plan performance step periods, or assign different interim step CO_2 emission performance rates, provided the CO_2 emission performance rates in the emission guidelines are achieved during the full interim period. Likewise, a state plan may meet the interim step state CO_2 emission goals in the emission guidelines or establish different interim step CO_2 emission levels, provided the state interim CO_2 goal is achieved during the full interim period.

[820] For simplicity, the EPA refers here to state measures under a state measures plan as being included "in the state plan" although such state enforceable measures are not codified as part of the federally enforceable approved state plan. However, the approval of a state measures plan is dependent on a demonstration in the state plan submittal that those state-enforceable measures meet the requirements in the emission guidelines and that those state measures, alone or in combination

(a) *State plan type designs that require a projection of CO_2 emission performance.* Whether a projection of affected EGU CO_2 emission performance must be included in a state plan submittal depends on the design of the state plan. The following plan designs do not require a projection of CO_2 emission performance by affected EGUs under the state plan because they ensure that the CO_2 emission performance rates or state rate-based or mass-based CO_2 goals are achieved when affected EGUs comply with the emission standards:

- State plan establishes separate rate-based CO_2 emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines during the interim and final plan performance periods.

- State plan establishes a single rate-based CO_2 emission standard for all affected EGUs that is equal to or lower than the state's rate-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.

- State plan establishes mass-based CO_2 emission standards for affected EGUs that cumulatively do not exceed a state's mass-based CO_2 goal in the emission guidelines during the interim and final plan performance periods.

- State plan establishes mass-based CO_2 emission standards for affected EGUs that, together

---

with federally enforceable emission standards for affected EGUs, will meet the mass-based CO_2 goal.

with state enforceable limits on mass emissions from new EGUs, cumulatively do not exceed the state's EPA-specified mass CO_2 emission budget [821] in the emission guidelines during the interim and final plan performance periods.

All other state plan designs must include a projection of CO_2 emission performance by affected EGUs under the state plan.

For example, if a state chooses to apply rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs (such as fossil fuel-fired electric utility steam generating units and stationary combustion turbines), at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal in the emission guidelines, then a projection is required. Also, if a state chooses to implement a mass-based program including both affected EGUs and new EGUs, but with total allowable emissions in excess of the presumptively approvable EPA-specified mass CO_2 emission budget for that state, the state must provide a projection of CO_2 emission performance. Likewise, if a state chooses a state measures state plan approach, a projection of CO_2 emission performance is required.

(b) *Methods and tools*. A satisfactory demonstration of the future CO_2 emission performance of affected EGUs must use technically sound methods that are reliable and replicable. A state plan submittal must explain how the projection

[821] A state's EPA-specified mass CO_2 emission budget is the state's mass-based CO_2 goal for affected EGUs plus the EPA-specified new source CO_2 emission complement. See section VIII.J.2.b.

method and/or tool works and why the method and/or tool chosen is appropriate considering the type of emission standards and/or state measures included (or relied upon, in the case of state measures) in a state plan. The results of the demonstration must be reproducible using the documented assumptions described in the state plan submittal. The method and projection of EGU generation and CO_2 emissions can differ from the EPA's forecast in the RIA. The EPA received comments on whether it would require specific modeling tools and input assumptions. Commenters raised concerns that the EPA may require states to use proprietary models, and that states do not have the financial resources to use such models. The EPA is not requiring a specific type of method or model, as long as the one chosen uses technically sound methods and tools that establish a clear relationship between electricity grid interactions and the range of factors that impact future EGU economic behavior, generation, and CO_2 emissions. The EPA will assess whether a method or tool is technically sound based on its capability to represent changes in the electric system commensurate to the set of emission standards and state measures in a state plan while accounting for the key parameters specified in section VIII.D.2.a.(3)(c) below. Including a base case CO_2 emission projection in the state plan submittal (*i.e.*, one that does not include any federally enforceable CO_2 emission standards included in a plan or state-enforceable measures referenced in a plan submittal), will help facilitate the EPA's assessment of the CO_2 emission performance projection. Methods and tools could range from applying future growth rates to historical generation and emissions data, using statistical analysis, or electric sector energy modeling.

(c) *Required documentation of projections.* When required to provide a CO_2 emission performance projection, the state must also provide comprehensive documentation of analytic parameters for the EPA to assess the reasonableness of the projection. The analytic parameters, when considered as a whole, should reflect a logically consistent future outlook of the electric system. Refer to the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD of the final rule for further details on quantifying impacts of eligible RE and demand-side EE measures.

The CO_2 emission performance projection documentation must include:

- Geographic representation, which must be appropriate for capturing impacts and/or changes in the electric system
- Time period of analysis, which must extend through 2031
- Electricity demand forecast (MWh load and MW peak demand) at the state and regional level. If the demand forecast is not from NERC, an ISO or RTO, EIA, or other publicly available source, then the projection must include justification and documentation of underlying assumptions that inform the development of the demand forecast, such as annual economic and demand growth rate, population growth rate.
- Planning reserve margins
- Planned new electric generating capacity

- Analytic treatment of the potential for building unplanned new electric generating capacity
- Wholesale electricity prices
- Fuel prices, when applicable;
- Fuel carbon content
- Unit-level fixed operations and maintenance costs, when applicable;
- Unit-level variable operations and maintenance costs, when applicable;
- Unit-level capacity
- Unit-level heat rate
- If applicable, EGU-specific actions in the state plan designed to meet the required CO_2 emission performance, including their timeline for implementation
- If applicable, state-enforceable measures, with electricity savings and renewable electricity generation (MWhs) expected for individual and collective measures, as applicable. Quantification of MWhs expected from EE and RE measures will involve assumptions that states must document, as described in the Incorporating RE and Demand-side EE Impacts into State Plan Demonstrations TSD.
- Annual electricity generation (MWh) by fuel type and CO_2 emission levels, for each affected EGU
- ERC or emission allowance prices, when applicable

The state must also provide a clear demonstration that the state measures and/or federally enforceable emission standards informing the projected achievement of the emission performance requirements will be permanent and remain in place.

The EPA encourages participation in regional modeling efforts which are designed to allow sharing of data and help promote consistent approaches across state boundaries. A state that submits a single-state plan must consider interstate transfer of electricity across state boundaries, taking into account other states' plan types reflecting the best available information at the time of the CO_2 emission performance projection. Projections of CO_2 emission performance for multi-state plans and single-state plans that include multi-state coordination must either use a single (regional) electricity demand forecast or must document the use of electricity demand forecasts from different information sources and demonstrate how any inconsistencies between the individual electricity demand forecasts have been reconciled.

(d) *Additional projection requirements under a rate-based emission standards plan.* For an emission standards plan that applies rate-based CO_2 emission standards to individual affected EGUs, or to subcategories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal in the emission guidelines, a projection of affected EGU CO_2 emission performance is required. The state must demonstrate that the weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh) from affected EGUs subject to the different rate-based emission standards, will be equal to or less than the CO_2 emission performance rates or the state's rate-based CO_2 emission goal during the interim and final plan performance periods.

The projection will involve 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. It must accurately represent the emission standards in the plan, including the use of market-based aspects of the emission standards (if applicable), such as use of ERCs or emission allowances as compliance instruments.

In addition to the elements described in the previous section (c), the projection under this plan design must include:

- The assignment of federally enforceable emission standards for each affected EGUs;
- A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time;
- Underlying assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible measures that can be issued ERCs;
- The specific calculation (or assumption) of how eligible MWh of electricity generation or savings that can be issued ERCs are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs, consistent with the accounting methods for adjusting the CO_2 emission rate of an affected EGU specified in section VIII.K.1 of the emission guidelines, if applicable;
- ERC prices, if applicable;

- If a state plan provides for the ability of RE resources located in states with mass-based plans to be issued ERCs for use in adjusting the reported CO_2 emission rates of affected EGUs, consideration in the projection that such resources must meet geographic eligibility requirements, based on power purchase agreements or related documentation, consistent with the requirements at section VIII.K.1 and section VIII.L; and

- Any other applicable assumptions used in the projection.

(e) *Additional projections requirements for a state measures plan.* For a state measures plan, a projection of affected EGU CO_2 emission performance must demonstrate that the state measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards for affected EGUs, will achieve the state's mass-based CO_2 goals in the emission guidelines for the interim and final periods. The projection must accurately represent individual state-enforceable measures (or bundled measures) and timing for implementation of these state measures.

A state must demonstrate that its state-enforceable measures, along with any federally enforceable CO_2 emission standards for affected EGUs included in a state plan, will achieve the state mass-based CO_2 goal. In addition to the elements described in section VIII.D.2.a.(3).(c), the state must clearly document, at a minimum:

- The assignment of federally enforceable emission standards for each affected EGUs, if applicable; and

- the individual state measures, including their projected impacts over time.

Because different types of state measures could have varying degrees of impact on reducing or avoiding CO_2 emissions from affected EGUs, and different state measures may interact with one another in terms of CO_2 emission reduction impacts, the method and tools a state uses to project CO_2 emissions impacts must have the capability to project how the combined set of state-enforceable measures are likely to impact CO_2 emissions at affected EGUs. If a state chooses to use an emission budget trading program as a mass-based state measure, for example, the state must choose an analytic method or tool that can account for and properly represent any program flexibilities that impact CO_2 emissions from affected EGUs, such as use of out-of-sector GHG offsets and cost-containment provisions. The state would show that the emissions budget trading program relied upon for the state measures plan, as well as any other state measures, ensure that the sum of emissions at all affected EGUs will be lower than or equal to the state's CO_2 emission goal in the time periods specified in these guidelines. All flexibilities must be clearly documented in the demonstration.

(4) *Monitoring, reporting and recordkeeping requirements for affected EGUs.*

The state plan submittal must specify how each emission standard is quantifiable and verifiable by describing the CO_2 emission monitoring, reporting and recordkeeping requirements for affected EGUs. The applicable monitoring, recordkeeping and reporting requirements for affected EGUs are outlined in section VIII.F.

In the June 2014 proposal, the EPA proposed that states must include in their state plans a record retention requirement for affected EGUs to maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Commenters requested clarification of the record retention requirements for states as compared to for affected EGUs and also requested that the EPA clarify onsite versus offsite record maintenance requirements for affected EGUs. The EPA is finalizing that states must include in their plans a record retention requirement for affected EGUs of not less than 5 years following the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest. Affected EGUs must maintain each record onsite for at least 2 years after the date of the occurrence of each record and may maintain records offsite and electronically for the remaining years. Each record must be in a form suitable and readily available for expeditious review. The EPA finds that these final recordkeeping requirements are appropriate and consistent with the requirements for other CAA section 111(d) emission guidelines.

(5) *State reporting and recordkeeping requirements.*

A state plan submittal must contain the process, content and schedule for state reporting to the EPA on plan implementation and progress toward meeting the CO_2 emission performance rates or state CO_2 emission goal.

The EPA requested comments on whether full reports containing all of the report elements should only be required every 2 years and on the appropriate frequency of reporting of the different proposed elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program transparency and effectiveness. Commenters recognized that different reporting frequencies may be appropriate for different types of state plans. The EPA agrees with the commenters and is finalizing state reporting requirements based on the type of plan the state chooses to adopt and implement. These state reporting requirements and reporting periods are discussed in section VIII.D.2.b (for emission standards plan types) and VIII.D.2.c (for state measures plan types). The EPA finalizes that each state report is due to the EPA no later than the July 1 following the end of each reporting period. The EPA recognizes the multiple comments received recommending extending the state report due date from July 1 to a later date or to allow the states the flexibility to propose an alternative report submittal date. The EPA is not pursuing these recommendations due to the implications of the state reports' due date and the trigger and schedule for implementation of corrective measures (for the emission standards approach) or the backstop federally enforceable emission standards (for the state measures approach). The EPA believes the July 1 deadline for states to submit reports to the EPA on plan implementation is feasible given that the information required to be included in the reports will be available per the reporting requirements for affected EGUs in state plans.

In addition to the state reporting requirements discussed in section VIII.D.2.b (for emission standards approach) and VIII.D.2.c (for state measures approach) and as discussed below, states must include in the supporting material of a final state plan submittal a timeline with all the programmatic plan milestone steps the state will take between the time of the final state plan submittal and 2022 to ensure the plan is effective as of 2022. The EPA is also finalizing a requirement that states must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic plan milestone steps that the state indicated it would take from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. A final state plan submission must include a requirement for the state to submit this report to the EPA no later than July 1, 2021. This report will help the EPA further assist and facilitate plan implementation with states as part of an ongoing joint effort to ensure the necessary reductions are achieved.

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, this includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The EPA is developing an electronic system to support this requirement that can be accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). See section VIII.E.8 for additional information on electronic submittal requirements.

In the June 2014 proposal, the EPA proposed that states must keep records, for a minimum of 20 years, of all plan components, plan requirements, plan supporting documentation and status of meeting the plan requirements, including records of all data submitted by each affected EGU used to determine compliance with its emission standards. The EPA received multiple comments recommending that the EPA reduce recordkeeping requirements due to the burden in expenditure of resources and manpower to maintain records for at least 20 years. Commenters recommended that recordkeeping requirements be reduced to 5 years consistent with emission guidelines for other existing sources.

After considering the comments received, this final rule requires that a state must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for the interim plan period from 2022–2029 (including interim steps 1, 2 and 3). 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 goals are being achieved. The EPA agrees with comments that a 20-year record retention requirement could be unduly burdensome, and has reduced the length of the record retention requirement for the final rule. During the interim period, states must keep records for 10 years from the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emission goal. During the final period, states must keep records for 5 years from the date the record is used to determine compliance with an emission standard, plan requirement, CO_2 emission performance rate or CO_2 emissions goal. All records must be in a form suitable and readily available for expeditious review. States must also keep records of all data submitted by each affected EGU that was used to determine compliance with each affected EGU's emission standard, and such data must meet the requirements of the emission guidelines, except for any information that is submitted to the EPA electronically pursuant to requirements in 40 CFR part 75. If the state is adopting and implementing the state measures approach, the state must also maintain records of all data regarding implementation of each state measure and all data used to demonstrate achievement of the mass CO_2 emission goal and such data must meet the requirements of the emission guidelines. The EPA finds that these final recordkeeping requirements balance the need to maintain records while reducing the strain on state resources.

(6) *Public participation and certification of hearing on state plan.*

A robust and meaningful public participation process during state plan development is critical. For the final plan submittal, states must meaningfully engage with members of the public, including vulnerable communities, during the plan development process. This section describes how the EPA will evaluate a state plan for compliance with the minimum required elements for public participation provided in the existing implementing regulations as well as recommendations for other steps the state can take to assure robust and inclusive public participation.

The existing implementing regulations regarding public participation requirements are in 40 CFR 60.23(c)–(f). Per the implementing regulations, states must conduct a public hearing on a final state plan before such plan is adopted and submitted. State plan development can be enhanced by tapping the expertise and program experience of several state government agencies. The EPA encourages states to include utility regulators (*e.g.* the PUCs) and state energy offices as appropriate early on and throughout in the development of the state plan.[822] The EPA notes that utility regulators and state energy offices have the opportunity during the public participation processes required for state plans to provide input as well. The EPA also encourages states to conduct outreach meetings (that could include public hearings or meetings) with vulnerable communities on its initial submittal before the plan is submitted. In its final plan submittal, a state must provide certification that the state made the plan submittal available to the public and gave reasonable notice and opportunity for public comment on the state plan submittal. The state must demonstrate that the public hearing on the state plan was held only after reasonable notice, which will be considered to include, at least 30 days prior to the date of such hearing, notice given to the public by prominent advertisement announcing the date(s), time(s) and place(s) of such hearing(s). For each hearing held, a state plan submittal must include in the supporting documentation the list of witnesses

[822] While we specifically encourage state environmental agencies and utility regulators to consult here, we note that, under CAA programs, state agencies have a history of consultation with one another as appropriate.

and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the implementing regulations at 40 CFR 60.23. Additionally, the EPA recommends that states work with local municipalities, community-based organizations and the press to advertise their state public hearing(s). The EPA also encourages states to provide background information about their proposed final state plan or their initial submittal in the appropriate languages in advance of their public hearing and at their public hearing. Additionally, the EPA recommends that states provide translators and other resources at their public hearings, to ensure that all members of the public can provide oral feedback.

As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location) are disproportionately affected by certain climate change related impacts.[823] Also as discussed in this rule, effects from this rule can be anticipated to affect vulnerable communities in various ways. Because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final

---

[823] USGCRP 2014: 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.

rule by states engaging in meaningful, active ways with such communities.

In addition, certain communities whose economies are significantly dependent on coal, or whose economies may be affected by ongoing changes in the utility power and related sectors, may be particularly concerned about the final rule. The EPA encourages states to make an effort to provide background information about their proposed initial submittal and final state plans to these communities in advance of their public hearing. In particular, the EPA encourages states to engage with workers and their representatives in the utility and related sectors, including the EE sector.

The EPA notes that meaningful public involvement goes beyond the holding of a public hearing. The EPA envisions meaningful engagement to include outreach to vulnerable communities, sharing information and soliciting input on state plan development and on any accompanying assessments, such as those described in section IX. The agency uses the terms "vulnerable" and "overburdened" in referring to low-income communities, communities of color, and indigenous populations that are most affected by, and least resilient to, the impacts of climate change, and are central to our community and environmental justice considerations. In section VIII.E, the EPA provides states with examples of resources on how they can engage with vulnerable communities in a meaningful way. With respect specifically to ensuring meaningful community involvement in their public hearing(s), however, the EPA recommends that states have both a Web site and toll-free number that all stakeholders, including overburdened communities, labor unions, and others can access to get more information regarding the upcoming hearing(s) and to get their questions related to upcoming hearings answered. Furthermore, the EPA recommends that states work with their local government partners to help them in reaching out to all stakeholders, including vulnerable communities, about the upcoming public hearing(s).

(7) *Supporting documentation.*

The state plan submittal must provide supporting material and technical documentation related to applicable components of the plan submittal.

(a) *Legal authority.*

In its submittal, a state must adequately demonstrate that it has the legal authority (regulations/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. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as copies of statutes, regulations, PUC orders, and any other applicable legal instruments. For states participating in a multi-state plan, the submittal(s) must also include as supporting documentation each state's necessary legal authority to implement the portion of the plan that applies within the particular state, such as copies of state regulations and statutes, including a showing that the states have the necessary authority to enter into a multi-state agreement.

(b) *Technical documentation.*

As applicable, the state submittal must include materials necessary to support the EPA's evaluation of the submittal including analytical materials used in the calculation of interim goal steps (if applicable), analytical materials used in the multi-state goal calculation (if multi-state plan), analytical materials used in projecting CO_2 emission performance that will be achieved through the plan, relevant implementation materials and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

(c) *Programmatic plan milestones and timeline.*

As part of the state plan supporting documentation, the state must include in its submittal a timeline with all the programmatic plan milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of January 1, 2022. The programmatic plan milestones and timeline should be appropriate to the overall state plan approach included in the state plan submittal.

(d) *Reliability.*

As discussed in more detail in section VIII.G.2, each state must demonstrate as part of its state plan submission that it has considered reliability issues while developing its plan.

b. *Additional components required for the emission standards plan type.* The EPA is finalizing requirements that a final plan submittal using the emission standards plan type must contain the following components, in addition to the components discussed in the preceding section VIII.D.2.a.

(1) *Identification of interim period emission performance rates or state goal (for 2022–2029), interim step performance rates or interim state goals (2022–2024; 2025–2027; 2028–2029) and final emission performance rates or state goal (2030 and beyond).*

The state plan submittal must indicate whether the plan is designed to meet the CO_2 emission performance rates or the state rate-based or mass-based CO_2 emission goal. As noted in the emission guidelines, the EPA is finalizing CO_2 emission performance rates for fossil fuel-fired steam generating units and for stationary combustion turbines. 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. The state may choose to develop a state plan that meets the CO_2 performance rates for the two subcategories of affected EGUs or develop a plan that adopts either the rate-based or the mass-based state CO_2 emission goal provided in the emission guidelines.

Each state plan submittal must identify the emission performance rates or rate-based or mass-based CO_2 emission goal that must be achieved through the plan (expressed in numeric values, including the units of measurement, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). The plan submittal must identify the CO_2 interim period performance rates or state goal (for 2022–2029), interim step performance rates or state goals (interim step performance rates or state goal 1 for 2022–2024; interim step performance rates or state goal 2 for 2025–2027; interim step performance rates or state goal 3 for 2028–2029) and final CO_2 emission performance rates or state goal of 2030 and beyond.

The EPA has finalized an interim performance rates or state goal for the interim period of 2022–2029 and a final performance rates or state goal to be met by 2030. For the interim period, the EPA has also finalized three interim step performance rates or state goals: interim step 1 performance rates or state goal for 2022–2024, interim step 2 performance rates or state goal for 2025–2027 and interim step 3 performance rates or state goal for 2028–2029.[824] States are free to establish different interim step performance rates or interim step state goals than those the EPA has specified in this final rule. If states choose to determine their own interim step performance rates or state goals, the state must demonstrate that the plan will still meet the interim performance rates or state goal for 2022–2029 finalized in the emission guidelines and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). For a rate-based multi-state plan this would be a weighted average rate-based

---

[824] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

emission goal, derived by the participating states, by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. For a mass-based multi-state plan, the joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) *Identification of federally enforceable emission standards for affected EGUs.*

The state plan submittal for an emission standards plan type must include federally enforceable emission standards that apply to affected EGUs. The emission standards must meet the requirement of component (3) of this section, "Demonstrations that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable." The plan must identify the affected EGUs to which these standards apply. The compliance periods for each emission standard for affected EGUs, on a calendar year basis, must be as follows for the interim period: January 1, 2022–December 31, 2024; January 1, 2025–December 31, 2027; and January 1, 2028–December 31, 2029. Starting on January 1, 2030, the compliance period for each emission standard is every 2 calendar years. States can choose to set shorter compliance periods for the emission standards than the compliance periods the EPA is finalizing in this rulemaking, but cannot set longer periods. As discussed in more detail in section VIII.F, the EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

For state plans in which affected EGUs may rely upon the use of ERCs for meeting a rate-based federally enforceable emission standard, the state plan must include requirements addressing the issuance, tracking and use for compliance of ERCs consistent with the requirements in the emission guidelines. These requirements are discussed in sections VIII.K.1–2. The state plan must also demonstrate that the appropriate ERC tracking infrastructure that meets the requirements of the emission guidelines will be in place to administer the state plan requirements regarding ERCs and document the functionality of the tracking system. State plan requirements must include provisions to ensure that ERCs are properly tracked from issuance to submission for compliance. The state plan must also demonstrate that the MWh for which ERCs are issued are properly quantified and verified, through plan requirements for EM&V and verification that meet the requirements in the emission guidelines. EM&V requirements are discussed in section VIII.K.3. Rate-based emission standards must also include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output for affected EGUs; and related compliance demonstration requirements and mechanisms. These requirements are discussed in more detail in sections VIII.F and VIII.K.

For state plans using a mass-based emission trading program approach, the state plan must include implementation requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements must include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions).

(3) *Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable.*

The plan submittal must demonstrate that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable with respect to an affected EGU, as outlined below.

An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.[825]

---

[825] A CO_2 continuous emissions monitoring system (CEMS) is the most technically reliable method of emission measurement for EGUs. A CEMS provides a measurement method that is performance based rather than equipment specific and is verified based on NIST traceable standards. A CEMS provides a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same

An emission standard is non-duplicative with respect to an affected EGU if it is not already incorporated in another state plan, except in instances where incorporated as part of a multi-state plan. An example of a duplicative emission standard would occur, for example, where a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA section 111(d) plan to adjust the reported CO_2 emission rate of an affected EGU (*e.g.*, through issuance and use of an ERC), except in the case of a multi-state plan where CO_2 emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan or where states are implementing coordinated individual plans that allow for the interstate transfer of ERCs.[826] This does not mean that measures used to comply with an emission standard cannot also be used for other purposes. For example, a MWh of electric generation from a wind turbine could be used by an electric distribution utility to comply with state RPS requirements and also be used by an affected EGU to

---

performance criteria, which helps to ensure a level playing field and consistent, accurate data.

[826] For example, an ERC that is issued by a state under its rate-based emission standards may be used only once by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with the emission standards. However, an ERC issued in one state could be used by an affected EGU to demonstrate compliance with its emission standard in another state, where states are collaborating in the implementation of their individual emission trading programs through interstate transfer of ERCs, or participating in a multi-state plan with a rate-based emission trading program. These coordinated multi-state approaches are addressed in sections VIII.C.5, VIII.J.3, and VIII.K.4.

comply with emission standard requirements under a state plan. Another example is when actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (*e.g.*, Regional Haze requirements, MATS).

An emission standard is permanent if the emission standard must be met for each applicable compliance period.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it.

An emission standard is enforceable if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) compliance requirements are clearly defined; (3) the entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is enforceable as a practical matter in accordance with EPA guidance on practical enforceability,[827] and the Administrator, the state, and third parties maintain the ability to enforce against affected EGUs for

---

[827] The EPA guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/ Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

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

In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA's prior guidance on enforceability.[828] These guidance documents serve as the foundation for the types of monitoring, reporting, and emission standards that the EPA has found can be, as a practical matter, enforced.

In the proposed regulatory text describing the enforcing measures that states must include in state plans, the EPA inadvertently excluded a required demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard included in a state plan via civil action pursuant to CAA section 304. Commenters noted the EPA's intent to require this demonstration based on statements in both the proposal preamble text and "State Plan Considerations" TSD[829] and based on the requirements of CAA section 304. We are finalizing a requirement for a demonstration that states and other third parties can enforce against affected EGUs for violations of an emission standard

[828] See prior footnote.

[829] State Plan Considerations technical support document for the Clean Power Plan Proposed Rule: *http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations*.

included in a state plan via civil action as part of the required plan component demonstrating enforceability. We are finalizing this requirement as a logical outgrowth of proposal preamble text, the proposal preamble citation to existing enforceability guidance documents that discuss this requirement, comments received, and the clear statutory foundation.

(4) *State reporting requirements.*

After consideration of the comments received regarding state reporting requirements, the EPA is finalizing for state plans using the emission standards approach that a state report is due to the EPA no later than the July 1 following the end of each reporting period. Within the interim period (2022–2029) the EPA is finalizing the following interim reporting periods: Interim step 1 covers the three calendar years 2022–2024, interim step 2 covers the three calendar years 2025–2027, and interim step 3 covers the two calendar years 2028–2029. A biennial state report is required starting in 2030 and beyond covering the two calendar years of each reporting period. This final reporting schedule reduces the reporting frequency for states implementing the emission standards approach and is responsive to comments received that different reporting frequencies may be appropriate for different type of state plans. The EPA believes that because of the federally enforceable emission standards that apply to affected EGUs and their corresponding monitoring, reporting and recordkeeping requirements under the emission standards plan type, a lesser frequency of reporting by the state is warranted.

The state must include in each report to the EPA the status of implementation of emission standards for affected EGUs under the state plan, including current aggregate and individual CO_2 emission performance by affected EGUs during the reporting period. The state report must include compliance demonstrations for affected EGUs and identify whether affected EGUs 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 state plan. For rate-based emission trading programs, the report must also include for EPA review the state's review of the administration of their state rate-based emission trading program, as discussed in section VIII.K.2.g.

As discussed in more detail in section VIII.F, the state must include an interim performance check in the report submitted after each of the first two interim step periods. The interim performance check will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period with the actual CO_2 emission performance achieved by affected EGUs during the period. In the report due to the EPA on July 1, 2030, the state must include a comparison of the actual CO_2 emission performance achieved by affected EGUs for the interim period (2022–2029) with the interim CO_2 emission performance rates or state rate-based or mass-based CO_2 interim goal, as applicable. The report due on July 1, 2030, must also include the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028–2029). Starting in 2032, the biennial state report must include a final performance check to demonstrate that the affected EGUs continue to meet the final CO_2 emission performance rates or state rate-based or mass-based CO_2 goal.

For state plans that use the emission standards approach and are subject to the corrective measures provisions in the emission guidelines, if actual CO_2 emission performance (*i.e.*, the emissions or emission rate) of affected EGUs exceeds the specified level of CO_2 emission performance in the state plan by 10 percent or more during the interim step 1 or step 2 reporting periods, the state report must include a notification to the EPA that corrective measures have been triggered. The same notification is required if actual CO_2 emission performance fails to meet the specified level of emission performance in the state plan for the 8-year interim performance period or any final plan reporting period. Corrective measures are discussed in detail in section VIII.F.

c. *Additional components required for the state measures approach.*

The EPA is finalizing requirements that a final plan submittal using the state measures approach must contain the following components, in addition to the components discussed in section VIII.D.2.a. We note again that states choosing the state measures plan type must use a mass-based state goal for the state measures and any emission standards on the affected EGUs prior to the triggering of the backstop.

(1) *Identification of interim state mass goal (for 2022–2029), interim step state mass goals (2022–2024; 2025–2027; 2028–2029) and final state mass goal (2030 and beyond).*

The state plan submittal must identify the mass-based CO_2 emission goal that must be achieved through the plan (expressed in tons of CO_2). The plan submittal must identify the state CO_2 interim period goal (for 2022–2029), interim step goals (interim step goal 1 for 2022–2024; interim step goal 2 for 2025–2027; interim step goal 3 for 2028–2029) and final CO_2 emission goal of 2030 and beyond.

For each state, the EPA has finalized an interim goal for the interim period of 2022–2029 and a final goal to be met by 2030. For the interim period, the EPA has also finalized three interim step goals: Interim step 1 goal for 2022–2024, interim step 2 goal for 2025–2027 and interim step 3 goal for 2028–2029.[830] States are free to establish different interim step goals than those the EPA has specified in this final rule. If states choose to determine their own interim step goals, the state must demonstrate that it will still meet the interim goal for 2022–2029 finalized in this action and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be

---

[830] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

replaced with an equivalent multi-state goal for each period (interim and final). The joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(2) *Identification of federally enforceable emission standards for affected EGUs (if applicable).*

If applicable, the state plan submittal must include any federally enforceable CO_2 emission standards that apply to affected EGUs, and demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section VIII.D.2.b. Specifically, the state plan submittal must demonstrate that each federally enforceable emission standard is quantifiable, non-duplicative, permanent verifiable, and enforceable. If a state measures plan type includes CO_2 emission standards that apply to affected EGUs, these emission standards must be federally enforceable.

(3) *Identification of backstop of federally enforceable emission standards.*

A state measures plan must include a backstop of federally enforceable emission standards for affected EGUs that fully achieve the interim and final CO_2 emission performance rates or the state's interim and final CO_2 emission goal if the state plan fails to achieve the intended level of CO_2 emission performance. The backstop emission standards could be based on the finalized model rule that the EPA is proposing in a separate action. For the federally enforceable backstop, the state plan submittal must identify the federally enforceable emission standards for affected EGUs, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the emission guidelines as discussed in section VIII.C.3.b and identify all necessary state administrative and technical procedures for implementing the backstop (*e.g.* how and when the state would notify affected EGUs that the backstop has been triggered). Aspects of the backstop are discussed in detail in section VIII.C.3.b.

(4) *Identification of state measures.*

A state adopting a state measures plan type must provide as a part of the supporting documentation of its plan submittal, a description of all the state enforceable measures the state will rely upon to achieve the requisite state mass-based goal, the applicable state laws or regulations related to such measures, and identification of parties or entities implementing or complying with such state measures. The state must also include in its supporting documentation the schedule and milestones for the implementation of the state measures, showing that the measures are expected to achieve the mass-based CO_2 emission goal for the interim period (including the interim step periods) and meet the final goal by 2030. A state measures plan submittal that relies upon state measures that include RE and demand-side EE programs and projects must also demonstrate in its supporting documentation that the minimum EM&V requirements in the emission guidelines apply to those programs and projects as a matter of state law.

(5) *State reporting requirements.*

After consideration of the comments received regarding state reporting requirements, the EPA is requiring in this final rule for states using the state measures approach that an annual state report is due to the EPA no later than July 1 following the end of each calendar year during the interim period. This annual state report must include the status of implementation of federally enforceable emission standards (if applicable) and state measures, and must include a report of the periodic programmatic state measures milestones to show progress in program implementation. The programmatic state measures milestones with specific dates for achievement should be appropriate to the state measures described in the supporting documentation of the state plan submittal. The EPA believes that annual state reporting is appropriate for state measures approach due to the flexibility inherent to the approach described in section VIII.C.3 including the potential use by the state of a wider variety of state measures, responsible parties, etc. This reporting frequency will also increase the degree of certainty on plan performance for states pursuing the state measures approach.

As discussed in section VIII.F, for states using the state measures approach, the EPA is finalizing that at the end of the first two interim step periods, the state must also include in their annual report to the EPA the corresponding emission performance checks. The interim performance checks will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period versus the actual CO_2 emission performance achieved by the aggregate of affected EGUs. In the report submitted to the EPA on July 1, 2030, the state must also report the actual CO_2 performance check for the interim period (2022–2029) with the interim mass-based CO_2 goal, as well as the actual CO_2 emission performance achieved by affected EGUs during the interim step 3 period (2028–2029).

Beginning with the final period, the state must submit biennial reports no later than July 1 after the end of each reporting period that includes an actual performance check to demonstrate that the state continues to meet the final state CO_2 goal.

If, at the time of the state report to the EPA, the state has not met the programmatic state measures milestones for the reporting period, or the performance check shows that the actual CO_2 emission performance of affected EGUs warrants implementation of backstop requirements,[831] the state must include in the state report a notification to the EPA that the backstop has been triggered and describe

---

[831] As explained in section VIII.C.3.b, state plans subject to the backstop requirement must require the backstop to take effect if actual CO2 emission performance by affected EGUs fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027).

the steps taken by the state to inform the affected EGUs that the backstop has been triggered. In the event of such an exceedance under the state measures approach, the backstop federally enforceable emission standards for the affected EGUs must be effective within 18 months of the deadline for the state reporting to the EPA on plan implementation and progress toward meeting the emission performance rates or mass-based or rate-based state CO_2 emission goal. For example, if a state report due on July 1, 2025, shows that actual CO_2 emission performance of affected EGUs is deficient by 10 percent or more relative to the specified level of emission performance for 2022–2024 in the state plan, the backstop federally enforceable emission standards for affected EGUs must be effective as of January 1, 2027.

(6) *Supporting documentation.*

(a) *Demonstration that each state measure is quantifiable, non-duplicative, permanent, verifiable and enforceable.*

A state using the state measures approach, in support of its plan, must also include in the supporting documentation of the state plan submittal the state measures that are not federally enforceable emission standards, and describe how each state measure is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

A state measure is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.

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, except in instances where incorporated in another state as part of a multi-state plan. This does not mean that measures in a state measure cannot also be used for other purposes. For example actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (*e.g.*, Regional Haze requirements, MATS) and state requirements (*e.g.*, RPS).

A state measure is permanent if the state measure must be met for each applicable compliance period.

A state measure is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state to independently evaluate, measure and verify compliance with it.

A state measure is enforceable [832] if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) compliance requirements are clearly defined; (3) the affected entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability,[833] and the state

---

[832] Under the state measures approach, state measures are enforceable only per applicable state law.

[833] The EPA's prior guidance on enforceability serves as the foundation for the types of measures that the EPA has found can be, as a practical matter, enforced. The EPA's guidance on enforceability includes: (1) September 23, 1987, memorandum and accom anying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and

maintains the ability to enforce against affected EGUs for violations and secure appropriate corrective actions pursuant to its plan or state law.

The EPA will disapprove a state plan if the documentation is not sufficient for the EPA to be able to determine whether the state measures are expected to yield CO_2 emission reductions sufficient to result in the necessary CO_2 emission performance from affected EGUs for the mass-based state CO_2 emission goal to be achieved.

d. *Legal basis for the components.*

(1) *General legal basis.*

Under section 111(d), state plans must "provide for the implementation and enforcement of [the] standards of performance." Similar language occurs elsewhere in the CAA. First, for SIPs, section 110(a)(1) requires SIPs to "provide for implementation, maintenance, and enforcement" of the NAAQS. However, section 110(a)(2), unlike 111(d), details a number of specific requirements for SIPs that, in part, speak exactly to how a SIP should "provide for implementation, maintenance, and enforcement" of the NAAQS. We note that section 111(d) provides explicitly only that the "procedures," and not the substantive requirements, for section 111(d) state plans should be "similar" to those in section 110, and thus a substantive requirement in section 110(a)(2) is not an independent source of authority for the EPA to require the same for section 111(d) plans. However,

---

Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," Appendix F.

when there is a gap for the EPA to fill in interpreting how a section 111(d) plan should "provide for implementation and enforcement of [the] standards of performance," and Congress explicitly addressed a similar gap in section 110, then it may be reasonable for the EPA to fill the gap in section 111(d) using an analogous mechanism to that in section 110(a)(2), to the extent that the section 110(a)(2) requirement makes sense and is reasonable in the context of section 111(d). On the other hand, that Congress did not explicitly provide such details as are found in section 110(a)(2) indicates that Congress intended to give the EPA considerable leeway in interpreting the ambiguous phrase "provides for implementation and enforcement of [the] standards of performance."

For example, section 110(a)(2)(E)(i) explicitly requires states to provide necessary assurances that they have adequate personnel, funding and authority to carry out the SIP. Section 111(d), on the other hand, does not explicitly contain this requirement. Thus, there is a gap to fill with respect to this issue when the EPA interprets section 111(d)'s requirement that plans "provide for implementation and enforcement" of the standards of performance, and it is reasonable for the EPA to fill the gap by requiring adequate funding and authority, both because adequate funding and authority are fundamental prerequisites to adequate implementation and enforcement of any program, and because Congress has explicitly recognized this fundamental nature in the section 110 context.[834]

[834] On the other hand, there are specific requirements in 110(a)(2) that are fundamental for SIPs, but would not make

We note two other places where the CAA requires a state program to satisfy similar language regarding implementation and enforcement. First, section 112(l)(1) allows states to adopt and submit a program for “implementation and enforcement” of section 112 standards. Section 112(l)(5) further provides that the program must (among other things) have adequate authority to enforce against sources, and adequate authority and resources to implement the program. Second, section 111(c) provides that, if a state develops and submits “adequate procedures” for “implementing and enforcing” section 111(b) standards of performance for new sources in that state, the Administrator shall delegate to the state the Administrator’s authority to “implement and enforce” those standards. The EPA has interpreted these ambiguous provisions in the EPA’s “Good Practices Manual for Delegation of NSPS and NESHAPS” and recommended (in the context of guidance) that state programs have a number of components, such as source monitoring, recordkeeping, and reporting, in order to adequately implement and enforce section 111(b) or 112 standards. This again indicates it is reasonable for the EPA to fill a gap in section 111(d)’s language and similarly require source monitoring, recordkeeping, and reporting, as these are fundamental to implementing and enforcing standards of performance that achieve the state performance rates or goals.

---

sense in the 111(d) context. For example, the specific requirement for an ambient air quality monitoring network in 110(a)(2)(B) is irrelevant in the 111(d) context.

Some commenters argued that states have primary authority over the content of state plans and that the EPA lacks authority to disapprove a state plan as unsatisfactory simply because it lacks one or more of these components. We disagree. The EPA has the authority to interpret the statutory language of section 111(d) and to make rules that effectuate that interpretation. With respect to the components of an approvable plan, we are interpreting the statutory phrase "provide for implementation and enforcement" and making rules that set out the minimum elements that are necessary for a state plan to be "satisfactory" in meeting this statutory requirement. This does not in any way intrude on the state's ability to decide what mix of measures should be used to achieve the necessary emission reductions. Nor does it intrude in any way on the state's ability to decide how to satisfy a component. For example, for legal authority, we are not dictating which state agencies or officials must specifically have the necessary legal authority; that is entirely up to the state so long as the fundamental requirement to have adequate legal authority to implement and enforce the plan is met.

In addition, the EPA has already determined in the 1975 implementing regulations that certain components, such as monitoring, recordkeeping, and reporting, are necessary for implementation and enforcement of section 111(d) standards of performance. 40 FR 53340, 53348/1 (Nov. 17, 1975). Thus, EPA's position here is hardly novel. The EPA notes in discussing the implementing regulations, nothing in this final rule reopens provisions or issues that were previously decided in the original promulgation of the regulations unless otherwise explicitly reopened for this rule.

(2) *Legal considerations with changes to affected EGUs.*

In the proposed rulemaking, the EPA proposed the interpretation that if an existing source is subject to a section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. 79 FR 34830, 34903–4. The EPA is not finalizing a position on this issue in this final rule, and is re-proposing and taking comment on this issue through the federal plan rulemaking being proposed concurrently with this action. The EPA's deferral of action on this issue does not impact states' and affected EGUs' pending obligations under this final rule relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source is subject to the requirements of a state plan. The EPA will propose and finalize its position on this issue through the federal plan rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

(3) *Legal considerations regarding design, equipment, work practice or operational standards.*

In the proposal, the EPA asked for comment on three approaches to inclusion of design, equipment, work practice and operational standards in section 111(d) plans. 79 FR 34830, 34926/3 (June 18, 2014). Under the first approach, states would be precluded from including these standards in section 111(d) plans unless the design, equipment, work practice or operational standard could be understood as a "standard of performance" or could be understood to "provide for implementation and enforcement" of standards of performance. We also asked, for the first approach, whether it was even possible, given the statutory language of 111(h), to consider a design, equipment, work practice or operational standard as a "standard of performance." Under the second approach, states could include design, equipment, work practice or operational standards in the event that it could be shown a "standard of performance" was not feasible, as set out in section 111(h). Under the third approach, a state could include design, equipment, work practice and operational standards in a 111(d) plan without any constraints. We also asked whether, if there was legal uncertainty as to the status of these standards, the EPA should authorize states to include them in their 111(d) plans with the understanding that if the EPA's authorization were invalidated by a court, states would have to revise their plans accordingly.

