On October 23, 2015, the EPA proposed the Model Trading Rules as presumptively approvable components of plans that states could submit to the EPA under the Clean Power Plan, which was promulgated at the same time. The public comment period for the proposed Model Trading Rules closed on January 21, 2016, and on November 3, 2016, the EPA submitted the draft Model Trading Rules to OMB for interagency review pursuant to Executive Order 12866.

The EPA has withdrawn the Model Trading Rules from interagency review and is making available to the public, stakeholders, and states the information contained in the drafts of the Clean Power Plan's Model Trading Rules' preamble and regulatory text. We are also making available drafts of the associated documents (technical support documents addressing "leakage" and evaluation, measurement, and verification (EM&V) for demand-side energy efficiency, and a white paper on allowance/credit tracking systems). The Model Trading Rules and associated documents remain under development and are subject to further change, re-submittal to OMB, and potentially, finalization under a subsequent administration.

The sharing of this information reflects the fact that we had been developing these materials in significant part in response to requests made to the EPA by a number of states and stakeholders over the past year for information that could assist them in pursuing actions – some pertinent to the CPP and others not directly related to the CPP - to address carbon dioxide emissions from the power sector. For example, in an April 28 letter to Acting Assistant Administrator for the Office of Air and Radiation, Janet McCabe, 14 states, citing a broad range of air quality and energy policy activities and obligations they were undertaking as well as their anticipation of possible eventual compliance with the Clean Power Plan, specifically requested that "EPA provide a final model rule or rules." The states also requested "additional information on … tracking systems for allowances or credits; and energy efficiency evaluation, measurement, and verification …." Similarly, many stakeholders requested additional information about addressing "leakage" – which in the CPP is identified as emissions associated with shifting generation to new plants when a state has a mass-based trading program covering only existing power plants. Because these materials are in draft, a state could not rely on them as meeting CPP requirements. However, we believe these materials make substantial progress toward the design of readily-implementable rate- and mass-based emission trading programs under the CPP.

We believe that the work we have done to date can also be of assistance to states to the extent they develop their own programs for their own purposes. Specifically, in making these draft Model Trading Rules and supporting technical documents available to the public, the EPA is providing information that the agency believes may be useful to states, stakeholders, and members of the public who are engaged in considering, developing, or implementing policies and programs aimed at reducing CO_2 emissions from the power sector. These drafts may be especially helpful to states considering the use of emissions trading programs or the expansion of existing trading programs, since one of the chief areas of focus of the draft Model Rules is emissions trading. Similarly, states interested in using or expanding energy efficiency programs might find the material presented in the draft EM&V TSD useful as well.

As EPA explicitly recognized in the proposed and final Clean Power Plan, a number of states, in fact, have been actively implementing programs and strategies to reduce greenhouse gas emissions from power plants. Some of those states, like California and the northeastern states participating in the Regional Greenhouse Gas Initiative, are currently engaged in expanding or strengthening their programs. At least one other state has indicated its intention to proceed with additional work addressing power plant CO_2 emissions. For this reason, EPA concluded that making available the kind of information contained in the draft Model Rules and supporting technical documents would be especially timely at this juncture.

The EPA is providing the drafts for informational purposes only. The draft materials (a draft preamble and accompanying illustrative Model Trading Rule text, as well as draft technical support documents) are still working drafts, and the agency is not taking final agency action at this time. EPA withdrew the Model Trading Rules and accompanying documents from OMB review before the review was completed, and the Administrator has not signed the Model Trading Rules. Furthermore, with respect to the Model Trading Rules, the EPA has not completed several of the steps necessary to conclude a rulemaking action under CAA section

307. For example, the agency has not completed the responses to comments and has not completed the docketing process for supporting materials at this time as would be required under CAA section 307(d)(6) for a final rule. The docket will remain open, with the potential for finalizing the Model Trading Rules at a later date. As simply draft documents, the materials have no legal force or effect, meaning they do not have binding effect on the obligations of any party. The material will not be published in the *Federal Register* or the *Code of Federal Regulations* and is not subject to judicial review. *See* CAA section 307(b)(1). EPA is releasing the draft material in the interest of disclosure and information sharing.