The EPA is finalizing the first approach. Specifically, a state's standards of performance (in other words, either the federally enforceable backstop under the state measures approach or the emission standards under the emission standards approach) cannot consist of (in whole or part) design, equipment, work practice or operational standards. A state may include such standards in a 111(d) plan in order to implement the standards of performance. For example, a state taking a mass-based approach may include in its 111(d) plan a limit on hours of operation on a particular affected EGU, but that operational standard itself cannot substitute for a mass-based emission standard on the affected EGU.[835]

This follows from the statute. First, section 111(h)(1) authorizes the Administrator, when it is not feasible for certain reasons (specified in 111(h)(2)) to prescribe or enforce a standard of performance, to instead promulgate a design, equipment, work practice or operational standard. If a standard of performance could include design, equipment, work practice or operational standards, such authority would be unnecessary. Second, 111(h)(5) states that design, equipment, work practice or operational standards "described in" 111(h) shall be treated as standards of performance for the purposes of the CAA. This creates a strong inference that standards of performance otherwise should not include design, equipment, work practice, or operational standards. Finally, the general definition of "standard of performance" in section 302(l) is similar to the definition of "emission limitation" (or "emission standard") in section 302(k), with the exception that the definition of "emission limitation" explicitly includes design, equipment, work practice and operational standards, but the definition of "standard of performance" omits them. Thus, as with our discussion of the term "standard of performance" above in VIII.C.6.b, even if the general definition of "standard of performance" in 302(l) applies to 111(d), the omission of design, equipment, work practice, and operational standards in 302(l)

---

[835] In particular, a state may include in its 111(d) state plan an emission standard that is reflective of the CO_2 performance resulting from operational standards the state imposes on an affected EGU.

confirms our interpretation that they cannot be a 111 "standard of performance" (except under the limited circumstances in 111(h)). We conclude that it is reasonable, and perhaps compelled, to interpret the term "standards of performance" in 111(d) to not include design, equipment, work practice and operational standards.

However, section 111(d) requires plans to "provide for implementation and enforcement of [the] standards of performance." This language does not explicitly prohibit a plan from including design, equipment, work practice and operational standards, and allows for them to be included so long as they are understood to provide for implementation of the standards of performance. If they are included, the 111(d) plan must still be "satisfactory" in other respects, in particular in establishing standards of performance that are not in whole or in part design, equipment, work practice, and operational standards.

(4) *Legal basis for engagement with communities.*

As previously discussed, section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit 111(d) plans. Section 110(a)(1) requires states to adopt and submit implementation plans "after reasonable notice and public hearings." The implementing regulations under 40 CFR 60.27 reflect similar public participation requirements with respect to section 111(d) state plans. The EPA is sensitive to the legal importance of adequate public participation in the state plan process, including public participation by affected communities. As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color, are disproportionately affected by certain climate change-related impacts. Because certain communities have a potential likelihood to be impacted by state plans for this rule, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. By requiring states to demonstrate how they have meaningfully engaged with vulnerable communities potentially impacted by state plans as part of the state plan development process, states meeting this requirement will satisfy the applicable statutory and regulatory requirements regarding public participation.

3. Components of the Federally Approved State Plan

In this action the EPA finalizes that, to be fully approved, a state plan submittal must meet the criteria and include the required components described above. The EPA will propose and take final action on each state plan submittal in the **Federal Register** and provide an opportunity for notice and comment. When a state plan submittal is approved by the EPA, the EPA will codify the approved 111(d) state plan in 40 CFR part 62. The following components of the state plan submittal will become the federally enforceable state 111(d) plan:

- Federally enforceable emission standards for affected EGUs
- Federally enforceable backstop of emission standards for affected EGUs

- Implementing and enforcing measures for federally enforceable emission standards including EGU monitoring, recordkeeping and reporting requirements
- State recordkeeping and reporting requirements

E. State Plan Submittal and Approval Process and Timing

1. Overview

In this action the EPA is finalizing that state plan submittals are due on September 6, 2016, with the option of an extension to submit final state plans by September 6, 2018, which is 3 years after finalization of this rule. The compelling nature of the climate change challenge, and the need to begin promptly what will be a lengthy effort to implement the requirements of these guidelines, warrant this schedule. The EPA also believes, for reasons further described in the next section, why this schedule is achievable for states to submit final plans. We discuss the timing of state plans in more detail in this section below.

Discussed in the following sections are state plan submittal and timing, required components for initial submittals and the 2017 update, multi-state plan submissions, process for EPA review of state plans, failure to submit a plan, state plan modifications (including modifications to interim and final CO_2 emission goals), plan templates and electronic submittal, and legal bases regarding state plan process.

2. State Plan Submittal and Timing

The implementing regulations (40 CFR 60.23) require that state plans be submitted to the EPA within 9 months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[836] For these 111(d) guidelines, the EPA is finalizing that each state must by September 6, 2016, either submit a final plan submittal or seek an extension to submit a final plan by September 6, 2018. In the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program. To seek an extension of the September 6, 2016 deadline until no later than September 6, 2018, a state must submit an initial submittal by September 6, 2016, that addresses three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. If an extension is requested and granted, states must also submit a 2017 update by September 6, 2017, that documents the state's continued progress towards meeting the September 6, 2018 final plan submittal deadline.

In the proposal, EPA proposed a 13 month final state plan submittal deadline, with a 1 year possible extension for states submitting individual state plans and a 2 year possible extension for states submitting multi-state plans as part of a multi-state region. The EPA received substantive comment on the achievability of these proposed deadlines for state plan submittals. Multiple commenters expressed concern that due to timing of legislative cycles (some of which

[836] 40 CFR 60.23(a)(1).

are every 2 years), regulatory processes, and other necessary tasks, states would find it extremely difficult to submit plans in 1 or 2 years, whether or not they were planning to submit as part of a multi-state region. The EPA agrees based on this input that a schedule shorter than 3 years will be challenging for many—though not all—states. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for a 2 year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Based on comments received, information the EPA has regarding steps states have already begun taking towards plan development, and extensive experience with similar state plan submission deadlines under CAA section 110 SIPs, the EPA believes states will be able to submit final plans within 3 years by September 6, 2018, in the event states are not required to submit a final plan by September 6, 2016. We address the substantive requirements of initial submittals and the 2017 update in the next section. States that receive 2-year extensions may submit the final plan earlier than September 6, 2018, if they so choose.

The EPA highlights that one purpose of the initial submittal is to encourage and potentially facilitate states to do necessary planning and engagement with stakeholders so states are able to submit an approvable final state plan by the extended deadline of September 6, 2018. Some states have well-developed existing programs and the attendant legal authority underpinning such programs to more easily meet the September 6, 2016 deadline by submitting a final plan which largely contains or relies upon such existing programs.[837] Based on comments and stakeholder feedback, however, the EPA anticipates that many states intending to develop and submit a final plan will seek the optional extension given the time it may take to undergo necessary legislative, stakeholder, and planning processes. The EPA acknowledges that the initial submittal of September 6, 2016, is not essential to the ability of states to submit final plans by September 6, 2018, so that even without this 2016 deadline, the EPA could require states to meet the 2018 deadline. Even so, this earlier date in the 3 year planning process serves as a useful "check-in" that provides several significant advantages. First, this earlier date provides all states an opportunity to understand what approaches other states are considering. Because there are significant benefits to regional cooperation, the EPA believes that a formal process to collect and then provide this information will help all states develop better plans. Second, because the guidelines provide significant flexibility, the ability for the EPA to provide early input to states who may be pursuing more innovative approaches will help ensure that all state plans are ultimately approvable. The EPA therefore believes the initial submittal is an appropriate means by which to offer the optional extension, and for reasons further described in section VIII.E.3, that the requirements of the initial submittal are achievable by September 6,

---

[837] Based on comments received, we understand that the Northeast and Mid-Atlantic states that participate in RGGI may be in this position.

2016, so states will be able to develop and submit a plan that meets the requirements of the final emission guidelines and section 111(d) of the CAA by the extended date.

Additionally, some states may not submit a state plan as required by the final emission guidelines and section 111(d) of the CAA. For states that do not submit a state plan, the CAA gives the EPA express authority to implement a federal plan for sources in that state upon determination by the EPA that a state has failed to submit a state plan by the required date. For states that do not intend to submit a state plan to meet the obligations of this final rule, by promulgating a federal plan for affected EGUs in states that do not submit a plan by September 6, 2016, such affected EGUs would have a maximum of an additional 2 years to plan for and determine compliance strategies than had promulgation of a federal plan been predicated on states failing to submit a plan by September 6, 2018. The EPA also notes that this final rule affords states and affected EGUs with many implementation flexibilities and approaches for state plans that the EPA itself may not have the authority to implement through a federal plan. Therefore, affected EGUs subject to a federal plan promulgated for a state that refuses to submit a state plan may benefit from an additional 2 years to plan for compliance with a federal plan with potentially fewer flexibilities.

If no affected EGU is located within a state, the state must submit a letter to the EPA certifying that no such facilities exist by September 6, 2016.[838] The EPA will publish a notice in the **Federal Register** to

[838] 40 CFR 60.23(b).

notify the public of receipt of such letters. If an affected EGU is later found to be located in that state, the state must submit a final plan addressing such affected EGU or the EPA will determine the state has failed to submit a plan as required by the emission guidelines and CAA section 111(d), and begin the process of implementing a federal plan for that affected EGU.

In the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the tribe either does not submit a CAA section 111(d) plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate to protect air quality.[839] See the proposed federal plan rulemaking for further information.

The EPA notes that the current implementing regulations at 40 CFR part 60 do not specify who has the authority to make a formal submission of the state plan to the EPA for review. In order to clarify who on behalf of a state is authorized to submit an initial submittal, 2017 update, final state plan (or negative declaration, if applicable), and any revisions to an approved plan, the EPA has included a requirement in this final rule mirroring that of the requirement in 40 CFR part 51 App. V.2.1.(a) with respect to SIPs that identifies the Governor of a state as the authorized official for submitting the state plan to the EPA. 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

---

[839] See 40 CFR 49.1 to 49.11.

the 2016 deadline for plan submittal so that they have the ability to submit the initial submittal or final plan in the State Plan Electronic Collection System (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 discussed in section VIII.E.8. 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. The EPA recommends this information be submitted early in the state planning process to allow sufficient time for completion of SPeCS registration so that those authorized to use the system are provided access.

3. Components of an Initial Submittal and 2017 Update

As noted, states may request a 2-year extension to submit a final plan through making an initial submittal by September 6, 2016. For the extension to be granted, the EPA is finalizing that the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018: [840]

- An identification of final plan approach or approaches under consideration, including a description of progress made to date.
- An appropriate explanation for why the state requires additional time to submit a final plan by September 6, 2018.
- Demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, [841] including vulnerable communities, during the time in preparation of the initial submittal and plans for engagement during development of the final plan.

During the public comment period, multiple commenters stated that the proposed timeframe for states to submit an initial submittal was not achievable, citing, among other things, the number of decisions needed to be made by a state or states, and that the EPA needed to clarify the requirements for an initial submittal. Multiple commenters also expressed concern that the requirements for an initial submittal required final decisions to be made by states, and that the initial submittal deadline was not enough time for states to make these decisions.

---

[840] As stated previously, in the case of a state electing to participate in the CEIP, this 2016 submittal must include a non-binding statement of intent to participate in the program.

[841] Such stakeholders may include labor unions and workers that have an interest in the state plan, and communities whose economies are dependent on coal.

It is important to note that the EPA is not requiring the adoption of any enforceable measures or final decisions in order for the state to address any of the initial submittal components by September 6, 2016. The EPA believes the absence of requiring enforceable measures to be included with the initial submittal greatly supports the ability of states intending to develop a final state plan to submit an initial submittal by September 6, 2016. States are required to submit enforceable measures supported by technically complex documentation, such as modeling, and adopted through state public participation and regulatory or legislative processes as part of SIPs under other parts of the CAA within timeframes comparable to the time the EPA is providing for initial submittals.[842]

In order to further address the commenters' concerns regarding possible ambiguity of the requirements for an initial submittal so that an extension is granted, the EPA is providing clarity regarding the required components for an initial submittal. Regarding the component that states address an appropriate explanation for an extension, the EPA proposed that appropriate explanations for seeking an extension beyond 2016 for submitting a final plan include: A state's required schedule for

---

[842] For example, 13 states were required to submit SIP revisions sufficient to regulate GHGs under the Prevention of Significant Deterioration (PSD) permitting requirements of the CAA within either 3 weeks or 12 months in response to the EPA's SIP call. *See* "Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call", 75 FR 77698, (December 13, 2010).

legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. In this final rule, the EPA is finalizing these as appropriate explanations for seeking an extension beyond 2016, but makes clear—as explained further below—that other appropriate explanations will be acceptable as well. It is important to note that the initial submittal does not require legislation and/or regulations to be passed prior in order for the state to be granted an extension, but the initial submittal should describe any concrete steps the state has already taken on legislation and/or administrative rulemaking and detail what the remaining steps are in those processes before a final plan can be submitted. The EPA also sought comment on other circumstances for which an extension of time would be appropriate, and also whether some explanations for extensions should not be permitted. Commenters stated that states should be able to seek extensions whenever an extension can be reasonably justified, and that the EPA should take at face value states' good faith efforts by accepting any state assertion that more time is needed to develop a plan unless there is clear evidence to the contrary. The EPA believes there may be appropriate explanations states may submit in addition to the ones described in this final rule sufficient to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. Given the opportunity for states to submit appropriate explanations other than the ones detailed here, the EPA believes addressing this component requiring an appropriate explanation for an extension is easily achievable by September 6, 2016.

In order to additionally clarify the required components of the initial submittal, the following are types of explanations of information states may provide as part of the initial submittal to sufficiently address each of the three required components for getting an extension:

- Details on whether a state is considering a single or multi-state plan, a plan that meets the CO_2 emission performance rates or state CO_2 rate or mass emission goal, and/or an emission standards or state measures plan type.
- A description of how the state intends to address development of the required components of the final state plan, including describing what actions have already been taken, what steps remain, and the schedule for completing those steps.
- A commitment to maintain any existing measures the state intends to rely upon for its final plan in order to achieve the necessary reductions once the performance period begins.
- Describing public participation opportunities such as stakeholder and community meetings, or public hearings, throughout the 3 year plan development process. This could also include leverage of public participation approaches that states already use to identify and engage potentially affected communities.

The EPA emphasizes the required initial submittal components are intended to provide a reasonable pathway for states to demonstrate whether they will be able to submit an approvable plan by the extended date of September 6, 2018. The EPA also anticipates that through the requirement to address these components, the initial submittal will also facilitate state planning and stakeholder engagement, particularly as one component requires the public and stakeholders to have an opportunity to comment on the initial submittal. As previously described, these components do not require final decisions to be made by states, and this is further illustrated by the clarifications on how states may meet each of the three required components. Accordingly, the EPA believes none of these components is onerous for states to address in an initial submittal by the September 6, 2016 deadline. To further underscore this point, the EPA is further explaining the clarifying examples listed above of how states may address the three required components, and highlighting the achievability of these examples for states to address through the initial submittal by September 6, 2016.

For identification of the final plan approach or approaches the state is considering, and description of progress made to date, states could identify whether the state is considering the option of the CO_2 emission performance rates, a rate-based CO_2 goal, or a mass-based CO_2 goal, and whether the state is intending to pursue a single-state or multi-state plan. Stakeholders commented that states will not be far enough along in the rule development process to have made these decisions. Commenters also stated that many state legislatures would need to pass legislation giving state environmental agencies legal authority and direction before they could begin to make decisions such as rate or mass-based approach or single or multi-state plan submittal. In order to address the commenters' concerns, the EPA wishes to clarify that state approaches identified in the initial submittal do not need to be final and/or formalized through a state legislature, and that states may opt to identify pursuit of more than one approach at the same time, or to indicate the status of the deliberation of this issue within the state.

The EPA received substantive comment regarding the potential adverse consequences for states pursuing a multi-state approach and receiving an extension until 2018, where, for various reasons, a state or states then decide(s) to pursue the single state approach. Commenters viewed this as being potentially problematic since, as proposed, a single state could only receive an extension until 2017, and if a multi-state plan effort does not work out the deadline for seeking the extension until 2017 would have passed. The EPA notes finalizing a 2 year extension that is available for any state, whether they are pursuing an individual state plan or a multi-state plan resolves the commenters' concern about conflicting extension deadlines if states involved in a multi-state effort decide not to pursue the multi-state approach. Importantly, such identification in an initial submittal does not obligate the state to then actually adopt that approach in their final plan as the EPA acknowledges that based on state processes and public input through plan development during the extended submission period, a state may end up adopting a state plan approach more suitable to the needs of that state and its affected EGUs than previously identified in the initial submittal.

States can also describe progress made to date by identifying steps already taken to address development of the final state plan, as the EPA recognizes that states in general have already taken a number of steps to prepare for state plan development to meet the obligations of this rule. For example, since proposal, states have: Begun exploring tradeoffs among various state plan approaches such as individual versus multistate coordination, increased utilization of demand-side EE and RE programs, and implementing rate-based versus mass-based programs; increased their understanding of existing state programs and policies that reduce carbon emissions; built relationships and communications between key state institutions such as environmental agencies, PUCs, governors' offices, and energy regulators; hosted public stakeholder meetings to educate and solicit input from the public; and begun discussing state processes for developing potential state plans. States may meet the first required component by describing steps such as these already undertaken.

The EPA underscores that states may easily address the first component of the initial submittal by describing such steps, and also address the second required component by identifying next steps (which may be a natural extension of these already implemented activities), and laying out a schedule for development of a final plan. States that have taken these steps would especially be able to address the component regarding an appropriate explanation for an extension as the EPA recognizes the substantial work such states have begun to put towards development of state plans, and the continuation of this work justifies additional time to complete necessary steps to result in an approvable state plan.

The EPA emphasizes that for states who intend to submit a final plan and need an extension, the components of the initial submittal are not intended to require burdensome final action by states by September 6, 2016, but to identify a viable path to completing a final plan by September 6, 2018.

An initial submittal that contains a commitment to maintain any existing measures the state intends to rely upon for its final plan in order to get the necessary reductions once the performance period begins (*e.g.* RE standards and demand-side EE programs the state intends to rely upon through a state measures plan type), at least until the final plan is approved, also addresses the requirement that states provide an appropriate explanation for an extension. Given the state's request for additional time prior to putting in place enforceable measures to reduce CO_2, it would be reasonable and appropriate, and in keeping with the goals of 111(d) to ensure that any existing CO_2 reduction measures that the state intends to rely upon remain in place while the state is developing a final plan. Such commitment would demonstrate that the state is taking substantive steps towards successful development of a final plan within 3 years.

Regarding the required public participation component of the initial submittal, the EPA believes this requirement is both achievable for states to submit an initial submittal by the September 6, 2016 deadline, and provides a benefit in facilitating state plan development so that states are more likely to be able to submit a final plan within 3 years if the extension is granted. The EPA can use a comment opportunity on the initial submittal to advise the state whether aspects of the draft initial submittal and overall plan development are appropriate for purposes of meeting the requirements of the final rule so that the state will be able to procure the extension through an acceptable initial submittal and submit a final plan by the extended deadline. The EPA notes the comment period on the initial submittal is only one opportunity the EPA has to assist a state in the state plan development process. The EPA has historically worked with states throughout the state plan development process to help ensure that the state plan is approvable once submitted to the EPA, and expects this level of engagement with states to continue throughout the plan development process. This requirement will also facilitate early identification of concerns stakeholders and the public may have with aspects of a final plan the state is considering. As states have longtime and extensive experience with responding to public comments in numerous contexts, including in the context of other CAA programs such as section 110 SIP development and in permit issuance under NSR and Title V, the EPA anticipates states will be able to timely address the initial submittal public participation.

As previously discussed, because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. Therefore, the public participation component of the initial submittal includes meaningful engagement with vulnerable communities, throughout the state plan development process and including through the initial submittal.

In order to demonstrate to the EPA that states are actively engaging with communities, states could provide in their initial submittal a summary of steps they have already taken to engage the public and how they intend to continue meaningful engagement, including with vulnerable communities, during the additional time (if an extension is granted) for development of the final plan. In addition to approaches that states already use to identify and engage potentially affected communities, the EPA encourages states to use the proximity analysis conducted for this rulemaking (which is described in section IX.A) as a tool to help them identify overburdened communities that could be potentially impacted by their plans. Other tools, such as EJ screen, can also be helpful. The EPA in its continued outreach with states during the implementation phase will also provide resources to assist them in engaging with communities. The EPA believes that through the provision of these resources states will also more easily be able to address this required component of the initial submittal regarding public engagement, including with vulnerable communities, by September 6, 2016.

In addition to the resources the EPA intends to provide to states, there are existing resources states can take advantage of to address this component as well. On the steps that states could take to engage vulnerable communities in a meaningful way, the Agency recommends that states consult the EPA's May 2015 *Guidance on Considering Environmental Justice During the Development of Regulatory Actions*. In this document, the EPA defines meaningful involvement as ensuring that "potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity (*i.e.*, rulemaking) that may affect their environment and/or health; the population's contribution can influence the EPA's [regulatory authority's] rulemaking decisions; the concerns of all participants involved will be considered in the decision-making process; and the EPA [decision-makers] will seek out and facilitate the involvement of those potentially affected by the EPA's [or other regulatory authority's] rulemaking process."[843] Additionally, this guidance document also encourages those writing rules to consider the positive impacts that a rulemaking will have on communities).[844] Another resource that the EPA recommends that states consult when devising their state plans is the document "Considering Environmental Justice in Permitting" available on the agency's Web site.[845] Both of the resources discussed above can add to what states may already have in place to effectively engage vulnerable communities in the rulemaking process.

The EPA recommends that as part of their meaningful engagement with vulnerable communities, states work with communities to ensure that they have a clear understanding of the benefits and any

---

[843] 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.

[844] Ibid.

[845] Considering Environmental Justice in Permitting. *http://www.epa.gov/environmentaljustice/plan-ej/permitting.html#actions*.

potential adverse impacts that a state plan might have on their overburdened communities and that there is a clear process for states to respond to input from communities.

If a state seeks an extension by submitting an appropriate initial submittal addressing the three required components as described above by September 6, 2016, the EPA will review the submittal. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. The EPA will notify a state by letter only if the initial submittal does not address the three required components. An extension for submitting a final plan will be deemed granted if the EPA does not deny the extension request based on the initial submittal. The EPA has determined this approach is authorized by, and consistent with, 40 CFR 60.27(a) of the implementing regulations.

For states that request and receive a 2-year extension, the state must submit an update halfway through that extension, by September 6, 2017. In the proposal the EPA included a requirement regarding a 2017 check in. Because the EPA is finalizing that states are able to get a 2-year extension regardless of whether they are submitting an individual or multi state final plan, the EPA believes it appropriate to ensure through the 2017 update that the state is making continuous progress on its initial submittal and that it is on track to meet the final plan submittal deadline of September 6, 2018. The EPA will also be able to use the information provided through the 2017 update to further assist states in plan development.

The final rule requires that states address in the 2017 update the following components:

- A summary of the status with respect to required components of the final plan, including a list of which components are not yet complete.

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

- An updated comprehensive roadmap with a schedule and milestones for completing the plan, including progress to date in developing a final plan and steps taken in furtherance of actions needed to finalize a final plan.

In order to assess whether a state is on track to submit a final plan by the 2018 extension deadline, the EPA is requiring that the 2017 update must contain a progress update on components from the initial submittal and a list of which final plan components are still not complete.

The EPA is also requiring that the 2017 update include a commitment to the type of plan approach the state will take in the final plan submittal. During the public comment period, many commenters stated that legislative action would be required to enact this final rule at the state level, and that the proposal did not provide enough time for legislative action or other regulatory actions needed for a state to be granted an extension. In order to respond to these comments, the EPA is clarifying that proposed or passed legislation or regulations are not required in the initial submittal due by September 6, 2016. While a state may indicate consideration of multiple state plan approaches in the initial submittal, the EPA is requiring that the state commit to one approach in the 2017 update. This commitment must include draft or proposed legislation or regulations that must become final at the state level prior to submitting a final plan submittal to the EPA. While commenters expressed concern with not being able to have legislation enacted in time to receive an extension until 2018, the EPA has determined that 2 years is a reasonable timeframe for a state to decide on the type of approach it will take in the final plan submittal and to draft legislation or regulations for this approach in order to timely meet the extended September 6, 2018 deadline.

4. Multi-State Plan Submittals

For states wishing to participate in a multi-state plan, the EPA is finalizing three forms of submittal that states may choose for the submittal of a multi-state plan.

First, the EPA is finalizing its proposed approach where one multi-state plan submittal is made on behalf of all participating states. The joint submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal must adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components (*e.g.*, plan emission goals, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

The EPA received comments from states requesting flexibility for multi-state plan submittals. In response to these comments, the EPA is also finalizing two additional options on which it solicited comment. First, states participating in a multi-state plan can provide a single submittal—signed by authorized officials from each participating state—that addresses common plan elements. This option requires individual participating states to provide supplemental individual submittals that provide state-specific elements of the multi-state plan. The common multi-state submittal must address all relevant common plan elements and each individual participating state submittal must address all required plan components (including common plan elements, even if only through cross reference to the common plan submittal). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review. The joint common submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state.

Second, the EPA is finalizing an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all required plan components. The EPA encourages states participating in this type of multi-state plan to use as much common material as possible to ease review of the state plans.

These approaches will provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options simplify the EPA's approval of remaining common or individual portions of a multi-state plan and help address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states. These additional submittal approaches also facilitate multi-state plans where the participating states are coordinating the implementation of their plans but are not taking on a joint multi-state emission goal for affected EGUs. For example, states may seek to engage in a multi-state approach that links rate-based or mass-based emission trading programs through appropriate authorizations (*e.g.* reciprocity agreements, or state regulations) that allow affected EGUs to use emission allowances or RE/EE credits issued in one state for compliance with an emission standard in another state.

In order to avoid a multi-state plan becoming unapprovable due to one state submitting an unapprovable portion of a multi-state plan, withdrawing from the multi-state plan, or failing to implement the multi-state plan, states may include express severability clauses if their multi-state plan is able to stand without further revision if one of the situations described above occurs. The severability clause must specify how the remainder of the multi-state plan or individual state plan would continue to function with the withdrawal of a state or states, and may also include pre-specified revisions. The EPA will evaluate the appropriateness of such a clause as part of its review of the multi-state plan submittal.

5. Process For EPA Review of State Plans

Our proposal laid out the basic steps for the EPA's review and action on submitted state plans and, at some length, discussed the required components of state plans, as further described in the preceding sections. We received a number of thoughtful and helpful comments on these issues. We are finalizing the basic requirements in this rule and are proposing, in the companion proposed federal plan under section 111(d), some additional procedural elements we believe will be helpful to states, stakeholders and the EPA moving forward.

Following the September 6, 2016 deadline for state plan submittals, the EPA will review plan submittals. For a state that submits an initial submittal by September 6, 2016, and requests an extension of the deadline for the submission of a final state plan submittal, the EPA will determine if the initial submittal meets the minimum requirements for an initial submittal. If the state does not submit an initial submittal by September 6, 2016, that contains the three required components, the EPA will notify the state by letter, within 90 days, that the agency cannot grant the extension request based the state's initial submittal. If the initial submittal meets the minimum requirements specified in the emission guidelines, the state's request for a deadline extension to submit a final plan submittal will be deemed granted, and the final plan submittal must be submitted to the EPA by no later than September 6, 2018.

After receipt of a final plan submittal, the EPA will review the plan submittal and, within 12 months, approve or disapprove the plan through a notice-and-comment rulemaking process publicized in the **Federal Register**, similar to that used for acting upon SIP submittals under section 110 of the CAA. The implementing regulations currently provide for the EPA to act on a final plan within 4 months after the deadline for submission, which is consistent with versions of section 110 prior to the 1990 Amendments to the CAA. 40 CFR 60.27(b). To be consistent with the current version of section 110, the EPA intends to adopt a timeline of 12 months to review final plan submittals upon receipt of complete submittals, as is generally consistent with the timing requirements of section 110 with respect to complete SIP submittals. Such a timeline would also provide the EPA with adequate time for review and rulemaking procedures, and ensuring an opportunity for public notice and opportunity for comment. We note, however, that we proposed this timeline for review and action on state plans in our proposal, but our proposal was specific to the timeline for state plans submitted pursuant to this rule rather than for state plans submitted under 111(d) generally.[846] We are finalizing as part of this rule that state plans submitted to meet the requirements of this

[846] The EPA proposed 12 months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof.

rule will be reviewed and acted upon by the EPA within 12 months of submission. Because such timeline would be appropriate to be made to 111(d) state plans more generally, we are also proposing the appropriate revisions to the implementing regulations as part of the federal plan proposal for section 111(d).

In addition, while the proposal and this final rule lay out in considerable detail the required components of a state plan, the EPA believes that it would also be helpful to include in the rule a completeness determination process, similar to that used for SIP submittals under section 110, which will allow the EPA to determine whether a final plan submittal contains the components necessary to enable the EPA to determine through notice and comment rulemaking whether such submittal complies with the requirements of section 111(d). This is a procedural requirement under CAA section 110(k)(1) for SIPs, and the EPA believes this requirement is appropriate to establish under section 111(d)'s direction to the EPA to prescribe through regulations a procedure similar to that provided by section 110. However, because the EPA did not propose such regulations as part of the proposal for this action, the EPA is proposing such regulations as part of the federal plan proposal for section 111(d). The EPA notes that this preamble (in section VIII.D) and final rule lay out required components of state plans and all the requirements for a state plan submittal, and therefore states have the necessary information at this time to develop state plans. The upcoming completeness criteria will not add to or change these required components, but only add a procedural step that allows the EPA to identify whether there are absent or insufficient components in the plan submittal that would render the EPA unable to act on such submittal because it is incomplete. As we further explain in the federal plan proposal, a determination by the EPA that a plan submittal is incomplete has the effect of a state having a still-pending statutory obligation to submit a plan that meets the requirements of section 111(d).

The EPA is planning to propose an amendment to the section 111(d) implementing regulations that will add the partial approval/disapproval and conditional approval mechanisms in section 110(k)(3) and (4) to the procedure for acting on section 111(d) plans. The input the agency received in response to the proposal for these guidelines indicated that the flexibility provided by these mechanisms could be useful getting state plans in place. The EPA agrees, and is proposing to amend the implementing regulations as part of the rulemaking for the federal 111(d) plan. The EPA is not taking final action on these changes in this action.

The later timing for our action on partial approval/disapproval and conditional procedures does not create any issue with finalizing this rule. These procedural adjustments will only come into play after states have submitted their plans and the EPA is required to act on them, and we intend to finalize these procedural changes prior to September 6, 2016, when the first plan submittals would occur. Until then, the EPA believes that every plan is submitted with the intent to be fully approvable and there is no need for states to rely on the possibility of these procedures when developing their plans. Conditional approval and partial approval/disapproval should be used to deal with approvability issues that arise despite the best efforts of states and the EPA to work together to make sure a submittal in the first instance is fully approvable. The EPA plans to finalize any changes in the implementing regulations before the EPA is required to act on state submittals, so that the EPA and states will have appropriate flexibility in the plan approval process.

6. Failure To Submit a Plan

If a state does not submit a final plan submittal by the applicable deadline, or submits a final plan the EPA determines to be incomplete, the EPA will notify the state by letter of its failure to submit. The EPA will publish a **Federal Register** notice informing the public of its finding of failure to submit. Upon a finding of failure to submit for a state, a regulatory clock will run requiring the EPA to promulgate a federal plan for such state no later than 1 year after the EPA makes the finding unless the state submits, and the EPA approves, a state plan during this time. Refer to the federal plan proposal for more details on how and when a federal plan would be triggered.

7. State Plan Modifications

a. *Modifications to an approved state plan.*

During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing enforceable measures with new measures. The EPA received broad support for allowing states to submit modifications to approved state plans, and we agree that this is an important aspect of this program. In this rulemaking, therefore, the EPA is finalizing that a state may revise its state plan, and states in a multi-state plan may revise their joint plan. Consistent with the timing for final plan submittals originally submitted by states, the EPA will act on state plan revisions within 12 months of a complete submittal. The EPA expects that the long plan performance timeframes in this final rule and flexibility provided to states in developing state plans will lessen the need for modifications to approved state plans.

A state may enter or exit a multi-state plan through a plan modification, with certain limitations. Multiple commenters stated that the EPA should clarify the plan modification process in such instances.

Where a state with a single-state approved plan seeks to join a multi-state plan, the state may submit a modification of its plan indicating that it is joining the multi-state plan and including the necessary plan components under the multi-state plan. The current participants of the multi-state plan will also need to submit a plan modification, to acknowledge the new state participant and to recalculate the multi-state rate-based or mass-based CO_2 goal. Functionally, both the modification of the single-state plan of the new participant and the multi-state plan of the current plan participants could be addressed through the same plan modification submittal or addressed under a plan modification submittal comparable to the alternate formats for multi-state plan submittals addressed in section VIII.E.4.

The entry or exit of a state to/from a multi-state plan involves the recalculation of the multi-state rate-based or mass-based CO_2 goal for affected EGUs in the participating states. The recalculated multi-state rate-based or mass-based CO_2 goal must take into account and ensure achievement of the individual state rate-based or mass-based CO_2 goal for any state that is joining the multi-state plan. If implementation of the individual state plan has triggered corrective measures or backstop emission standards prior to the plan modification, as described in section VIII.F.3, the modification must take into account the need to make up for any shortfall in CO_2 emission performance in the individual state plan prior to joining the multi-state plan. Where one or more states are leaving a multi-state plan through a plan modification, the process is similar and the same considerations must be taken into account in connection with the states that are leaving the multi-state plan.

As a result of these requirements and considerations, the EPA is finalizing certain requirements for multi-state plan modifications. A multi-state plan modification may be submitted to the EPA at any time. However, an approved multi-state plan modification may only take effect at the beginning of a new interim or final plan performance period. These requirements are necessary to ensure that the emission performance rates or state rate-based or mass-based CO_2 goals in the emission guidelines are achieved. In addition, such requirements for the timing of the effective date of multi-state plan modifications are necessary for coordination of the implementation of multi-state plans, especially where such plans include a multi-state emission trading approach. This approach is also consistent with the approach the EPA is proposing for the implementation of federal plan, where relevant for a state(s).

The EPA solicited comment on whether, for new projections of emission performance included in a submitted plan modification, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance. Comments received on this topic were generally supportive of allowing the use of updated data in state plan modifications, citing that states should have the ability to determine whether the original data and assumptions or updated data and assumptions are appropriate. The EPA is finalizing that new projections of emission performance, the projection methods, tools, and assumptions do not have to match those used for the projection in the original demonstration of plan performance; they can be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

As discussed in more detail in section VIII.G.2, the final rule has several measures to ensure that it does not interfere with the industry's ability to maintain reliability. One such measure is that if a state cannot address a reliability issue in accordance with an approved state plan, the state can submit a request to the EPA to modify the state plan. See section VIII.G.2 for a more detailed discussion of this issue.

The EPA is not finalizing any circumstances under which a state may or may not revise its state plan, with the exception that a state may not revise its state plan in a way that results in the affected EGU or EGUs not meeting the requisite CO_2 emission performance levels.

b. *Modifications to interim and final CO_2 emission goals.*

As discussed in section VII, the final rule specifies that the state interim and final CO_2 emission goals for affected EGUs in a state may be adjusted to address changes within a state's fleet of affected EGUs. If these changes occur before a state submits its initial submittal or final plan, the state should indicate in its submittal the circumstance that necessitates the goal adjustment and the revised interim or final CO_2 emission goal. If the circumstances occur after a state has an approved plan, a state must submit a modification to its approved plan. The plan revision submittal must indicate the circumstance that necessitates the goal adjustment, the revised interim and/or final CO_2 emission goal, and the adjustments to the enforceable measures in the plan.

8. Plan Templates and Electronic Submittal

The EPA is finalizing the requirement that submissions related to this program be submitted electronically. Specifically, that includes negative declarations, state plan submittals (including any supporting materials that are part of a state plan submittal), any plan revisions, and all reports required by the state plan. The rule provides that files that are submitted to the EPA in an electronic format may be maintained by states in an electronic format. The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version, the EPA is also requiring that all plan components designated as federally enforceable must be submitted in an editable version as well, as discussed below.

a. *Submittal of an editable version of federally enforceable plan components.*

To ensure that the EPA has the ability to identify, evaluate, merge, update and track federally enforceable plan components in a timely and comprehensive manner, the EPA is requiring states to submit an editable copy of the specific plan components in their submittals that are designated as federally enforceable, either effective upon the EPA plan approval or as a state plan backstop measure. The editable version is in addition to the non-editable version. Examples of editable file formats include Microsoft Word, Apple Pages and WordPerfect.

b. *Revisions to an approved plan.*

States shall provide the EPA with both a non-editable and 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, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. This approach to identifying the changes made to the existing federally enforceable plan components is consistent with the criteria for determining the completeness of SIP submissions set forth in Section 2.1(d) of Appendix V to 40 CFR part 51.

c. *Electronic submittal.*

It is the EPA's experience that electronic submittal of information has increased the ease and efficiency of data submittal and data accessibility. The EPA is developing the SPeCS, a web accessible electronic system to support this requirement that will be accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). The EPA will pre-register authorized officials and plan preparers in CDX. See section VIII.E.2 for additional information on the pre-registration process for authorized officials and plan preparers. Detailed instructions for accessing CDX and SPeCS will be outlined in the "111(d) SPeCS User Guide: How to submit state 111(d) plan material to EPA" which will be available on the EPA's Clean Power Plan Toolbox for States. The EPA will provide SPeCS training for states prior to the state plan submittal due date.

Once in CDX, SPeCS can be selected from the Active Program Service List. The preparer (*e.g.*, state representative compiling a state plan submittal) assembles the submission package. The preparer can upload files and complete electronic forms. However, the preparer may not formally submit and sign packages. Only registered authorized officials may submit and sign for the state with the exception of draft submittals. The EPA's intent is to allow submittal of draft plans or parts of plans for early EPA review prior to formal submission by the authorized official and will allow preparers, as well as authorized officials, to submit draft documents. The authorized official will be able to assemble submission packages and will be able to modify submission packages that a preparer has assembled. The key difference between the preparer and the authorized official is that the authorized official can submit and sign a package for formal EPA review using an electronic signature. In the case of a multi-state plan, each participating state's authorized official must provide an electronic signature.

The process has been designed to be compliant with the Cross-Media Electronic Reporting Rule (CROMERR), under 40 CFR part 3, which provides the legal framework for electronic reporting under all of the EPA's environmental regulations. The framework includes criteria for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document. In other words, the electronic signature is as equally enforceable as a paper signature. For more information on CROMERR, see the Web site: *http://www.epa.gov/cromerr/*. 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.

The EPA received a number of comments on the electronic submittal of state plans. Some commenters preferred the option to submit electronically rather than the requirement to do so. In the final rule, for the reasons discussed below, the EPA is requiring electronic submittal of state plans and not allowing alternate options for plan submittal (*e.g.* paper submittal).

Requiring electronic submittal is in keeping with current trends in data availability and will result in less burden on the regulated community. Electronic submittal will facilitate two-way business communication between states and the EPA, will guide states through the submittal process to ensure submission of all required plan components, and will enable states to submit proposed plans to the EPA electronically for early EPA comments. Electronic submittal will also facilitate, expedite and promote national consistency in the EPA's review of state plans and promote transparency by providing stakeholder-specific access to updated information on state plan status and posting of plan requirements for viewing by the public, government regulators and regulated entities. The EPA recently implemented an electronic submittal process for SIPs under CAA section 110 and continues to explore opportunities to increase the ease and efficiency with which states and the regulated community can meet regulatory data submittal requirements. In summary, the EPA believes electronic submittal will be enormously beneficial in terms of improving coordination and cooperation between the EPA and its state partners in developing approvable state plans. We note, however, that there may be some circumstances where having paper copies of the plan is needed to facilitate public engagement, and encourage states to take those considerations into account.

d. *Plan templates.*

In the proposal, the EPA requested comment on the creation of templates for initial submittals and final state plan submittals. Multiple commenters requested the EPA provide state plan templates. One commenter requested templates for different plan designs (*e.g.* a mass-based trading framework, a rate-based trading framework, multi-state compliance and a utility-based portfolio approach) and for specific plan components (*e.g.* how to incorporate a state RE standard and an EE program into a state plan, how to assess the emission reductions delivered by RE and EE). The EPA has determined that the broad range of approaches states may take in preparing individual or multi-state plans makes the development of specific templates challenging and likely not useful to states. However, concurrent with this final rule, the EPA is proposing model rules for both rate- and mass-based programs in conjunction with the proposed federal plan. These effectively can serve as a template for states when preparing their state plan submittals. The EPA will continue extensive outreach to states and work closely with them on the need for additional tools and guidance to facilitate the development of approvable state plans.

9. Legal Basis Regarding State Plan Process

CAA section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit CAA section 111(d) plans. The EPA has interpreted this provision previously in the implementing regulations found in 40 CFR part 60 subpart B. As discussed above, the EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether certain procedures are appropriate for the EPA's action on CAA section 111(d) state plans, and if so, precisely how those procedures should apply. The EPA is proposing these revisions to the CAA section 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan being issued concurrently with this final rule. In this section we discuss the legal basis for procedures that the EPA is finalizing in this action: Initial submittals, extensions, and plan revisions.

First, by using the ambiguous word "similar," Congress delegated authority to the EPA to determine precisely what procedures would govern 111(d) plans. "Similar" does not have an identical meaning as the word "same." One definition of "similar" is "having likeness or resemblance, especially in a general way." The American College Dictionary 1127 (C.L. Barnhart, ed. 1970). On the other hand, "same" is defined as "alike in kind, degree, quality; that is, identical" or "unchanged in character." *Id.* at 1073.

Had Congress intended that the procedures for section 111(d) plans be indistinguishable from those in section 110, Congress knew how to say so. *See, e.g.*, 36 U.S.C. 2352(b)(2)(B) ("same procedures"). And had Congress intended that the procedures for section 111(d) plans be as close as possible to those in section 110, Congress knew how to say that. *See, e.g.*, 38 U.S.C. 4325(c) (agency "shall ensure, *to the maximum extent practicable, that the procedures are similar* to" certain other procedures). Therefore, Congress must have intended to give the EPA leeway to create procedures for section 111(d) state plans that somewhat vary from those in section 110, so long as the section 111(d) procedures are reasonably tied to the purpose and text of section 111(d). In other words, "similar" creates a gap in the statute that the EPA may reasonably fill.

a. *Initial submittals and extensions.*

Initial submittals in this instance are a reasonable gap-filling procedural step. As explained in our proposal, certain aspects of section 111(d) plan development for these particular guidelines warrant our creation of this procedural step, even though section 110 does not provide for initial submittals. As explained above, though, we are not bound under section 111(d)(1) to follow exactly the same procedures.

With respect to the timing of initial submittals, final submittals, and extensions, we note that section 111 does not prescribe any particular deadlines, instead leaving it to EPA's discretion to establish "similar" procedures to section 110. The implementing regulations for section 111(d) plans require state plans to be submitted within 9 months of finalization of emission guidelines. Section 110(a)(1) provides that states should adopt and submit SIPs that provide for implementation, maintenance, and enforcement of the NAAQS within 3 years, or such shorter period as the Administrator may prescribe.[847] As further explained in Section VIII.E., the EPA is providing states with up to 3 years to submit a final plan under this rule, contingent upon the grant of an extension through an initial submittal due by September 6, 2016. Section 110(a)(1) does not provide any particular factors for the Administrator to consider in prescribing a shorter period. Thus, the EPA's prescription of a shorter period for either an initial submittal or a final plan submittal is consistent with the discretion granted in section 110(a)(1). We further discuss why the September 6, 2016 initial submittal deadline is reasonable in Section VIII.E., and such deadline is achievable by states seeking to submit a final plan within 3 years. We also note that section 110(b)

[847] Under this grant of authority to prescribe shorter deadlines, the EPA has in a number of occasions required SIPs to be submitted in 1 year.

provides for extensions of 2 years for plans to implement secondary NAAQS, that other provisions in part D provide for extensions of due dates of attainment plans in certain circumstances, and that the section 111(d) implementing regulations provide for extensions generally. We conclude, in view of the above discussion of "similar," that the approach of initial submittals and extensions of due dates as proposed are reasonable procedures that, while not identical to the procedures in section 110, are still similar.

Some commenters argued that the 1-year period for initial submittals and, even assuming an extension, the additional 1- to 2-year period for final submittals were unreasonably short, particularly in light of the possibility that some state legislatures might need to act to provide adequate legal authority for these particular plans. We are not finalizing the 1-year extension for single state submittals, and we have addressed concerns about legal authority for the initial submittals by allowing states to identify remaining legislative action in those submittals.

With respect to the overall period of up to 3 years for submittals, we continue to find it reasonable and consistent with other deadlines in the CAA. First, section 110(a)(1) requires states to submit a plan for implementation, maintenance, and enforcement of new NAAQS within 3 years of promulgation of that NAAQS. This is true even if the EPA promulgates a NAAQS for a previously non-criteria pollutant. In that case, it is possible and even likely that at least some state agencies will lack statutory authority to regulate the new pollutant. Nonetheless, Congress dictated that states should submit section 110(a)(1) plans within 3 years.

Furthermore, we note that under subpart 1 of Part D of Title 1, attainment plans are generally due no later than 3 years after designation of a nonattainment area, and under other subparts of Part D, plans are due even more quickly. For example, under subpart 4, attainment plans for particulate matter are generally due 18 months after designation, and under subpart 5, the same deadline applies for attainment plans for sulfur oxides, nitrogen dioxide and lead. Developing attainment plans may or may not require states to seek additional legislative authority, but certainly in terms of complexity they are similar to section 111(d) plans for this guideline. In general, attainment plans must contain (among other things) a comprehensive inventory of sources of the relevant pollutant and its precursors (which in populated areas can be very numerous), control measures for those sources (including individualized control measures for the larger sources), and modeled demonstrations of attainment (which in some instances requires photochemical grid modeling). Thus, it is reasonable to have the same timeline for these section 111(d) plans as Congress generally provided for attainment plans in section 172(b).

b. *State plan modifications.*

Section 110(l) provides for states to revise their SIPs, as does 40 CFR 60.28 for section 111(d) plans. Section 110(l) also sets out a standard for revisions: It prohibits the EPA from approving a SIP revision that would interfere with any applicable requirement concerning attainment or reasonable further progress, or any other applicable requirement of the CAA. Under the existing section 111(d) implementing regulations, the Administrator will disapprove section 111(d) plan revisions as unsatisfactory when they do not meet the requirements of subpart B to part 60. See 40 CFR 60.27(c)(3). However, the implementing regulations do not set forth a substantive standard like that in section 110(l).

Section 111(d)(1) does not mention revisions (except indirectly through the reference to section 110) and, therefore, does not explicitly provide any substantive requirements for them. There is, therefore, a gap in the statute that the EPA may reasonably fill, since many stakeholders commented on the desirability of states being able to modify their plans, and the EPA agrees. It is reasonable, at a minimum, that the state plan as revised should continue to provide for implementation and enforcement of the standards of performance, and to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. This is analogous to the substantive requirements of section 110(l), which as explained above for section 110(a)(2), we may consider in determining how to reasonably fill statutory gaps for section 111(d) plans.

In our proposal, we stated that certain revisions to state plans under these emission guidelines, those that revised enforceable measures for affected EGUs, should satisfy some additional conditions. First, the state should demonstrate that the plan continues to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. We proposed that this demonstration might be simple for minor revisions, but for major revisions a more complete demonstration may be required. We are finalizing this proposal. As legal basis for this position, we note that a demonstration is necessary to show that a state plan provides for implementation of standards of performance that achieve the CO_2 emission performance rates or state CO_2 emission performance goal, and as explained above we can reasonably require the same of revisions.

It is also reasonable to tailor the requirements of the demonstration to the magnitude of the revision. The EPA has taken a similar approach to tailoring the requirements for a technical demonstration that, under section 110(l), a SIP revision does not interfere with any applicable requirement concerning attainment of the NAAQS. If a SIP revision does not relax the stringency of any SIP measure, then the demonstration is simple. If the SIP revision does relax the stringency of SIP measures, then a qualitative or quantitative analysis may be necessary to show non-interference, depending on the nature of the revision, the current air quality in the area, and other factors.

Finally, we proposed that revisions "should not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no 'backsliding' on overall plan emission performance through a plan modification would be allowed." 79 FR 34917/1. We received adverse comments that this standard did not have a basis in section 111(d). According to commenters, since the standard for EPA approval of a section 111(d) plan is whether the plan is satisfactory in establishing and providing for implementation and enforcement of standards of performance that achieve the emission performance rates or goal, the same standard should apply to revisions. In other words, the standard for revisions should be whether the plan as revised is satisfactory. We believe that our proposal was unclear as to this point, and we agree that the standard for revisions should be the same as for submittals. We have finalized this position.

F. State Plan Performance Demonstrations

This section describes state plan requirements related to compliance periods, monitoring and reporting for affected EGUs; plan performance demonstrations; consequences if the CO_2 emission performance rates or state CO_2 emission goals are not met; and out-year requirements.

1. Compliance Periods, Monitoring and Reporting Requirements for Affected EGUs

For plans that include emission standards on affected EGUs, the EGU emission standards for the interim period must have schedules of compliance for each interim step 1, 2 and 3 for the calendar years 2022–2024, 2025–2027 and 2028–2029, respectively. For the final period, EGUs must have emission standards that have schedules of compliance for each 2 calendar years starting in 2030 (*i.e.*, 2030–2031, 2032–2033, 2034–2035, etc.). If a backstop is triggered for a state measures plan, the schedule of compliance for the federally enforceable emission standards must begin no later than 18 months after the backstop is triggered and end at the end of the same compliance period. For example, if a backstop is triggered on July 1, 2025, the compliance period for the backstop emission standards must begin no later than January 1, 2027, and end on December 31, 2027. The next compliance period for the backstop emission standards would be January 1, 2028–December 31, 2029.

In the June 2014 proposal, the EPA proposed that the appropriate averaging time for any rate-based emission standard for affected EGUs be no longer than 12 months within a plan performance period and no longer than 3 years for a mass-based standard. The EPA solicited comments on longer and shorter averaging times for emission standards included in state plans. The EPA received comments stating that the proposed 12-month averaging was too short and that there was no reason why the compliance period under a rate-based plan should be different from a mass-based plan. Comments stated that a multi-year averaging period is appropriate for rate-based and mass-based plans to account for variations that can occur in a single year, allowing operators the flexibility they need to manage unforeseen events. The commenters also recommended that the final rule use discrete 3-year periods for compliance reconciliation instead of the rolling-average approach proposed.

The EPA has considered all comments received on this matter and is finalizing the compliance periods specified above, which respond to the comments by applying to both rate- and mass-based programs, providing compliance periods longer than 1 year, and establishing block compliance periods rather than a rolling average approach. We agree with comments that longer averaging periods allow for operational and seasonal variability to even out. The EPA finalizes that states can choose to set shorter compliance periods for their emission standards but none that are longer than the compliance periods the EPA is finalizing in this rulemaking. If a state chooses to set shorter compliance periods, we urge them to make efforts to be cognizant of other deadlines facing EGUs to assure that there will not be conflicts. The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. "The time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month." See *e.g.*, June 13, 1989 "Guidance on Limiting Potential to Emit in New Source Permitting" and January 25, 1995 "Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits." However, the EPA has determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts. The distinction between these unique characteristics and the EPA's general practice regarding compliance periods is bolstered by the EPA guidance on appropriate averaging periods for emission limitations in NAAQS implementation. For example, the EPA guidance has stated that in implementation of the ozone standards, which have a short averaging period, the averaging period for VOC emission limitations should be correspondingly short. See 51 FR 43857. A longer averaging period for VOC emission limitations (VOCs are one of the key precursors to ozone formation) can allow spikes in emissions that adversely impact ambient air and violate the short term ozone standards. This is precisely the opposite of the unique characteristics cited above: the long-lived persistence of CO_2 in the stratosphere and the intent of these guidelines to address the long-term impacts.

State plans must contain requirements for tracking and reporting actual plan performance during implementation, which includes reporting of CO_2 emissions from affected EGUs. Affected EGUs must comply with emissions monitoring and reporting requirements that are largely incorporated from 40 CFR part 75 monitoring and reporting requirements. The majority of affected EGUs are already familiar with the reporting requirements of part 75, and because of this, the EPA has chosen to streamline the applicable reporting requirements for affected EGUs under the state plans in the final rule. States must require all affected EGUs to monitor and report hourly CO_2 emissions and net energy output (including total net MWh output that is comprised of generation, and where applicable, useful thermal output converted to net MWhs) on a quarterly basis in accordance with 40 CFR part 75. Note that this requirement applies for all types of state plans, regardless of whether the state chooses the option of the CO_2 emission performance rates, a state rate-based CO_2 emission goal, or a state mass-based CO_2 emission goal.

In the June 2014 proposal, the EPA proposed that state plans must include monitoring, reporting and recordkeeping requirements for useful energy output from affected EGUs. Multiple commenters questioned whether gross rather than net electrical production should be reported by affected EGUs and recommended that the EPA should utilize gross rather than net generation. Many commenters recommended electricity be reported in the form used in the 111(b) rules for consistency between reporting requirements and simplification of calculation of emission limitations between new and old sources. Commenters also stated that to the extent the EPA seeks to provide guidance to states regarding its preferred monitoring and reporting procedures, the EPA should encourage states to avoid imposing additional monitoring and reporting burdens by taking advantage of the monitoring requirements that already exist to the greatest extent possible. For example, the commenters noted that the 40 CFR part 75 monitoring procedures used to comply with other programs, such as the Title IV Acid Rain Program, provide much of the data that would be needed to demonstrate compliance under the rule. Comments stated that the June 2014 proposal appeared to mandate a monitoring approach that would eliminate key flexibilities provided in the part 75 regulations, thus requiring utilities to maintain separate document collection and reporting procedures and potentially eliminating important alternative monitoring options intended to ensure representative, cost-effective monitoring approaches are available. The commenters asked the EPA to revise its proposal to make clear that the procedures established under part 75 will suffice or explain the need for any exceptions. Commenters indicated that the rule should require all affected EGUs to monitor CO_2 emissions and net hourly electric output under 40 CFR part 75, and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS) assuring a more uniform monitoring and reporting process for all EGUs. The EPA believes that the final monitoring and reporting requirements (via ECMPS) address the issue of duplicative requirements and alleviate concern about lost flexibility raised by commenters.

2. Plan Performance Demonstrations

The state plan must include emission performance checks, and for state measures plans, periodic program implementation milestones. The state plan must provide for tracking of emission performance, and for measures to be implemented if the emission performance of affected EGUs in the state does not meet the applicable CO_2 emission performance rates or state CO_2 emission goal during a performance period.

As discussed above in section VII, the agency is finalizing CO_2 emission performance rates or state-specific CO_2 emission goals that represent emission levels to be achieved by 2030 and emission levels to be achieved over the 2022–2029 interim period, and over three interim steps of 2022–2024, 2025–2027 and 2028–2029. A state may choose to define different interim step emission levels for achieving its required 2022–2029 average performance rate. The EPA recognizes the importance of ensuring that, during the 8-year interim period (2022–2029) for the interim performance rates or interim state goal, a state is making steady progress toward achieving the required level of emission performance. For both emission standards plans and state measures plans, the final rule requires periodic checks on overall emission performance leading to corrective measures or implementation of the backstop, if necessary, as described in section VIII.F.3 below. States must demonstrate that the interim steps were achieved at the end of the first two interim step periods.

In 2032 and every 2 years thereafter, states must demonstrate that affected EGUs achieved the final performance rates or state goal on average or cumulatively, as appropriate, during each 2-year reporting period (*i.e.*, 2030–31, 2032–33, 2034–2035 etc.). The multi-year performance periods for measuring actual plan performance against the performance rates or state goals allow states some flexibility that accounts for seasonal operation of affected EGUs, and inclusion of RE and demand-side EE efforts.

For a rate-based plan, emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of each reporting period divided by cumulative MWh energy output [848] from affected EGUs over the reporting period, with rate adjustments for qualifying measures, such as RE and demand-side EE measures. For a mass-based plan, emission performance is total tons of CO_2 emitted by affected EGUs over the reporting period.

For emission standards plans, as discussed in section VIII.D, the state must submit a report to the EPA containing the emissions performance comparison for each reporting period no later than the July 1 following the end of each reporting period (*i.e.*, by July 1, 2025; July 1, 2028; July 1, 2030; July 1, 2032; and so on). As discussed in section VIII.D, the

[848] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022–2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period.

The EPA notes that for certain types of emission standards plans, with mass-based emission standards in the form of an emission budget trading program, achievement of a state's mass-based CO_2 goal (including interim step goals and final goal) will be assessed by the EPA based on compliance by affected EGUs with their emission standards under the program, rather than CO_2 emissions during a specific interim step period or final period. This approach is limited to plans with emission budget trading programs where compliance by affected EGUs with the emission standards will ensure that, on a cumulative basis, the state interim and final mass-based CO_2 goals are achieved.[849] This approach allows for CO_2 allowance banking across plan performance periods, including from the interim period to the final period. As a result, CO_2 emissions by affected EGUs could differ from the state mass-based CO_2 goal during an individual plan performance period, but on a cumulative basis CO_2 emissions from affected EGUs

[849] Emission budget trading programs in such plans establish CO_2 emission budgets equal to or less than the state mass CO_2 goal, as specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final 2-year plan performance periods.

would not exceed what is allowable if the interim and final CO_2 goals are achieved.

Also as discussed in section VIII.D, states that choose a state measures plan must submit an annual report no later than July 1 following the end of each calendar year in the interim period. This annual report must include the status of the implementation of programmatic state measures milestones identified in the state plan submittal. The annual report that follows the end of each reporting period (*i.e.*, 2022–2024, 2025–2027, and 2028–2029) must also include an emissions performance comparison for the reporting period, as described above for the emission standards plan. As discussed in section VIII.D, the emission comparison required in the July 1, 2030 report must compare the actual emissions from affected EGUs over the interim period (2022–2029) with the interim CO_2 emission performance rates or state CO_2 emission goal. The report is not required to include a comparison for the interim step 3 period, but must include the actual emissions from affected EGUs during the interim step 3 period. Beginning with the final period of 2030 and onward, states using a state measures plan must submit a biennial report no later than July 1 following the end of each reporting period with an emission performance comparison for each reporting period, consistent with the reporting requirements for emission standards plans.

In the June 2014 proposal, the EPA proposed that a state report is due to the EPA no later than July 1 of the year immediately following the end of each reporting period. The EPA requested comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requested comment on whether full reports containing all of the elements should only be required every 2 years rather than annually and whether these reports should be submitted electronically, to streamline transmission.

The EPA mainly received adverse comments for requiring annual state reporting; commenters stated that this requirement was too burdensome for both states and the EPA. Commenters also requested that the EPA extend the due date of the annual report from July 1 to at least December 31. Commenters stated that because of the timing of current data collection and the need to leave time to organize and submit the reports, allowing only 6 months after the close of the year is problematic. Commenters asked that the EPA consider reducing the amount of data required if annual reporting was required.

Considering the comments received and the goals of minimizing unnecessary burdens on states and ensuring program effectiveness, the EPA has reduced the frequency of reporting of emissions data to every 3 years for the first two interim steps and every 2 years thereafter. However, the EPA is finalizing that state reports are due to the EPA no later than July 1 following the end of each reporting period. The EPA believes states can design their state plans to receive the data and information needed for these reports in a timely manner so that this requirement can be met. Furthermore, some of the state reporting requirements, such as reporting of EGU emissions, can be met through existing reporting mechanisms

(ECMPS) and would not place additional burdens on states.

3. Consequences if Actual Emission Performance Does Not Meet the CO_2 Emission Performance Rates or State CO_2 Emission Goal

The EPA recognizes that, under certain scenarios, an approved state plan might fail to achieve a level of emission performance that meets the emission guidelines or the level of performance established in a state plan for an interim milestone. Despite successful implementation of certain types of plans, emissions under the plan could turn out to be higher than projected at the time of plan approval because actual conditions vary from assumptions used when projecting emission performance. Emissions also could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The final rule specifies the consequences in the event that actual emission performance under a state plan does not meet, or is not on track to meet, the applicable interim and interim step CO_2 emission performance rates or state goals in 2022–2029, or does not meet the applicable final CO_2 emission performance rates or state CO_2 emission goal in 2030–2031 or later. The determination that a state is not on track to meet the applicable interim goal or interim step goals in 2022–2029 or the applicable final goal in 2030–2031 or later, or the CO_2 emission performance rates, will be made through the actual performance checks to be included in state reports of performance data described in section VIII.D.2.a above.

For emission standards plans, the final rule specifies that corrective measures must be enacted once triggered. Corrective measures apply only to emission standard plans in which full compliance by affected EGUs would not necessarily lead to achievement of the emission performance rates or CO_2 emission goals.[850] For such plans, corrective measures are triggered if actual CO_2 emission performance by affected EGUs is deficient by 10 percent or more relative to the specified level of emission performance in the state plan for the step 1 or step 2 interim performance periods. Corrective measures also are triggered if actual emission performance fails to meet the specified level in the plan for the 8-year interim period 2022–2029, or for any 2-year final goal performance period (beginning in 2030). In such cases, the state report must include a notification to the EPA that corrective measures have been triggered. If, in the event of such an exceedance, the EPA determines that corrective measures have been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that corrective measures have been triggered.[851]

---

[850] To be specific, corrective measures requirements apply to all emission standard plan designs that do not mathematically assure that the plan performance level will be achieved when all affected EGUs are in compliance with their emission standards, regardless of electricity production and electricity mix. Corrective measures requirements apply, for example, to emission standards plans that include standards on affected EGUs that differ from the emission performance rates in the guidelines. Backstop requirements apply to state measures plans.

[851] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans

When corrective measures are triggered, if the state plan does not already contain corrective measures, the state must submit to the EPA a plan revision including corrective measures that adjust requirements or add new measures. The corrective measures must both ensure future achievement of the CO_2 emission performance rates or state CO_2 emission goal and achieve additional emission reductions to offset any emission performance shortfall that occurred during a performance period. The shortfall must be made up as expeditiously as practicable. 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 to the EPA as expeditiously as practicable and within 24 months after submitting the state report indicating the exceedance. The 24-month time period allows time to identify corrective measures and make rule changes through state regulatory processes. The EPA will then act on the plan revision within 12 months, consistent with other plan revisions and with the timing for final plan submittals originally submitted by states. The state must implement corrective measures within 6 months of the EPA's approval of a plan revision adding them.

For states using the state measures approach, the EPA is finalizing the backstop requirement as described in section VIII.C.3 of this preamble. As discussed in section VIII.D.2, the determination that a state using the state measures approach is not on

---

in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

track to meet the applicable interim goal or interim step goals in 2022–2029, or the applicable final goal in 2030–2031 or later, is based on checks that must be included in state reports that must be submitted annually during the interim period and biennially during the final period. The state must annually report on its progress in meeting its programmatic state measures milestones during the interim period. In addition, the state must report actual emission performance checks, similar to the requirements discussed above for emission standards plans, in 2025, 2028, 2030, and every 2 years thereafter. If, at the time of the state report to the EPA, the state did not meet the programmatic state measures milestones for the reporting period, or the performance check shows that the plan's actual CO_2 emission performance warrants implementation of backstop requirements,[852] the state must include in the state report a notification to the EPA that the backstop has been triggered. If, in the event of such an exceedance, the EPA determines that the backstop has been triggered and the state has failed to notify the EPA,

[852] As explained in section VIII.C.3.b., state measures plans must require the backstop to take effect if actual CO_2 emission performance fails to meet the level of emission performance specified in the plan over the 8-year interim performance period (2022–2029), or for any 2-year final goal performance period. The plan also must require the backstop to take effect if actual emission performance is deficient by 10 percent or more relative to the performance levels that the state has chosen to specify in its plan for the interim step 1 period (2022–2024) or the interim step 2 period (2025–2027).

the EPA will inform the affected EGUs that the backstop has been triggered.[853]

For multi-state plans, corrective measure or backstop provisions would be required for the same plan approaches for which those provisions are required in individual state plans. For multi-state plans using plan approaches to which corrective measures or backstop requirements apply, all states that are party to the multi-state plan would be subject to corrective action or backstop requirements, and requirements to make up the past CO_2 emission performance shortfall, if those requirements were triggered. This is because multi-state plans are joint plans (even if created through separate state submittals). That would not be the case for coordinated individual state plans linked through interstate ERC or emission allowance trading. In the case of coordinated individual state plans, for plan types subject to corrective measure or backstop requirements, the state where the CO_2 emission performance deficiency occurs would be required to implement corrective measures or backstop requirements for affected EGUs, as applicable, and remedy the past CO_2 emission performance shortfall.

Multiple commenters requested that corrective measures not be required in the case of a catastrophic, uncontrollable event. We recognize that there are potential system emergencies that cannot be anticipated that could cause a severe stress on the

[853] The EPA notes that as part of the proposed federal plan rulemaking, it is proposing a regulatory mechanism to call plans in the instances of substantial inadequacy to meet applicable requirements or failure to implement an approved plan.

electricity system for a length of time such that the multi-year requirements in a state plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. We are finalizing a reliability safety valve, which includes an initial period of up to 90 days during which a reliability-critical affected EGU or EGUs will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard. While the initial 90-day period is in use, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emission performance rate for affected EGUs and will not be counted as an exceedance that would otherwise trigger corrective measures under an emission standard plan type or an exceedance that would trigger a backstop under a state measures plan type. Use of the reliability safety valve will not alter or abrogate any other obligations under the approved state plan. After the initial period of up to 90 days, the reliability-critical affected EGU is required to continue to operate under the original state plan emission standard or an alternative standard as part of the reliability safety valve, and the state must revise its plan to accommodate changes needed to respond to ongoing reliability requirements and to ensure than any emissions excess of the applicable state goals or performance rates occurring after the initial period of up to 90 days are accounted for and offset. See section VIII.G.2.e of this preamble.

Multiple commenters supported the inclusion of strong enforcement measures for ensuring the interim and final goals are met, including the required use of corrective measures when triggered. Other commenters provided feedback as to the percentage that actual emission performance would need to exceed the level of emission performance specified in the statewide plan to trigger corrective measures. Some commenters supported the trigger that we are finalizing (actual emissions or emission rate performance that is 10 percent or more than the specified level of emission performance in the state plan for the interim step 1 or step 2 performance periods), while some recommended a lower or higher trigger.

The agency is finalizing the trigger at the level of 10 percent for the interim step 1 or step 2 performance periods. Ten percent is a reasonable level to ensure that when deficiencies in state plan performance begin to emerge, corrective measures (or backstop requirements) will be implemented promptly to avoid emissions shortfalls (or minimize the extent of shortfalls) relative to the 8-year interim goal and the final goal, which reflect the BSER. The 10 percent figure also provides latitude for a state's emission improvement trajectory during the interim period to deviate a bit from its planned path without triggering these requirements, as the state initiates or ramps up programs to meet the 8-year interim goal and final goal.

The EPA requested comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the CO_2 emission performance rates or state CO_2 emission goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time. If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A). 79 FR 34830, 34908/1–2 (June 18, 2014).

The EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether the EPA has authority to call for plan revisions under section 111(d) when a state's plan is not complying with the requirements of this guideline, and if so, precisely what procedures should apply. The EPA is proposing these revisions to the 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan. The EPA is not taking final action now on this issue or the related change to the implementing regulations.

a. *Legal basis for corrective measures.*

The EPA discussed the concept of corrective measures in our 1992 General Preamble for the Implementation of Title I of the CAA Amendments of 1990. 57 FR 13498 (Apr. 16, 1992). The General Preamble sets out four general principles that apply to all SIPs, "including those involving emissions trading, marketable permits and allowances." *Id.* at 13568. The fourth principle, accountability, means (among other things) that "the SIP must contain means . . . to track emission changes at sources and provide for corrective action if emissions reductions are not achieved according to the plan." In the General Preamble, we noted that Part D of Title I explicitly provided for this in certain instances by requiring milestones and contingency measures.

Some commenters noted that the contingency measures explicitly required by part D are required to be adopted in the attainment plan and ready to implement when a milestone is not achieved or the area fails to attain the relevant NAAQS. These commenters therefore concluded that corrective measures for 111(d) plans should likewise already be adopted in the 111(d) plan and ready to implement. We disagree. Under Part D, contingency measures are not expected to fully bring the area into attainment. In fact, this would not be possible given the difficulty of predicting in advance exactly what measures would be needed to fully attain. A better analogue in Part D for the corrective measures in these guidelines is the primary way Part D addresses failure to attain: The state is required to revise its plan in various ways within a certain time in order to bring about attainment. See, *e.g.*, section 179(d). This is analogous to what we are requiring for corrective measures. Thus, part D contingency measures are unlike the corrective measures in this rule.

However, the requirement to revise an attainment plan in response to failure to attain differs somewhat from the corrective measures in these guidelines. Under these guidelines, the corrective measures must make up the difference by which the plan fell short of the goal, including any prior shortfall that had accumulated if the plan fell short of the goal in prior years. There is no corresponding requirement in attainment planning to increase the stringency of the plan by an amount that somehow makes up for any shortfall in attainment from prior years; instead the revised plan must demonstrate attainment going forward, and other more stringent requirements (such as requirements for best available control measures) may be triggered.

This distinction is the natural result of the difference between these guidelines and NAAQS attainment planning. In this case, we are finalizing guidelines representing technology-based standards for a pollutant with cumulative and long-lasting effects. If a plan falls short of a performance goal, then in effect the standards of performance in the plan have failed to reflect the BSER over the corresponding period. Due to the cumulative effects of CO_2, it is possible to remedy this failure by requiring the plan to be revised in such a way that the standards of performance in the revised plan will reflect the BSER over the cumulative plan period, and this can be done by requiring the revised plan to make up the shortfall from the previous period. In short, the flexibility that these guidelines provide should not come at the cost of allowing the standards of performance to reflect less than the BSER over the long run.[854]

Some commenters noted that 111(d) does not contain explicit provisions regarding corrective measures, and they therefore inferred that the EPA is not authorized to require them. That inference is mistaken. The requirement for 111(d) plans to "provide for implementation and enforcement" of the standards of performance is ambiguous and does not directly speak to whether corrective measures should or should not be required. There is therefore a gap for the EPA to fill. While the discussion above about Part

---

[854] Similar considerations apply to the requirement under the state measures approach to revise the plan to make up the shortfall.

D does not independently provide any authority to fill this gap, the fact that Congress created a scheme with stages of planning in Part D suggests that it would be reasonable, if appropriate, to fill this gap in 111(d) in a similar way.

In this guideline, it is appropriate for emission standards plans to fill this gap with corrective measures if triggered. There are two ways an emission standards plan can provide for implementation of standards of performance that achieve the CO_2 emission performance rates or requisite state CO_2 emission performance goal. First, the state can set emission standards that necessarily achieve the performance rates or goal, even if the affected EGUs in the future vary in their relative amounts of electricity generated. Second, the state can set emission standards that are demonstrated to achieve the performance rates or goal based on assumptions about the relative amounts of electricity generated, but which may turn out to not actually achieve the goal even if all affected EGUs comply. This is analogous to an attainment plan that demonstrated attainment by the applicable attainment date, but due to unpredicted economic changes actually failed to attain. In this second case, the EPA interprets the ambiguous language "provide for implementation . . . of standards of performance" in the context of achieving the performance rate or emissions goal, to mean that at the time the plan is submitted it must contain some mechanism to check the progress of the plan and correct course. The EPA has determined that, for this particular rule, the minimum mechanism is the set of milestones and provisions for corrective measures specified in this rule. Indeed, not requiring corrective measures in the case of deficient plan performance would undercut the viability of state plan options other than emission standard plans with uniform rates applied to all affected EGUs within the state.

4. Out-Year Requirements: Maintaining or Improving the Level of Emission Performance Required by the Emission Guidelines

The agency is determining CO_2 emission performance rates and state CO_2 emission goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should be maintained at the 2030 level—or instead should be further improved—once the final CO_2 emission performance rate or state CO_2 emission goal is met in 2030. This involves questions of performance rate and goal-setting as well as questions about state planning. The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be maintained or, through silence, authorized the EPA to reasonably require maintenance. Other CAA section 111(d) emission guidelines set emission limits that do not expire. Therefore, the EPA is finalizing that the level of emission performance for affected EGUs represented by the final CO_2 emission performance rates or state CO_2 emission goal must continue to be maintained in the years after 2030.

As noted above, the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal. The state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset. After implementation, the state is required to compare actual plan performance against the final goal on a 2-year average basis starting in 2030, and to implement corrective measures or a backstop if triggered.

In the proposal, the EPA noted that "CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources" in order to assure regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The proposal "requests comment on the implications of this concept, if any, for CAA section 111(d)." 79 FR 34830, 34908/3 (June 18, 2014).

We acknowledge the obligation to review section 111(b) standards as stated. The EPA is not finalizing any position with respect to any implications of this concept for section 111(d). We are promulgating rules for section 111(d) state plans that will establish standards of performance for existing sources to which a section 111(b) standard of performance would apply if such sources were new sources, within the definition in section 111(a)(2) of "new source." It is not necessary to address at this time whether subsequent review and/or appropriate revision of the corresponding section 111(b) standard of performance have any implications for review and/or revision of this rule.

a. *Legal basis for maintaining emission performance.*

In the proposal, the EPA proposed "that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained." The EPA explained that "Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently." 79 FR 34830, 34908/2 (June 18, 2014). We also requested comment on whether "we should establish BSER-based state performance goals that extend further into the future (*e.g.* beyond the proposed planning period), and if so, what those levels of improved performance should be." *Id.* at 34908/3.

We received adverse comment on establishing BSER-based state performance goals beyond the proposed planning period. Commenters argued that we did not have a sufficient basis at this time to determine what those future goals should be. We agree and have decided not to establish such goals. We are finalizing, though, that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained, for the reasons given in our proposal and quoted above.

The general structure of the CAA supports our interpretation. Section 111(d) plans establish standards of performance that reflect the BSER, a technology-based standard. Generally speaking, in the future technology will only improve, and correspondingly the CAA does not provide explicit processes to relax technology-based standards. In contrast, the provisions in Part D of title I that address attainment of health-based standards, the NAAQS, explicitly provide that once the NAAQS are attained, emission reduction measures may be relaxed so long as the NAAQS are maintained. The absence in section 111(d) of explicit provisions for future relaxation of emission reduction measures, as compared to Part D, supports our interpretation that the emission reductions continue to be on-going after the CO_2 emission performance rates or state CO_2 emission goals are achieved in 2030. This is consistent with our past practice for section 111(d) rules, which do not contain any provision that in the future removes or relaxes the promulgated guidelines. In light of the persistence of CO_2 as a pollutant and its long-term impacts, it is particularly critical in these guidelines to explicitly provide for continuing emission reductions.

G. Additional Considerations for State Plans

1. Consideration of a Facility's "Remaining Useful Life" and "Other Factors"

This section discusses the way in which the final emission guidelines address the CAA section 111(d)(1) provision requiring the Administrator, in promulgating 111(d) regulations, to "permit the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

The final guidelines permit a state, in developing its state plan, to fully consider and take into account the remaining useful life of an affected EGU and other factors in establishing the requirements that apply to that EGU, as discussed further below. Therefore, consideration of facility-specific factors and in particular, remaining useful life, does not justify a state making further adjustments to the performance rates or aggregate emission goal that the guidelines define for affected EGUs in a state and that must be achieved by the state plan. Thus, these guidelines do not provide for states to make additional goal adjustments based on remaining useful life and other facility-specific factors because they can fully consider these factors in designing their plans.

a. *Statutory and regulatory backdrop.*

This section describes the statutory and existing regulatory background concerning facility-specific considerations in implementation of section 111(d).

Section 111(d)(1)(A) requires states to submit a plan that "establishes standards of performance" for existing sources. Under section 111(d)(1)(B), the plan must also "provide for implementation and enforcement of such standards of performance." Finally, the last sentence of section 111(d)(1) provides: "Regulations of the Administrator under this paragraph shall 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."

The EPA's 1975 implementing regulations [855] addressed a number of facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for designated pollutants, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

This provision was amended in 1995 (60 FR 65387, December 19, 1995), and is now prefaced with the language "Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities." 40 CFR 60.24(f).

b. *Our proposal regarding the implementing regulations.*

Our proposal stated that the reference to "[u]nreasonable cost of control resulting from plant age" in 60.24(f) "implements" the statutory provision on remaining useful life. We also stated that the implementing regulations "provide the EPA's default structure for implementing the remaining useful life

[855] 40 FR 53340 (Nov. 17, 1975).

provision of CAA section 111(d)." We noted that the prefatory language "unless otherwise specified in the applicable subpart" gives the EPA discretion to alter the extent to which the implementing rules applied if appropriate for a particular source category and guidelines. We requested comment on our analysis of the existing implementing regulations and any implications for our regulatory text in respect to how these guidelines relate to those regulations.

Commenters stated, among other things, that the sentence concerning "remaining useful life" was added in the 1977 CAA Amendments and that therefore it could not be said that provisions from the 1975 implementing regulations "implement" the sentence. The EPA does not think as a general matter that it is necessarily impossible that a pre-statutory amendment rule could continue to serve as a reasonable implementation of a post-statutory amendment provision. However, we also think it is appropriate, as we suggested in the June 2014 proposal, to specify in the applicable subpart for these guidelines that the provisions in 60.24(f) should not apply to the class of facilities covered by these guidelines. As a result, regardless of whether the implementing regulations appropriately implement the "remaining useful life" provision in general, the relevant consideration is that, as we now explain, these particular guidelines "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."

c. *How these emission guidelines permit states to consider remaining useful life and other facility-specific factors.*

The EPA notes that, in general, the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are similar to a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, Kraft pulp plants, and municipal solid waste landfills specify emission limits for sources.[856] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these final guidelines for state plans to limit CO_2 from affected EGUs, however, the agency does not specify presumptive performance rates that each individual EGU is to achieve in the absence of trading. Instead, these guidelines provide collective

---

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

performance rates for two classes of affected EGUs (steam generating units and stationary combustion turbines), and give states the alternative of developing plans to achieve a state emission goal for the collective group of all affected EGUs in a state. Providing states with the ability to consider facility-specific factors such as remaining useful life in designing their state plans is one of the fundamental reasons that the EPA designed the final rule in this way. In addition, the significant revisions since proposal to address achievability concerns (*e.g.*, moving the start date from 2020 to 2022, and other changes in interim and final state goals summarized in the next section) will help to ensure that states in practice can consider remaining useful life and other facility-specific factors in setting EGU requirements. Of course, EGUs vary considerably in age, so remaining useful life is potentially relevant to regulation of some units and not others.

The guidelines capitalize on the inherent flexibility offered by the CO_2 emission performance rates and by the state CO_2 emission goals approach, allowing states flexibility on the form of the EGU standards that they include in CAA section 111(d) plans. A state could select a form of standards (*e.g.*, marketable credits or permits, retirement of certain older facilities after their useful life, etc.) that avoids or diminishes concerns about facility-specific factors such as remaining useful life. If a state adopted the CO_2 emission performance rates for fossil fuel-fired electric utility steam generating units and stationary combustion turbines in conjunction with rate-based trading, though, the state would be taking remaining useful life into consideration by allowing affected

EGUs to comply using ERCs. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs than the second facility. Buying ERCs would avoid excessive up-front capital expenditures that might be unreasonable for a facility with a short remaining useful life, and would reduce the potential for stranded assets.

In addition to providing states with flexibility on the form of the standards of performance in their plans, the guidelines leave to each state the design of the specific requirements that fall on each affected EGU in applying those standards. To the extent that an emission standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state may make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions to meet the state goal) in the state's CAA section 111(d) plan submission.

Finally, we note that these guidelines permit states to use a rate or mass CO_2 emission goal, and that each of these pathways allow states multiple design choices. Under either pathway states can take into consideration remaining useful life and seek to avoid stranded assets.

The EPA believes that this approach to permitting states to consider remaining useful life is appropriate because it reflects, and is compatible with, the interconnected nature of the electricity system.

Although this discussion emphasizes state flexibility on plan design, it is important to note that the main intended beneficiaries of state flexibility are the affected EGUs themselves. As a key case in point, the EPA has endeavored to craft the final guidelines to support and facilitate state plans that include trading systems, including interstate trading systems that can help EGUs continue to operate with the flexibility that they currently enjoy on regional grid levels.

Trading can provide affected EGUs that have a limited remaining useful life with the flexibility to comply through purchasing allowances or ERCs, thereby avoiding major capital expenditures that would create long-term debt. By buying allowances or ERCs, affected EGUs with a limited remaining useful life contribute to achieving emission reductions from the source category during the years that they operate. During its lifetime, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same.[857]

In part to help states address remaining useful life considerations, the final guidelines facilitate state plans that employ trading in multiple ways:

[857] Trading of course has other benefits beyond helping to address remaining useful life concerns. For example, trading can lower costs of achieving a given level of emission reduction and can provide economic incentives for innovation and development of cleaner technologies.

- By allowing trading under emission standards plans and state measures plans, and under rate-based plans and mass-based plans;
- By defining national EGU performance rates that make it easier for states to set up rate-based trading regimes that allow for interstate trading of ERCs;
- By clearly defining the requirements for mass-based and rate-based trading systems to ensure their integrity; and
- By providing information on potential allocation approaches for mass-based trading.

In addition, the EPA is separately proposing model trading rules for rate-based and mass-based trading to assist states with design of these programs in the section 111(d) context.

d. *Why remaining useful life and other facility-specific factors do not warrant adjustments in the guidelines' performance rates and state goals.*

Under the final guidelines, remaining useful life and other facility-specific considerations do not provide a basis for adjusting the CO_2 emission performance rates, or the state's rate-based or mass-based CO_2 emission goals, nor do they affect the state's obligation to develop and submit an approvable CAA section 111(d) plan that adopts the CO_2 emission performance rates or achieves the goal by the applicable deadline. After considering public comments discussed below and in the response to comments document, the EPA has retained this aspect of the proposed rule for the reasons described below.

As noted above, the final guidelines provide aggregate emission goals for affected EGUs in each state, in addition to the CO_2 emission performance rates. The guidelines also reflect a number of changes from proposal to address concerns about achievability of proposed state goals that were raised in public comments, many of which were explicitly prompted by consideration of the remaining useful life issue. The result is to afford states with broad flexibility to design requirements for affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goals in ways that avoid requiring major capital expenditures, or imposing unreasonable costs, on those affected EGUs that have a limited remaining useful life. State plans may use any combination of the emissions reduction methods represented by the building blocks, and may also choose to employ emission reduction methods that were not assumed in calculating state goals.

To be more specific, the EPA notes that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. A state may use any combination of measures, including those not specifically factored into the BSER by the EPA. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish EGU emission rates and state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the agency's computations, according to each state's needs and preferences. The guidelines provide further flexibility by allowing state plans to use emission reduction methods not reflected in the BSER. A description of multiple emission reduction methods is provided in sections VIII.I–K.

e. *Response to key comments on remaining useful life.*

In response to the proposed guidelines, some commenters said that the proposed state goals were unachievable and therefore too stringent to provide states, as a practical matter, with the flexibility to consider remaining useful life for individual units. These commenters said the result would be premature retirements and stranded assets.

In the final guidelines, the EPA has addressed the comments about lack of practical flexibility to consider remaining useful life by revising key elements of the guidelines in ways that will ensure that the CO_2 emission performance rates and state CO_2 emission goals are achievable considering cost. At the same time, the final guidelines maintain the broad flexibility of each state to design its own compliance pathway, taking into account any facility-level concerns—including remaining useful life—in designing EGU requirements.

The changes to the BSER and goal-setting methodologies include:

- Starting the interim goal period in 2022 rather than 2020, which allows more lead time for states and regulated entities and helps to ensure that the interim goal is achievable

- Revising the goal-setting formula and the state goals themselves

- Updating analyses of achievable levels of improvement through the building blocks that together represent the BSER, while keeping them at reasonable, rather than maximum, levels (thus creating headroom which can, and is intended to, help to accommodate the range of ages of different facilities)
- Providing an explicit phase-in schedule for meeting the revised interim goals, while also allowing a state the option of choosing its own emission reduction trajectory

The final guidelines also contain changes to avoid certain inconsistencies between the goal-setting methodology and accounting of reductions under state plans that could have made state goals less achievable for some states.