While these are deliberative documents that EPA is not required to release at this point in the process, for the reasons discussed above we thought it appropriate to provide the public with our work to date on these topics. This is in keeping with the agency's general ability to share deliberative material with the public at its discretion in appropriate circumstances.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 62, and 78

[EPA-HQ-OAR-2015-0199; FRL 9930-67-OAR]

RIN 2060-AS47

DRAFT - Model Trading Rules for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes two model trading rules (MRs) that states may adopt in state plans under the Clean Power Plan (CPP), the Environmental Protection Agency's (EPA's) emission guidelines (EGs) under section 111(d) of the Clean Air Act (CAA) for carbon dioxide (CO_2) emissions from existing fossil-fuel fired power plants. The mass-based MR provides an approach and rule language that implements mass-based emission standards for affected electric generating units (EGUs) that can be met through an emission budget trading program. The rate-based MR provides an approach and rule language that implements rate-based emission standards that can be met through the use of a rate-based emission trading program utilizing emission rate

credits (ERCs). Both MRs are designed to be ready-for-interstate-trading and would allow states to incorporate the Clean Energy Incentive Program (CEIP). The provisions of these final MRs are presumptively approvable for meeting the relevant state plan requirements of the CPP. They comprise a substantial portion of a state's plan that, when supplemented with state specific elements that are described in the CPP, will constitute a complete state plan submission. While the U.S. Supreme Court's stay of the CPP is in effect, no state or other party has to comply with the CPP, and all deadlines for action, including submission of state plans, are currently unenforceable. The EPA is finalizing this action at this time in order to provide states that wish to move forward voluntarily with planning an important resource for doing so, and so that the MRs will be available for states once the litigation is resolved.

DATES: This final rule is effective [Insert date 30 days after publication in the **Federal Register**].

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2015-0199. All documents in the docket are listed on the http://www.regulations.gov Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through http://www.regulations.gov.

FOR FURTHER INFORMATION CONTACT: Mr(s). XXXX, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (XXX) XXX XXXX; fax number: (XXX) XXX XXXX; email address: XXXX.XXXX@epa.gov.

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ANSI	American National Standards Institute
ARP	Acid Rain Program
ATCS	Allowance Tracking and Compliance System
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CEIP	Clean Energy Incentive Program
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSAPR	Cross-state Air Pollution Rule
DOE	U.S. Department of Energy
DS-EE	Demand-side Energy Efficiency
EE	Energy Efficiency
EGs	Emission Guidelines
EGU	Electric Generating Unit

EIA	Energy Information Administration
EJ	Environmental Justice
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
ERC	Emission Rate Credit
ERC-TCS	Emission Rate Credit Tracking and Compliance System
FERC	Federal Energy Regulatory Commission
FR	Federal Register
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GJ/h	Gigajoule per Hour
HAP	Hazardous Air Pollutants
ICR	Information Collection Request
IGCC	Integrated Gasification Combined Cycle Facility
lbs	Pounds
MATS	Mercury and Air Toxics Standards
M&V	Monitoring and Verification
MMBtu/h	Million British Thermal Units per Hour
MRs	Model Trading Rules
MW	Megawatts
MWh	Megawatt-hours
NGCC	Natural Gas Combined Cycle
NSPS	New Source Performance Standards
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
NO_X	Nitrogen Oxides
PRA	Paperwork Reduction Act
RE	Renewable Energy
REC	Renewable Energy Certificate
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SCT	Stationary Combustion Turbine
SGU	Steam Generating Unit
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TSD	Technical Support Document
The Court	United States Court of Appeals for the District of Columbia Circuit
TTN	Technology Transfer Network
UMRA	Unfunded Mandates Reform Act
UNFCCC	United Nations Framework Convention on Climate Change
U.S.	United States

WWW World Wide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Executive Summary

On October 23, 2015, the EPA published emission guidelines for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired EGUs(known as the “Clean Power Plan” or CPP).[1] Specifically, the EPA established: 1) CO_2 emission performance rates for existing fossil fuel-fired EGUs, and 2) equivalent state-specific CO_2 goals expressed as both a mass and a rate reflecting the CO_2 emission performance rates. These provisions are codified at 40 CFR part 60, subpart UUUU. As directed by section 111(d) of the CAA, states must develop, submit, and implement state plans that establish emission standards and associated implementing and enforcement measures to achieve the CO_2 emission performance rates. The CPP acknowledges the benefits of both intra- and interstate emission trading programs and allows states to choose to include emission trading programs in their plans.