Together, the changes described above help to ensure that the CO_2 emission performance rates and state CO_2 emission goals established in the final guidelines are achievable, and leave states with the practical ability to issue rules that take into account the remaining useful life of affected EGU.

As explained in the Legal Memorandum accompanying this rule, the EPA believes that Congress intended the remaining useful life provision to provide a mechanism for states to avoid the imposition of unreasonable retrofit costs on existing sources with relatively short remaining useful lives, a scenario that could result in stranded assets. However, commenters on the proposed rule raised a different stranded assets concern not primarily related to retrofit costs—a concern that the proposed rule could cause changes in economic competitiveness of particular EGUs that would prompt their retirement before the end of their economically useful lives. These commenters said the proposed state goals were so stringent that states would have no choice but to adopt requirements that would result in retirements of coal-fired capacity that had been built relatively recently or had recently made pollution control investments. In response to these comments, the EPA has conducted a stranded assets analysis which demonstrates that the CO_2 emission performance rates and state goals in the final guidelines provide sufficient flexibility to states to address stranded asset concerns. The EPA shares the goal of minimizing stranded assets. Although nothing in section 111(d) explicitly bars a guideline that results in some facilities becoming uneconomic before the end of their useful lives, the EPA nonetheless has striven to design the guidelines so as to give states flexibility to develop plans that include, for example, differential treatment of affected EGUs or opportunities to rely on emissions trading, to allow power companies to recover their investments in generation units.

For purposes of the stranded assets analysis, the EPA considered a potential "stranded asset" to be an investment in a coal-fired EGU (or in a capital-intensive pollution control installed at such an EGU) that retires before it is fully depreciated. Book life is the period over which long-lived assets are depreciated for financial reporting purposes. The agency estimated typical book life by researching financial statements of utility and merchant generation companies in filings to the Securities and Exchange Commission. The agency estimated the book life of coal-fired EGUs to be 40 years, and assumed a 20-year book life for pollution control retrofits. The book life of coal-fired EGUs (coal steam and IGCC) is twice as long as the debt life and the depreciation schedule used for federal tax purposes. Although the book life for environmental retrofits is often 15 years, the agency conservatively assumed 20 years in this analysis.

The analysis examined coal generation in the three large regional interconnections of the U.S. The analysis found that in both 2025 and 2030, for each region, the amount of 2012 coal generation included in the final guidelines' emission performance rate calculation—specifically, the generation remaining after the BSER calculation—is greater than the amount of 2012 generation from coal-fired EGUs that are not fully depreciated in those years under the book life assumptions described above. This shows that the final rule allows flexibility for states to preserve these units as part of their plans.

To put this analysis in perspective: The EPA's role is to set emission guidelines that meet the statutory requirements, which includes consideration of cost in identifying the BSER, as the EPA has done in these guidelines. States have a broad degree of flexibility to design plans to achieve the rates in the emission guidelines in a manner that meets their policy priorities, including ensuring cost-effective compliance. Although not a required component of the EPA's consideration of cost, this analysis shows that the CO_2 emission performance rates in the final guidelines can be met without the retirement of affected EGUs before the end of their book life, and without the retirement of affected EGUs before the end of the book life of capital-intensive pollution control retrofits installed on those EGUs. Thus, according to this analysis, the CO_2 emission performance rates and state CO_2 emission goals need not result in stranded assets. The EPA recognizes that power plant economics are determined by many aspects of markets that are outside of the EPA's control, such as wholesale power prices and capacity prices, and that the compliance path of least cost may involve retiring assets that have not fully depreciated. Nonetheless, this analysis further demonstrates the extent of flexibility available to states in designing their plans to best serve the policy priorities of the state. Details are available in a memorandum to the docket.[858]

Several commenters said that the statute does not authorize the EPA to require other facilities to achieve greater reductions to compensate for a facility that warrants relief based on remaining useful life. One said that consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve the BSER, and that the EPA turns that approach on its head by prohibiting a state from providing such relief to a specific facility unless it can identify another facility to "punish" by requiring additional emissions reductions to offset that relief.

The EPA disagrees with these comments, which proceed from an incorrect premise. The EPA is not determining a BSER-based emission level achievable by each individual facility without trading, and then requiring better-than-BSER from some facilities to make up for worse-than-BSER performance that a state authorizes for other facilities because of a short

---

[858] Memorandum to Clean Power Plan Docket titled "Stranded Assets Analysis" dated July 2015.

remaining useful life. Rather, as previously noted, the guidelines set CO_2 emission performance rates and state CO_2 emission goals that represent the average or aggregate emission level achievable by affected EGUs based on regional average estimates of the impact of applying the BSER to collective groupings of affected EGUs.[859] In estimating the amount of improvement achievable through each building block (*e.g.*, improvement in heat rate or amount of generation shift to lower-emitting EGUs), the EPA has estimated the average level achievable by EGUs in a region rather than attempting to estimate the level achievable by each and every affected EGU in the absence of trading. Thus, the fact that an individual facility may be unable, for example, to achieve the average level of heat rate improvement assumed in goal-setting is consistent with the EPA's analysis, and does not undermine the EPA's determination of CO_2 emission performance rates and state CO_2 emission goals. The Legal Memorandum discusses additional reasons that the agency disagrees with comments that the guideline must permit adjustments in the guidelines' CO_2 emission performance rates and state CO_2 emission goals based on remaining useful life considerations.

An additional reason that the EPA believes that consideration of remaining useful life and other facility-specific factors does not warrant adjustments

---

[859] The EPA expects that states that choose to adopt the national CO_2 emission performance rates for all of their EGUs would permit ERC trading, rather than requiring each facility to meet the applicable rate without trading. In effect, the presence of trading means that the EGU performance rates can be achieved by each EGU involved in trading.

to state goals is that the design of the guidelines does not mandate that states impose requirements that would call for substantial capital investments at affected EGUs late in their useful life. Multiple methods are available for reducing emissions from affected EGUs that do not involve capital investments by the owner/operator of an affected EGU. For example, generation shifts among affected EGUs, and addition of new RE generating capacity do not generally involve capital investments by the owner/operator at an affected EGU. Additional emission reduction methods available to states that do not entail significant capital costs at affected EGUs are discussed elsewhere in this preamble.

Heat rate improvements at affected EGUs may require capital investments. However, states have flexibility to design their plan requirements; they are not required to mandate heat rate improvements at plants that have limited remaining useful life. In fact, a state can choose whether or not to require heat rate improvements at all. The agency also notes that capital expenditures for heat rate improvements would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove SO_2; a fleet-wide average cost for heat rate improvements based primarily on best practices at coal-fired generating units would not likely exceed \$100/kW, compared with a typical SO_2 wet scrubber cost of \$500/kW (costs vary with unit size).[860] Even if a state did choose to adopt

[860] Heat rate improvement methods and related capital costs are discussed in the GHG Mitigation Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's

requirements for heat rate improvements, the proposed guidelines would allow states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (*e.g.*, averaging and trading programs). Under the EPA's final approach—establishing state goals and providing states with flexibility in plan design—states have flexibility to make exactly the kind of judgments necessary to avoid requiring capital investments that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant as states determine requirements that are directly applicable to affected EGUs. If relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that will achieve the CO_2 emission performance rates or state CO_2 emission goals on time. The EPA therefore concludes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be regarded as a basis for adjusting the CO_2 emission performance rates or a state CO_2 emission goal, and should not relieve a state of its obligation to develop and submit an approvable plan that achieves that goal on time.

f. *Legal considerations regarding remaining useful life*. Section 111(d)(1) requires the EPA in promulgating section 111(d) regulations to "permit the State in applying a standard of performance to any particular source under a plan submitted under this

---

IPM Base Case v5.13, Chapter 5, Table 5-3, available at *http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf*.

paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Here, we discuss the legal basis for determining that the emission guidelines are consistent with this statutory requirement. For details, please see the Legal Memorandum.

Section 111(d)(1) only requires that EPA emission guidelines permit states to take into account remaining useful life (among other factors), but section 111(d)(1) does not specify how the EPA must permit that. In other words, the meaning of the provision and the way that the EPA is to implement it in promulgating guidelines are not specified further in the provision. The provision is ambiguous and capable of implementation in several ways, and therefore the EPA has discretion to interpret and apply it. Furthermore, section 111(d)(1) does not suggest that states must be given carte blanche to consider remaining useful life in any way that can be imagined. As detailed above in sections VIII.G.1.c–e, these guidelines permit states to take into account remaining useful life in a number of reasonable ways and thus the guidelines satisfy the statutory obligation.

The phrase "remaining useful life" also appears in the visibility provisions of section 169A. There, in determining best available retrofit technology (BART), the state (or the EPA) must take into consideration (among other factors) "the remaining useful life of the source." 42 U.S.C. 7491(g)(2); see also *id.* (g)(1) (reasonable progress). In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR Pt. 51, App. Y, IV.D.4.k.1. This annualized cost is then used to determine a cost effectiveness, in dollars per ton of pollutant removed on an annual basis. As a result, a technology with a large initial capital cost that might have a reasonable cost-effectiveness for a facility with a long remaining useful life would have a much higher and possibly unreasonable cost-effectiveness for a facility with a short remaining useful life.

Although section 111(d)(1) is different than section 169A(g)(2) and need not be interpreted in the same way, we would note (as discussed in detail in sections VIII.G.1.c–e, section 5.11 of the Response to Comments document, and the Legal Memorandum) that (for example) a trading program under these section 111(d) guidelines only requires compliance on a periodic basis and does not require any initial capital expenditures. Thus, over the life of the facility, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same. In other words, under a trading program remaining useful life of a source is automatically accounted for in the way it is accounted for under the visibility program.

Some commenters stated that the EPA's interpretation of remaining useful life is impermissible. These commenters claimed that states, if they wish to take into account remaining useful life at one affected EGU, must relax the stringency of the emission standard for that EGU. Then, the state would be compelled to increase the stringency of emission standards at other affected EGUs in order to achieve the state performance goal. According to these commenters, section 111(d) does not allow this outcome.

First, the commenters are mistaken in their premise. As discussed in section VIII.G.1, section 5.11 of the Response to Comments document, the Legal Memorandum, and in the example immediately above, states can impose the exact same emission standards on two affected EGUs and still take into account remaining useful life through the availability of trading. In other words, states need not relax an emission standard here and strengthen an emission standard there in order to take into account remaining useful life. Thus, these guidelines permit states to take into account remaining useful life without any of the effects commenters are concerned about.

Second, even if states decide to relax emission standards at one EGU, on the basis of remaining useful life or any other factor, nothing in the last sentence of section 111(d)(1) prohibits these guidelines from requiring the state plan to still meet the CO_2 emission performance rates or state CO_2 emission goal. In fact, that sentence is completely silent on the issue. Thus, the EPA has the discretion to determine what should be the concomitant effects if a state chooses to consider remaining useful life in a particular way. In this case the concomitant effect of a state relaxing one emission standard may be that the state must make up for it elsewhere in order to meet the goal, but nothing in section 111(d)(1), including the statutory requirement to permit consideration of remaining useful life, prohibits that outcome.

2. Electric Reliability

The final rule features overall flexibility, a long planning and implementation horizon, and a wide range of options for states and affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goal. This design reflects, among other things, the EPA's commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Comments from state, regional and federal reliability entities, power companies and others, as well as consultation with the Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC), helped inform a number of changes made in this final rule to address reliability. In addition, FERC conducted one national and three regional technical conferences on the proposed rule in which the EPA participated and at which the issue of reliability was raised by numerous participants.

As discussed throughout the preamble and TSDs, the electricity sector is undergoing a period of intense change. While the change in the resource mix has accelerated in recent years, wind, solar, other RE, and EE resources have been reliably participating in the electric sector for a number of years. Many of the potential changes to the electric system that the final rule may encourage, such as shifts to cleaner sources of power and efforts to reduce electricity demand, are already well underway in the electric industry. To the extent that the final rule accelerates these changes, there are multiple features well embedded in the electricity system that ensure that electric system reliability will be maintained. Electric system reliability is continually being considered and planned for. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by FERC and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, DOE, state PUCs, ISOs/RTOs, and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for, and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry's efforts regarding electric system reliability have become multidimensional, comprehensive, and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[861] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[862] Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain, and implement a set of plans to mitigate operating emergencies.[863]

As the electricity market changes and new challenges emerge, electric system regulators and industry participants make changes to how the electric system is designed and operated to respond to these challenges. For example, expressing reliability and rate concerns about fuel assurance issues, FERC recently issued an order requiring ISOs/RTOs to report on the status of their efforts to address market and system performance associated with fuel assurance.[864] In February of 2015, Midcontinent

---

[861] Casazza, J. and Delea, F., *Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations*, IEEE Press, at 160 (2010).

[862] *Id.*

[863] NERC Reliability Standard EOP-001-2.1b—Emergency Operations Planning, available at *http://www.nerc.net/standardsreports/standardssummary.aspx.*

[864] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014). FERC generally defines fuel assurance as "generator access to sufficient fuel supplies and the firmness of generator fuel arrangements". *Id.* P 5.

Independent System Operator (MISO), California Independent System Operator Corporation (CAISO), New York Independent System Operator (NYISO), Southwest Power Pool (SPP), ISO New England (ISO-NE), and PJM Interconnection (PJM) each filed a report with FERC highlighting their efforts to respond to fuel assurance concerns.[865] This is just one of many examples where electric system regulators and industry participants recognize a potential reliability issue and are proactively searching for solutions.

The EPA's approach in this final rule is consistent with our commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Many aspects of the final rule's design are intended to support system reliability, especially the long compliance period and the basic design that allows states and affected EGUs flexibility to include a large variety of approaches and measures to achieve the environmental goals in a way that is tailored to each state's and utility's energy resources and policies. Despite the flexibility built into the

[865] For example, ISO-NE and PJM each filed "pay-for-performance" proposals to address fuel assurance in their regions. FERC recently acted on ISO-NE market rule changes providing increased market incentives in capacity, energy, and ancillary services markets for generators to be available to meet their obligations during reserve shortages. *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014). Additionally, FERC conditionally approved a PJM "pay-for-performance" proposal that creates a new capacity product to provide greater assurance of delivery of energy and reserves during emergency conditions, establishing credits for superior performance and charges for poor performance. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015).

design of the proposal, and the long emission reduction trajectory, many commenters expressed concerns that the proposed rule could jeopardize electric system reliability. We note that the EPA has received similar comments in EPA rulemakings dating as far back as the 1970s. The EPA has always taken and continues to take electric system reliability comments very seriously. These reoccurring comments with regard to reliability notwithstanding, the electric industry has done an excellent job of maintaining reliability, including when it has had to comply with environmental rules with much shorter compliance periods and much less flexibility than this final rule provides. Now, more than ever, the electric industry has tools available to maintain reliability, including mandatory and enforceable reliability standards.[866]

---

[866] For example, Andrew Ott, then Executive Vice President-Markets and current President of PJM, an RTO with a substantial amount of coal-fired capacity and generation, discussed the success of PJM's market design in assuring that PJM met and exceeded target reserve margins while MATS was being implemented. *See* Statement of Andrew Ott, PJM Executive Vice President-Markets, FERC Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000, at 3, 7 (Sept. 25, 2013), *available at http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6944&CalType=&CalendarID=116&Date=09/25/2013&View=Listview*. At the FERC national Clean Power Plan Technical Conference, Michael J. Kormos, PJM Executive Vice President-Operations, said that PJM's markets have proven, "resilient enough to respond to different policy initiatives . . . Whether it is the Sulfur Dioxide Trading Program of the 1990s, the MATS rule or individual state RPS initiatives, the markets have been able to send the appropriate price signals that produce competitive outcomes." *See* Michael J. Kormos, PJM Executive Vice President,

As with numerous prior CAA regulations affecting the electric power sector, environmental requirements for this industry are accommodated within the existing extensive framework established by federal and state law to ensure that electricity production and delivery are balanced on an ongoing basis and planned sufficiently to ensure reliability and affordability into the future. In addition, changes that the EPA is making in this final rule respond directly to the comments and the suggestions that we received on reliability and provide further assurance that implementation of the final rule will not create reliability concerns.

First, the final rule allows significant flexibility in how the applicable CO_2 emission performance rates or the statewide CO_2 goals are met. Given the differing characteristics of the electric grid within each state and region, there are many paths to meeting the final rule's requirements that can be taken while continuing to maintain a reliable electricity supply. As further described elsewhere in section VIII, states can develop plans to meet the CO_2 emission performance rates or state CO_2 emission goals by choosing from a variety of state plan types and approaches that afford states and affected EGUs appropriate flexibility. EE and other measures that were not included in the determination of the BSER can strengthen a state's ability to establish a plan to meet the CO_2 emission performance rates or state CO_2

Statement at FERC Technical Conference on EPA's Clean Power Plan, AD15-4-000, at 3 (Feb. 19, 2015), *available at http://www.ferc.gov/CalendarFiles/20150213081650-Kormos,%20PJM.pdf*.

emission goals by providing a considerable amount of headroom above the levels of the rates and goals. EE especially, because it reduces load, can provide assurance that reliability can and will be maintained. Additionally, the final rule offers opportunities for trading among affected EGUs within and between states, and other multi-state approaches that will further support electric system reliability.

Second, the final rule provides sufficient time to ensure system reliability. The final rule retains the 2030 date for the final period, which commenters largely supported as reasonable and not a concern for reliability, and addresses one of the key issues that commenters pointed to as a reliability-related concern by both moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a more gradual phasing-in of the initial reduction requirement and thus a more gradual emissions reduction trajectory or glide path to the final 2030 goals. These changes deliver on the intent of the proposal to afford states and affected EGUs the latitude to determine their own emissions reduction schedules over the interim period. Both FERC's May 15, 2015 letter[867] and the comment record made it clear that providing sufficient time for planning and implementation is essential to ensuring electric system reliability. The EPA has responded by providing additional time to allow for planning and implementation of the final rule requirements, while

---

[867] On May 15, 2015, the five FERC Commissioners sent a letter to Acting Assistant Administrator Janet McCabe regarding the EPA's Clean Power Plan proposal. *See* FERC letter, *available at http://ferc.gov/media/headlines/2015/ ferc-letter-epa.pdf.*

at the same time allowing enough time between the beginning of the interim period and 2030 to achieve state goals or emission performance rates. We note that the final rule does not require that all states have met their interim goal or performance rate by 2022 but rather that they meet it on average or cumulatively, as appropriate, during the 2022 to 2029 period.

As a result of these changes, the states themselves will have a meaningful opportunity—which, again, many commenters suggested the timing and stringency of the proposal failed to create despite our intent to do so—to determine the timing, cadence and sequence of actions needed for states and sources to meet final rule requirements while accommodating the ongoing activity needed to ensure system reliability. The final rule provides more than 6 years before reductions are required and an 8-year period from 2022 to 2029 to meet interim goals. Moreover, while the final rule requires each state to submit a plan by September 6, 2016, we recognize that some states may need more than 1 year to complete all of the actions needed for their final state plans, including consideration of reliability. Therefore, states have the opportunity to receive an extension for submitting a final plan. If the state needs additional time to submit a final plan, then the state may submit an initial submittal by September 6, 2016, that must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018.

Third, we are including in the final rule a requirement that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. This was suggested by a number of commenters, and we agree that it is a useful element to state plan development.

Fourth, the final rule provides a mechanism for a state to seek a revision to its plan in order to address changes in circumstances that could have reliability impacts if not accommodated in the plan. The long compliance timeframe, with several interim steps, naturally provides opportunities for states, working with their utilities and reliability entities, to assess how implementation is proceeding, identify unforeseen changes that may warrant plan revisions, and work with the EPA to make necessary revisions. Similarly, the ready availability of emissions trading as a compliance tool affords EGUs ample flexibility to integrate compliance with both routine and critical reliability needs.

Fifth, in response to a variety of comments, we are providing a reliability safety mechanism that provides a path for a state to come to the EPA during an immediate, unforeseen, emergency situation that threatens reliability to notify the EPA that an affected EGU or EGUs may need to temporarily comply with modified emission standards to respond to this kind of reliability concern.

Sixth and finally, we are committed to maintaining an ongoing relationship with FERC and DOE as this final rule is implemented to help ensure continued reliable electric generation and transmission.

We provide more details about these various elements of the final rule, as well as other features of the rule that support system reliability, below.

a. *Summary of key comments.*

The EPA received a number of comments regarding the proposed rule and electric reliability. Many commenters provided specific, useful ideas regarding changes that could be made to the proposal to specifically address their reliability concerns. For example, many commenters state that allowing additional time to comply could help in meeting the final rule requirements while addressing their reliability concerns. Some commenters suggest that additional time would allow them to evaluate potential reliability impacts and system changes that need to be made to comply with final rule requirements while allowing affected EGUs time to meet interim CO_2 emissions goals. The EPA also received comment that market-based approaches have features that could help support reliability, and therefore we should encourage states to join or form regional market-based programs. Commenters also stated that the EPA should require states to consult with grid operators who would analyze the impact of state plans on reliability. A number of commenters also suggested that the EPA should include some sort of reliability safety valve in the final rule. We note that many participants at the FERC technical conferences on the proposed rule also discussed a reliability safety valve in great detail with many suggestions for how such a reliability mechanism could be designed. The EPA appreciates these and all the comments we received regarding the interaction of the proposal and electric reliability. We have carefully considered all comments, consulted further with FERC and incorporated many of the suggested changes in this final rule.

b. *Final rule flexibility.*

In issuing this final rule, the EPA considered public comments on the potential interaction between the proposal and electric reliability. While we have made every effort to develop guidelines that would allow states and utilities to steer clear of potential reliability disruptions, a number of commenters argued that the possibility of an unanticipated reliability event cannot be entirely eliminated. It is important to note that there are many factors that influence system reliability and, given the complexity of the electric grid, electric system planners and operators likely will not completely avoid reliability issues, even in the absence of these guidelines. The EPA designed the final rule to ensure to the greatest extent possible that actions taken by states and affected EGUs to comply with the final rule do not increase potential reliability issues or complicate their resolution. In fact, to the extent that meeting final rule requirements results in the reduction of demand, upgrades in transmission efficiency and infrastructure, and investment in new, more efficient technologies, the outcome could be that the system is more robust and faces fewer risks to electric reliability.

One specific concern raised by many commenters is that the proposed plan development schedule may not leave sufficient time to conduct reliability planning between the development of state plans and the proposed start of the interim period in 2020. To address these concerns and to support a more effective reliability planning process, the EPA is moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a gradually phased-in initial reduction requirement and a more gradual glide path to the final 2030 goals. This more gradual application of the BSER over the 2022–2029 interim period provides the state with substantial latitude in selecting the emission reduction glide path for affected EGUs over that period. As noted above, the final rule also provides states with up to 3 years to adopt and submit their final state plans, and afterwards states can, if necessary, revise their plans, as discussed in section VIII.E.7. This timing gives system planners and operators the opportunity to do what they have already been doing; looking ahead to forecast potential contingencies that pose reliability risks and identifying those actions needed to mitigate those risks. The final rule allows states to develop a pathway over the interim period that reflects their own circumstances, such as reflecting planned additions and changes in generation mix and potentially taking advantage of opportunities for trading of credits or allowances by affected EGUs within and between states. Because achievement of the emission rates or goals can be demonstrated over several years, state plans can accommodate situations where, for example, it may take time to develop new generation, pipelines, or transmission while still providing many options for meeting the final rule requirements and planning for the reliability of the system.

c. *Considering reliability during state plan development process.*

Under CAA section 111(d)(1)(B), state plans must provide for the implementation and enforcement of standards of performance for affected EGUs. The EPA does not believe a state that establishes standards of performance for affected EGUs without taking reliability concerns into consideration satisfactorily provides for the implementation of such standards of performance as required by CAA section 111(d)(1)(B), as a serious reliability issue would disrupt the state's provision of implementation of the state plan. Therefore, the EPA is requiring that each state demonstrate as part of its final state plan submission that it has considered reliability issues while developing its plan in order to ensure that standards of performance can be implemented and enforced as required by the CAA. If system reliability is threatened, the ability of affected EGUs to meet the requirements of this final rule could be compromised if they are required to operate beyond the emission standards established in state plans in order to maintain the reliability of the electric grid. The requirement that states consider reliability as part of the development of state plans is therefore designed to ensure that state plans are flexible enough to avoid this kind of potential conflict between maintaining reliability and providing for the implementation of emission standards for affected EGUs as required by the CAA.

A number of commenters, notably ISOs and RTOs, also discussed reliability concerns in the context of state plans and pointed out that planning and anticipation of change are among the essential ingredients of ensuring the ongoing reliability of the electricity system. To that end, they recommended that as states are developing state plans, their activity include the consideration of the reliability needs of the region in which affected EGUs operate and of the potential impact of actions to be taken in compliance with state plans. Therefore, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. One particularly effective way in which states can make this demonstration is by consulting with the relevant ISOs/RTOs or other planning authorities as they develop their plans and documenting this consultation process in their state plan submissions. If a state chooses to consider reliability through consultation with the ISO/RTO or other planning authority, the EPA recommends that the state request that the planning authority review the state plan at least once during the plan development stage and provide its assessment of any reliability implications of the plan. Additionally, we encourage states that are considering reliability through an ISO/RTO or other planning authority consultation process to have a continuing dialogue with those entities during development of their final state plan. While following the recommendations of the planning authority would not be mandatory, the state should document its consultation process, any response and recommendations from the planning authority, and the state's response to those recommendations in its final state plan submittal to the EPA. This consultation is designed to inform how the state might adjust its plan for meeting the CO_2 reduction requirements under this guideline; the consultation is not a basis for relaxing that requirement. While we consider this process to be an effective way for a state to demonstrate that it considered reliability in developing its final state plan, a state may provide other comparable support for a demonstration that it has considered reliability during the state plan development process.[868] Also as discussed elsewhere in this preamble, the EPA encourages states to include state utility regulators and the state energy offices in the development of the state plan. These agencies have expertise that can help to assure that state plans complement the state's power sector. The EPA believes that this requirement to demonstrate consideration of reliability will provide an effective reliability evaluation in the state plan development process. It should further help states avoid any conflicts between state plans and the maintenance of reliability during implementation of the state plan and associated emission standards. Finally, we also encourage states as they develop their plans to consider, to the extent possible, other potential issues that may impact affected EGUs. For example, an affected EGU may be in an ISO/RTO that puts certain deadlines on generators that may not line up perfectly with state plan deadlines.

d. *State plan modifications.*

If, during the implementation of a state plan, a reliability issue cannot be addressed within the range of actions or mechanisms encompassed in an approved state plan, the state can submit a plan revision to the EPA to amend its plan. In such a circumstance, the state plan may need to be adjusted to enable affected EGUs to continue to meet final rule requirements without causing an otherwise unmanageable reliability threat. In all cases the plan revision must

[868] While the EPA is requiring that the states demonstrate that they have considered reliability in developing their plans, state plan submissions will not be evaluated substantively regarding reliability impacts.

still ensure the affected EGUs meet the emission performance level set out in the 111(d) final rule. Whether or not these circumstances occur will depend in part upon how each state designs its state plan. States that design plans with a high level of flexibility, such as market-based plans or multi-state plans, are less likely to face a potential conflict between state plan requirements and the maintenance of reliability. States that participate in multi-state programs will be better able to weather unexpected reliability risks.

Events not anticipated at the time of the final plan submittal—such as the retirement of a large low- or zero-emitting unit—may trigger the request for state plan revisions. It may also be the case that affected EGU-specific emission standards in a state plan are proving to be too inflexible to allow the plan to accommodate market or other changes in the power sector. In such instances, there should be a lead time between the announced retirement of the unit and the need to amend the state plan. Therefore, the state should be able to utilize the revisions process that the EPA provides.

The EPA will review a plan revision per the implementing regulation requirements of 40 CFR part 60.28. If the state's request for a state plan revision must be addressed in an expedited manner to assure a reliable supply of electricity, the state must document the risks to reliability that would be addressed by the plan revision by providing the EPA with a separate analysis of the reliability risk from the ISO/RTO or other planning authority. This analysis should be accompanied by a statement from the ISO/RTO or other planning/reliability authority that there are no practicable alternative resolutions to the reliability risk. In this case, the EPA will conduct an expedited review of the state plan revision.[869]

e. *Reliability safety valve.*

In this section we describe a reliability safety valve, available to states with affected EGUs providing reliability-critical generation in emergency circumstances. Specifically and as discussed below the reliability safety valve provides i) a 90-day period during which the affected EGU will not be required to meet the emission standard established for it under the state plan but rather will meet an alternative standard, and ii) a period beginning after the initial 90 days during which the reliability-critical affected EGU may be required to continue to operate under an alternative standard rather than under the original state plan emission standard, as needed in light of the emergency circumstances, and the state must during this period revise its plan to accommodate changes needed to respond to ongoing reliability requirements. Any emissions in excess of the applicable state goals or performance rates occurring after the initial 90-day period must be accounted for and offset.

Many commenters expressed concerns that a serious, unforeseen event could occur during the final rule implementation period that would require immediate reliability-critical responses by system operators and affected EGUs that would result in

---

[869] The EPA will still undertake notice and comment rulemaking per the requirements of the Administrative Procedures Act when acting on such state plan revision, but intends to prioritize review of plan revisions needed to address reliability concerns.

unplanned or unauthorized emissions increases. After reviewing the comments, we believe that it is highly unlikely that there would be a conflict between activities undertaken under an approved state plan and the maintenance of electric reliability, except in the case of a state plan that puts relatively inflexible requirements on specific EGUs. While some have pointed out that severe weather or other short-term events could potentially conflict with state plans, we note that most of those events are of short duration and would not require major—if any—adjustments to emission standards for affected EGUs or to state plans. For example, during an event like the extreme cold experienced in periods of the winter of 2013–2014, affected EGUs may need to run at a higher level for a short period of time to accommodate increased demand and/or short-term unavailability of other generators. However, because compliance by affected EGUs will be demonstrated over 2–3 years, such a short-term event would not cause affected EGUs to be out of compliance with their applicable emission standards. States can also ensure that this is true by developing plans that allow adequate compliance flexibility to accommodate such short-term events. We note that we have included in this final rule a number of different features designed to facilitate emissions trading between and among EGUs on an interstate basis—and have done so, in no small part, in response to comments from states and stakeholders seeking to put in place or operate under state-level and interstate emissions trading regimes. Affected EGUs operating in those circumstances and operating, in addition, subject to state plans that incorporate flexible glide paths and trading would be able to accommodate an unanticipated reliability event.

We recognize, however, that affected EGUs operating in a state with a relatively inflexible state plan could face unanticipated system emergencies that could cause a severe stress on the electricity system for a length of time such that the requirements in that state's plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. In particular, there could be extremely serious events, outside the control of affected EGUs, that would require an affected EGU or EGUs operating under an inflexible state plan to temporarily operate under modified emission standards to respond to this kind of reliability concern. Examples of such an event could include, a catastrophic event that damages critical or vulnerable equipment necessary for reliable grid operation; a major storm that floods and causes severe damage to a large NGCC plant so that it must shut down; or a nuclear unit that must cease generating unexpectedly and therefore other affected EGUs need to run so as to exceed their requirements under the approved state plan. This is not an all-inclusive list, but the examples illustrate several key attributes of the kinds of circumstances in which the reliability safety valve would apply. First, the event creating the reliability emergency would be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event. Second, the relief provided would be for EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face some form of failure. Third, the EGU or EGUs in question would be subject to the requirements of a state plan that imposes emissions constraints such that the EGU or EGUs' operation in response to the reliability emergency resulted in levels of emissions that violated those constraints. We do not anticipate that EGUs operating under a plan that permitted emissions trading would meet these criteria.

The final guidelines provide a reliability safety valve for these types of situations. If an emergency situation arises, the state must submit an initial notification to the appropriate EPA regional office within 48 hours that it is necessary to modify the emission standards for a reliability-critical affected EGU or EGUs for up to an initial 90 days. The notification must include a full description, to the extent it is known at the time, of the emergency situation that is being addressed. It must also identify with particularity the affected EGU or EGUs that are required to run to assure reliability. It must also specify the modified emission standards at which the affected EGU or EGUs will operate. The EPA will consider this notification to be an approved short-term modification to the state plan, allowing the EGU to operate at an emission standard that is an alternative to the emission standard originally specified in the relevant state plan, subject to confirmation by the further documentation described below.[870]

Within 7 days of submitting the initial notification, the state must submit a second notification providing

---

[870] The EPA reserves the right to review such notification, 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 original approved state plan emission standards.

documentation to the appropriate EPA regional office that includes 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 (including discussion of why the flexibilities provided under the state's plan are insufficient to address the concern). The state must also describe in its documentation how it is coordinating or will coordinate with relevant reliability coordinators and planning authorities to alleviate the problem in an expedited manner, and indicate 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, and the modified emission standards or levels at which the affected EGU or EGUs will be operating at during this period if it has changed from the initial notification. The documentation must also include 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. Additionally, if the relevant planning authority has conducted a system-wide or other analysis of the reliability concern, the state must include that information in its request. 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.

It is important to note that the affected EGUs must continue to monitor and report their emissions and generation pursuant to requirements in this final rule and under the state plan during any short-term modification. For the duration of the up to 90-day short-term modification, the emissions of the affected EGU or EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emission performance rate for affected EGUs. Such a modification will not alter or abrogate any other obligations under the approved state plan.

During this short-term modification period, the EPA expects that the source, the state and the relevant reliability coordinator and/or planning authority will assess whether the reliability issue can be addressed in a way that would allow the EGU or EGUs to resume operating under the original approved state plan within the 90-day period or whether revisions to the state plan need to be made to address the unexpected circumstances for the longer term (the unexpected unavailability of a nuclear unit, for example).

The EPA recognizes that an emergency may persist past 90 days. At least 7 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 that the EGU or EGUs can resume meeting the original emission standards established in the state plan prior to the short-term modification.

If there still is a serious, ongoing reliability issue at the end of the short-term modification period that necessitates the EGU or EGUs to emit beyond the amount allowed under the state plan, the state must provide to the EPA a notification that it will be submitting a state plan revision and submit the plan revision as expeditiously as possible, specifying in the notice the date by which the revision will be submitted. The state must document the ongoing emergency with a second written concurrence from the relevant reliability coordinator and/or planning authority confirming the continuing urgent need for the 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 EGU or EGUs to operate under an alternative emission standard than originally approved under the state plan. In this event, the EPA will work with the state on a case-by-case basis to identify an emission standard for the affected EGU or EGUs for the period before a new state plan revision is approved. 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 goal or emission performance rate for affected EGUs.

The EPA intends for this reliability safety valve to be used only in exceptional situations. In addition, this reliability safety valve applies only to this final rule and has no effect on CAA requirements to which the state or the affected EGUs are otherwise subject. As discussed earlier, we are providing states with the flexibility to design programs that allow affected EGUs to meet compliance obligations while responding to reliability needs, even in emergency situations. This flexibility means that a conflict between the requirements of the state plan and maintenance of reliability should be extremely rare. We recognize, however, that a state with an inflexible plan could be faced with more than one emergency and in this case the reliability safety valve may be used more than once. If the state finds that a second reliability emergency arises that conflicts with the state plan, the state must submit a revision to its state plan so that the state plan is flexible enough to assure that such conflicts do not recur and that the state is providing for the implementation of the standards of performance for affected EGUs as required by the CAA.

f. *Coordination among federal partners.*

The EPA, DOE, and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor final rule implementation, share information, and resolve any difficulties that may be encountered. This strategy is based on the successful working relationship that the three agencies established in their joint effort to work together to monitor reliability during MATS implementation.

g. *Analyses of the reliability impacts of the proposal.*

The EPA appreciates that a large number of entities from many different industry perspectives have published reports and analysis with respect to electric reliability and the 111(d) proposed rule. We take concerns about reliability very seriously, and we appreciate the attention given to this issue in the comments and shared with us in public forums. It is important to note that these studies were conducted prior to promulgation of this final rule, and thus were only able to consider electric reliability with respect to the proposal. The EPA has made changes and improvements to the proposal in response to comments and new information, and some of the changes are relevant to the final rule's potential effect on electric reliability. One notable change pertains to the start of the interim period, which is now 2022 rather than 2020. Another important change to the final rule is a more gradual phase-in of the BSER for affected EGUs over the interim period (from 2022 through 2029). The final rule also provides considerable flexibility and multiple pathways to states, including allowing their EGUs to use multi-state trading and other approaches, which would allow essential units to continue to meet their compliance obligation while generating even at unplanned but reliability-critical levels. In addition, we have included in the final rule a reliability safety valve provision that can be utilized in certain emergency situations. These changes, in addition to already existing industry mechanisms and planning requirements, will help to ensure that industry will be able to maintain electric reliability. The EPA is confident that the final rule will cut harmful electric power plant pollution while maintaining a reliable electric grid because the final rule provides industry with the time and flexibility needed to continue its current and ongoing planning and investing to modernize and upgrade the electric power system.

In June of 2015, M.J. Bradley & Associates issued a report that enumerated a set of useful guiding principles for studying and evaluating the reliability impacts of the final rule.[871] The report enumerated six principles: (1) A study should be transparent about the assumptions and data used; (2) a study should accurately reflect the existing status of the grid in its modeling assumptions; (3) a study should clearly identify the base case and not confuse what will happen as a result of the final rule with what would have happened anyway; (4) where possible, a study should contain sensitivities and probabilities as they are looking into the future which is necessarily uncertain; (5) a study should reflect the flexibility provided to states to allow them to design compliance approaches to maximize reliability; and (6) a study should provide realistic and reliability-focused results. These principles are helpful to keep in mind when reviewing recent studies.

NERC published its analyses of the proposed rule in November 2014 and again in April 2015.[872] The EPA appreciates NERC's attention to, and interest in, the proposed rule. However, we note that like some other studies, NERC assumes considerably less

---

[871] M.J. Bradley & Associates, *Guiding Principles for Reliability Assessments Under EPA's Clean Power Plan* (June 3, 2015), *available at http:// www.mjbradley.com/node/295*.

[872] North American Electric Reliability Corporation, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* (Nov. 5, 2014), *available at http://www.nerc.com/news/Pages/Reliability-Review-of-Proposed-Clean-Power-Plan-Identifies-Areas-for-Further-Study,-Makes-Recommendations-for-Stakeholders.aspx*; North American Electric Reliability Corporation, *Potential Reliability Impact of EPA's Proposed Clean Power Plan: Phase 1* (Apr. 21, 2015), *available at http://www.nerc.com/news/Pages/Assessment-Uses-Scenario-Analysis-to-Identify-Potential-Reliability-Risks-from-Proposed-Clean-Power-Plan.aspx.*

flexibility than actually is provided to states and EGUs in this final rule. The final rule provides states with considerable time and latitude in designing plans that are tailored to the system in which their EGUs operate, which should be reflected in any reliability analysis. Also, the NERC study does not fully reflect the current electric grid. For example, the amount of RE generation that NERC assumes for 2020 is similar to levels of generation that we see today whereas projections for 2020 are considerably higher.[873] Further, NERC conflates retirements that may happen as a result of the rule with those that are already planned. The Brattle Group has also reviewed NERC's November 2014 initial analysis of the proposed rule, noting that it is important to distinguish between concerns about the building blocks and reliability concerns about compliance with state plans.[874] The Brattle Group concluded that there are real world solutions to NERC's concerns. These include making use of the many flexible options available to states under the rule to mitigate reliability risks.

Multiple ISOs/RTOs also provided analyses of the proposed rule, including MISO, PJM, ERCOT, and

---

[873] EIA, Annual Energy Outlook 2015, with Projections to 2040, April 2015, *available at http://www.eia.gov/forecasts/aeo/pdf/0382(2015).pdf.*

[874] Brattle Group, *EPA's Clean Power Plan and Reliability, Assessing NERC's Initial Reliability Review* (Feb. 2015), *available at http://info.aee.net/hs-fs/hub/211732/file-2486162659-pdf/PDF/EPAs-Clean-Power-Plan-Reliability-Brattle.pdf?t=1434398407867.*

SPP.[875] For example, MISO conducted an analysis of coal units at risk for retirement, finding that 14 GW of coal may be at risk.[876] SPP performed a resource adequacy analysis that assumes planned retirements plus the EPA's projected retirements, but did not similarly account for the building of new generation capacity.[877] While we appreciate MISO's and SPP's concerns regarding retirements and the potential that reserves will fall below reserve requirement levels, it is important to consider the many ways in which states can develop plans that account for their potential reliability concerns. The final rule continues to give states significant flexibility in how they comply

---

[875] *See* MISO, *Analysis of EPA's Proposal to Reduce CO_2* Emissions from Existing Units (Nov. 12, 2014), *available at https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposal ReduceCO2Emissions.pdf*; PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at http://www.pjm.com/documents/reports.aspx;* SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, (Oct. 8, 2014), *available at http://www.spp.org/publications/CPP%20Reliability%20Analysis%20 Results%20Final%20Version.pdf*; ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available athttp://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf*; and

[876] MISO, *Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Units*, at 14 (Nov. 12, 2014), *available at https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAProposalReduceCO2Emissions.pdf.*

[877] SPP, *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, (Oct. 8, 2014), *available at http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf.*

with requirements, including both BSER measures and measures that were not included in the determination of the BSER as a means to comply. For example, demand-side EE measures can greatly assist states and affected EGUs in meeting the standards and/or state plan. Many studies assume that state plans will simply apply the BSER and do not recognize the large number of compliance approaches and opportunities that states and affected EGUs have available to them. The Analysis Group recently analyzed reliability considerations in MISO as the region considers how to comply with the final rule.[878] The Analysis Group found that despite the large amount of coal-fired generating capacity that will likely be retired in MISO in the coming years, the entities responsible for electric system reliability in MISO are prepared to collaboratively address any reliability issues that arise and that there is a "strong tool kit for managing 'Essential Reliability Services' needed to assure high-quality electric service."[879]

ERCOT also performed an analysis, modeling numerous scenarios.[880] ERCOT stated that its

---

[878] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO* (June 8, 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.*

[879] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO*, at 2 (June 8, 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.*

[880] ERCOT, *ERCOT Analysis of the Clean Power Plan* (Nov. 17, 2014), *available at http://www.ercot.com/content/*

modeling identified two potential reliability problems—impacts of units retiring and increased levels of renewable generation on the ERCOT grid.[881] As noted above, the final rule gives additional time for compliance, providing needed time to obtain new or replacement generation necessary as some existing generators retire. Moreover, affected EGUs needed for reliability should be able to employ the flexibilities afforded to them as they seek lower and zero-emitting generation. Finally, we note that ERCOT has a history of notable success in integrating RE into its electric grid, giving ERCOT significant expertise regarding challenges that may arise with the addition of new RE in order to comply with the final rule. In fact, a recent Brattle Group report used ERCOT as a case study for how to effectively integrate a large number of RE into the electric grid.[882]

PJM conducted its own analysis at the request of the Organization of PJM States (OPSI).[883] This analysis is consistent with many of the M.J. Bradley guiding

---

news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.