To assist states in designing state plans, on October 23, 2015, the EPA proposed MRs that states could use under the CPP.[2]

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 FR 64661 (October 23, 2015).

[2] Federal Plan Requirements for Greenhouse Gas Emissions From Electric Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule, 80 FR 64966 (October 23, 2015).

This action finalizes the MRs, which states can choose to incorporate, in whole or in part, into their state plan submissions. This action provides further context and rationale for the MRs and responds to public comments on the proposal related to the MRs.[3] The MRs are examples of approaches that states may use in developing their state plans, but they in no way limit the options and flexibility that states have in the design of their plans as described and finalized in the CPP. The CPP was designed to provide states with flexibility in designing state plans. At the same time, many states and stakeholders requested guidance and direction from the EPA on the design of approvable state plans, and also requested that the EPA provide a means to facilitate streamlined and efficient implementation of the CPP. States also expressed a desire for guidance from EPA on consistent language states could use to be approved for interstate trading. Thus, these MRs provide two options for emission trading programs that align with CPP requirements.

[3] The EPA is not taking any action with respect to the federal plans proposed concurrently with the MRs on October 23, 2015. Topics raised in public comments related solely to a federal plan are not being addressed in this notice and are beyond the scope of this action.

The EPA is finalizing two options, a mass-based MR and a rate-based MR. Both MRs include provisions to make them “ready for interstate trading” as defined in the CPP, with the intention of facilitating the development of broader regional emission trading programs. There is wide-spread agreement among states and stakeholders that a broad-scale emission trading program is particularly effective in achieving pollution control cost-effectively and in alignment with the operation of the electric power system. In addition, consistency in trading program requirements across states benefits both affected EGUs and states in their role as administrators of an interstate emission trading program. The EPA encourages states to use the MRs in their entirety, though as discussed below, states are free to make changes to the MRs so long as CPP requirements are met.

A state plan that adopts either of these two MRs in its entirety would be presumptively approvable with respect to the those CPP state plan requirements covered by the provisions or elements of the MRs. The EPA would not need to perform analyses to evaluate components of a state’s plan that are adopted from a MR to assess the plan’s compliance with applicable CPP requirements. It is sufficient for the EPA to identify in a state plan evaluation rulemaking that the provisions in the state plan are the same as the provisions in one of the MRs that have been determined in this action to meet CPP requirements. As explained below, these MRs do not address every state plan requirement. EPA review of a state plan submittal will evaluate whether all applicable regulatory and statutory requirements, including requirements in the CPP, are met.[4] States may submit state plans that differ from the MRs. The EPA will review all state plans and approve them if they meet the requirements in the CPP. It is a state's responsibility to develop and submit an approvable state plan.

These MRs have no associated burden, health or environmental risk, or cost associated with them because they are simply a model for states to use or adopt, at their option, in the development of a CPP state plan. They do not impose requirements, and states are free to develop state plans that differ from the MRs so long as they meet the applicable statutory and regulatory requirements. In section VIII of this

[4] For a discussion of the context and meaning of the term "presumptively approvable," see section II.B of this preamble.

preamble, the agency explains how it has conducted all statutory or executive order (EO) reviews that apply to this final action.