[881] ERCOT, *ERCOT Analysis of the Clean Power Plan*, at 9 (Nov. 17, 2014), *available at http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.*

[882] Brattle Group, *Integrating Renewable Energy Into the Electricity Grid: Case Studies Showing How System Operators are Maintaining Reliability* (June 2015), *available at http://info.aee.net/integrating-renewable-energy-into-the-electricity-grid.*

[883] PJM, *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (Mar. 2, 2015), *report listed at http://www.pjm.com/documents/reports.aspx.*

principles. PJM designed various scenarios to capture the impact of the proposed rule under a series of assumptions. Because the EPA had not yet issued the final rule, PJM cautioned against using the report as a reliability analysis or predictor of the future. PJM stated that, since 2007, PJM's capacity markets have helped to attract 35,000 MWs of additional generation. Even though 26,000 MWs will retire between 2009 and 2016, the PJM capacity market has procured sufficient resources to maintain reliability.

WECC also produced a study which is part of a longer-term, phased effort.[884] The assumptions, methodology, and limitations were all clearly presented, and there was extensive involvement by a range of stakeholders. WECC stated that it is embarking on a phased-study process that seeks to "provide the industry with unbiased and independent analysis of this issue."[885] WECC concluded that the effects of the proposal on resource adequacy may be minimal but that resource adequacy cannot be fully assessed without realistic and/or proposed compliance scenarios.[886]

---

[884] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report* (Sept. 19, 2014), *available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.*

[885] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report*, at 1 (Sept. 19, 2014), *available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default &DefaultItemOpen=1.*

[886] WECC, *EPA Clean Power Plan: Phase I—Preliminary Technical Report*, at 30 (Sept. 19, 2014), *available at*

Analysis Group analyzed the proposed rule, finding that it provides states and affected EGUs with a wide range of options and operational discretion that can prevent reliability issues while also reducing carbon pollution and costs.[887] Analysis Group noted that some of the concerns raised by stakeholders about the proposed rule assume "inflexible implementation, are based upon worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is far too late to act" to ensure reliability.[888] It stated that these assumptions are not consistent with past actions.

We appreciate the time that multiple entities took to analyze and consider the potential impacts of the proposed rule. As we issue the final rule and states draft plans to implement the rule, we look forward to further analysis by these and other groups. Such analysis can provide states with needed resources to help them design state plans that will augment the efforts of the industry to maintain electric reliability.

---

https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf&action=default&DefaultItemOpen=1.

[887] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices* (Feb. 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.*

[888] Analysis Group, *Electric System Reliability and EPA's Clean Power Plan Tools and Practices*, at ES-3 (Feb. 2015), *available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf.*

3. Consideration of Effects on Employment and Economic Development

States in designing their state plans should consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. To the extent possible, states should try to assure that any communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The EPA's illustrative analysis indicates that there may be some additional job losses in sectors related to coal extraction and generation that are attributable to implementation of this rule. At the same time, the EPA's illustrative analysis indicates that there may be new jobs in the utility power sector associated with both improving the efficiency of fossil fuel-fired power plants, construction and operation of new natural gas-fired and RE production, and actions to increase demand-side EE. Consideration of these effects in the context of the particulars of the state plan can help states craft plans that, to the extent possible, meet multiple environmental, economic, and workforce development goals.

The Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative is a new interagency effort led by the Economic Development Administration in the Department of Commerce. POWER was launched to respond to current trends in the power sector: "The United States is undergoing a rapid energy transformation, particularly in the power sector. This transformation is producing cleaner air and healthier communities, and spurring new jobs and industries. At the same time, it is impacting workers and communities who have relied on the coal industry as a source of good jobs and economic prosperity, particularly in Appalachia, where competition with other coal basins provides additional pressure."[889] The POWER Initiative aligns, leverages, and targets economic and workforce development assistance to communities and workers affected by changes in the coal industry and the utility power sector. The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of Commerce, Department of Labor, Small Business Administration, and the Appalachian Regional Commission to partnerships anchored in impacted communities. These grants will help communities organize themselves, develop comprehensive strategic plans that chart their economic future, and execute coordinated economic and workforce development activities based on their strategic plans.[890]

In addition to POWER, however, the EPA encourages states to use economic and labor market analysis to identify where they can deploy strategies to: (1) Provide a range of employment and training assistance to workers, and economic development assistance to communities affected by the rapid changes underway in the power sector and closely related industries, to diversify their economies, attract new sources of investment, and create new jobs; and

---

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

[890] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.*

(2) mobilize existing education and training resources, including those of community and technical colleges and registered apprenticeship programs, to ensure that both incumbent and new workers are trained for the skills necessary to meet employer demand for new workers in the utility, construction and related sectors, that such training includes career pathways for members of low-income communities and other vulnerable communities to attain employment in these sectors, and that such training results in validated skill certifications for workers.

4. Workforce Considerations

Some stakeholders commented that, to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. A good way to ensure a highly proficient workforce is to require that workers have been certified by: (1) An apprenticeship program that is registered with the U.S. DOL, Office of Apprenticeship or a state apprenticeship program approved by the DOL; (2) a skill certification aligned with the U.S. DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or (3) other skill certification validated by a third party accrediting body.

5. Tenth Amendment Legal Considerations

Some commenters have raised concerns that the emission guidelines and requirements for 111(d) state plans violate principles of federalism embodied in the U.S. Constitution, particularly the Tenth Amendment. These commenters claim that states will be unconstitutionally "coerced" or "commandeered" into taking certain actions in order to avoid the prospect of either a federal 111(d) plan applying to sources in the state, or of losing federal funds.

We disagree on both fronts. First, the prospect of a federal plan applying to sources in a state does not "coerce" or "commandeer" that state into submitting its own satisfactory plan. Far from violating principles of federalism, this rule provides states with the initial opportunity to submit a satisfactory state plan, and provides states flexibility in developing that plan. If a state declines to take advantage of that opportunity, affected EGUs in that state will instead be subject to a federal plan that satisfies statutory requirements.[891] This approach is consistent with ordinary cooperative federalism regimes that federal courts have routinely upheld against Tenth Amendment challenges.[892]

---

[891] Among other things, a federal plan will implement standards of performance subject to specific statutory requirements. *See* 42 U.S.C. 7411(a)(1). The APA and CAA would prohibit the imposition of any federal plan that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. 706(2)(a). Particularly given these independent constraints on the EPA's authority with respect to any potential federal plan, the prospect of any such plan would not commandeer states or coerce them into submitting their own state plans.

[892] *See, e.g.*, *Hodel* v. *Va. Surface Mining & Reclamation Ass'n, Inc.*, 452 U.S. 264, 283–93 (1981); *Texas* v. *EPA*, 726 F.3d 180, 196–97 (D.C. Cir. 2013) (noting that "Supreme Court precedent repeatedly affirm[s] the constitutionality of federal statutes that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it").

Second, states that decline to take certain actions under this rule will not face the prospect of sanctions, such as withdrawn federal highway funds. CAA section 111 does not contain sanctions provisions, and we are finalizing revisions to these emission guidelines making explicit that the EPA will not withhold federal funds from a state on account of that state's failure to submit or implement an approvable 111(d) state plan.

Some commenters pointed to section 110(m) as a possible source of the EPA's sanction authority.[893] Section 110(m) grants the EPA discretionary authority to withhold some federal highway funds under certain conditions. However, section 110(m) requires the EPA to adopt regulations to "establish criteria for exercising" this discretionary authority, and the only EPA regulations implementing section 110(m) apply to SIPs submitted under section 110.[894]

The EPA never intended to even imply that we would contemplate using this authority to encourage state participation in this rule under section 111. To the contrary, we believe that imposition of a federal plan rather than sanctions is the appropriate path in the context of this program. Accordingly, regardless of whether the EPA could theoretically apply discretionary sanctions against states in the section

---

[893] Other commenters point to CAA section 179 as a possible direct source of this sanctions authority. However, the mandatory sanctions outlined in section 179 clearly apply only in the contexts of nonattainment SIPs and responses to SIP Calls made under CAA section 110(k)(5). *See* 42 U.S.C. 7509(a).

[894] 40 CFR 52.30 (defining "plan or plan item").

111(d) context, the final rule forbids the agency from exercising any such authority. We have included in this rule a provision that prohibits the agency from imposing sanctions in the event that a state fails to submit or implement a satisfactory plan under this rule. As states consider whether to take advantage of the opportunity to develop state plans, they can be assured that the EPA will not withdraw federal funding should they decline to participate.

6. Title VI

States that are recipients of EPA financial assistance must comply with all federal nondiscrimination statutes that together prohibit discrimination on the bases of race, color, national origin (including limited-English proficiency), disability, sex and age. These laws include: Title VI of the Civil Rights Act of 1964; Section 504 of the Rehabilitation Act of 1973; Section 13 of the Federal Water Pollution Control Act Amendments of 1972; Title IX of the Education Act Amendments of 1972; and the Age Discrimination Act of 1975. Compliance with these nondiscrimination statutes is a recipient's separate and distinct obligation from compliance with environmental regulations. In other words, all recipients are required to ensure that all aspects of their state plans do not violate any of the federal nondiscrimination statutes, including Title VI.

The EPA's Office of Civil Rights (OCR) is responsible for carrying out compliance with these federal nondiscrimination statutes and does so through a variety of means including: Complaint investigation; agency-initiated compliance reviews; pre-grant award assurances and audits; and technical assistance and outreach activities. Anyone who believes that any of the federal nondiscrimination laws enforced by OCR have been violated by a recipient of EPA financial assistance may file an administrative complaint with the EPA's OCR.

H. Resources for States To Consider in Developing Plans

As part of the stakeholder outreach and comment processes, the EPA asked states what the agency could do to facilitate state plan development and implementation. In addition, after the comment period closed, the EPA continued to consult with state organizations including the Association of Air Pollution Control Agencies (AAPCA), Environmental Council of the States (ECOS), National Association of Clean Air Agencies (NACAA), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Energy Officials (NASEO) and the National Governors Association (NGA).

Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for RE and demand-side EE in state plans. They requested clear methodologies for estimating emission reductions from RE and demand-side EE policies and programs so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA's "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," as well as the State Energy Efficiency Action Network's "Energy Efficiency Program Impact Evaluation Guide."

In addition, stakeholders requested clear guidance on how to measure the impacts of RE and demand-side EE programs using established EM&V protocols.

The EPA also heard that states would like guidance on plan development to be released at the same time as this final rule. This guidance should include allowable programs and policies for compliance, examples of compliance pathways, clear information on multi-state plan development, and identification of tools.

As a result of this feedback, in consultation with U.S. DOE and other federal agencies, the EPA continued to refine its toolbox of decision support resources at: *http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox.* The site includes information on regulatory requirements, including state plan guidance and state plan decision support. The state plan guidance section serves as a central repository for the final emission guidelines, RIA, guidance documents, TSDs and other supporting materials. The state plan decision support section includes information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section includes, for example, a summary of existing state climate and RE and demand-side EE policies and programs, information on electric utility actions that reduce CO_2, and tools and information to estimate the emissions impact of RE and demand-side EE programs.

The EPA notes that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the Web site does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant criteria and adequately addresses elements of the plan components discussed in section VIII.D of this preamble.

I. Considerations for CO_2 Emission Reduction Measures That Occur at Affected EGUs

This section describes a range of emission reduction actions that may be taken at affected EGUs that reduce CO_2 emissions from an affected EGU and/or improve its CO_2 emission rate, and the accounting treatment for these actions in a state plan. Some of these actions do not necessitate additional accounting, monitoring or reporting requirements. Such actions are discussed in section VIII.I.1 below, and include heat rate improvements, fuel switching from one fossil fuel to another, integration of RE into EGU operations, and combined heat and power (CHP) expansion or retrofit. Other actions, however, do necessitate additional accounting, monitoring, or reporting requirements. These include use of CCS, CCU and biomass, as discussed in section VIII.I.2 below.

The discussion in this section applies for both rate-based and mass-based plans. Additional accounting considerations for mass-based plans are discussed in section VIII.J. Additional accounting considerations for rate-based plans, including how actions that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU, are discussed in section VIII.K.

1. Actions Without Additional Accounting and Reporting Requirements

Many actions will reduce the reported CO_2 emissions or CO_2 emission rate of an affected EGU, without the need for additional accounting or monitoring and reporting requirements beyond the required CEMS tracking of actual stack CO_2 emissions and tracking of actual energy output.[895] The effect of these actions will result in changes in reported CO_2 emissions and/or energy output by an affected EGU. These actions include:

- heat rate improvements;
- fuel switching to a fossil fuel with lower carbon content (*e.g.*, from coal to natural gas);
- integrated RE; [896] and
- CHP, including retrofit of an affected EGU to a CHP configuration, or revising the useful energy outputs (electrical and thermal) at an affected EGU already operating in a CHP configuration.[897]

---

[895] Monitoring and reporting requirements for affected EGU CO_2 emissions and useful energy output are addressed in section VIII.F.

[896] "Integrated RE" refers to RE that is directly incorporated into the mechanical systems and operation of the EGU. An example is a solar thermal energy system used to preheat boiler feedwater. Such approaches reduce the amount of fossil fuel heat input per unit of useful energy output.

[897] The emission reduction potential from CHP stems from the unit using less fuel for producing useful electrical and thermal outputs than would be required to run separate electrical and thermal units. The emission reduction would depend on the type of affected EGU and available steam hosts in the vicinity of the affected EGU. A conventional combustion turbine generator, for example, converted into a CHP unit could effectively result in a

Heat rate improvements, fuel switching, integrating RE and CHP would not require any additional accounting or monitoring and reporting, because under the emission guidelines affected EGUs are already required to monitor and report CO_2 emissions at the stack level, and to monitor and report useful energy outputs. Stack monitoring would reflect reductions in CO_2 emissions from efficiency improvements, changes in fuel use (including incorporation of RE), and other on-site changes.

2. Actions With Additional Accounting and Reporting Requirements

Certain actions that may be taken at an affected EGU to reduce CO_2 emissions, specifically application of CCS and CCU, and use of biomass, require additional accounting and reporting.

a. *Application of CCS.* Affected EGUs may utilize retrofit CCS technology to reduce reported stack CO_2 emissions from the EGU.[898] Affected EGUs that apply CCS under a state plan must meet the same monitoring, recordkeeping and reporting requirements for sequestered CO_2 as new units that implement CCS to meet final standards of performance under CAA section 111(b) for new

---

reduction of 25 percent or more in the reported CO_2 emission rate. The potential retrofitte EGU CHP market consists of converted simple cycle turbines, older steam plants in urban areas, and combined cycle units near beneficial thermal loads.

[898] Addition of retrofit CCS technology should not trigger CAA section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications and addition of CCS technology does not count toward the capital costs of reconstruction for NSPS.

EGUs.[899] Specifically, the final CAA section 111(b) rule for new sources requires that, if a new affected EGU uses CCS to meet the applicable CO_2 emission limit, the EGU must report in accordance with 40 CFR part 98 subpart PP (Suppliers of Carbon Dioxide), and the captured CO_2 must be injected at a facility or facilities that report in accordance with 40 CFR part 98 subpart RR (Geologic Sequestration of Carbon Dioxide).[900,901] See 40 CFR 60.5555(f). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting. As detailed in the preamble for the CAA section 111(b) standards for new EGUs, the EPA found that there is ample evidence that CCS is technically

[899] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.

[900] The final CAA section 111(b) rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) The electronic GHG Reporting Tool identification (e-GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR. As noted, the final 111(b) rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emission limit must transfer the captured CO_2 to a facility that reports under 40 CFR part 98 subpart RR.

[901] Under final requirements in the CAA 111(b) NSPS, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR. A UIC Class II well's regulatory status does not change because it receives such CO_2, nor does it change by virtue of reporting under subpart RR.

feasible and that partial CCS can be implemented at a new fossil fuel-fired steam generating EGU at a cost that is reasonable and that is consistent with the cost of other dispatchable, non-NGCC generating options. In the June 2014 proposal, the EPA noted that CCS technology at existing EGUs would entail additional considerations beyond those at issue for newly constructed EGUs. Specifically, the cost of integrating a retrofit CCS system into an existing facility may be expected to be substantial, and some existing EGUs may have space limitations and thus may not be able to accommodate the expansion needed to install the equipment to implement CCS. Further, the EPA noted that aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. Because there are lower-cost systems of emission reduction available to reduce emissions from existing plants, the EPA did not propose nor finalize CCS as a component of the BSER for existing EGUs.

However, the EPA noted that CCS may be a viable CO_2 mitigation technology at some existing sources and that it would be available to states and to sources as a compliance option. Numerous commenters agreed with the EPA's proposed determination that CCS technology is not part of the BSER building blocks for existing EGUs. Other commenters opposed inclusion of CCS requirements in state plans and provided specific reasons why CCS would not be applicable in certain states. Many commenters felt that CCS technology is not adequately demonstrated and is not economically practical at this time. Other commenters argued that CCS is an available technology and that it can be implemented at more EGUs than predicted by EPA modeling.

Some commenters noted that there are opportunities to reduce the cost of CCS implementation by selling the captured CO_2 for use in Enhanced Oil Recovery (EOR) operations. One commenter expressed concern that federal requirements under the Greenhouse Gas Reporting Program—specifically the requirement (mentioned above) to report under 40 CFR part 98 subpart RR—would foreclose, rather than encourage, the use of captured CO_2 for EOR. The EPA received similar public comments on the CAA 111(b) proposal for new EGUs. The EPA disagrees with the commenters' assertions and addressed those in the preamble for the final standards of performance and in the Response-to-Comments (RTC) document for the CAA 111(b) NSPS rulemaking. The EPA noted that the cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. The costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field.

After consideration of the variety of comments we received on this issue, we are confirming our proposal that CCS is not an element of the BSER, but it is an available compliance measure for a state plan. EGUs implementing CCS would need to follow reporting requirements established in the final CAA section 111(b) rule for new affected EGUs.

b. *Application of CCU.*

The EPA received comments suggesting that carbon capture and utilization (CCU) technologies should also be allowed as a CO_2 emission rate adjustment measure for affected EGUs.

Potential alternatives to storing CO_2 in geologic formations are emerging and may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. For example, these carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine® project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products including sodium carbonate and sodium bicarbonate.[902] Other companies—including

---

[902] *http://skyonic.com/technologies/skymine.*

Calera [903] and New Sky [904]—also offer commercially available technology for the beneficial use of captured CO_2. These processes can be utilized in a variety of industrial applications—including at fossil fuel-fired power plants.

However, consideration of how these emerging alternatives could be used to meet CO_2 emission performance rates or state CO_2 emission goals would require a better understanding of the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the captured CO_2 or displaces other CO_2 emissions from the atmosphere.

Several commenters also suggested that algae-based CCU (*i.e.*, the use of algae to convert captured CO_2 to useful products—especially biofuels) should be recognized for its potential to reduce emissions from existing fossil-fueled EGUs.

Unlike geologic sequestration, there are currently no uniform monitoring and reporting mechanisms to demonstrate that these alternative end uses of captured CO_2 result in overall reductions of CO_2 emissions to the atmosphere. As these alternative technologies are developed, the EPA is committed to working collaboratively with stakeholders to evaluate the efficacy of alternative utilization technologies, to address any regulatory hurdles, and to develop appropriate monitoring and reporting protocols to demonstrate CO_2 reductions.

---

[903] *http://www.calera.com/beneficial-reuse-ofco2/process.html.*

[904] *http://www.newskyenergy.com/index.php/products/carbo ncycle.*

In the meantime, state plans may allow affected EGUs to use qualifying CCU technologies to reduce CO_2 emissions that are subject to an emission standard, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission. State plans 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. The EPA would then review the appropriateness and basis for the analysis and the verification requirements in the course of its review of the state plan.

c. *Application of biomass co-firing and repowering.*

The EPA received multiple comments supporting the use of biomass feedstocks as a means of reducing CO_2 emissions within state plans. Several commenters also asserted that states should be able to determine how biomass can be used in their plans. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion. Some argued that all biomass feedstocks should be considered "carbon neutral," while others maintained that only the full stack emissions from biomass combustion should be counted. As discussed in the next section, the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources* [905] and 2012 Science Advisory Board peer review of the *2011 Draft*

[905] *www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf*.

Framework find that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral, but that the net biogenic CO_2 atmospheric contribution of different biomass feedstocks can vary and depends on various factors, including feedstock type and characteristics, production practices, and, in some cases, the alternative fate of the feedstock.[906] Other comments focused on the use of sustainably-derived agricultural and forest biomass feedstocks, including stakeholders who supported and those against such feedstocks as approvable elements, and those who wanted further definition of these feedstocks. As discussed above and in more detail below, these final guidelines provide that states can include qualified biomass in their plans and include provisions for how qualified biomass feedstocks or feedstock categories will be determined. The EPA will review the appropriateness and basis for determining qualified biomass feedstocks or feedstock categories in its review of the approvability of a state plan.

(1) *Considerations for use of biomass in state plans.*

The EPA recognizes that the use of some biomass-derived fuels can play a role in controlling increases of CO_2 levels in the atmosphere. The use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However, these benefits can typically only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account.

---

[906] *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

In November 2014, the agency released a second draft of the technical report, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*. The revised *Framework*, and the EPA's Science Advisory Board (SAB) peer review of the *2011 Draft Framework*, finds that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral" and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[907] The revised Framework also found that the production and use of some biogenic feedstocks and subsequent biogenic CO_2 emissions from stationary sources will not inevitably result in increased levels of CO_2 to the atmosphere, unlike CO_2 emissions from combustion of fossil fuels.

The SAB peer review panel agreed that the use of biomass feedstocks derived from the decomposition of biogenic waste in landfills, compost facilities or anaerobic digesters did not constitute a net contribution of biogenic CO_2 emissions to the

---

[907] Specifically, the SAB found that "There are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality is not an appropriate a priori assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably." *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

atmosphere. And further, information considered in preparing the second draft of the Framework, including the SAB peer review and stakeholder input, supports the finding that use of waste-derived feedstocks [908] and certain forest-derived industrial byproducts (such as those without alternative markets) are likely to have minimal or no net atmospheric contributions of biogenic CO_2 emissions, or even reduce such impacts, when compared with an alternate fate of disposal.

In addition, as detailed in the President's Climate Action Plan,[909] part of the strategy to address climate change includes efforts to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. This country's forests currently play a critical role in addressing carbon pollution, removing more than 13 percent of total U.S. GHG emissions each year.[910] Conservation and sustainable management can help ensure our forests and other lands will continue to remove carbon from the atmosphere while

---

[908] Types of waste-derived biogenic feedstocks may include: Landfill gas generated through the decomposition of MSW in a landfill; biogas generated from the decomposition of livestock waste, biogenic MSW, and/or other food waste in an anaeroic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities.

[909] *www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf*.

[910] *www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-6-Land-Use-Land-Use-Change-and-Forestry.pdf*.

also improving soil and water quality, reducing wildfire risk and enhancing forests' resilience in the face of climate change.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, RE incentives and standards, and GHG accounting procedures. Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as climate change mitigation through carbon storage. Oregon has several programs focused on best forest management practices and sustainability, including the Oregon Indicators of Sustainable Forests, that promote environmentally, economically and socially sustainable management of state forests. California's Forest Practice Regulations support sustained production of high-quality timber while considering ecological, economic and social values, and the state's Greenhouse Gas Reduction Fund provides resources for forestry projects to improve forest health, maintain carbon storage and avoid GHG emissions from pests, wildfires and conversion to non-forest uses.

Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts RPS, which, among other requirements, limits old growth forest harvests. Many states employ complementary programs that together work to address sustainable forestry practices. For example, Wisconsin uses a state forest sustainability framework that provides a common system to measure the sustainability of the state's public and private forests, in conjunction with a series of voluntary best management guideline manuals for sustainable woody biomass and agriculturally-derived biomass. In addition to state-specific programs, some states also actively participate in sustainable forest management or certification programs through third-party entities such as the Sustainable Forestry Initiative (SFI) and the Forest Stewardship Council (FSC). For example, in addition to other state sustainability programs, New York has certified more than 780,000 acres of state forestland to both SFI and FSC's sustainable forest management programs. SFI and FSC have certified more than 63 and 35 million acres of forestland across the U.S., respectively.

These examples demonstrate how states already use diverse strategies to promote sustainable forestry and agricultural management while realizing their unique economic, environmental and RE goals. As states evaluate options for meeting the emission guidelines, they may consider how sustainably-derived biomass and sustainable forestry and agriculture programs, such as the examples highlighted above, may help them control increases of CO_2 levels in the atmosphere. In addition, the EPA's work on assessing biogenic CO_2 emissions from stationary sources may also help inform states' efforts to assess the role of different biogenic feedstocks in their plans and broader climate strategies.[911]

The EPA is engaging in a second round of targeted peer review on the revised Framework with the SAB

---

[911] As highlighted in a November 2014 memorandum to the EPA's Regional Air Division Directors. *www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

in 2015.[912] As part of this technical process, and as the EPA and states implement these emission guidelines, the EPA will continue to assess and closely monitor overall bioenergy demand and associated landscape conditions for changes that might have negative impacts on public health or the environment.

(2) *Additional considerations and requirements for biomass fuels.*

The EPA anticipates that some states may consider the use of certain biomass-derived fuels used in electricity generation as a way to control increases of CO_2 levels in the atmosphere, and will include them as part of their state plans to meet the emission guidelines. Not all forms of biomass are expected to be approvable as qualified biomass (*i.e.*, biomass that can be considered as an approach for controlling increases of CO_2 levels in the atmosphere). Affected EGUs may use qualified biomass in order to control or reduce CO_2 emissions that are subject to an emission standard requirement, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal.

State plan submissions must describe the types of biomass that are being proposed for use under the state plan and how those proposed feedstocks or feedstock categories should be considered as "qualified biomass" (*i.e.*, a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere). The submission must also address the proposed valuation of biogenic CO_2

---

[912] *www.epa.gov/sab.*

emissions (*i.e.*, the proposed portion of biogenic CO_2 emissions from use of the biomass feedstock that would not be counted when demonstrating compliance with an emission standard, or when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal).

With regard to assessing qualified biomass proposed in state plans, the EPA generally acknowledges the CO_2 and climate policy benefits of waste-derived biogenic feedstocks and certain forest- and agriculture-derived industrial byproduct feedstocks, based on the conclusions supported by a variety of technical studies, including the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources.* The use of such waste-derived and certain industrial byproduct biomass feedstocks would likely be approvable as qualified biomass in a state plan when proposed with measures that meet the biomass monitoring, reporting and verification requirements discussed below and other measures as required elsewhere in these emission guidelines.

Given the importance of sustainable land management in achieving the carbon goals of the President's Climate Action Plan, sustainably-derived agricultural and forest biomass feedstocks may also be acceptable as qualified biomass in a state plan, if the state-supplied analysis of proposed qualified feedstocks or feedstock categories can adequately demonstrate that such feedstocks or feedstock categories appropriately control increases of CO_2 levels in the atmosphere and can adequately monitor and verify feedstock sources and related sustainability practices. Information in the revised Framework, the second SAB peer review process, and the state and third party programs highlighted in the previous section can assist states when considering the role of qualified biomass in state plan submittals.

Regardless of what biomass feedstocks are proposed, state plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches for qualified biomass feedstocks. As discussed in section VIII.D.2, state plan submittals must include CO_2 emission monitoring, reporting and recordkeeping measures. In the case of sustainably-derived forest- and agriculture-derived feedstocks, this will also include measures for verifying feedstock type, origin and associated sustainability practices. Section VIII.K describes how state plan submittals must specify the requirements and procedures that EM&V measures must meet. As discussed in section VIII.K, the EPA is addressing potential EM&V measures for qualified biomass in EPA's model trading rule and draft EM&V guidance, such as measures that would ensure that biomass-related biogenic CO_2 benefits are quantifiable, verifiable, non-duplicative, permanent and enforceable.

State plan submittals must ensure that all biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits, such as using robust, independent third party verification and establishing measures to maintain transparency, including disclosure of relevant documentation and reports. State plan submittals must include measures for tracking and auditing performance to ensure that biomass used meets the state plan requirements for qualified biomass and associated biogenic CO_2 benefits. Details on how to adjust CO_2 rates through the use of qualified biomass feedstocks are provided in section VIII.K.1.

The EPA will review the appropriateness and basis for proposed qualified biomass and biomass treatment determinations and related accounting, monitoring and reporting measures in the course of its review of a state plan. The EPA's determination that a state plan satisfactorily proves that proposed biomass fuels qualify would be based in part on whether the plan submittal demonstrates that proposed state measures for qualified biomass and related biogenic CO_2 benefits are quantifiable, verifiable, enforceable, non-duplicative and permanent. The EPA recognizes that CCS technology (described above in section VIII.I.2.a) could be applied in conjunction with the use of qualified biomass.

(3) *Biomass co-firing.*

Affected EGUs may use qualified biomass co-fired with fossil fuels at an affected EGU. As discussed above in this section, not all forms of biomass are expected to be approvable and states should propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable. The EPA will review the appropriateness and basis for such determinations and accounting measures in the course of its review of a state plan.

An affected EGU using qualified biomass as a fuel must monitor and report both its overall CO_2 emissions and its biogenic CO_2 emissions. If biomass is to be used as means to control increases of CO_2 levels in the atmosphere in a state plan, the plan must specify requirements for reporting biogenic CO_2 emissions from affected EGUs.

(4) *Biomass repowering.*

Affected EGUs could fully repower to use primarily qualified biomass. The characteristics of affected EGUs, as discussed in section IV.D, include the use of at least 10 percent fossil fuel for applicability of these emission guidelines. An EGU repowering with at least 90 percent biomass fuels instead of fossil fuels becomes a non-affected EGU.[913] An EGU repowering with less than 90 percent biomass would remain an affected EGU and therefore need to propose biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis where applicable.

J. Additional Considerations and Requirements for Mass-Based State Plans

This section discusses considerations and requirements for different types of mass-based state plans. This includes mass-based state plans using emission budget trading programs, and coordination among such programs where states retain individual mass CO_2 emission goals. CAA section 111(d) requires states to submit, in part, a plan that establishes standards of performance for affected EGUs which reflect the BSER. The state plan must be satisfactory with respect to this requirement in order for the EPA to approve the plan. As previously described, states

---

[913] For such an EGU to be considered non-affected, the EGU must be subject to a federally enforceable or practically enforceable condition, expressed in (for example) a construction permit or otherwise, that limits the amount of fossil fuel that may be used to 10 percent or less.

meet the statutory requirements of 111(d) and the requirements of the final emission guidelines by establishing emission standards for affected EGUs that meet the performance rates, which reflect the application of BSER as determined by the EPA. This final rule allows states to alternatively establish emission standards that meet rate-based or mass-based goals. The state goals must be equivalent to the performance rates in order to reflect the application of the BSER as required by the statute and the final emission guidelines. Therefore, a state choosing a mass-based implementation must address leakage as part of its mass-based plan in order to satisfactorily establish emission standards for affected EGUs that reflect the BSER as set by the EPA.

1. Accounting for CO_2 Emission Reduction Measures in Mass-Based State Plans

As discussed in section VIII.I, measures that occur at affected EGUs will result in CO_2 emission reductions that are automatically accounted for in reported CO_2 emissions. Other measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs, such as demand-side EE, are automatically accounted for under a mass-based plan to the extent that these measures reduce reported CO_2 emissions from affected EGUs. Unlike under a rate-based plan, no additional accounting is necessary in order to recognize these emission reductions.

2. Use of Emission Budget Trading Programs

This section addresses the use of emission budget trading programs in a mass-based state plan, including provisions required for such programs and the design of such programs in the context of a state plan. This includes program design approaches that ensure achievement of a state mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) (section VIII.J.2.b), as well as how states can use emission budget trading programs with broader source coverage and other flexibility features in a state plan, such as the programs currently implemented by California and the RGGI participating states (section VIII.J.2.c). Section VIII.J.2.d addresses other considerations for the design of emission budget trading programs that states may want to consider, such as allowance allocation approaches. Section VIII.J.3 addresses multi-state coordination among emission budget trading programs used in states that retain their individual state mass-based CO_2 goals.

a. *State plan provisions required for a mass-based emission budget trading program approach.*

For a mass-based emission trading program approach, the state plan would include as its federally enforceable emission standards requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements would include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions). Mass-based emission standards that take the form of an emission budget trading program must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

Where a state plan establishes mass-based emission standards for affected EGUs only, the emission standards and the implementing and enforcing measures may be included in the state plan as the full set of requirements implementing the emission budget trading program. Where an emission budget trading program in a state plan addresses affected EGUs and other fossil fuel-fired EGUs or emission sources, pursuant to the approaches described in sections VIII.J.2.b–d below, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs. Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other emission sources (if relevant) must be described as supporting documentation in the state plan submittal for EPA to evaluate the approvability of the plan by determining whether the affected EGUs will achieve the requisite goal.

b. *Requirement for emission budget trading programs to address potential leakage.*

In Section VII.D, the EPA specifies that potential emission leakage must be addressed in a state plan with mass-based emission standards. The EPA received comments suggesting various solutions to this concern, such as the inclusion of new sources under the rule and quantitative adjustments to mass CO_2 goals for affected EGUs. In response to this issue, the EPA has sought to give states flexibility in how they meet this requirement and base the acceptable solutions on what will best suit a state's unique characteristics and state plan structure.

To address the potential for emission leakage to new sources under a mass-based plan approach, which could prevent a mass-based program from successfully achieving a mass-based CO_2 goal consistent with BSER, the EPA is requiring that a state submitting a plan that is designed to meet a state mass-based CO_2 goal for affected EGUs demonstrate that the plan addresses and mitigates the risk of potential emission leakage to new sources. The following options provide sufficient demonstration that potential emission leakage has been addressed in a mass-based state plan: [914]

1. Regulate new non-affected fossil EGUs as a matter of state law in conjunction with emission

[914] The first two options need not be mutually exclusive; they can both be implemented as part of a mass-based plan.

standards for affected EGUs in a mass-based plan. If a state adopts an EPA-provided mass budget[915] that includes the state mass-based CO_2 goal for affected EGUs plus a new source CO_2 emission complement, this option could be presumptively approvable.

2. Use allocation methods in the state plan that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. If a state adopts allowance set-aside provisions exactly as they are outlined in the finalized model rule, this option could be presumptively approvable.

3. Provide a demonstration in the state plan, supported by analysis, that emission leakage is unlikely to occur due to unique state characteristics or state plan design elements that address and mitigate the potential for emission leakage.

In the first option, states may choose to regulate new non-affected fossil fuel-fired EGUs, as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs under a mass-based plan. This regulation of both new and existing sources, as part of a state plan approach, is conceptually analogous to a method that has been adopted by the mass-based systems adopted by California and the RGGI participating states. To address potential emission leakage under this option, the mass-based plan includes federally enforceable emission standards for affected EGUs, and the supporting documentation for the plan describes state-enforceable regulations for, at a minimum, all new

---

[915] In Table 14, we have provided a mass budget for each state that includes the state mass-based CO_2 goal and a projection for a new source CO_2 emission complement.

grid-connected fossil fuel-fired EGUs that meet the applicability standards for EGUs subject to CAA section 111(b). States have the option of regulating a wider array of sources if they choose, as a matter of state law.

For this option, a state must adopt, as a matter of state law, a mass CO_2 emission budget of sufficient size to cover both affected EGUs under the existing source mass CO_2 goal provided in this final rule, along with sufficient CO_2 emission tonnage to cover projected new sources. There are two pathways that states can use for adopting such an emission budget that applies to both affected EGUs and new sources. The EPA is providing a mass budget for each state that account for the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources, referred to as the new source CO_2 emission complement. States that both adopt the EPA-provided mass budget, based on the state mass-based CO_2 goal for affected EGUs plus the new source CO_2 emission complement, and regulate new sources under this emission budget as a matter of state law, in conjunction with federally enforceable emission standards for affected EGUs as part of the mass-based state plan may be able to submit a presumptively approvable plan. Such a plan would include federally enforceable emission standards for affected EGUs, and in the supporting documentation of the plan, would describe that the state is regulating new sources under a mass CO_2 emission budget that is equal to or less than the state mass-based CO_2 goal for affected EGUs plus the EPA-specified CO_2 emission complement, in conjunction with the federally enforceable emission standards for affected EGUs. If the state plan is designed to achieve the EPA provided mass budget, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, and new sources regulated as a matter of state law, together meet the total mass budget that includes the state's mass CO_2 goal for affected EGUs and a complementary emission budget for new sources.

EPA-specified mass CO_2 emission budgets for each state, including the state's mass CO_2 goal and a new source CO_2 emission complement, are provided in Table 14 below. The derivation of the new source CO_2 emission complements is explained in a TSD titled New Source Complements to Mass Goals, which is available in the docket.

TABLE 14—NEW SOURCE COMPLEMENTS TO MASS GOALS

State	New source complements (short tons of CO_2)		Mass goals[916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Alabama	856,524	755,700	63,066,812	57,636,174
Arizona	1,424,998	2,209,446	34,486,994	32,380,197
Arkansas	411,315	362,897	34,094,572	30,685,529
California	2,846,529	4,413,516	53,873,603	52,823,635
Colorado	1,239,916	1,922,478	34,627,799	31,822,874
Connecticut	135,410	119,470	7,373,274	7,060,993
Delaware	78,842	69,561	5,141,711	4,781,386
Florida	1,753,276	1,546,891	114,738,005	106,641,595
Georgia	677,284	597,559	51,603,368	46,944,404
Idaho	94,266	146,158	1,644,407	1,639,013
Illinois	818,349	722,018	75,619,224	67,199,174
Indiana	939,343	828,769	86,556,407	76,942,604
Iowa	298,934	263,745	28,553,345	25,281,881
Kansas	260,683	229,997	25,120,015	22,220,822

[916] The state mass CO_2 goals can be found in Table 13 in section VII.

State	New source complements (short tons of CO_2)		Mass goals[916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Kentucky	752,454	663,880	72,065,256	63,790,001
Louisiana	484,308	427,299	39,794,622	35,854,321
Maine	40,832	36,026	2,199,016	2,109,968
Maryland	170,930	150,809	16,380,325	14,498,436
Massachusetts	225,127	198,626	12,972,803	12,303,372
Michigan	623,651	550,239	53,680,801	48,094,302
Minnesota	286,535	252,806	25,720,126	22,931,173
Mississippi	410,440	362,126	27,748,753	25,666,463
Missouri	668,637	589,929	63,238,070	56,052,813
Montana	421,674	653,801	13,213,003	11,956,908
Nebraska	216,149	190,706	20,877,665	18,463,444
Nevada	770,417	1,194,523	15,114,508	14,718,107
New Hampshire	71,419	63,012	4,314,910	4,060,591
New Jersey	313,526	276,619	17,739,906	16,876,364
New Mexico	527,139	817,323	14,342,699	13,229,925
New York	522,227	460,753	34,117,555	31,718,182
North Carolina	692,091	610,623	57,678,116	51,876,856
North Dakota	245,324	216,446	23,878,144	21,099,677

State	New source complements (short tons of CO_2)		Mass goals[916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Ohio	949,997	838,170	83,476,510	74,607,975
Oklahoma	581,051	512,654	45,191,382	41,000,852
Oregon	453,663	703,399	9,096,826	8,822,053
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Rhode Island	70,035	61,791	3,727,420	3,584,016
South Carolina	344,885	304,287	29,314,508	26,303,255
South Dakota	46,513	41,038	3,995,462	3,580,518
Tennessee	358,838	316,598	32,143,698	28,664,994
Texas	5,328,758	8,516,408	213,419,599	198,105,249
Utah	981,947	1,522,500	27,548,327	25,300,693
Virginia	450,039	397,063	30,030,110	27,830,174
Washington	531,761	824,490	12,211,467	11,563,662
West Virginia	602,940	531,966	58,686,029	51,857,307
Wisconsin	364,841	321,895	31,623,197	28,308,882
Wyoming	1,185,554	1,838,190	36,965,606	33,472,602
Lands of the Navajo Nation	809,562	1,255,217	25,367,354	22,955,804
Lands of the Uintah and Ouray Reservation	84,440	130,923	2,645,885	2,394,354

State	New source complements (short tons of CO_2)		Mass goals[916] + new source complements (short tons of CO_2)	
	Interim	Final	Interim	Final
Lands of the Fort Mojave Tribe	37,162	57,619	648,264	646,138
Total....................................	33,717,871	41,187,289	1,878,255,620	1,709,291,348

States can, in the alternative, provide their own projections for a new source CO_2 emission complement to their mass-based CO_2 goals for affected EGUs. In the supporting documentation for the state plan submittal, the state must specify the new source budget, specify the analysis used to derive such a new source CO_2 emission complement, and demonstrate that under the state plan affected EGUs in the state will meet the state mass-based CO_2 goal for affected EGUs as a result of being regulated under the broader CO_2 emission cap that applied to both affected EGUs and new sources. Such a projection should take into account the mass goal quantification method outlined in section VII.C and the CO_2 Emission Performance Rate and Goal Computation TSD, including the fact that the mass-based state goals already incorporate a significant growth in generation from historical levels. The EPA will evaluate the approvability of the plan based on whether the federally enforceable emission standards for affected EGUs in conjunction with the state-enforceable regulatory requirements for new sources will result in the affected EGUs meeting the state mass-based CO_2 goal. If, rather than designing a plan to achieve the EPA provided mass budget, the state uses its own projections for a new source complement and the plan is approved to meet this new source complement, plan performance will be evaluated based on whether the existing affected EGUs, regulated under the federally enforceable state plan, meet the state's mass CO_2 goal for affected EGUs.

The second demonstration option allows states to use allowance allocation methods that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources. These allocation approaches must be specified in state plans as part of the provisions for state allocation of allowances required under a mass-based plan approach (see section VIII.J.2.a). The EPA is proposing the inclusion of two allocation strategies as part of the mass-based approach in the proposed federal plan and model rule: Updating output-based allocations and an allowance set-aside that targets RE. These options are described in more detail below. If a state were to adopt allowance set-aside provisions exactly as they are outlined in the finalized model rule, they could be considered presumptively approvable. The allowance allocation alternative for addressing leakage was chosen for the federal plan and model rule proposal because EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include them under a federal mass-based plan approach.

An updating output-based allocation method allocates a portion of the total CO_2 emission budget to affected EGUs based, in part, on their level of electricity generation in a recent period or periods. Therefore, the total allocation to an EGU that is eligible to receive allowances from an output-based allowance set-aside is not fixed, but instead depends on its generation. Under this approach, each eligible affected EGU may receive a larger allowance allocation if it generates more. Therefore, eligible affected EGUs will have an incentive to generate more in order to receive more allowances, aligning their incentive to generate with new sources.

This allocation method can be implemented through the creation of a set-aside that reserves a subset of the total allowances available to sources, and distributes them based upon the criteria described above. Because the total number of allowances is limited, this allocation approach will not exceed the overall state mass-based CO_2 goal for affected EGUs. Instead, it merely modifies the distribution of allowances in a manner designed to mitigate potential emission leakage.

The other allocation strategy included as part of the mass-based approach in the proposed federal plan and model rule is a set-aside of allowances to be allocated to providers of incremental RE. A set-aside can also be allocated to providers of demand-side EE, or to both RE and demand-side EE. The increased availability of RE generation can serve as another source of generation to satisfy electricity demand. Increased demand-side EE will reduce the demand that sources need to meet. Therefore, both RE and demand-side EE can serve to reduce the incentive that new sources have to generate, and therefore align their incentives with affected EGUs. Thus, increased RE and demand-side EE, supported by a dedicated set-aside, can also serve to address potential emission leakage.

If a state is submitting a plan with an allocations approach that differs from that of the finalized model rule, the state should also provide a demonstration of how the specified allocation method will provide sufficient incentive to counteract potential emission leakage.

Finally, a state can provide a demonstration that emission leakage is unlikely to occur, without implementing either of the two strategies above, as a result of unique factors, such as the presence of existing state policies addressing emission leakage or unique characteristics of the state and its power sector that will mitigate the potential for emission leakage. This demonstration must be supported by credible analysis. The EPA will determine if the state has provided a sufficient demonstration that potential emission leakage has already been adequately addressed, or if additional action is required as part of the state plan.

Aside from the possible incentives for emission leakage addressed in this section, there may be other potential generation incentives across states and unit subcategories that could increase CO_2 emissions, particularly in an environment where various states are implementing a variety of state plan approaches in a shared grid region. Some examples of these incentives, particularly those that were specified by commenters, are discussed in section VIII.L. That section also describes how the EPA has structured this final rule to either prevent or minimize the potential for foregone emission reductions from differential incentives that may result from state plan implementation. These safeguards include placing restrictions on interstate trading when there could be a risk of such differential incentives. Additionally, the nature of the CO_2 emission performance rates and state rate-based CO_2 goals helps to minimize these potential effects, as does the MWh-accounting method for adjusting the CO_2 emission rates of affected EGUs under rate-based plans.

However, without a better understanding of the different mechanisms that states may ultimately choose to meet the emission guidelines, and how different requirements in different states may interact, the EPA cannot project every potential differential incentive that could lead to a loss of CO_2 emission reductions. Therefore, once program implementation begins, the EPA will assess how emission performance across states may be affected by the interaction of different regulatory structures implemented through state plans. Based upon that evaluation, the EPA will determine whether there are potential concerns and what course of action may be appropriate to remedy such concerns.

c. *Emission budget trading programs that ensure achievement of a state CO_2 goal.*

A mass-based emission budget trading program can be designed such that compliance by affected EGUs will achieve the state mass-based CO_2 goal. Under this approach, a state plan would establish CO_2 emission budgets for affected EGUs during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 goals specified in section VII. A mass-based emission budget trading program can also be designed such that compliance by affected EGUs in conjunction with new fossil fuel-fired EGUs meeting applicable requirements under state law will achieve a mass-based CO_2 goal plus new source CO_2 emission complement. Under this approach, a state would establish CO_2 emission budgets under state law for affected EGUs plus new sources during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 emission goal plus the new source CO_2 emission complement specified in Table 14 in section VIII.J.2.b above, and describe such emission budgets in the supporting documentation of the state plan. Under either program, compliance periods for affected EGUs (or for affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would also be aligned with the interim and final plan performance periods. This approach would limit total CO_2 emissions from affected EGUs (or total CO_2 emissions from affected EGUs and new fossil fuel-fired EGUs meeting applicable requirements under state law) during the interim and final plan performance periods to an amount equal to or less than the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

Under this approach, compliance by affected EGUs with the mass-based emission standards in a plan would ensure that the state achieves its mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). No further demonstration would be necessary by the state to demonstrate that its plan would achieve the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

For this type of plan, where the emission budget is equal to or less than the state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement),[917] the EPA would assess achievement of the state goal based on compliance by affected EGUs with the mass-based emission standards, rather than reported CO_2 emissions by affected EGUs during the interim plan performance periods and final plan performance periods. This approach would allow for

---

[917] As specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

allowance banking between performance periods, including the interim and final performance periods outlined in this final rule.

Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs. This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later. It is also beneficial when addressing pollutants that are long-lived in the atmosphere, such as CO_2, and where increasing atmospheric concentration of the pollutant leads to increasing adverse atmospheric impacts.

Banking also provides long-term economic signals to affected emission sources and other market participants where actions taken today will have economic value in helping meet tighter emission constraints in the future, provided those emission sources expect that the banked ERCs or emission allowances may be used for compliance in the future. Linking short-term and long-term economic incentives, which allows owners or operators of affected EGUs and other market participants to assess both short-term and long-term incentives when making decisions about compliance approaches or emission reduction investments, reduces long-term compliance costs for affected EGUs and ratepayer impacts. In addition, the increased temporal flexibility provided by banking would further help address potential electric reliability concerns, as banked ERCs can be used to meet emission standard requirements for an affected EGU.

d. *Addressing emission budget trading programs with broader source coverage and other flexibility features.*

As described in section VIII.C above, under the emission standards plan type, a mass-based emission budget trading program with broader source coverage and other flexibility features may be designed such that compliance by affected EGUs (or compliance by affected EGUs plus new fossil fuel-fired EGUs meeting applicable requirements under state law) would assure achievement of the applicable state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).[918]

However, emission budget trading programs, including those currently implemented by California and the RGGI participating states, include a number of different design elements that functionally expand the emission budget under certain circumstances. If a state chose, it could apply such mass-based emission standards, in the form of an emission budget trading program that differs in design from that outlined in section VIII.J.2.c above. These types of emission budget trading programs must be submitted as a part of a state measures plan type. Where an emission

[918] Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

budget trading program addresses affected EGUs and other fossil fuel-fired EGUs, the requirements that must be included in the state plan are the federally enforceable emission standards in the state plan that apply specifically to affected EGUs, and the requirements that specifically require affected EGUs to participate in and comply with the requirements of the emission budget trading program. This includes the requirement for an affected EGU to surrender emission allowances equal to reported CO_2 emissions, and meet monitoring and reporting requirements for CO_2 emissions, among other requirements. These requirements may be submitted as part of the federally enforceable state plan through mechanisms with the appropriate legal authority and effect, such as state regulations, relevant Title V permit requirements for affected EGUs, and other possible instruments that impose these requirements specifically with respect to affected EGUs.[919] Under this approach, the full set of regulations establishing the emission budget trading program that applies to affected EGUs and other fossil fuel-fired EGUs and other emission sources (if relevant) must be described as supporting documentation in the state plan submittal. This structure is appropriate to ensure that states with an emission budget trading program that addresses both affected EGUs and other fossil fuel-fired EGUs do not inappropriately submit requirements regarding entities other than affected

[919] This approach for establishing federally enforceable emission standards based on requirements for affected EGUs subject to a broader emission budget trading program that also covers non-affected emission sources is addressed in section VIII.J.2.d. above.

EGUs for inclusion in the federally enforceable state plan.

Such state programs could include a number of different design elements. This includes broader program scope, where a program includes other emission sources beyond affected EGUs subject to CAA section 111(d) and new fossil fuel-fired EGUs, such as industrial sources. Programs might also include design elements that make allowances available in addition to the established emission budget. This includes project-based offset allowances or credits from GHG emission reduction projects outside the covered sector and cost containment reserve provisions that make additional allowances available at specified allowance prices.[920]

In the case where an emission budget trading program contains elements that functionally expand the emission budget in certain circumstances, compliance by affected EGUs with the mass-based emission standards would not necessarily ensure that CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). However, states could modify such programs to remove flexibility mechanisms that functionally expand the emission budget, such as out-of-sector offsets and certain cost containment reserve mechanisms, and

---

[920] For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

submit the program under an emission standards plan type.

Where a state chooses to retain such flexibility mechanisms as part of an emission budget trading program, the program may only be implemented as part of a state measures plan type because these state flexibility mechanisms would not assure CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). A description of the state measures plan type and related requirements is provided in section VIII.C.3.

Under this type of approach, the state would be required to include a demonstration,[921] in its state plan submittal, of how its state measures, in conjunction with any emission standards on affected EGUs, would achieve the state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement). This demonstration would include a projection of the total CO_2 emissions from the fleet of affected EGUs that would occur as a result of compliance with the emission standards in the plan. Section VIII.D.2 discusses how such demonstrations could address design elements of emission budget trading programs with broader scope and additional compliance flexibility mechanisms, such as those included in the California and RGGI programs. Once the plan is implemented, if the mass-based CO_2 goal is not achieved during a plan performance period, the

[921] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is one of the required plan components, as described in section VIII.D.2.

backstop federally enforceable emission standards included in the state plan that apply to affected EGUs would be implemented, as described in section VIII.C.3.b.[922]

e. *Considerations for mass-based emission budget trading programs.*

The EPA notes that while an emission budget trading program included in an emission standards plan must be designed to achieve a state mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement), states have wide discretion in the design of such programs, provided the emission standards included in the plan are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

(1) *Allowance allocation.* A key example is state discretion in the CO_2 allowance allocation methods included in the program.[923] This includes the methods used to distribute CO_2 allowances and the parties to which allowances are distributed. For example, if a

---

[922] Achievement of the state mass-based CO_2 goal would be determined based solely on stack CO_2 emissions from affected EGUs. Where a state program includes the ability of an affected emission source to use GHG offsets to meet a portion of its allowance compliance obligation, no "credit" is applied to reported CO_2 emissions by the affected EGU. The use of offset allowances or credits in such programs merely allows an affected EGU to emit a ton of CO_2 in the amount of submitted offset allowances or credits. In all cases, there is no adjustment applied to reported stack emissions of CO_2 from an affected EGU when determining compliance with its emission limit.

[923] Allowance allocation refers to the methods used to distribute CO_2 allowances to the owners or operators of affected EGUs and/or other market participants.

state chose, it could include CO_2 allowance allocation provisions that provide incentives for certain types of complementary activities, such as RE generation, that help achieve the overall CO_2 emission limit for affected EGUs established under the program. In addition, a state could use its allocation provisions to encourage investments in RE and demand-side EE in low-income communities. States could also use CO_2 allowance allocation provisions to provide incentives for early action, such as RE generation or demand-side EE savings that occur prior to the beginning of the interim plan performance period in 2022. For example, a state could include CO_2 allowance allocation provisions where CO_2 allowances are distributed to RE generators based on MWh of RE generation that occurs prior to 2022. Such provisions might be addressed through a finite set-aside of CO_2 allowances that are available for allocation under these provisions. This set-aside could be additional to a set-aside created by the state for the CEIP discussed in section VIII.B.2.

(2) *Facility-level compliance.* If a state chose, it could evaluate compliance (*i.e.*, allowance true-up) under its emission budget trading program at the facility level, rather than at the individual unit level. The EPA has adopted facility-level compliance in the emission budget-trading programs it administers, including the Acid Rain Program (70 FR 25162), Clean Air Interstate Rule (70 FR 25162), and Cross-State Air Pollution Rule (76 FR 48208). Under this approach, states would still track reported unit-level CO_2 emissions—while evaluating compliance at the facility level—allowing them to track increases and decreases of CO_2 emissions at individual EGUs.

3. Multi-state coordination: Mass-based emission trading programs.

An individual state may provide for the use of CO_2 allowances issued by another state(s) for compliance with the mass-based emission standards in its plan. This type of state plan would include requirements that enable affected EGUs to use allowances issued in other states for compliance under the state's emission budget trading program. This type of state plan must also indicate how CO_2 allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or use of an EPA-administered tracking system.[924]

Two different implementation approaches could be used to create such links. A state could submit a "ready-for-interstate-trading" plan using an EPA-approved tracking system, but the plan would not identify links with other states. A state could also submit a plan with specified bilateral or multilateral links that explicitly identify partner states.

Interstate allowance linkages would not affect the approvability of each state's individual plan. However, different considerations apply for the approvability of an individual plan with such links, based on whether the emission budget trading program in the plan

---

[924] The emission standards in each individual state plan must include requirements that address the issuance of CO_2 allowances and tracking of CO_2 allowances from issuance through use for compliance. The description here addresses how those requirements will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

applies only to affected EGUs or includes other emission sources, and if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement).

Under the first "ready-for-interstate-trading" implementation approach, a state would indicate in its state plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.[925] State plans using a specified EPA-approved tracking system would be deemed by the EPA as ready for interstate linkage upon approval of the state plan. No additional EPA approval would be necessary for states to link their emission budget trading programs, and affected EGUs in those states could engage in interstate trading subsequent to EPA plan approval.

A state would indicate in its plan submittal that its emission budget trading system will use a specified EPA-approved tracking system. The state would also indicate in the regulatory provisions for its emission budget trading program that it would recognize as usable for compliance any emission allowance issued by any other state with an EPA-approved state plan that also uses the specified EPA-approved tracking system.

---

[925] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of emission allowances. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

States could also adopt such a collaborative emission trading approach over time (through appropriate state plan revisions if the plan is not already structured as ready-for-interstate-trading), without requiring all of the original participating states to revise their EPA-approved plans.

Under the second implementation approach, a state could specify the other states from which it would recognize issued emission allowances as usable for compliance with its emission budget trading program. The state would indicate in the regulatory provisions for its emission budget trading program that emission allowances issued in other identified partner states may be used by affected EGUs for compliance. Such plans must indicate how allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or EPA-administered tracking system. The EPA would assess the design and functionality of this tracking system(s) when reviewing individual submitted state plans.

Under this approach, states could also join such a collaborative emission trading approach over time. However, all participating states would need to revise their EPA-approved plans. If the expanded linkage is among previously approved plans with mass-based emission standards, approval of the plan revision would be limited to assessing the functionality of the shared tracking system or interoperable tracking systems in order to maintain the integrity of the linked programs.[926]

---

[926] Depending on the specific regulatory provisions in the emission standards in their approved state plans, participating

a. *Considerations for linked emission budget trading programs.*

For individually submitted plans, interstate emission allowance linkages would not affect the approvability of each state's plan. However, approvability of an individual linked plan would differ based on the structure of the emission budget trading program included in the plan. These differences for plan approvability address distinctions among programs that include only affected EGUs and programs that cover a broader set of emission sources, as well as if the plan is designed to meet a state mass-based CO_2 goal for affected EGUs only or to meet a mass-based CO_2 goal plus a new source CO_2 emission complement. Differences in approval criteria are necessary to ensure that each individual state plan demonstrates it will achieve a state's mass-based CO_2 emission goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement). The accounting applied to individual plans to assess whether a state achieves its mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will also differ, based on whether an emission budget trading program includes only affected EGUs (or affected EGUs and applicable new fossil fuel-fired EGUs) or a broader set of emission sources. These considerations are addressed below, for both types of emission budget trading programs.

---

states may also need to revise their implementing regulations (and by extension their state plans) to accept CO_2 emission allowances issued by new partner states as usable for compliance with their mass-based emission standards.

(1) *Links among emission budget trading programs that only include affected EGUs* or affected EGUs and applicable new fossil fuel-fired EGUs. Where the emission budget trading programs in each plan apply only to affected EGUs subject to the final rule (or emission budget trading programs that apply to affected EGUs under the state plan and applicable new fossil fuel-fired EGUs under state law), and include compliance timeframes for affected EGUs that align with the interim and final plan performance periods, both plans would functionally be meeting an aggregated multi-state mass-based goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement), but without formally aggregating the goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement). CO_2 emissions from affected EGUs in both states could not exceed the total combined CO_2 emission budgets under the emission standards in the two states. A net "import" of CO_2 allowances from one state would mean that allowable CO_2 emissions in the other net "exporting" state are less than that state's established emission budget. On a multi-state basis, CO_2 emissions from affected EGUs could not exceed the sum of the states' emission budgets.

Under this approach, if the emission budget for the mass-based emission standard in each plan is equal to or lower than the state's mass-based CO_2 goal (or aggregated mass-based CO_2 goal plus new source CO_2 emission complement, if applicable), compliance by affected EGUs with the mass emission standard in a state[927] would ensure that cumulatively the mass CO_2 goals (or mass-based CO_2 goals plus new source CO_2 emission complements) of the linked states are achieved. As a result, achievement of an individual state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be assessed by the EPA based on compliance by affected EGUs with the mass-based emission standards in the state plan, rather than reported CO_2 emissions by affected EGUs in the state.[928]

The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources (*e.g.*, sources beyond affected EGUs, or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), as described below. In all cases, where a state plan includes an emission budget trading program that applies only to affected EGUs (or beyond affected EGUs plus applicable new fossil fuel-fired EGUs), and includes compliance timeframes that align with plan performance periods, achievement of a state mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be assessed by the EPA

---

[927] Compliance by an affected EGU with the emission standard is demonstrated based on surrender to the state of a number of CO_2 allowances equal to its reported CO_2 emissions.

[928] This approach is warranted because under such linked programs, CO_2 emissions from affected EGUs in one state that exceed a state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be accompanied by CO_2 emissions from affected EGUs in another linked state that are below that state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

based on whether affected EGUs comply with the mass-based emission standard, rather than reported CO_2 emissions from affected EGUs.

(2) *Links with emission budget trading programs that include a broader set of emission sources.* State plans may involve emission budget trading programs that include affected EGUs, applicable new fossil fuel-fired EGUs if a plan includes a new source CO_2 emission complement, and other non-affected emission sources.[929]

Generally, such plans must demonstrate that the mass-based CO_2 goal for affected EGUs (or mass-based CO_2 goal plus new source CO_2 emission complement) in a state will be achieved, as a result of implementation of the emission budget trading program.[930] Where a program includes other non-affected emission sources (*i.e.*, non-affected emission sources that are not subject to a new source CO_2 emission complement) and is linked with other

---

[929] This may apply under both an emission standards plan and a state measures plan. Section VIII.J.2.a describes how state plan submissions must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

[930] Under a program that applies to affected EGUs and other emission sources, compliance by affected EGUs with the emission standard—a requirement to surrender emission allowances equal to reported emissions—will not assure that a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) is achieved. As a result, a further demonstration is required in the plan that compliance by affected EGUs with the program will result in CO_2 emissions from affected EGUs that are at or below a state's CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

programs,[931] the state plan submittal must include a demonstration that the mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) will be achieved, considering the emission allowance links with other programs. The EPA, in determining the approvability of each state's plan under this approach, would evaluate the linkages between plans. Specifically, the EPA would evaluate whether the linkages would enable the affected EGUs (or affected EGUs in conjunction with applicable new fossil fuel-fired EGUs) in each participating state to meet the state's applicable mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement).

During plan implementation, the EPA would assess whether the affected EGUs in a state achieved the state's mass-based CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) as follows. Reported CO_2 emissions from affected EGUs under such plans must be at or below a state's mass-based CO_2 emission goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an identified plan performance period, with the following state accounting adjustments for net "import" and net "export" of CO_2 allowances:

- *Net "imports" of CO_2 allowances:* Reported CO_2 emissions from affected EGUs in a state may exceed the state CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) during an

[931] Section VIII.J.2.a describes how state plan submittals must include as requirements, or describe as part of supporting documentation, relevant aspects of such emission budget trading programs.

identified plan performance period in the amount of an adjustment for the net "imported" CO_2 allowances during the plan performance period. The adjustment represents the CO_2 emissions (in tons) equal to the number of net "imported" CO_2 allowances. 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 applicable new fossil fuel-fired EGUs). Net "imports" of allowances are determined through review of tracking system compliance accounts.

- *Net "exports" of CO_2 allowances:* Reported CO_2 emissions from affected EGUs in a state during an identified plan performance period must be equal to or less than the CO_2 mass goal (or mass-based CO_2 goal plus new source CO_2 emission complement) minus an adjustment for the "exported" CO_2 allowances during the plan performance period. The adjustment represents CO_2 emissions (in tons) equal to the number of net "exported" CO_2 allowances. Net "exports" of allowances are determined through review of tracking system compliance accounts.

Where CO_2 emissions from affected EGUs exceed these levels (based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowance "imports" or "exports") over the 8-year interim period or during any final plan reporting period, or by 10 percent or more during the interim step 1 or step 2 periods, a state would be considered to, in the case of the interim and final periods, not have met its CO_2 mass goal during an identified plan performance period, and in the case of the interim step periods, to not be on course to meet the final goal. As a result, under a state measures state plan, implementation of the backstop federally enforceable emission standards for affected EGUs in the state plan would be triggered.

A net transfer of CO_2 allowances during a plan performance period represents the net number of CO_2 allowances (issued by a respective state) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another state.[932] This net transfer is determined based on compliance account holdings at the end of the plan performance period.[933] For example, assume two states, State A and State B, with emission budgets of 1,000 tons of CO_2. Each state issues 1,000 CO_2 allowances. At the end of a plan performance

---

[932] A net transfer metric is applied as of the end of the plan performance period. This net accounting as of a specified date is necessary because multiple individual allowance transfers may occur among accounts during a plan performance period, representing normal trading activity. In addition, net transfers are based on compliance account holdings, because these represent the CO_2 allowances directly available at that point in time for use by an affected EGU for complying with its emission limit. Emission budget trading programs typically allow non-affected entities to hold allowances in general accounts. These parties are free to hold and trade CO_2 allowances, providing market liquidity. General account holdings are not assessed as part of a periodic state net transfer accounting, as these allowances may subsequently be transferred to other accounts in multiple states and do not represent allowances currently held by an affected EGU that can be used for complying with its emission limit.

[933] 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.

period, affected EGUs in State A collectively hold 500 CO_2 allowances in their compliance accounts that were issued by State A. Affected EGUs in State B collectively hold in their compliance accounts 500 CO_2 allowances issued by State A and 1,000 CO_2 allowances issued by State B. In this simplified example, a net transfer of 500 CO_2 allowances has occurred between State A and State B. State A has "exported" 500 CO_2 allowances to State B, while State B has "imported" 500 CO_2 allowances from state A.

K. Additional Considerations and Requirements for Rate-Based State Plans

This section discusses considerations and requirements for rate-based state plans. This section discusses eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. These measures may be used to adjust the CO_2 emission rate of an affected EGU under a rate-based state plan. This adjustment may occur when an affected EGU is demonstrating compliance with a rate-based emission standard, or when a state is demonstrating achievement of the CO_2 emission performance rates or applicable rate-based state CO_2 emission goal in the emission guidelines. This section also discusses requirements for state plans that include rate-based emission trading programs, including approaches and requirements for coordination among such programs where states retain individual state rate-based CO_2 emission goals.

1. Adjustments to CO_2 Emission Rates in Rate-Based State Plans

Section VIII.K.1.a below describes the basic accounting method for adjusting a CO_2 emission rate, as well as eligibility requirements for measures that may be used for adjusting a CO_2 emission rate. Section VIII.K.1.b addresses measures that may not be used to adjust the CO_2 emission rate of an affected EGU in a state plan, and explains the basis for this exclusion. Section VIII.K.1.c addresses measures that reduce CO_2 emissions outside the electric power sector. Such measures may not be counted under either a rate-based or mass-based state plan.

a. *Measures taken to adjust the CO_2 emission rate of an affected EGU.* This section describes how measures that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU. This section discusses the required accounting method for adjusting a CO_2 emission rate, as well as general eligibility requirements that apply to different categories of measures that may be used to adjust a CO_2 emission rate. Where relevant, this section also discusses additional specific accounting methods and other relevant requirements that apply to different categories of measures.

A CO_2 emission rate adjustment may be applied in different rate-based state plan contexts. For example, in a rate-based emission trading program, adjustments may be applied through the use of

ERCs.[934] Regardless of the type of plan in which an adjustment is applied, the same basic accounting and general eligibility requirements described in this section will apply.

As discussed in this section, a wide range of actions may be taken to adjust the reported CO_2 emission rate of an affected EGU in order to meet a rate-based emission standard and/or demonstrate achievement of a state CO_2 rate-based emissions goal. All of the measures described in this section will substitute for generation from affected EGUs or avoid the need for generation from affected EGUs, thereby reducing CO_2 emissions. This includes incremental NGCC and RE measures included in the EPA's determination of the BSER, as well as other measures that were not included in the determination of the BSER, such as other RE resources, demand-side EE, CHP, WHP, electricity transmission and distribution improvements, nuclear energy, and international RE imports connected to the grid in the contiguous U.S., as discussed elsewhere in this preamble.

The EPA believes that the broad categories of measures listed in this section address the wide range of actions that are available to reduce CO_2 emissions from affected EGUs under a rate-based state plan. However, the actions that a state could include in a rate-based state plan are not necessarily limited to

[934] ERCs may be issued for the measures presented in this section, as well as to affected EGUs that emit at a CO_2 emission rate below their assigned emission rate limit. ERC issuance and trading is discussed in detail in section VIII.K.2. That section addresses the accounting method for ERC issuance to affected EGUs that perform below their assigned CO_2 emission rate.

those described in this section. Other specific actions not listed here may be incorporated in a state plan, provided they meet the general eligibility requirements listed in this section, as well as the other relevant requirements in the emission guidelines.[935] Nor are states required to include in their plans all of the actions that are described in this section.

This section discusses the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, through the use of measures that substitute for or avoid generation from affected EGUs. That method is based on adding MWh from such measures to the denominator of an affected EGU's reported CO_2 emission rate (lb CO_2/MWh). Those additional MWh are based on quantified and verified electricity generation or electricity savings from eligible measures, and in the case of an affected EGU's compliance with its emission standard, are reflected in ERCs. This section also addresses eligibility requirements for resources that are used to adjust an affected EGU's CO_2 emission rate.

(1) *General accounting approach for adjusting a CO_2 emission rate.*

In this final rule, the reported CO_2 emission rate of an affected EGU may be adjusted based on quantified and verified MWh from qualifying zero-emitting and low-emitting resources, as described in sections VIII.K.1.a.(2)–(10) below. These MWh are added to the denominator of an affected EGU's reported CO_2

[935] These requirements are discussed in section VIII.D.

emission rate, resulting in a lower adjusted CO_2 emission rate.

The measures described in these sections reduce mass CO_2 emissions from affected EGUs by substituting zero- or low-emitting generation for generation from affected EGUs, or by avoiding the need for generation altogether (in the case of resources that lower electricity demand through improved demand-side EE and DSM). In both of these cases, generation from an affected EGU is replaced, through substitute generation or a reduction in electricity demand. To the extent that qualifying zero-emitting and low-emitting resources result in reduced generation and CO_2 emissions from an individual affected EGU, those emission impacts are reflected in lower reported CO_2 emissions and a reduction in MWh generation from the affected EGU. However, while there will be a reduction in CO_2 emissions at the affected EGU, the fact that both CO_2 emissions and MWh generation are reduced means that such impacts do not alter the reported CO_2 emission rate of the affected EGU. As a result, the MWh of replacement generation must be added to the denominator of the reported CO_2 emission rate in order to represent those impacts in the form of an adjusted CO_2 emission rate. In this manner, adding MWh from these resources to the denominator of an affected EGU's CO_2 emission rate allows mass CO_2 emission reductions from these measures to be fully reflected in an adjusted CO_2 emission rate.

The following provides a simple calculation example of how MWh of replacement generation added to the denominator of an affected EGU's reported CO_2 emission rate results in a lower adjusted CO_2 emission rate. Assume an affected EGU with CO_2 emissions of 200,000 lb and electric generation of 100 MWh during a reporting period. The affected EGU's reported CO_2 emission rate is 2,000 lb/MWh (200,000 lb CO_2/100 MWh = 2,000 lb/MWh). When complying with its rate-based emission limit, the affected EGU submits 10 ERCs, representing 10 MWh of replacement generation.[936] Adding 10 MWh of replacement generation to the reported MWh generation of the affected EGU results in an adjusted CO_2 emission rate of 1,818 lb CO_2/MWh (200,000 lb CO_2/110 MWh = 1,818 lb CO_2/MWh).

In the case of rate-based CO_2 emission standards, an affected EGU demonstrates compliance with the emission standards if the affected EGU's adjusted CO_2 emission rate calculated in the aforementioned manner is less than or equal to the applicable CO_2 emission standard rate.[937] The CO_2 emission performance rates or rate-based CO_2 goal in the emission guidelines are met if the adjusted CO_2 emission rate of affected EGUs in a state is at or below the specified CO_2 emission rate in a state plan that applies for an identified plan performance period.

Numerous commenters requested that the EPA ensure consistency between goal-setting calculations and the methodology used to demonstrate achievement of a CO_2 emission rate under a state plan. This approach for adjusting a CO_2 emission rate

---

[936] Requirements for the issuance of ERCs and a further discussion of how ERCs are used in compliance with rate-based emission limits are addressed in section VIII.K.2.

[937] Any ERCs used to adjust a CO_2 emission rate must meet requirements in the emission guidelines.

corresponds with how RE, one of the components of the BSER that involves adjustment of a CO_2 emission rate, is represented in the CO_2 emission performance rates in the emission guidelines. Specifically, in the calculation of final CO_2 emission performance rates, the MWhs of RE are reflected in two adjustments of the rate: A reduction of CO_2 emissions from affected EGUs in the numerator and a one-to-one replacement of affected EGU generation in the denominator, where it is assumed that replaced generation from an affected EGU is subtracted from the denominator and the same number of zero-emitting MWh are added.[938]

When demonstrating achievement of a CO_2 emission performance rate, the reported CO_2 emissions already reflect the actual emission reductions from the deployment of qualifying zero-emitting and low-emitting resources across the regional grid; a further adjustment of CO_2 emissions would double count CO_2 emissions impacts across the grid. Consistent with the EPA's calculation of the CO_2 emission performance rates and state rate-based CO_2 goals in the emission guidelines, the zero-emitting MWhs (from substitute generation or a reduction in electricity demand) must still be added to the denominator of a reported CO_2 emission rate to calculate an adjusted CO_2 emission rate that appropriately reflects the replaced generation. Thus, the resultant rate, where the numerator reflects CO_2 emission reductions from qualifying measures, and the denominator reflects replaced generation, is consistent with the goal-setting calculation.

---

[938] For a detailed discussion of this method, see Section VI.C.3. Form of the Performance Rates, in the Equation section.

Several commenters suggested that the EPA consider the regional nature of the electricity grid and how RE and demand-side EE impacts generation and CO_2 emissions across the grid when accounting for the impacts of RE and demand-side EE measures in a rate-based plan approach. This MWh accounting structure corresponds with the regional treatment of RE resources in the BSER that provide substitute generation in the EPA-calculated CO_2 emission performance rates in the emission guidelines. Consistent with assumptions used in calculating the CO_2 emission performance rates in the emission guidelines, affected EGUs and states can take full credit for the MWh resulting from eligible measures they are responsible for deploying, no matter where those measures are implemented. CO_2 emission reductions from the eligible measures may occur across the region; however, an affected EGU or a state may only take credit for avoided CO_2 emissions at that affected EGU or set of EGUs in question, as reflected in the reported stack CO_2 emissions of affected EGUs.

Because of the separate accounting of MWhs and CO_2 emissions, with emission impacts inherent in reported stack CO_2 emissions and zero-emitting MWh impacts requiring explicit adjustments, the accounting method corresponds with the use of MWh-denominated ERCs in the rate-based emission trading framework specified in this rule. The accounting method only requires a quantification of the MWh generated or avoided by an eligible measure, and thus credits or adjustments can be denominated in MWh and do not need to represent an approximation of the CO_2 emission reductions that result from those MWhs. This creates a crediting system or rate adjustment process that is simpler to implement than one that requires an approximation of avoided CO_2 emissions.

The MWh accounting method also creates a crediting system or rate adjustment process that is indifferent to the rate-based CO_2 emission goals of individual states, or the specific CO_2 emission rate standards that states may apply, and the relative stringency of those goals or standards. Use of ERCs in rate-based emission trading programs is addressed in detail in section VIII.K.2. As a result, the MWh accounting method addresses interstate effects, because it inherently accounts for how generation replacement and CO_2 emission reduction impacts may cross state borders. For example, if the accounting method was informed by avoided CO_2 emission rates, it could create perverse incentives for development of zero- or low-emitting resources in states that result in the greatest calculated estimate of CO_2 emission reductions for each replacement MWh. Instead, this accounting method is indifferent to avoided CO_2 emission rates and creates the same number of zero-emitting credits or adjustment for each MWh of energy generation or savings, wherever they occur. For a detailed discussion on how the accounting method addresses interstate effects, see section VIII.L.

(2) *General eligibility requirements for resources used to adjust a* CO_2 *emission rate.*

The EPA is finalizing certain general eligibility requirements for resources used to adjust a CO_2 emission rate. These requirements align eligibility with certain factors and assumptions used in establishing the BSER, and by extension, application of the BSER to the performance levels established for affected EGUs in the emission guidelines, as well as state rate and mass CO_2 goals. As a result, the requirements ensure that measures that may be used in a state plan are treated consistently (to the extent possible) with the EPA's assessment of the BSER.[939] These general requirements also address potential interactions among rate and mass plans, as discussed more fully in section VIII.L.

As discussed in the sections that follow, the general eligibility criteria address:

- The date from which eligible measures may be installed (*e.g.*, installation of RE generating capacity and installation of EE measures);
- the date from which MWh from eligible measures may be counted, and applied toward adjusting a CO_2 rate; and
- the need to demonstrate that eligible measures replace or avoid generation from affected EGUs.

(a) *Eligibility date for installation of RE/EE and other measures and MWh generation and savings.*

Incremental emission reduction measures, such as RE and demand-side EE, can be recognized as part of state plans, but only for the emission reductions they provide during a plan performance period. Specifically, this means that measures installed in any year after 2012 are considered eligible measures under this final rule, but only the quantified and verified MWh of

[939] For example, eligibility requirements include installation dates for eligible RE measures that may be used in a state plan. These dates generally align with the dates used for broadly defining incremental RE resources that were considered in establishing the BSER.

electricity generation or electricity savings that they produce in 2022 and future years may be applied toward adjusting a CO_2 emission rate. For example, MWh generation in 2022 from a wind turbine installed in 2013 may be applied toward adjusting a CO_2 emission rate. This 2012 date applies to all eligible measures that are used to adjust a CO_2 emission rate under a state plan. For example, eligible measures, such as CHP, nuclear power and DSM, also must be installed after 2012, but only their generation or savings produced in 2022 and after can be used to adjust a CO_2 emission rate.

As discussed in section VIII.C.2.a, a MWh of generation or savings that occurs in 2022 or a subsequent year may be carried forward (or "banked") and applied in a future year. For example, a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years, without limitation.[940] These MWh may be banked from the interim to final periods.

This eligibility date criterion is consistent with the date of installation for "incremental" RE capacity that is included in the BSER building block 3, which is the basis for RE MWh incorporated in the CO_2 emission performance rates for affected EGUs in the emission guidelines. For more information on RE in the BSER, see section V.E.

Many commenters asserted that proposed state goals did not sufficiently account for actions states take that reduce CO_2 emissions prior to the first plan

---

[940] Similarly, as discussed in section VIII.C.2.b.(2).(a), allowances may be banked in a mass-based trading program.

performance period, and therefore requested that MWhs of electricity generation or electricity savings that occur prior to the first plan performance period be eligible to apply toward adjusting the CO_2 emission rates of affected EGUs. The EPA recognizes the importance of early state action as the basis for significant CO_2 emission reductions and as a key part of enabling state plans to achieve the CO_2 emission performance levels or state CO_2 goals. The ability to count eligible measures installed in 2013 and subsequent years for the MWhs they generate during a plan performance period provides significant recognition for early action, corresponding with the BSER framework that is based on cost-effective actions that many sources are already doing, while still conforming to CO_2 performance rates and state goals that are forward-looking. In order to provide additional incentives for early investment in RE and demand-side EE, the EPA is also establishing the CEIP, as discussed in section VIII.B.2. ERCs distributed by states and the EPA through this program may also be used by affected EGUs to demonstrate compliance with an emission standard, and may be banked from the interim to final periods.

Commenters' concerns about treatment of early actions are further addressed by changes from proposal to the BSER assumptions and the methodology used by the EPA to establish the CO_2 emission performance levels and rate-based state CO_2 goals in the emission guidelines. The specifics of these changes are addressed in section V.A.3. Three examples of those changes are provided below.

First, affected EGUs that have maximized their CO_2 emission reduction opportunities available through early action will be better positioned to meet the BSER CO_2 emission performance rates or state goal applied to affected EGUs in their state. For example, a steam generating unit that has already reduced its CO_2 emission rate through a heat rate improvement may have a CO_2 emission rate of 2,000 lb/MWh whereas its rate was 2,100 lb/MWh prior to the improvement. Therefore, it has less distance to cover to meet its CO_2 emission performance rate.

Second, generation from existing RE capacity installed prior to 2013 has been excluded from the EPA's calculation of the CO_2 emission performances rates in the emission guidelines. That RE generating capacity will still provide zero-emitting generation to the grid meeting demand that will not need to be addressed by existing affected EGUs and will better position states and affected EGUs to meet the CO_2 performances rates or state rate- or mass-based CO_2 goals.

Third, commenters expressed concern that demand-side EE targets as part of proposed state goals reflected an assumption of installation of increased EE measures starting in 2017, which seemed to be an implicit requirement to take action prior to the performance period. Because demand-side EE is not used in calculating the CO_2 emission performance rates in the final emission guidelines, this is no longer a concern. Furthermore, eligible demand-side EE actions that occur after 2012 can be applied toward adjusting the CO_2 emission rates of affected EGUs, providing a significant compliance option that is not assumed in emission performance rates or state goals.

(b) *Demonstration that measures substitute for grid generation.*

Eligible measures must be grid-connected. This eligibility criterion aligns incremental NGCC generation in building block 2. It also aligns with RE generation in building block 3 of the BSER, which substitutes for the need for generation from affected EGUs.

All EE measures must result in electricity savings at a building, facility, or other end-use location that is connected to the electricity grid. EE measures only avoid electric generation from grid-connected EGUs if the electrical loads where the efficiency improvements are made are interconnected to the grid.

Commenters sought clarity on this issue, so the EPA is providing this requirement as part of the final rule. Some commenters advocated for the inclusion of measures that were not grid connected as eligible resources, arguing that some of these measures substituted for non-affected EGUs and resulted in reductions in CO_2 emissions. However, eligible measures must be able to substitute for generation from affected EGUs as defined under this rule, and thus must be tied to the electrical grid.

(c) *Geographic eligibility.*

All eligible emission reduction measures, including RE generation and demand-side EE, may occur in any state, with certain limitations, as described below. To the extent these measures are tied to a state plan,[941] these measures may be used to adjust a CO_2

---

[941] As used here, a measure is "tied to a state plan" if it is issued an ERC under approved procedures in a rate-based

emission rate, regardless of whether the associated generation or electricity savings occur inside or outside the state.[942] This approach is generally consistent with the approach used in building block 3 of the BSER, which reflects regionally available RE. It also recognizes that emission reduction measures have impacts on electricity generation across the electricity system, both within and beyond a state's borders. A more in-depth discussion of the basis for treatment of in-state and out-of-state measures is provided in section VIII.L.

State plans must demonstrate that emission standards and state measures (if applicable) are non-duplicative. Given the geographic eligibility approach described here, this includes a demonstration that a state plan does not allow recognition of a MWh, for use in adjusting the CO_2 emission rate of an affected EGU, if the MWh is being or has been used for such a purpose under another state plan. Discussion of how such a demonstration can be made in the context of a rate-based emission trading program is in section VIII.D.2.b.

emission standards plan or represents quantified and verified MWh energy generation or energy savings achieved by an approved state measure in a state measures plan.

[942] For example, under a rate-based emission standard with credit trading, ERCs may be issued for qualifying actions that occur both inside and outside the state, provided the measures meet requirements of EPA-approved state regulations and the provider applies to the state for the issuance of ERCs. Similarly, under a state measures plan, a state might include state requirements such as an RPS, where compliance with the RPS can be met through out-of-state RE generation.

The EPA received many comments on the treatment of in-state and out-of-state RE and demand-side EE. Most commenters recommended crediting of both in-state and out-of-state RE and demand-side EE measures, similar to the final rule approach for eligible emission reductions measures. Commenters argued that this approach makes sense based on the nature of the interconnected electricity grid and allows states and utilities to fully account for their RE and demand-side EE efforts, whether that RE or EE, and its related impacts, occurs inside or outside of their state. Some commenters expressed concerns that, at proposal, states with significant RE resources had large amounts of existing RE capacity included in their state CO_2 goals, but that RE was functionally credited to other states for use in meeting their goals because it was associated with measures (such as an RPS) likely to be included in another state's plan. This concern has been addressed through changes in the BSER RE assumptions in the final rule. This includes regionalization of the RE building block, and removal of existing RE capacity constructed prior to 2012 from the building block. The result of these changes is that the RE incorporated in the BSER is more equally shared across states.