As it did in the CPP itself, the agency took into account reliablity when it designed the MRs. The MRs provide substantial flexibility for affected EGUs in meeting either a rate- or mass-based emission standard, while also minimizing any possible adverse effects on electric system reliability. A key feature of both MRs is the compliance flexibility inherent in an emission trading program. Both the rate-based and mass-based trading programs specified in the MRs allow the owners or operators of affected EGUs to determine the best way to achieve CO_2 emission reductions. The EPA has also designed the MRs as “ready for interstate trading” in order to facilitate their use by states in the development of multi-state emission trading programs. As a result, the MRs are designed such that compliance strategies can be integrated with the ongoing operation of the electricity grid as it continues to ensure an uninterrupted supply of affordable and reliable electricity. This flexibility is especially valuable whenever the need to address specific reliability concerns may arise. It allows owners and operators of reliability-critical affected EGUs to continue to meet their emission standard compliance obligations while operating to maintain electric system reliability.

B. What types of model trading rules are being provided?

1. Mass-Based Model Trading Rule

The mass-based MR is in the form of an emission budget trading program for affected EGUs. A state adopting the mass-based MR would establish an emission budget that is equal to the state mass-based CO_2 goal for affected EGUs established in the CPP. The MR provides for the use of CO_2 allowances when demonstrating compliance with an affected EGU emission standard. Each CO_2 allowance represents a limited right to emit one short ton of CO_2 from an affected EGU. CO_2 allowances may be bought and sold, or banked for use in later years.

After each compliance period, the owner or operator of any facility with affected EGUs must hold for deduction CO_2 allowances equal in number to the quantity of the reported CO_2 emissions of the affected EGUs at the facility during the compliance period; this allowance-holding requirement is the emission standard for an individual affected EGU. Section IV of this preamble discusses key components of the mass-based MR, including compliance periods, emission budgets, allowance trading and banking, allowance tracking and compliance system

(ATCS), allowance allocation, approaches to address potential emission leakage, trading program operations and compliance, and monitoring and reporting requirements for affected EGUs.

The regulatory provisions for the mass-based MR finalized in this action are codified in 40 CFR part 62, subpart MMM. In response to comments, the EPA is not finalizing the proposed allowance allocation provisions as part of the final mass-based MR. As a result, a state will need to add its own allowance allocation provisions to the mass-based MR when submitting its state plan. The EPA’s rationale for not including the proposed allowance allocation provisions in the final mass-based MR is discussed in section IV.F of this preamble.

2. Rate-Based Model Trading Rule

In the rate-based MR, affected EGUs must meet applicable rate-based emission standards. These standards are the uniform subcategorized CO_2 emission performance rates from the CPP, expressed as a rate of pounds of CO_2 per megawatt hour (lbs/MWh). If an affected EGU emits above its assigned rate standard, the owner or operator must acquire a sufficient number of ERCs, each representing a MWh with zero deemed associated CO_2 emissions for compliance purposes, to bring its adjusted CO_2 emission rate into compliance. Emission rate credits may be issued to affected EGUs or other entities (called “eligible resources”) that supply zero- or low-emitting electricity generation or savings to the grid through a state approval and issuance process. Emission rate credits may be bought and sold, or banked for use in later years. Section V of this preamble discusses the rate-based MR, including the subcategorized emission standards; the ERC mechanism; ERC tracking systems; ERC issuance process and requirements, including evaluation, measurement, and verification (EM&V); ERC trading, transfers, and banking; compliance provisions; and monitoring, recordkeeping, and reporting requirements. The regulatory provisions of the rate-based MR finalized in this action are codified at 40 CFR part 62, subpart NNN.

II. Background

A. What is the statutory authority for this action?

These MRs are being issued under the EPA’s statutory authority in the CAA. Specifically, this action provides states presumptively approvable models for state plans under the CPP EGs, issued by the agency pursuant to section 111(d) of the CAA, 42 U.S.C. 7411(d). This action also is authorized by the agency’s general authority to implement and administer CAA under section 301(a), 42 U.S.C. 7601(a). This action is further supported by sections 102 and 103 of the CAA, 42 U.S.C. 7402, 7403, which direct the EPA to undertake a variety of cooperative and capacity-building activities in furtherance of air pollution prevention and control objectives, including "encourage[ing] the enactment of improved and, so far as practicable in the light of varying conditions and needs, uniform State and local laws relating to the prevention and control of air pollution." *Id.* section 7402(a).