(i) *Measures that occur in states with mass-based plans.*

As discussed above, eligible measures for adjusting the CO_2 emission rate of an affected EGU may occur in any state, with certain conditions. This includes a condition that applies to eligible measures that occur in a state with an EPA-approved plan that is meeting a state mass-based CO_2 goal. Eligible measures that could be used to adjust a CO_2 emission rate under a rate-based state plan which are located in a state with a mass-based plan are restricted from being counted under another state's rate-based plan. An exception is made for RE measures that occur in such mass-based states, because of its unique role in BSER. RE measures must meet additional eligibility criteria in order to be used to adjust the CO_2 emission rate of an affected EGU in a state with a rate-based plan. This exception only applies to RE; other emission reduction measures that were not included in the determination of the BSER located in mass-based states, including demand-side EE, are restricted from ERC issuance in rate-based states.

These criteria are intended to address the fact that eligible measures should lead to substitution of generation from affected EGUs, with related impacts on CO_2 emissions from affected EGUs. Where states with mass-based plans implement mass-based CO_2 emission standards, CO_2 emissions reductions from affected EGUs must occur in order to comply with these emission standards and, unlike the rate-based approach, zero- and low-emitting MWhs do not play a specified role in demonstrating that the mass-based standards have been met.[943] Since they are not counted in the mass-based demonstration, eligible measures located in mass-based states could be used in a state with a rate-based plan to adjust the CO_2 emission rate of affected EGUs. Such adjustments would obviate the need for comparable CO_2 emission

---

[943] Where such measures substitute for generation from affected EGUs subject to a mass CO_2 emission limit, such measures reduce the cost of meeting those mass emission limits, but do not result in incremental CO_2 emission reductions.

reductions at affected EGUs in the rate-based state or the use of other measures to make a rate adjustment. In this scenario, to the extent that eligible measures substitute solely for generation from affected EGUs in a state with mass-based emission limits, and are also used to adjust the reported CO_2 emission rate of affected EGUs in a rate-based state, no incremental CO_2 emissions reductions would occur in the rate-based state as a result of the eligible measures.[944] The result would be forgone CO_2 emission reductions that would otherwise occur across the two states. These dynamics are further addressed in section VIII.L.

For RE measures located in a mass-based state to have some or all of its generation counted under a rate-based plan in another state, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[945] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

Under an emission standards plan, this demonstration must be made by the provider of the RE

[944] As used here, incremental emission reductions refers to emission reductions that are above and beyond what would be achieved solely through compliance with the emission standards in the mass-based state.

[945] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

measure seeking ERC issuance under the rate-based emission standards in a rate-based state, as part of the eligibility application for the measure.[946] The rate-based state must include in its state plan provisions that describe a sufficient demonstration of geographic eligibility for the RE generation under rate-based emission standards.

Further examples of eligible demonstrations and how they should be outlined in state plans are provided in section VIII.L.

(ii) *Measures that occur in states, including areas of Indian country, that do not have affected EGUs.*

States, including areas of Indian country, that do not have any affected EGUs within their borders may be providers of credits for generation from zero- or low-emitting resources to adjust CO_2 emission rates. In its supplemental proposal for the proposed rulemaking, the EPA sought comment on whether or not jurisdictions without affected fossil fuel generation units subject to the proposed emission guidelines should be authorized to participate in state plans. Commenters were supportive of allowing those jurisdictions without affected EGUs the opportunity to participate in state plans. CO_2 reduction measures in areas without affected EGUs have the potential to provide cost-effective opportunities to reduce emissions and should be available on a voluntary basis to affected EGUs. Commenters noted that some tribes, for example, have many untapped RE resources that could be developed, and they should be able to realize

---

[946] Requirements for ERC issuance are addressed in section VIII.K.2.

the benefits of contributing to a state plan. Commenters stated that because of the integrated nature of the U.S. electricity grid, it is appropriate to allow all jurisdictions with the ability to contribute to and benefit from CO_2 emission reductions or CO_2 emission rate adjustments.

For participating states, they must adhere to EM&V standards, installation dates, and any other criteria that apply to all states. Section VIII.K.3 below identifies and discusses the EM&V requirements used to quantify MWh savings from generation from zero- or low-emitting sources.

States, including areas of Indian country, that do not have any affected EGUs 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. To qualify for ERCs from zero or low-emitting resources, it must be demonstrated that the generation was delivered to the grid to meet electricity load in a state with a rate-based plan.[947] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must describe the nature of the required demonstration and have it be approved by the EPA.

In addition to generation from zero- or low-emitting resources, demand-side EE resources in areas of Indian country located within the borders of states

---

[947] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

with rate-based emission standards for affected EGUs may also be issued ERCs. In these instances, the area of Indian country is located within the rate-based service area subject to a rate-based state plan. The ERCs from demand-side EE resources must meet the eligibility requirements to adjust a CO_2 emission rate, including installation date and EM&V requirements described below in section VIII.K.3. If the area of Indian country is located within the borders of a state that is meeting a mass-based CO_2 goal, then the demand-side EE resources are not eligible to be issued ERCs. Similarly, demand-side EE resources in any state with a mass-based CO_2 goal are not eligible to provide ERCs.

Non-contiguous states and territories may not be providers of ERCs to the contiguous U.S. states. As discussed previously in section VII.F, we have not set CO_2 emission performance goals for Alaska, Hawaii, Guam, or Puerto Rico in this final rule at this time.

(iii) *Measures that occur outside the U.S.*

The EPA will work with states using the rate-based approach that are interested in allowing the use of RE from outside the U.S. to adjust CO_2 emission rates. In these cases, all conditions for creditable domestic RE must be met, including that RE resources must be incremental and installed after 2012, and all EM&V standards must be met. In addition, the country generating the ERCs must be connected to the U.S. grid, and there must be a power purchase agreement or other contract for delivery of the power with an entity in the U.S. RE generation capacity outside the U.S. that existed prior to 2012 but was not exported to the U.S. is not considered new or incremental generation and, therefore, not eligible for adjusting CO_2 emission rates under this rule. For example, a new transmission interconnection to existing RE in Canada would not be considered incremental, but a new interconnection to RE where the RE was built after 2012 would be considered incremental. See below in section VIII.K.1.a.(3) for more specifics regarding the use of incremental hydroelectric power in a rate-based approach.

The EPA received comments encouraging the use of international zero-emitting electricity imports in state plans, particularly hydroelectric power from Canada. Canada currently provides states such as Minnesota and Wisconsin with RE through existing grid connections. New projects are in various stages of development to increase generating capacity, which could be called upon as a base load resource to supplement variable forms of RE generation. Commenters said that the EPA should permit the use of all incremental hydropower—both domestic and international—towards EGU CO_2 emission rate adjustments providing that double-counting can be prevented; and the EPA acknowledges this may be allowable, as long as the specified criteria have been met.

(3) *RE.*

RE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity generation is properly quantified and verified.[948] As

---

[948] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and

used in this section, RE includes electric generating technologies using RE resources, such as wind, solar, geothermal, hydropower, biomass and wave and tidal power. A capacity uprate at an existing RE facility (*i.e.*, an uprate to generating capacity originally installed as of 2012 or earlier) is eligible to adjust a CO_2 emission rate. The capacity uprate must occur after 2012. Such uprates to capacity represent incremental capacity added after 2012.

Quantification and accounting criteria for incremental RE (and nuclear generation) are as follows. The incremental generating capacity (in nameplate MW) is divided by the total uprated generating capacity (in nameplate MW) and then multiplied by generation output (in MWh) from the uprated generator. For example, if a hydroelectric power plant expands generating nameplate capacity from 100 MW to 125 MW and generation output increased to 1,000 MWh, then 200 MWh ((25 MW/125 MW) * 1,000 MWh) is eligible for use in adjusting a CO_2 emission rate, regardless of the overall level of generation for the period.[949]

Many commenters supported using RE deployment as measures to adjust the CO_2 emission rate of affected EGUs. Some commenters specifically agreed with the EPA's determination that only new and incremental RE (including hydropower) should be used to adjust CO_2 emission rates. Those commenters objected to

---

section VIII.K.3 for discussion of EM&V requirements for use of RE relied on in a state plan.

[949] For example, the overall generation from the uprated hydroelectric power plant may be higher or lower than generation levels that occurred at the plant prior to the capacity uprate.

counting existing RE that are already embedded in the baseline emissions and generation mix. A significant number of commenters supported the integration of RE into a rate-based credit trading system.

Certain additional requirements apply for hydropower and biomass (including waste-to-energy) RE, as described below.

(a) *Hydroelectric power.*

Consistent with other types of RE, new hydroelectric power generating capacity installed after 2012 is eligible for use in adjusting a CO_2 emission rate.

Relicensed facilities are considered existing capacity and, therefore, are not eligible for use in adjusting a CO_2 emission rate, unless there is a capacity uprate as part of the relicensed permit. In such a case, only the incremental capacity is eligible for use in adjusting a CO_2 emission rate.

The EPA noted that many commenters preferred that generation from hydropower displace generation from fossil sources. One commenter suggested that existing zero-emitting sources, including hydropower, do not reduce emissions from existing fossil generation, but that new or uprated zero-emitting sources would, because of their low variable rate, reduce fossil emissions. Several commenters recommended allowing incremental generation from new or uprated zero-emitting sources, including hydropower, be available for compliance.

(b) *Biomass.*

RE generating capacity installed after 2012 that uses qualified biomass as a fuel source is eligible for use in adjusting a CO_2 emission rate.[950] As discussed in section VIII.I.2.c., if a state intends to allow for the use of biomass as a compliance option for an affected EGU to meet a CO_2 emission standard, a state must propose qualified biomass feedstocks and treatment of biogenic CO_2 emissions in its plan, along with supporting analysis and quality control measures, and the EPA will review the appropriateness and basis for such determinations in the course of its review of a state plan. Where an RE generating unit uses qualified biomass, as designated in an approved state plan, MWh generation from the unit could be used to adjust the reported CO_2 emission rate of an affected EGU. Total MWh generation from an RE generating unit that uses qualified biomass must be prorated based on either the heat input supplied from qualified biomass as a proportion of total heat input or on the proportion of biogenic CO_2 emissions compared to total stack CO_2 emissions from the RE generating unit. Either approach must incorporate the approved valuation of biogenic CO_2 emissions from qualified biomass in the plan (*i.e.*, the proportion of biogenic CO_2 emissions from use of qualified biomass feedstock that would not be counted).

Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively

---

[950] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

approvable EM&V approaches that are included in the final model trading rule.

(c) *Waste-to-energy.*

Qualified biomass may include the biogenic portion of MSW combusted in a waste-to-energy facility.[951] With regard to assessing qualified biomass proposed in state plans, the EPA generally acknowledges the CO_2 emissions and climate policy benefits of waste-derived biomass, which includes biogenic MSW inputs to waste-to-energy facilities. The process and considerations for the use of biomass in state plans are discussed in section VIII.I.2.c.

MSW can be directly combusted in waste-to-energy facilities to generate electricity as an alternative to landfill disposal. In the U.S., almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where the waste is combusted and energy is recovered.[952] Total MSW generation in 2012 was 251 million tons, but of that total volume generated, almost 87 million tons were recycled and composted.[953] Increasing demand for electricity generated from waste-to-energy facilities could increase competition for and generation of waste stream materials—including discarded organic waste materials—which could work against programs promoting waste reduction or cause diversion of these

[951] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.

[952] 2014 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[953] *http://www.epa.gov/osw/nonhaz/municipal/pubs/2012_msw_fs.pdf.*

materials from existing or future efforts promoting composting and recycling. The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste prevention, starting with waste reduction programs as the highest priority and then focusing on all other productive uses of waste materials to reduce the volume of disposed waste materials.[954] For example, Oregon and Vermont have strategies that emphasize waste prevention, followed by reuse, then recycling and composting materials prior to treatment and disposal.[955]

Information in the revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* and other technical studies and tools (*e.g.*, EPA Waste Reduction Model, EPA Decision Support Tool) should assist both states and the EPA in assessing the role of biogenic feedstocks used in waste-to-energy processes, where use of such feedstocks is included in a state plan.[956]

When developing their plans, states planning to use waste-to-energy as an option for the adjustment of a CO_2 emission rate should assess both their 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.

---

[954] *http://www.epa.gov/wastes/nonhaz/municipal/hierarchy.htm.*

[955] *http://www.anr.state.vt.us/dec/wastediv/WastePrevention/main.htm.*

[956] *http://epa.gov/epawaste/conserve/tools/warm/Warm_Form.html, https://mswdst.rti.org/.*

States must include that information in their plan submissions. The EPA will reject as qualified biomass any proposed waste-to-energy component of state plans if states do not include information on their efforts to strengthen existing or implement new waste reduction as well as reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Only electric generation at a waste-to-energy facility that is related to the biogenic fraction of MSW and that is added after 2012 is eligible for use in adjusting a CO_2 emission rate.

A state 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. The EPA will evaluate the method as part of its evaluation of the approvability of the state plan. Measuring the proportion of biogenic to fossil CO_2 emissions can be performed through sampling and testing of the biogenic fraction of the MSW used as fuel at a waste-to-energy facility (*e.g.*, via ASTM D-6866-12 testing or other methods—ASTM, 2012; Bohar, et al. 2010), or based on the proportion of biogenic CO_2 emissions to total CO_2 emissions from the facility. For an example of the former method, if the biogenic fraction of MSW is 50 percent by input weight, only the proportion of MWh output attributable to the biogenic portion of MSW at the waste-to-energy facility may be used to adjust an affected EGU CO_2 emission rate. Alternatively, as an example of the latter method, if biogenic CO_2 emissions represent 50 percent of total reported CO_2 emissions, a facility would need to estimate the fraction of biogenic to fossil MSW utilized and the net energy output of each component (based on relative higher heating values) to determine the percent of the MWh output from the waste-to-energy facility that may be used to adjust an affected EGU's CO_2 emission rate. Section VIII.K describes the requirements and procedures for EM&V, and discusses how all eligible resources must demonstrate how they will quantify and verify MWh savings using best-practice EM&V approaches. One way to make this demonstration for eligible resources could be to use the presumptively approvable EM&V approaches that are included in the final model trading rule.

The EPA received multiple comments supporting the use of waste-to-energy as part of state plans. Some commenters expressed concern that non-biogenic materials, such as plastics and metal, would be incinerated along with biogenic materials. As discussed above, only electric generation related to the biogenic fraction of MSW at a waste-to-energy facility added after 2012 is eligible for use in adjusting a CO_2 emission rate. The EPA also received comments that expressed concern about the potential negative impacts on recycling and waste reduction efforts, while other commenters asserted that waste-to-energy practices encourage recycling programs. Some commenters also expressed concern about what treatment would be approvable for emissions from waste-to-energy practices. As discussed above, potential negative impacts from waste-to-energy production on recycling, waste reduction, and composting programs should be evaluated and efforts to mitigate negative impacts must be discussed in the supporting documentation of state plans.

(4) *DSM.*

Avoided MWh that result from DSM may be used to adjust a CO_2 emission rate. Eligible DSM actions are those that are zero-emitting and avoid, rather than shift, the use of electricity by an electricity end-user.[957] The MWh that may be used for such an adjustment are determined based on the MW of demand reduction multiplied by the hours during which such a demand reduction is achieved (MW of demand reduction × hours = MWh avoided). DSM measures must be appropriately quantified and verified, in accordance with requirements in the emission guidelines, as discussed in section VIII.K.3.

(5) *Energy storage.*

Energy storage may not be directly recognized as an eligible measure that can be used to adjust a CO_2 emission rate, because storage does not directly substitute for electric generation from the grid or avoid electricity use from the grid.[958] The electric generation that is input to an energy storage unit may be used to adjust a CO_2 emission rate, but the output

---

[957] An example is a utility direct load control program, such as those where customer air conditioning units are cycled during periods of peak electricity demand. Actions that shift electricity demand from one time of day to another, without reducing net electricity use, are not eligible, as these measures do not avoid electricity use from the grid. Use of emitting generators as a DSM measure is also not eligible.

[958] Energy storage depends on a generation source, either from a utility-scale EGU (*e.g.*, a fossil EGU, a wind turbine, etc.) or a distributed generation source at an electricity end-user (*e.g.*, a PV system installed at a building).

from the energy storage unit may not.[959] However, energy storage can be used as an enabling measure that facilitates greater use of RE, which can be used to adjust a CO_2 emission rate. For example, utility scale energy storage may be used to facilitate greater grid penetration of RE generating capacity and can also be used to store RE generation that may have otherwise been shed in times of excess generating capacity. Likewise, on-site energy storage at an electricity end-user can enable greater use of RE to meet on-site electricity demand.[960]

The EPA received multiple comments regarding the overall merits of energy storage. Consistent with the discussion above, the majority of commenters observed that storage technology enables greater grid penetration of RE and supports more efficient and effective operations of both RE and fossil-fuel plants. Commenters further noted that energy storage can provide RE to the grid when it is most needed, while simultaneously taking pressure off fossil-fuel plants to respond to sudden shifts in demand. Despite broad acknowledgment of the benefits of storage, public comments underscore its indirect and supporting role in providing zero-emission MWh to the grid

---

[959] This approach focuses on counting the qualifying electric generation, which may be an input to an energy storage unit. Counting both the generation input to energy storage and the output from the energy storage unit would be a form of double counting. The electric generation that is stored may be counted; the subsequent output from the storage unit may not.

[960] For example, battery storage at a building with solar PV can enable the PV system to meet the building's entire electrical load, by storing energy during times of peak PV system output for later use when the sun is not shining.

(consistent with the EPA's decision to exclude energy storage as an eligible measure that can be used to adjust a CO_2 emission rate).

(6) *Transmission and distribution (T&D) measures.*

Electricity T&D measures that improve the efficiency of the T&D system and/or reduce electricity use may be used to adjust a CO_2 emission rate. This includes T&D measures that reduce losses of electricity during delivery from a generator to an end-user (sometimes referred to as "line losses" [961]) and T&D measures that reduce electricity use at the end-user, such as conservation voltage reduction (CVR).[962] The EPA received many comments in support of advanced energy technologies, including energy

---

[961] T&D system losses (or "line losses") are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6 percent of the electricity that is transmitted and distributed in the U.S. each year.

[962] Volt/VAR optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss. VVO efforts are often closely related to CVR, which are actions taken to reduce initial delivered voltage levels in feeder transmission lines while remaining within the 114 volt to 126 volt range (for normal 120-volt service) required at the customer meter, per the ANSI C84.1 standards.

storage and transmission and distribution upgrades, and including these technologies in the suite of potential measures that states could consider for emission rate adjustments in their state plans. Comments pointed out that in addition to helping achieve emission standards, T&D efficiency improvements make the grid more robust and flexible, as well as delivering environmental benefits. In many parts of the country, grid operators, transmission planners, transmission owners and regulators are already taking steps to expand and modernize T&D networks. Commenters suggested that the EPA clarify the eligibility and criteria under which such measures would be permitted in a state plan.

To be eligible, T&D measures must be installed after 2012. This general eligibility requirement is discussed above in section VIII.K.1.a. The MWh of avoided losses or reduction in end-use that result from T&D measures must be appropriately quantified and verified, as discussed in section VIII.K.3.

(7) *Demand-side EE, including water system efficiency.*

Demand-side EE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity savings are properly quantified and verified.[963] As used in this section, demand-side EE may include a range of eligible measures, provided

[963] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.K.2 for discussion of requirements for the issuance of ERCs, and section VIII.K.3 for discussion of EM&V requirements for use of demand-side EE relied on in a state plan.

that the measures can be quantified and verified in accordance with the EM&V requirements in the emission guidelines, which are addressed in section VIII.K.3. Examples of demand-side EE measures include, but are not limited to, EE measures that reduce electricity use in residential and commercial buildings, industrial facilities, and other grid-connected equipment. Water efficiency programs that improve EE at water and wastewater treatment facilities also provide demand-side EE savings opportunities. EE measures, for the purposes of this section, may consist of EE measures installed as the result of individual EE projects, such as those implemented by energy service companies, as well as multiple EE measures installed through an EE deployment program (*e.g.* appliance replacement and recycling programs, and behavioral programs) administered by electric utilities, state entities, and other private and non-profit entities.[964] EE measures, for the purposes of this section, may also consist of state or local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards. Other interventions that result in electricity savings may also be considered an EE measure for the purposes of this section, provided the intervention can be specified and quantified and verified in accordance with EM&V requirements in the emission guidelines.

[964] EE programs may also be implemented by other entities. Eligible EE measures that are deployed through EE programs are not limited to those EE measures deployed through EE programs administered by the types of entities listed here.

Numerous commenters expressed support for including demand-side EE as an eligible measure states and affected EGUs can use to meet the emission guidelines. Commenters touted the value of demand-side EE as a resource that delivers energy savings, lowers bills, creates jobs and reduces CO_2 emissions. Commenters called for the EPA to allow for the use of a broad range of demand-side EE measures to meet the emission guidelines, including, but not limited to, utility and non-utility EE deployment programs; energy savings performance contracts; measures that reduce electricity use in residential and commercial buildings, industrial facilities and other grid-connected equipment; state and local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards; appliance replacement and recycling programs; and behavioral programs. The EPA also received comments supporting the use of water sector EE programs and projects. Commenters identified water and wastewater utilities as particularly well-suited for participating in EE programs and providing a source of electricity savings. Investments such as replacing pumps and other aging equipment and repairing leaks can result in greater EE. The EPA agrees that these electricity savings should be eligible for adjustments to CO_2 emission rates at affected EGUs.

(8) *Nuclear power.*

As is discussed in section V.A.3, upon consideration of comments received, the EPA has not included nuclear generation from either existing or under construction units in the determination of the BSER. In addition to comments received on the provisions for determining the BSER, the EPA also received comments requesting that the EPA allow all generation from nuclear generating units to be recognized as an eligible measure that can be used to adjust a CO_2 emission rate. Commenters also recommended that the EPA consider nuclear generating units and RE generating units in a consistent manner for CO_2 emission rate adjustments in state plans. We agree with comments that nuclear generation and RE should be treated consistently when it comes to CO_2 emission rate adjustments.

The EPA has determined that generation from new nuclear units and capacity uprates at existing nuclear units will be eligible for use in adjusting a CO_2 emission rate, just like new and uprated capacity RE. However, consistent with the reasons discussed for not including the preservation of existing nuclear capacity in the BSER—namely, that such preservation does not actually reduce existing levels of CO_2 emissions from affected EGUs—preserving generation from existing nuclear capacity is not eligible for use in adjusting a CO_2 emission rate.

In contrast, any incremental zero-emitting generation from new nuclear capacity would be expected to replace generation from affected EGUs and, thereby, reduce CO_2 emissions; and the continued commitment of the owner/operators to completion of the new units and improving the efficiency of existing units through uprates can play a key role in state plans. Therefore, consistent with treatment of other low- and zero-emitting generation, new nuclear power generating capacity installed after 2012 and incremental generation resulting from nuclear uprates after 2012 are measures eligible for adjusting a CO_2 emission rate. However, existing nuclear units (*i.e.*, those that originally commenced operation in 2012 or earlier years) that receive operating license extensions are not eligible for use in adjusting a CO_2 emission rate, except where such units receive a capacity uprate as a result of the relicensing process. Only the incremental capacity from the uprate is eligible for use to adjust a CO_2 emission rate.

Applicable generation (in MWh) from incremental nuclear power is determined in the same manner as that described for incremental RE above.

(9) *Combined heat and power (CHP) units.*

Electric generation from non-affected CHP units [965] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. Electrical generation from non-affected CHP units that meet the eligibility criteria under section VIII.K.1.a can be used to adjust the reported CO_2 emission rate of an affected EGU.

Where a state plan provides for the use of electrical generation from eligible non-affected CHP units to

---

[965] The accounting considerations described in this section are for a "topping cycle" CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/ or mechanical energy. A CHP unit can also be configured as a "bottoming cycle" unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some waste heat power (WHP) units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

adjust the reported CO_2 emission rate of an affected EGU, the state plan must provide a required calculation method for determining the MWh that may be used to adjust the CO_2 emission rate. This proposed accounting method must adequately address the considerations discussed below. The EPA will review whether a state's proposed accounting method for electric generation from eligible non-affected CHP units is approvable per the requirements of the final emission guidelines, as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method for non-affected CHP units. The accounting method provided in a final model rule could be a presumptively approvable accounting approach.

The proposed accounting method in a state plan must address the following considerations. The accounting approach proposed in a state plan must take into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. In accordance with these considerations, a non-affected CHP unit's electrical MWh output that can be used to adjust the reported CO_2 emission rate of an affected EGU should be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's "incremental CO_2 emission rate") compared to a reference CO_2 emission rate. This "incremental CO_2 emission rate" related to the electric generation from the CHP unit would be relative to the applicable CO_2 emission rate for affected EGUs in the state and would be limited to a value between 0 and 1.

This low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method proposed in a state plan should not presume that CO_2 emission reductions occur outside the electric power sector, but instead only would account for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

Non-affected CHP units can use qualified biomass fuels. As described in section VIII.I.2.c, states must submit state plan requirements regarding qualified biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis and quality control measures, and the EPA would review the appropriateness and basis for such determinations in the course of its review of the approvability of a state plan. Considerations for qualified biomass included in state plans are discussed in section VIII.I.2.c, while accounting requirements for RE using biomass are provided in section VIII.K.1.a.(3)(b).

Most comments received on CHP recommended that the EPA explicitly describe how CHP can be accounted for in a state plan. Commenters described the CO_2 emission reductions achieved through CHP's thermal efficiency and the precedent set in other federal and state rules that have included CHP as a compliance option. Some commenters pointed out that without such a description, states would not be able to readily take advantage of the CO_2 emission reductions that result from the use of CHP.

(10) *WHP*.

WHP units that meet the eligibility criteria under section VIII.K.1 may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity.[966] There are also WHP facilities where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP facilities could be considered zero-emitting, for the purposes of meeting the emission guidelines, and the

[966] In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.

MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[967] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.[968] Most commenters that addressed WHP noted the benefits of WHP at the same time that they discussed the benefits of CHP. The commenters reflected that WHP is another potential compliance option and requested it be discussed explicitly as a compliance option that can be used to meet the emission guidelines. The comments discussed WHP benefits but did not elaborate on a preferred accounting method for MWh of electrical generation from WHP that could be used to adjust the CO_2 emission rate of an affected EGU.

b. *Measures that may not be used to adjust a CO_2 emission rate.*

This section addresses measures that may not be used to adjust a CO_2 emission rate. New, modified, and reconstructed EGUs covered under the CAA section 111(b) final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule are not

[967] This only applies where no additional fossil fuel is used to supplement the use of waste heat in a WHP facility. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

[968] This limitation prevents oversizing the thermal output of a WHP unit to exceed the usefulindustrial or other thermal load it is meeting, prior to generation of electricity.

approvable sources of electric generation for adjusting the CO_2 emission rate of an affected EGU under a rate-based state plan. As discussed earlier in section VII.D of this preamble, a key concern under this rule is leakage to new units that are not covered by the emission guidelines. Emissions leakage, or increased CO_2 emissions due to increased utilization of unaffected sources, is contradictory to objectives of this rule and should, therefore, be minimized. Allowing affected EGUs to adjust their emission rates as a result of lower-emitting new NGCC units not covered under this section 111(d) rule would not mitigate leakage concerns, and could even exacerbate the situation. Consequently, new EGUs covered under the CAA section 111(b) rule are not allowable measures in state plans because the EPA believes it would result in increased emission leakage.

The EPA received comments both supporting and opposing the use of new NGCC units in state plans. In addition to leakage concerns, commenters expressed concern with the potential incentives created by including new NGCC capacity in the BSER or as a compliance mechanism in state plans. Some commenters suggested that including new NGCC capacity in the BSER or for compliance would distort market incentives to build new NGCC units, particularly if new units were allowed to generate ERCs that could be sold to affected EGUs. These commenters suggested that the additional incentive for new NGCC units could make existing NGCC units less competitive. Other commenters suggested that including new NGCC capacity in state plans would promote generation from new CO_2-emitting units at the expense of new zero-emitting units, increasing overall emissions within a state. This effect would be exacerbated if state plans allowed new NGCC units to be treated as "zero-emitting" for purposes of compliance—as suggested by other commenters. In addition, commenters expressed concern that the EPA's inclusion of new NGCC capacity in setting the BSER or in compliance could negatively impact ratepayers over the long-term by sending the wrong signal to industry and resulting in stranded assets if, in the future, carbon emissions become more expensive or the EPA proposes to incorporate sources built under the forthcoming section 111(b) standard into the section 111(d) program. Commenters also expressed concern that including generation from new NGCC units could create unreasonable uncertainty, given limitations on the ability to accurately project new NGCC builds, could create undue pressure on natural gas prices, and could create unfair disparities in the compliance opportunities afforded different states. In light of the emissions leakage concerns, and in consideration of these comments, the EPA is not allowing shifting generation to new NGCC units to be used as a measure for adjusting CO_2 emission rates for affected EGUs in rate-based state plans.

In addition, other new and existing non-affected fossil fuel-fired EGUs that are not subject to CAA section 111(b) or 111(d), such as simple cycle combustion turbines, may not be used to adjust the CO_2 emission rate of an affected EGU. While generation from such units could substitute for generation from affected EGUs, the EPA has determined that additional incentives for such generation, in the form of an explicit adjustment to the CO_2 rate of an affected EGU, are not necessary or warranted. Providing for such an adjustment could create perverse incentives for the construction of new simple cycle combustion turbines that are not subject to the applicability criteria of the final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule. These units could provide only limited adjustment credit, as operation beyond a certain capacity factor threshold would trigger applicability under CAA section 111(b). Further, providing for the ability to generate adjustment credits would provide incentives for construction of less efficient fossil generating capacity than would likely otherwise be constructed (*e.g.*, addition of a simple cycle combustion turbine rather than a NGCC unit). In addition, providing for the ability to generate adjustment credits could create perverse incentives for the continued operation of less efficient existing fossil generating capacity. Such outcomes run counter to the objectives of this final rule.

c. *Measures that reduce CO_2 emissions outside the electric power sector.*

Measures that reduce CO_2 emissions outside the electric power sector may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal, under either a rate-based or mass-based approach, because all of the emission reduction measures included in the EPA's determination of the BSER reduce CO_2 emissions from affected EGUs. Examples of measures that may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal include GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors,[969] direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification.

2. Requirements for Rate-Based Emission Trading Approaches

As made clear in the proposal,[970] all emission standards in a state plan must be quantifiable, verifiable, enforceable, non-duplicative and permanent.[971] This requirement is applicable to emission standards that include a rate-based emission trading program. The State Plan Considerations TSD for the proposal also explained that in order to ensure a plan is enforceable, a state plan must: identify in its plan the entity or entities responsible for meeting compliance and other enforceable obligations under the plan; include mechanisms for demonstrating compliance with plan requirements or demonstrating that other binding obligations are met; and provide a mechanism(s) for legal action if affected EGUs are not in compliance with plan requirements or if other entities fail to meet enforceable plan obligations. A

[969] We note, however, that the final emission guidelines allow state measures like emission budget trading programs to include out-of-sector GHG offsets. For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

[970] 79 FR 34830, 34913.

[971] These requirements are described in detail in section VIII.D.2.

state plan using a rate-based emission trading approach must therefore include rate-based emission standards for affected EGUs along with related implementation and compliance requirements and mechanisms.[972] These related requirements include those applicable to rate-based emission standards more broadly: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output. By satisfactorily addressing these requirements, state plans including a rate-based emission trading program will be able to meet the statutory requirements of CAA section 111(d) regarding the need for state plans to provide for the implementation and enforcement of emission standards, as well as meet the requirement that each emission standard be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU.

The EPA also specifically proposed that for state plans that rely on measures that avoid EGU CO_2 emissions, such as RE and demand-side EE measures, the state will also need to include quantification, monitoring, and verification provisions in its plan for these measures. The EPA is finalizing requirements specific to rate-based emission trading programs as requirements the EPA has determined are necessary to assure the integrity of a rate-based approach that includes an emission trading program, and therefore assures a state plan using such an approach

[972] As described below, these requirements would likely be provided in a state plan in the form of state regulations, but could potentially be provided in another form.

appropriately provides for the implementation and enforcement of rate-based emission standards in accordance with CAA section 111(d).[973] These specific requirements for a rate-based emission trading program include provisions for issuance of ERCs by the state and/or its designated agent; provisions for tracking ERCs, from issuance through submission for compliance; and the administrative process for submission of ERCs by the owner or operator of an affected EGU to the state, in order to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard.[974] These requirements must be submitted for inclusion in the federally enforceable plan, per the statutory requirement that states provide for the implementation and enforcement of emission standards. A rate-based trading program would provide for the implementation and enforcement of rate-based emission standards for a state plan that allows its affected EGUs to adjust a rate by the use of an ERC.

The EPA will review a state plan submittal including a rate-based emission trading program to assure that the plan contains the requirements necessary to assure the integrity of a rate-based approach, and therefore provide for the

[973] By "integrity of a rate-based emission trading program", the EPA is referring to elements in the design and administration of a program necessary to assure that emission standards implemented using a rate-based emission trading approach are quantifiable, verifiable, enforceable, nonduplicative, and permanent.

[974] See section VIII.K.1 for a discussion of the accounting method used to adjust a CO_2 emission rate.

implementation and enforcement of rate-based emission standards. These requirements are discussed in more detail in this section.

The EPA also notes it is proposing model rules for both mass-based and rate-based emission trading programs. State plans that include the finalized model rule for a rate-based emission trading program could be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines. The EPA would evaluate the approvability of such plans through independent notice and comment rulemaking.

A state may issue ERCs to an affected EGU that performs at a CO_2 emission rate below a specified CO_2 emission rate, as well as to providers of qualifying measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. This latter category includes providers of qualifying RE and demand-side EE measures, as well as other types of measures, as discussed in section VIII.K.1.a.[975]

ERCs may be used by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard. This adjustment is made by adding MWh to the

[975] As used in this section, the term "EE program" refers to an EE deployment program. An EE program involves deployment of multiple EE measures or EE projects, such as utility- or state-administered EE incentive programs that accelerate the deployment of EE technologies and practices. As used in this section, the term "EE/RE project" refers to a discrete EE project (*e.g.*, an EE upgrade to a commercial building or set of buildings) or a RE generator (*e.g.*, a single wind turbine or group of turbines).

denominator of an affected EGU's reported CO_2 emission rate, in the amount of submitted ERCs, resulting in a lower adjusted rate. To demonstrate compliance with a rate-based emission standard, an affected EGU would report its CO_2 lb/MWh emission rate to the state regulatory body, and would also surrender to the state any ERCs it wishes to use to adjust its reported emission rate. The state regulator would then cancel the submitted ERCs. The affected EGU would add the MWh the ERCs represent to the denominator of its reported CO_2 lb/MWh emission rate to demonstrate compliance with its emission standard. The state regulator could facilitate its evaluation of the affected EGU's compliance (as well as evaluation by the affected EGU, the EPA, and others) by providing functionality in its tracking system to run such compliance calculations. If the affected EGU's adjusted CO_2 emission rate is equal to or lower than its applicable emission rate standard, the affected EGU would be in compliance.

a. *Issuance of ERCs to affected EGUs.*

ERCs may be issued to affected EGUs that emit below a specified CO_2 emission rate, as discussed below. For issuance of ERCs to affected EGUs, the state plan must specify the accounting method and administrative process for ERC issuance. This includes the calculation method for determining the number of ERCs to be issued to an affected EGU, based on reported CO_2 emissions and MWh energy output, in comparison to a reference CO_2 emission rate. The reference rate is a specified CO_2 lb/MWh emission rate that an affected EGU's reported CO_2 emission rate is compared to, when determining the amount of ERCs that may be issued to an affected EGU.

Following determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate, the state regulatory body would issue those ERCs into a tracking system account held by the owner or operator of the affected EGU. Tracking system requirements are addressed below at section VIII.K.2.c.

The accounting method that may be applied in a state plan differs depending on whether a state plan includes a single rate-based emission standard that applies to all affected EGUs (*e.g.*, if a plan is designed to meet a state rate-based CO_2 goal) or separate rate-based emission standards that apply to subcategories of affected EGUs, namely fossil fuel-fired electric utility steam generating units and stationary combustion turbines. In both cases, ERCs are issued in MWh, based on the difference between an affected EGU's reported CO_2 emission rate (in CO_2 lb/MWh) and a specified CO_2 lb/MWh emission rate that the reported rate is compared to (referred to as a "reference rate"). The reference rate may be an affected EGU's assigned CO_2 emission limit rate or another CO_2 emission rate, as described below. Where an affected EGU's reported CO_2 emission rate is lower than the specified reference CO_2 emission rate, ERCs may be issued.

Where a state plan includes emission standards in the form of a single rate-based emission standard that applies to all affected EGUs, the reference rate is the CO_2 emission rate limit for affected EGUs. In this instance, ERCs may be issued based on an affected EGU's reported CO_2 emission rate as a proportion of the emission limit rate. For example, if the emission rate limit is 2,000 lb CO_2/MWh and the affected EGU emits at a rate of 1,000 lb CO_2/MWh, 0.5 MWh would be awarded for every MWh generated by the affected EGU. ERCs would be issued to affected EGUs in whole MWh increments. The calculation method is as follows:

ERCs [976] = reported MWh by affected EGU [977] × ((CO_2 emission rate limit for affected EGUs [978] — affected EGU reported CO_2 emission rate [979])/CO_2 emission rate limit for affected EGUs)

For the example above, the calculation is as follows:

ERCs = MWh reported × (2,000–1,000)/2,000 = MWh reported × 0.5

If the affected EGU in this example generated 1,000,000 MWh, 500,000 ERCs would be issued.

Where a state plan includes separate emission standards for subcategories of affected EGUs, specifically affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, the reference rate differs for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Additionally, if the state plan applies emission standards for its affected EGUs that are equal to the subcategorized CO_2 emission performance rates there is a unique

---

[976] For all calculations in this section, where the result is a negative value, no ERCs would be issued.

[977] This term represents the reported MWh by the affected EGU on an annual basis.

[978] This term represents the "reference rate."

[979] This term represents the annual reported CO_2 emission rate of the affected EGU.

opportunity for the adjustment of an affected EGU's emission rate using ERCs that are generated as a result of building block 2 incremental NGCC unit operation. The EPA is requiring state plans to account for incremental NGCC generation in ERC generation if a state plan applies the subcategorized CO_2 emission performance rates to its affected EGUs as emission standards. Additionally, the EPA is requiring that a NGCC unit is not able to use ERCs generated by it or any other NGCC unit's building block 2 incremental generation.

For affected steam generating units, the reference CO_2 emission rate is the assigned CO_2 emission rate limit for steam generating units, and the following accounting method for generating ERCs applies:

ERCs [980] = reported MWh × ((steam generating unit CO_2 emission rate limit [981]—steam generating unit reported CO_2 emission rate)/steam generating unit CO_2 emission rate limit).

For an affected NGCC stationary combustion turbine in a subcategorized rate-based emission trading program, the following equation provides a required accounting method for generating ERCs based on operation with respect to the NGCC unit's emission standard:

ERCs = NGCC unit's reported MWh—((NGCC unit's CO_2 emission standard [982] —NGCC unit's

[980] For all calculations in this section, where the result is a negative value, no ERCs would be issued.

[981] The "reference rate."

[982] The "reference rate."

reported CO_2 emission rate)/NGCC unit's CO_2 emission standard)

According to this equation, ERC issuance is assessed based on the difference between the CO_2 emission rate standard for the NGCC unit [983] and the reported CO_2 emission rate of the affected NGCC unit. In other words, affected NGCC stationary combustion turbines earn ERCs for generation when they perform at an emission rate better than the reference rate for stationary combustion turbines, similarly to how affected steam units can earn ERCs.

In a subcategorized rate-based emission trading program, a state must use the incremental operation of an affected NGCC unit quantified for building block 2 to allow a NGCC unit to generate ERCs based on its expected incremental generation.

A state plan that provides for the use of ERCs issued based on incremental affected NGCC generation must provide a required calculation method that allows for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units (as represented in building block 2), while also respecting the fact that affected stationary combustion turbines must also meet an assigned CO_2 emission rate limit for the entirety of its MWh energy output. This accounting method must reflect the application of the BSER, as described in section V, and the accounting method must not create incentives to rearrange dispatch between existing

[983] This is the CO_2 emission performance rate for affected stationary combustion turbines in the emission guidelines.

NGCC units to generate additional ERCs without changing the overall level of NGCC generation.

The EPA will review whether a state's accounting method is approvable per the requirements of the statute and this final rule as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. The EPA notes that the proposed model rule for a rate-based emission trading program includes a proposed accounting method and takes comments on alternatives. The accounting method provided in a final model rule could be a presumptively approvable approach for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units. A state's accounting requirements for generation of ERCs based on incremental affected NGCC generation must maintain consistency with the EPA's application of the BSER when calculating CO_2 emission performance rates for affected stationary combustion turbine and steam generating units. In particular, a state's accounting method must maintain consistency of accounting in a state rate-based CO_2 emission standard with the EPA's application of building block 2 in calculating CO_2 emission performance rates for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, which is based on use of incremental generation from affected stationary combustion turbine to replace generation from affected steam generating units.

b. *Issuance of ERCs for RE, demand-side EE, and other measures.*

ERCs may be issued for qualifying measures.[984] For issuance of ERCs for qualifying measures, state plan requirements for ERC issuance must include a two-step process. In the first step of the process, a potential ERC provider submits an eligibility application for a qualifying program or project [985] to the administering state regulator (or its agent [986]). The state regulator reviews the application to determine whether, in this example, an EE/RE program or project meets eligibility requirements for the issuance of ERCs. [987] An eligibility application

---

[984] Qualifying measures that can be used to adjust the CO_2 emission rate of an affected EGU are discussed at section VIII.K.1, and include incremental NGCC, RE, demand-side EE, and other measures, such as DSM, CHP and incremental nuclear generation.

[985] For example, for an EE/RE program or project, as described in this section for illustrative purposes. The requirements described in this section for EE/ RE programs and projects also apply for all other eligible qualifying measures discussed in section VIII.K.1

[986] As used here, an agent is a party acting on behalf of the state, based on authority vested in it by the state, pursuant to the legal authority of the state. A state could designate an agent to provide certain limited administrative services, or could choose to vest an agent with greater authority. Where an agent issues an ERC on behalf of the state, such issuance would have the same legal effect as issuance of an ERC by the state.

[987] The entity implementing the EE/RE program or project (referred to in the preamble as a "provider") would submit the application. This is the identified entity to which ERCs would ultimately be issued, to a tracking system account held by the entity. Such entities could include a wide variety of parties that implement EE/RE programs and projects, including owners or

must include a description of the program or project, a projection of the MWh generation or energy savings anticipated over the life of the program or project, and an EM&V plan that meets state plan requirements. The EM&V plan must describe how MWh of RE generation or energy savings resulting from the program or project will be quantified and verified.[988] A state, in its emission standard regulations, must include requirements for EM&V plans that are consistent with the requirements in the emission guidelines for EE/RE measures and other eligible measures, as discussed in sections VIII.K.1 and VIII.K.3.

The EPA has determined that state requirements for an eligibility application must include review of the application by an independent verifier, approved by the state as eligible per the requirements of the final emission guidelines to provide such verification, prior to submittal. This requirement builds on the approach used for assessing GHG offset projects, both in international emission trading programs and the GHG emission budget trading programs implemented by California and the RGGI participating states.[989] An

---

operators of affected EGUs, electric distribution companies, independent power producers, energy service companies, administrators of state EE programs, and administrators of industrial EE programs, among others.

[988] The verification process includes confirmation that quantified MWh are non-duplicative and permanent (*i.e.*, are not being used in any other state plan to demonstrate compliance with an emission standard or achievement of an emission performance rate or state CO_2 emission goal).

[989] Information about the verification process for GHG offsets under the RGGI program, including verifier accreditation

assessment by an independent verifier would be included as a component of an eligibility application.

The EPA has determined that independent verification requirements are necessary to ensure the integrity of state rate-based emission trading programs included in a state plan, given the wide range of eligible measures that may generate ERCs and the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for state regulatory bodies to ensure that eligibility applications and M&V reports are thoroughly reviewed prior to issuance of ERCs. Inclusion of an independent verification component is also consistent with similar approaches required by state PUCs for the review of demand-side EE program results and GHG offset provisions included in state GHG emission budget trading programs.

State plans with rate-based emission trading programs must include requirements regarding the qualification status of an independent verifier. An independent verifier is a person (including any company, any corporate parent or subsidiary, any contractors or subcontractors, and the actual person) 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

---

requirements and access to relevant documents, is available at *http://www.rggi.org/market/offsets/verification*. Similar information about the verification process for GHG offsets under the California program is available at *http://www.arb.ca.gov/cc/capandtrade/offsets/verification/verification.htm*.

subject of its verification report or ERCs that could impact its impartiality in performing verification services. State plans must require that a person be approved by the state as an independent verifier, as defined by this final rule, as eligible to perform the verifications required under the approved state plan. State plans must also include a mechanism to temporarily or permanently revoke the qualification status of an independent verifier, such that it can no longer provide verification services related to an eligibility application or M&V report for at least the duration of the period it does not meet the qualification requirements for independent verifiers in an approved state plan. The EPA's proposed model rate-based emission trading rule contains provisions addressing accreditation and conflicts of interest for independent verifiers. State plans that adopt the finalized model rule could be presumptively approvable with respect to these requirements regarding independent verifiers.

The state's eligibility requirements and application procedures must ensure that only eligible actions may generate ERCs and that documentation is submitted only once for each program or project, and to only one state program.[990] These provisions will ensure that actions that are eligible for the issuance of ERCs are "non-duplicative."[991] The tracking system used to administer a state's rate-based emission trading

[990] This includes ensuring that multiple parties do not submit an eligibility application for the same EE program or project, or for the same RE generator.

[991] Emission standards must be "non-duplicative" as described in section VIII.D.2.

system must provide transparent, electronic, public access to information about program and project eligibility applications, including EM&V plans, and regulatory approval status.

In the second step of the process, following implementation of the RE/EE program or project (as described in this example) that was approved in step one, the RE/EE provider periodically submits a M&V report to the state regulatory body documenting the results of the program or project in MWh of electric generation or energy savings.[992] These results are quantified according to the EM&V plan that was approved as part of step one. These results are verified by an accredited independent verifier, and its verification assessment must be included as part of the M&V report submitted to the state regulatory body. The administering state regulator (or its agent) then reviews the M&V report, and determines the number of ERCs (if any) that should be issued, based on the report. Finally, the state regulatory body (or its agent) issues ERCs to the provider of the approved program or project. These ERCs are issued to the tracking system account held by the program or project provider.

State plan requirements must ensure that only one ERC is issued for each verified MWh. This is addressed through registration in the tracking system

[992] State rate-based emission trading program regulations must specify the frequency for submission of M&V reports for approved qualified measures that have been deemed eligible to generate ERCs. These reporting periods should be annual, but a state could consider shorter or longer periods, depending on the type of ERC resource.

of programs and projects that have been qualified for the issuance of ERCs, to ensure that documentation is submitted only once for each RE/EE action, and to only one state program.[993] The tracking system must provide transparent electronic public access to submitted M&V reports and regulatory approvals related to such reports.[994] Such reports are the basis for issuance of ERCs.

c. *Tracking system requirements.*

State requirements must include provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are "surrendered" by the owner or operator of an affected EGU and "retired" or "cancelled"), to ensure they are only used once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[995] and an accompanying tracking system that meets requirements specified in the emission trading program regulations. Each issued ERC must have a

---

[993] EE/RE programs and projects, and other eligible measures, with an approved eligibility application would be designated in a tracking system as qualified programs or projects. Qualified programs and projects may be issued ERCs, based on approved M&V reports.

[994] This must include electronic Internet access to such information in the tracking system.

[995] "Compliance true-up" refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission standard.

unique identifier (*e.g.*, serial number) and the tracking system must provide for traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. This could include regional systems and/or a national system. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

d. *Effect of improperly issued ERCs.*

Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and state issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the emission guidelines. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud.

An approvable state plan that allows affected EGUs to comply with their emission standards in part through reliance on ERCs must include provisions making clear that an affected EGU may only demonstrate compliance with an ERC that represents the one MWh of actual energy generation or savings that it purports to represent and otherwise meets the emission guidelines.

e. *Banking of ERCs.*

ERCs issued in 2022 or a subsequent year may be carried forward (or "banked") and used for demonstrating compliance in a future year.[996] For example, an ERC issued for a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years without limitation. ERCs may be banked from the interim plan performance period to the final plan performance period. Banking provides a number of advantages while ensuring that the same output-weighted average CO_2 emission rates of the interim and final state CO_2 goals are achieved over the course of a state plan. Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs.[997] This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes

---

[996] States also have the option to participate in the CEIP, under which they can issue ERCs for MWh generation or savings that occur in 2020–2021 for measures implemented following submission of a final state plan, and receive matching ERCs from a federal pool. See section VIII.B.2 for a detailed discussion. The ERCs issued under this program can also be banked during and between the interim and final compliance period.

[997] Banking under mass-based emission budget trading programs, and the rationale for banking provisions, is addressed below in section VIII.J.2.c.

apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later.[998] State plans must specify whether the state is allowing or restricting the banking of ERCs between compliance periods for affected EGUs. State plans must also prohibit borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources.

f. *Considerations for ERC issuance.*

The EPA notes that state-administered and state-overseen EE programs, such as those administered by state-regulated electric distribution utilities, could play a key role in supplying energy savings to a rate-based emission trading system in the form of ERCs. These programs have been the primary means for delivering EE programs and energy savings at scale, and also allow for a state to conduct a portfolio planning process to guide EE program design and focus in a manner that best provides multiple benefits

---

[998] The absence of banking creates an incentive to defer both relatively low-cost and higher-cost CO_2 emission reduction actions until a later period when emission rate limits become more stringent, rather than incentives to undertake the low-cost activities sooner in order to further delay the high cost actions. Under a rate-based emission trading program, banking will encourage ERC providers to generate larger numbers of ERCs in early years of a plan performance period, in anticipation of rising ERC prices over time, when demand for ERCs is expected to increase as rate-based CO_2 emission standards become more stringent.

to electricity ratepayers in a state. Such portfolio planning processes typically treat EE as an energy resource comparable to electricity generation.

The EPA also notes that non-ERC certificates may be issued by states and other bodies for MWh of energy generation and energy savings that are used to meet other state regulatory requirements, such as state RPS and EERS, or by individuals to make environmental or other claims in voluntary markets.

The EPA defines an ERC in the emission guidelines as a tradable compliance instrument that represents a zero-emission MWh (for the purposes of meeting the emission guidelines) from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA section 111(d). The sole purpose of an ERC is for use by an affected EGU in demonstrating compliance with a rate-based emission standard in such an approved state plan.

An ERC is issued separately from any other instruments that may be issued for a MWh of energy generation or energy savings from a qualifying measure. Such other instruments may be issued for use in meeting other regulatory requirements (*e.g.*, such as state RPS and EERS requirements) or for use in voluntary markets. An ERC may be issued based on the same data and verification requirements used by existing REC and EEC tracking systems for issuance of RECs and EECs.

The EPA notes that the definitions of other instruments, such as RECs, differ (as established under state statute, regulations, and PUC orders) and that requirements under state regulatory programs that use such instruments, such as state RPS, also differ. As a result, states may want to assess, when developing their state plan, how such existing instruments may interact with ERCs. For example, a state may want to assess how issuance of ERCs pursuant to a state plan may interact with compliance with a state RPS by entities affected under relevant state RPS regulations or PUC orders. The interaction of other instruments and ERCs may also impact existing or future arrangements in the private marketplace. Actions taken by states, separate from the design of their state plan, could address a number of these potential interactions. For example, state RPS regulations that specify a REC for a MWh of RE generation, and the attributes related to that MWh, may or may not explicitly or implicitly recognize that the holder of the REC is also entitled to the issuance of an ERC for a MWh of electricity generation from the eligible RE resource. This could impact existing and future RE power purchase agreements or REC purchase agreements. Such interactions among existing instruments and ERCs could also impact how marketing claims are made in the voluntary RE market. How a state might choose to address these potential interactions will depend on a number of factors, including the utility regulatory structure in the state, existing statutory and regulatory requirements for state RPS, and existing RE power purchase agreements and REC contracts.

g. *Program review.*

The EPA is requiring that states periodically review the administration of their rate-based emission trading programs. The results of these program reviews must be submitted by states to the EPA as part of their required reports on the implementation of their state plans, as described in sections VIII.D.a.(5) and VIII.D.2.b.(4), and must be made publicly available. Such a review submitted as part of a required state report provides for the implementation of rate-based emission standards per the requirements of CAA section 111(d)(2). For a rate-based emission trading program, the review must cover the reporting period addressed in the state's periodic reports to the EPA on plan implementation.

The program review must address all aspects of the administration of a state's rate-based emission trading program, including the state's evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and the state's issuance of ERCs. The program review must assess whether the program is being administered properly in accordance with the state's approved plan; whether ERC eligibility applications and M&V reports are being properly evaluated and acted upon (*i.e.*, approved or disapproved); 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 verifiers, including the quality of verifier reviews. Where significant deficiencies are identified by the state's program review, those deficiencies must be rectified by the state in a timely manner.

States must collect, compile, and maintain sufficient data in an appropriate format to support the periodic program review. The EPA will review the results of each program review. The EPA may also audit a state's administration of its rate-based emission trading program and pursue appropriate remedies where significant deficiencies are identified.

3. EM&V Requirements for RE, Demand-Side EE, and Other Measures Used to Adjust a CO_2 Rate

This section discusses EM&V for RE, demand-side EE, and other measures that are used to generate ERCs or otherwise adjust an emission rate.[999] EM&V is applied for purposes of quantifying and verifying MWh in rate-based state plans, as described below. Rate-based state plans must require that eligible resources document in EM&V plans and M&V reports how all MWh saved and generated from eligible measures will be quantified and verified. Additionally, with respect to EM&V, the EPA's proposed model rule identifies certain industry best practices that, upon finalization, could be adopted as presumptively approvable components of a state plan.[1000]

---

[999] EM&V is defined to mean the set of procedures, methods, and analytic approaches used to quantify the MWh from demand-side EE and RE and other measures, and thereby ensure that the resulting savings and generation are quantifiable and verifiable.

[1000] The EPA recognizes that EM&V best practices are routinely evolving to reflect changes in markets, technologies and data availability. Therefore the agency is providing draft EM&V guidance with the proposed model rule, which can be updated over time to address any such changes to best practices. The guidance can also identify and describe alternative quantification approaches that may be approved for use, provided that such

As discussed in section VIII.K.1, quantified and verified MWh of RE generation, EE savings,[1001] and other eligible measures may be used to adjust a CO_2 emission rate when demonstrating compliance with the emission guidelines. In states implementing emission standard type plans with rate-based trading, affected EGUs adjust their reported emission rate using ERCs, which represent MWh that are quantified and verified according to the EM&V requirements described in this section. The EPA will evaluate the overall approvability of the state plan taking into consideration whether the state's submitted EM&V requirements satisfy these final emission guidelines.

a. *Discussion of proposed EM&V approach and public comment.*

The EPA proposed that a state plan that incorporates RE and demand-side EE measures must include an EM&V plan that explains how the effect of these measures will be determined in the course of plan implementation. The proposal sought comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan, and on whether harmonization of state approaches, or supplemental actions and procedures, should be

---

approaches meet the requirements of the finalized EM&V requirements.

[1001] In the context of demand-side EE, "measure" refers to an installed piece of equipment or system at an end-use energy consumer facility, a strategy intended to affect consumer energy use behaviors, or a modification of equipment, systems or operations that reduces the amount of electricity that would have delivered an equivalent or improved level of end-use service in the absence of EE.

required in an approvable state plan, provided that supporting EM&V documentation meets applicable minimum requirements. In the proposal, the EPA also indicated that it would issue guidance to help states, sources, and project providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts.

The proposal and associated "State Plans Considerations" TSD [1002] suggested that the EPA's EM&V requirements could leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The proposal also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh.

As a result, the agency took comment on whether this infrastructure is appropriate in the context of approvable state plans for use in rate-based state plans that include RE, demand-side EE, and other measures. The majority of commenters addressing

---

[1002] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: *http://www2.epa.gov/carbonpollution-standards/clean-power-plan-proposedrule-state-plan-considerations*.

this question responded affirmatively, indicating that existing EM&V infrastructure is appropriate to assure quality, credibility, and integrity. However, commenters also noted that EM&V methods are routinely improving and changing over time, and that the EPA's requirements and guidance should be responsive to such changes, should avoid locking in outdated methods, and should be updated to maintain relevance.

Another point made by commenters is that, despite the observed improvements in EM&V over time, quantification knowledge is more robust for some EE program and policy types than for others. Additionally, there is relatively limited experience applying EM&V protocols and procedures to emission trading programs, where each MWh of replaced generation can be bought and sold by a regulated source. As a result, the EPA's final emission guidelines and proposed model rule include a number of safeguards and quality-control features that are intended to ensure the accuracy and reliability of quantified EE savings.

b. *Requirements for EM&V and M&V submittals.*

As discussed in section VIII.K.2, these final guidelines require that state plans include a requirement that EM&V plans and M&V reports be submitted to the state for rate-based emission trading programs. States must require that at the initiation of an eligible measure, project providers must develop and submit to the state an EM&V plan that documents how requirements for quantification and verification will be carried out over the period that MWh generation or savings are produced. States must also require that after a project or program is implemented, the provider must submit periodic M&V reports to confirm and describe how each of the requirements was applied. These reports must also specify the actual MWh savings or generation results, as quantified by applying EM&V methods on a retrospective (ex-post) basis. States may not allow MWh values that are quantified using ex-ante (pre-implementation) estimates of savings. As previously described, the EPA took comment on the suitability of current state and utility EM&V approaches for RE and demand-side EE programs in the context of an approvable state plan. These final requirements regarding EM&V plans and M&V reports are intended to leverage and closely resemble those already in routine use.

For energy generating resources, including RE resources, states may leverage the programs and infrastructure they have in place for achievement of their RPS and take advantage of registries in place for the issuance and tracking of RECs. Many existing REC tracking systems already include well-established safeguards, documentation requirements, and procedures for registry operations that could be adapted to serve similar functions in relation to the final emission guidelines. For example, a key element of RPS compliance in many states that parallels the final rule's requirements is that each generating unit must be uniquely identified and recorded in a specified registry to avoid the double counting of credits at the time of issuance and retirement. In addition, the existing reports and documentation from tracking systems may, together with eligible independent third party verification reports, serve as the substantive basis for eligibility applications, EM&V plans and M&V reports for the issuance of ERCs to energy generating resources for affected EGUs to meet their obligations under the final rule. With respect to actual monitoring requirements, many existing REC registries include provisions for the monitoring of MWh of generation that would be appropriate to meet state plan requirements pursuant to the final rule, such as requirements to use a revenue quality meter.

For demand-side EE, states must require that EM&V plans that are developed for purposes of adjusting an emission rate under this final rule include several specific components. The EPA notes these components reflect existing provisions in a wide range of publicly or rate-payer funded EE programs and energy service company projects. One of these components state plans must require is a demonstration of how savings will be quantified and verified by applying industry best-practice protocols and guidelines, as well as an explanation of the key assumptions and data sources used. State plans must require EM&V plans to include and address the following:

- A baseline that represents what would have happened in the absence of the EE intervention, such as the equipment that would most likely have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance at the time of EE implementation

- The effects of changes in independent factors affecting energy consumption and savings; that is, factors not directly related to the EE action, such as weather, occupancy, or production levels

- The length of time the EE action is anticipated to continue to remain in place and operable, effectively providing savings (in years)

Examples and discussion of industry best-practices for executing each of the above-listed components is provided in the EPA's draft EM&V guidance for demand-side EE, which is being released in conjunction with the proposed model rule. The model trading rule defines certain EM&V provisions for demand-side EE, as well as specific provisions for non-affected CHP and RE resources, including incremental hydroelectric power, biomass RE facilities, and waste-to-energy facilities, that may be presumptively approvable upon finalization.

The EPA notes that state plans incorporating the finalized model rule for rate-based emission trading programs could be presumptively approvable as meeting the requirements of CAA section 111(d) and the EM&V provisions in these emission guidelines. The EPA will evaluate the approvability of such state plans through independent notice and comment rulemaking.

c. *Skill certification standards.*

Using a skilled workforce to implement demand-side EE and RE projects and other measures intended to reduce CO_2 emissions, and to evaluate, measure, quantify and verify the savings associated with EE projects or the additional generation from performance improvements at existing RE projects are both important in existing best industry practices. Several commenters pointed out that skill certification standards can help to assure quality and credibility of demand-side EE, RE, and other CO_2 emission reduction projects. The EPA also recognizes that a skilled workforce performing the EM&V is important to substantiate the authenticity of emissions reductions.

The EPA is therefore recommending in conjunction with the EM&V requirements discussed in this section, that states are encouraged to include in their plans a description of how states will ensure that the skills of workers installing demand-side EE and RE projects or other measures intended to reduce CO_2 emissions as well as the skills of workers who perform the EM&V of demand-side EE and RE performance will be certified by a third party entity that:

(1) Develops a competency based program aligned with a job task analysis and certification scheme;

(2) Engages with subject matter experts in the development of the job task analysis and certification schemes that represent appropriate qualifications, categories of the jobs, and levels of experience;

(3) Has clearly documented the process used to develop the job task analysis and certification schemes, covering such elements as the job description, knowledge, skills, and abilities;

(4) Has pursued third-party accreditation aligned with consensus-based standards, for example ISO/IEC 17024.

Examples of such entities include: Parties aligned with the Department of Energy's (DOE) Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or by an apprenticeship program that is registered with the federal Department of Labor (DOL), Office of Apprenticeship; or with a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body. This can help to substantiate the authenticity of emission reductions due to demand-side EE and RE and other CO_2 emission reduction measures.

4. Multi-State Coordination: Rate-Based Emission Trading Programs

Individual rate-based state plans may provide for the interstate transfer of ERCs, which would enable an ERC issued by one state to be used for compliance by an affected EGU with a rate-based emission standard in another state. Such plans would include regulatory provisions in each state's emission standard requirements that indicate that ERCs issued in other partner states may be used by affected EGUs for compliance. Such plans must indicate how ERCs will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[1003]

The approaches described in this section are only allowed for states that impose rate-based emission limits for affected EGUs that are equal to the CO_2 emission performance levels in the emission guidelines. This approach is necessary to ensure that each state that is allowing for the interstate transfer

---

[1003] The emission standards in each individual state plan must include regulatory provisions that address the issuance of ERCs and tracking of ERCs from issuance through use for compliance, as described in section VIII.K.2. The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

of ERCs is implementing rate-based emission standards for affected EGUs at the same lb CO_2/MWh level.[1004] This assures that all the participating states are issuing ERCs to affected fossil steam and NGCC units that emit below their assigned emission standards on the same basis.

This approach avoids providing different incentives, in the form of issued ERCs, to affected steam generating units and NGCC units in different states that have comparable CO_2 emission rates. Providing different incentives to similar affected EGUs across states could create distortionary effects that lead to shifts in generation among states based on the different CO_2 emission rate standards applied by states to similar types of affected EGUs. Providing for the interstate trading of ERCs in this instance would exacerbate these distortionary effects by providing arbitrage opportunities.

When demonstrating that a state's CO_2 emission goal is achieved as a result of plan implementation, a state with linkages to other states would be required to demonstrate that any ERCs issued by another state that are used by affected EGUs in the state for compliance with its rate-based CO_2 emission

---

[1004] States also have the option of implementing a multi-state plan with a single rate-based emission standard that applies to all affected EGUs in the participating states. This approach would also allow for interstate transfers of ERCs. Under this approach, a rate-based multi-state plan would include emission standards for affected EGUs based on a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs.

standards were issued by states with an EPA-approved state plan.[1005]

States could implement these linkages among state plans with rate-based emission trading systems through three different implementation approaches: (1) Plans that are "ready-for-interstate-trading;" (2) plans that include specified bilateral or multilateral linkages; and (3) plans that provide for joint ERC issuance among states with materially consistent regulations. These approaches are summarized below:

- *Ready-for-interstate-trading plans:* A state plan recognizes ERCs issued by any state with an EPA-approved plan that also uses a specified EPA-approved[1006] or EPA-administered tracking system. Plans are approved individually. A state plan need not designate the individual states by name from which it would accept issued ERCs. States can join such a coordinated approach over time, without the need for plan revisions.[1007]

[1005] This could be done by reference to data in the tracking system used to implement a state's ratebased emission trading program that identifies the origin of each ERC (*e.g.*, by serial identifier).

[1006] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of ERCs, as described in section VIII.K.2. Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

[1007] The EPA notes that it is proposing a model rule for a rate-based emission trading program that could be used by states interested in implementing a ready-for-interstate-trading plan approach. A state plan that included the finalized rate-based model rule could be presumptively approvable as meeting the requirements of CAA section 111(d) and the emission guidelines.

- *Specified bilateral linkage:* States recognize ERCs issued by named partner states. Partner states must demonstrate that they use a shared tracking system, interoperable tracking systems, or an EPA-administered tracking system. Plans are approved individually, including review of the shared tracking system or interoperable tracking systems.

- *Joint ERC issuance:* States implement materially consistent rate-based emission trading program regulations and share a tracking system. States coordinate their review of submissions for ERC issuance[1008] and their issuance of ERCs to the shared tracking system. Issued ERCs are recognized as usable for compliance in all states using the shared tracking system. Plans are approved individually, including review of the shared tracking system.

These implementation approaches are designed to streamline the process for linking emission trading programs, avoid or limit the need for plan revisions as new states join a collaborative emission trading approach, and facilitate the development of regional or broader multi-state markets for ERCs.[1009]

If a state plan also met the requirements described in this section for ready-for-interstate-trading plans, it could be approved as ready-for-interstate trading.

[1008] This refers to eligibility applications and M&V reports, which are required submittals for non-affected EGU entities seeking the issuance of ERCs. Where affected EGUs are issued ERCs for emission performance below a specified CO_2 emission rate, these ERCs are issued by the individual state in which they are subject to a ratebased emission standard. Requirements for ERC issuance are discussed in section VIII.K.2.

[1009] The EPA also notes that individual state plans may utilize RE and demand-side EE (and other eligible measures), that occur

L. Treatment of Interstate Effects

This section discusses how differing characteristics across states and sources could create risks of increased emissions under this rule through double counting of emission reduction measures or through foregone emission reductions due to movement of generation from source to source. The section also discusses how the final rule addresses these concerns: First, through the characteristics of goal-setting and the framework of state plans, and second, through specific requirements intended to minimize the risk of double counting and increased emissions.[1010]

The section is structured as follows. First, this section discusses the dynamics that cause these risks to potentially arise. Second, it provides a discussion of how the risks of double counting and foregone reductions are minimized through the following provisions: The nature of the final emission performance rates, multi-state plan options that limit distortionary effects, the structure of mass-based plan

---

in other states, as described in section VIII.L addressing interstate effects. Under an individual state plan, ERCs could be issued for RE and demand-side EE measures that occur in other states, provided the EE/RE provider submits the measures to the state and the measures meet requirements in the state plan's rate-based emission trading program requirements. The multistate approaches described above provide additional flexibility for states to informally and formally coordinate their implementation of ratebased plans across states while retaining individual rate-based state goals.

[1010] This section does not discuss emission leakage and how it is addressed by this final rule. See section VII.D for a discussion of emission leakage and its impact on state goal equivalence. See section VIII.J for a discussion of requirements for mass-based plans to address leakage.

and rate-based plan accounting for emission reductions measures, and specified restrictions on the counting in a rate-based plan of emission reduction measures located in a mass-based state. Finally, the section discusses how the rate-based accounting framework minimizes incentives to develop emission reduction measures in particular states due to differences in rates.

In the June 2014 proposal, the EPA acknowledged that emission reduction measures implemented under a state plan will likely have impacts across many affected sources both within and across state boundaries due to the dynamic and interstate nature of the electric grid. These interactions may be driven in part due to differences in power sector dynamics across states, including the types of affected EGUs in a state, the availability of eligible zero-emitting resources, and the costs of different compliance options and existing policies in states. These state-level characteristics play out across dynamic regional grids that provide electricity across states. EGUs are dispatched both within and across state borders and are constantly adjusting behavior in response to available generation and electricity demand on the regional grid. Whenever CO_2 emission reduction measures, such as RE or demand-side EE, are implemented, the measure can affect EGU generation and CO_2 emissions across the regional grid. These impacts can change across multiple affected EGUs on a minute-to-minute, hour-to-hour, and day-to-day basis as electricity demand changes and different generating resources are dispatched. These impacts will also change in the long-term, as the generating fleet and load behavior change over a period of years.

Interactions among EGUs across states may be further driven by the plan types (*i.e.*, rate-based or mass-based) and the individual characteristics of the plans that states choose to adopt.

In the context of this complex environment of federal and state policies and interstate grids, commenters expressed concern about the risk of double-counting of measure impacts, particularly across state plans. Commenters stated that there is potential for distortionary incentives that could undermine overall CO_2 emission reductions (often termed emissions "leakage"). Commenters requested that the EPA ensure that states avoid double-counting and minimize leakage effects when demonstrating achievement of state goals.

The EPA acknowledges that some amount of shifts in generation between sources within and across state borders will inevitably be present and unavoidable in the context of this rule and may affect how affected EGUs achieve the applicable CO_2 performance rates or state goals under a state plan. In fact, the definition of the BSER is premised upon shifts in generation across sources, particularly shifts from higher- to lower-emitting units that result in overall emission reductions. However, in the context of these shifts, the extent to which the movement of generation may be driven not by the potential to capture lower-cost emission reduction but by arbitrage across different emission rates, causing inefficiencies in the power markets and possibly eroding overall emission reductions, should be minimized.

In particular, the EPA has determined final emission performance rates that serve to reduce relative differences between state goals, and thus also focus the potential for generation shifting between affected EGUs on achieving the emission reductions quantified in the BSER. In the proposal, goals differed more substantially between states based upon an assessment of what emission reduction potential units could access located within their state. Commenters observed that due to the interconnected nature of the power sector, units are not limited to such emission reduction measures within their state, and indeed any operational decisions that units take necessarily influence operational decisions at other units throughout the interconnected grid. As a result, in the final rule, we are finalizing CO_2 emission performance rates, informed by regional emission reduction potential, for fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are applied consistently across all affected EGUs. As the same source category-specific performance rates are applied to all units in the contiguous U.S. regardless of the state in which they are located, any differences between state goals in this final rule stem only from the relative prevalence in each state of fossil fuel-fired electric utility steam generating units and stationary combustion turbines. Consequently, there is substantially less incentive in this final rule for units to shift generation across state lines based solely on differences in state goals, since there is substantially less difference between the final rule's state goals, and since those state goals are themselves premised on nationally consistent source category-specific performance rates.

The EPA has also incorporated elements into the rule that seek to minimize double-counting and the distortionary effects that could potentially increase emissions. First, states have the option to adopt multi-state plans that reflect regional interactions while eliminating chances for double counting and providing a level playing field for trading of rate-based ERCs or mass-based allowances. Second, in the method for rate-based plan compliance, the rule provides a general accounting approach for adjusting an affected EGU's or state's CO_2 rate that inherently acts to minimize state differences. These points are further discussed below.

For both rate-based and mass-based approaches, the rule provides states with the option of creating either "ready-for-interstate-trading" plans or multi-state plans. These options for states working together provide opportunities to enable protections against double counting and minimize the presence of distortionary effects.

"Ready-for-interstate-trading" and multi-state plans engage multiple states in the same system for the purpose of trading mass-based allowances or issuing and trading rate-based ERCs. This allows for efficient implementation of protections against double counting provided in state plan requirements, as multiple states are participating in the same tracking systems. This is particularly useful in the context of rate-based ERC issuance and tracking, where it must be ensured that the ERCs being generated are unique across rate-based plans.

This final rule also reduces distortionary effects within the context of multi-state plans. It does so by restricting states to interstate trading with equivalently denominated mass-based allowances or rate-based ERCs. In a mass-based context, all affected EGUs will trade uniform mass-based allowances, whether in a “ready-for-interstate-trading” plan or multi-state plan. In a rate-based plan context, “ready-for-interstate-trading” states must all adopt as their goal the CO_2 emission performance rates as their joint goal. This assures that all the participating states are issuing ERCs using the same subcategorized performance rates, and that the sources in each state have equivalent incentives for trading ERCs. Similarly, under multi-state plans, the relevant states must choose to adopt identical rates, either the CO_2 emission performance rates or a weighted average goal rate based on the rate-based goals of all the states involved. These requirements along with a method for calculating a weighted average goal rate are specified in section VIII.C.5.

Under all types of state plans, states must ensure that the emission reduction measures counted as part of meeting their plan requirements are not duplicative of any measures that are counted by another state, in order to avoid double counting of the MWhs of generation or energy savings that these measure produce. Depending on the accounting method used to reflect these measures in state goals, interstate effects could still allow for the double counting of the emission reductions resulting from these measures, particularly if mathematical adjustments were made to stack emissions to reflect these reductions. Depending on how these measures are accounted for, the reductions could be counted by both the state that deployed the measure, and the state that reports a reduction in fossil generation or reported emissions. In this final rule, the accounting approaches for both mass-based and rate-based plans have been specifically designed to eliminate the risk of double counting of reductions, because emission reduction measures are accounted for only through their inherent impact on stack emissions for affected EGUs.

Mass-based plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. This means that under a mass-based plan any emission reduction measures that are implemented are automatically accounted for in reduced stack emissions of CO_2 from affected EGUs, which avoids concerns about counting the same mass reductions in two different mass-based states.

In a rate-based plan, there needs to be an explicit adjustment of reported CO_2 emission rates from affected EGUs, to reflect the measures that substitute low- or zero-emitting generation or energy savings for affected EGU generation. States with rate-based plans must demonstrate that measures used to adjust their CO_2 emission rate, such as RE and demand-side EE, are non-duplicative. The proposal attempted to address this issue in part by limiting demand-side EE that states could claim to in-state measures. In fact, those in-state measures still have an impact outside of the state and under the proposal's approach, states would have been restricted from taking credit for all the measures they have put in place that reduce CO_2 emissions. Therefore, the EPA is finalizing a treatment that allows states to count all in-state and out-of-state measures, while addressing interstate effects through the structure of the rule's accounting approach for adjusting the CO_2 emission rate of an affected EGU, detailed in section VIII.K.1 above, used to show that the state has met its obligation under its state plan.

The general accounting approach for adjusting the CO_2 emission rate of an affected EGU inherently accounts for the regional nature of how substitute generation and energy savings will impact affected EGU generation and CO_2 emissions. The following discussions refer to the substituting generation and energy savings in question as RE and demand-side EE, but this method can apply to other measures that were not included in the determination of the BSER that substitute for affected EGU generation. The adjusted CO_2 emission rate gives credit to the affected EGU or state for the MWhs of RE and demand-side EE it is responsible for deploying, by allowing those MWhs to be added to the denominator of the CO_2 rate, but makes no adjustment to the numerator. Instead, the numerator reflects reported stack emissions, which will reflect the extent to which RE and demand-side EE reduced the affected EGU's generation and emissions, without needing to account for the state in which the RE or demand-side EE originated, or approximating exactly how it impacted the regional grid. Double-counting of CO_2 emission reductions is prevented because the reported emissions from each unit are represented in the numerator of each of those units' emission rates, and those real emissions capture whatever emission reduction impact occurred with regard to any particular MWh of RE or demand-side EE. Because the general accounting approach disallows any adjustment to any EGU's reported emissions, it is not possible for the real emission reductions prompted by any particular measure to be double-counted.

Double-counting of MWhs in the denominator can be avoided because it is relatively straightforward to quantify the MWhs that the affected EGU is responsible for deploying and add them to the denominator, and this method aligns well with the MWh-denominated trading system described in this final rule. As long as it is assured that the MWhs of RE and demand-side EE are only being claimed by one affected EGU or state, as is outlined in section VIII.K, then there is no double-counting of MWh. Therefore, the accounting method avoids double counting of both CO_2 emission reductions and MWhs, the two characteristics of RE and demand-side EE measures that affect CO_2 emission rates. For further discussion of the MWh-based accounting method, including a calculation example, see section VIII.K.1.

There may also be interactions between mass-based and rate-based plans regarding counting measures, specifically where measures that provide substitute or avoided generation, such as RE and demand-side EE, are located in a mass-based state and can also be used by a rate-based state in meeting the CO_2 performance rates or state goals. The EPA received comments on this particular issue, and many expressed concerns that this use of mass-based resources in a rate-based state would result in double-counting of emission reductions.

Commenters provided analyses specifying how two states can benefit from the same RE and demand-side EE measures as a result of rate- and mass-based plan interactions. Some commenters considered this double-counting of emission reductions, and requested specific mathematical adjustments of reported generation or CO_2 emissions from affected EGUs under either rate-based or mass-based state plans in order to eliminate double-counting.

The EPA has determined that, in the context of interactions among rate-based and mass-based plans, there is not explicit double-counting of the CO_2 emission reductions associated with counting measures located in mass-based states, considering the accounting methods outlined in this final rule. First, as discussed above, the accounting method for adjusting the CO_2 emission rate only counts the MWhs generated by a measure to adjust the MWh in the denominator of the reported CO_2 emission rate. The CO_2 emissions impacts of the measures will be reflected in the rate-based state only to the extent that the MWhs resulted in lower reported CO_2 emissions from an affected EGU in the rate-based state. To the extent that measures that provide substitute or avoided generation reduce generation from affected EGUs in a mass-based state, the effect of those measures is reflected in lower reported CO_2 emissions of the mass-based EGUs. The CO_2 emission reductions reflected in the rate and the mass state will necessarily be mutually exclusive, because both are based on reported stack emissions. Additionally, the mechanism in the mass-based state that is assuring CO_2 emission reductions is the mass budget, which is met by affected EGUs adjusting their generation. Low- or zero-emitting MWhs from resources like RE and demand-side EE can serve load in the mass-based state and play a role in lowering compliance costs, but they play no direct role in mass-based compliance. As a result, no double-counting of emission reductions can take place.

Though there is no risk of double-counting emissions, some commenters expressed the concern that overall CO_2 emissions reductions would be foregone in situations where a source in a rate-based state counts the MWh from measures in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state. Therefore the EPA is restricting the ability of rate-based states to claim emission reduction measures, such as RE and demand-side EE, located in mass-based states.

While the EPA understands this concern regarding foregone reductions, we do not believe it is appropriate to restrict RE crediting unilaterally between rate-based and mass-based states. Such a restriction could cut some states off from regional RE supplies that are assumed in the BSER building block 3 and incorporated in the CO_2 emission performance rates and state CO_2 goals. Allowing crediting between rate- and mass-based states, as long as the risk of foregone CO_2 emission reduction actions in rate-based states are minimized, will assure a supply of eligible RE MWhs that will further enable affected EGUs and states to meet obligations under the final rule. Therefore, the EPA has determined that it is appropriate for rate-based states to count MWhs from RE located in mass-based states, subject to the condition that the generation in question was intended to meet electricity load in a state with a rate-based plan.[1011] This may apply to some or all of the generation from an individual RE installation. To assure that the RE generation in question meets this condition, the EPA is requiring that RE generation from RE installations located in a mass-based state can only be counted in a rate-based state if the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load that included the rate-based state. This can be demonstrated through, for example, the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question. The EPA is providing flexibility to states regarding the nature of the required demonstration, though the state must specify eligible demonstrations for approval in state plans. Under an emission standards plan, this demonstration would be made by the provider of the measure seeking ERC issuance to the rate-based state.

The following are examples of how requirements for a demonstration could be established in state plans and used to allow RE in a mass-based state to be counted in a rate-based state. For an emission standards state plan, a state could specify in the regulations for the rate-based emission standards included in its state plan that it will require an RE provider that seeks the issuance of ERCs to show that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that

[1011] This does not need to necessarily be the state where the MWh of energy generation from the RE measure is used to adjust the CO_2 emission rate of an affected EGU.

occurs in a mass-based state to meet load in a rate-based state. Under this approach, an RE provider in a mass-based state could submit as part of an eligibility application a delivery contract or power purchase agreement showing that the generation was procured by the utility, and was treated as a generation resource used to serve regional load that included the rate-based state. This documentation would be sufficient demonstration to allow the RE generating resource to meet this additional geographic eligibility requirement for the amount of generation in question. All quantified and verified RE MWhs submitted for ERC issuance would need to be associated with that power purchase contract or agreement, and this fact would need to be demonstrated in the M&V reports submitted for issuance of ERCs.

The ability for a rate-based state to count MWhs located in a mass-based state under the above conditions is limited to RE. Rate-based states are not allowed to claim demand-side EE or any other emission reduction measures that were not included in the determination of the BSER located in mass-based states for ERC issuance. While this limits rate-based sources' access to additional resources, providing that access would result in a risk of foregone reductions. Further, unlike RE, there is no obligation related to demand-side EE and other measures that were not included in the determination of the BSER incorporated in the CO_2 emission performance rates or state rate-based goals which would necessitate facilitating access to those resources. This treatment also does not apply to fossil-fuel fired EGUs, such as NGCC units. If a mass-based emission standard has been applied to an affected EGU, there is no valid way to calculate whether it has MWh that are eligible for crediting, as is possible under a rate-based plan.

Finally, as stated earlier, commenters also expressed concern about the potential for relative increases in emissions to occur given relative differences between sources and states. These differences could include states' goals under either the rate- or mass-based approaches, or states' accounting of new sources. These differences could induce increased generation in one state over another because the costs of compliance and relative costs of generation would vary between states. There was particular concern regarding how these differences would provide incentives for increasing generation at new fossil sources and expanding utilization of existing affected EGU generation in states that have less stringent goals, and that this movement of generation would result in increased emissions overall. This could potentially result in the achievement of performance rates but with fewer overall CO_2 emissions reductions than projected nationally under the proposal.

Commenters suggested that the issuance and trading of emission credits across states under a rate-based approach would result in incentives to create credits, through the development of RE for example, in certain states with higher state goals, and this could also be a source of increased overall emissions. They noted that RE siting would thus not occur in the most optimal locations. The commenters assumed that zero-emitting credits are denominated in mass units by multiplying the number of MWh by some emission rate: Either the state goal rate, the current state emission rate, a regional emission rate, or a calculated marginal rate. If those rates were higher in any states, zero-emitting MWhs would create more mass-denominated credits in those states, and thus RE and demand-side EE would be more valuable.

The incentive to target the location of zero-emitting generation or energy savings between states based on variation in its emission reduction value has been minimized by the fact that states participating in rate-based interstate trading must adopt the same emission performance rates or rate-based state goals. It is further minimized, even outside of an interstate trading framework, by the nature of the accounting method finalized in this rule. As explained above regarding the general accounting approach and the trading framework, we are adjusting rates using calculated MWhs, not based upon an emission reduction approximation as commenters outlined above. Not only does the method allow emission reductions to be accounted for as they occur across the grid, but it means the ERCs being traded across states represent one MWh of zero-emitting generation in whatever state it originated, and its value is unaffected by any emission rate associated with its state of origin. Thus, the finalized accounting and trading methods minimize the relative incentives for generating zero-emitting ERCs in a particular state based upon the rates that apply to that state.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.[1012] As described in the Executive Summary, climate change is an environmental justice issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 section XII.J of this preamble). While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, droughts, and the like are experienced in individual communities.

[1012] In this preamble, the EPA discusses environmental justice in two sections. Section XI.J specifically addresses how the agency has met the directives under Executive Order 12898. 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. This section of the preamble addresses actions that the agency is taking related to environmental justice and other issues (*e.g.*, increased electricity costs) that may affect communities covered by Executive Order 12898 as well as other communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts. The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the electric generating units that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NO_X, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart or lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[1013] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of state plans will produce significant reductions in emissions of conventional pollutants, particularly in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

[1013] Six Common Air Pollutants. *http://www.epa.gov/oaqps001/urbanair/*.