This action is nationally applicable within the meaning of section 307(b)(1) of CAA, 42 U.S.C. 7607(b)(1), because it provides MR provisions that are presumptively approvable if timely submitted in a state plan by any state in the United States with affected EGUs under the CPP. The meaning of "presumptively approvable" is discussed in section II.B of this preamble. Under section 307(b)(1) of CAA, judicial review of these MRs is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by [INSERT DATE 30 DAYS FROM THE DATE OF PUBLICATION IN THE **FEDERAL REGISTER**]. The agency recognizes that, as MR provisions that states may or may not choose to adopt, these provisions lack any immediate force and effect, and are not federally enforceable until a state adopts, and EPA approves, such provisions in a state plan under CAA section 111(d). If a state chooses to adopt one of the MRs as its state plan, and the EPA takes final action on that state plan through notice and comment rulemaking, that EPA action will constitute final agency action with respect to that state’s plan, which would be judicially reviewable under CAA section 307, except to the extent any such review could have been obtained with respect to this action. Section 307(d)(7)(B) of the CAA further provides that “[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.” This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, “[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.” Any person seeking to make such a demonstration to the agency should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, 1200 Pennsylvania Ave., NW, Washington, DC 20460, with a copy to the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW, Washington, DC 20460.

This action is consistent with, and the EPA's authority in taking this action is unaffected by, the Supreme Court's stay orders in West Virginia, et al. v. EPA, et al., No. 15A773 (February 9, 2016). The Supreme Court granted applications for a stay of the CPP pending disposition of the Stay Applicants' petitions for review of the CPP in the Court, including any subsequent review by the Supreme Court. That litigation is currently pending, and the Supreme Court's stay is in effect.

A stay has the effect of "halting or postponing some portion of [a] proceeding, or [] temporarily divesting an order of enforceability." Nken v. Holder, 556 U.S. 418, 428 (2009). A stay is distinct from an injunction, which "direct[s] the conduct of a particular actor." *Id.* While the stay is in effect, no party is obligated to comply with the CPP. Because the legal operation of the CPP is carried out through deadlines for states to submit state plans, this means the CPP deadlines are currently unenforceable, and states are under no obligation to submit plans while the stay is in effect. Further, because the EPA’s authority to issue a federal plan under CAA section 111(d) requires the agency to first take action on a required state plan, or find that a state failed to submit a plan, no federal plan can be promulgated for a state while the stay is in effect either.

The stay does not otherwise constrain the agency or states, and the EPA has not been enjoined from continuing to work on the CPP. A judicial stay of one agency action should not be construed to otherwise limit the discretion of an administrative agency or “interfere[] with the normal agency processes.” Samson v. Murray, 415 U.S. 61, 77-78 (1974). Agencies generally remain free to conduct statutorily-authorized rulemaking, even where such rulemaking is related to, or potentially impacted by, a prior rulemaking that has been stayed or enjoined. NAACP, Jefferson County Branch v. Donovan, 737 F.2d 67, 71-72 (D.C. Cir. 1984).

The agency notes that in addition to its CAA section 111 and section 301 authority to engage in this rulemaking, the EPA possesses multiple other authorities under the CAA that direct it to engage in capacity building and provide technical and financial assistance to states in order to effectuate the air pollution reduction objectives of the CAA.[5] These authorities typically support, but operate independently of, the CAA's regulatory mandates. Under section 102 of the CAA, for example, the EPA shall "encourage cooperative activities by the States and local governments for the prevention and control of air pollution; encourage the enactment of improved and … uniform State and local laws relating to the prevention and control of air pollution; and encourage the making of agreements and compacts between States for the prevention and control of air pollution." 42 U.S.C. section 7402(a). The EPA is also authorized under section 103 of CAA to conduct a variety of research and development activities, render technical services, provide financial assistance to air pollution control agencies and other entities, and conduct and promote coordination of training for individuals – all for the purpose of the "prevention and control of air pollution." 42 U.S.C. section 7403(a).

The EPA may, among other things, "collect and disseminate, in cooperation with other federal departments and agencies, and

[5] It is undisputed that CO_2, as a GHG, is an air pollutant under the CAA. *See* Massachusetts v. EPA, 549 U.S. 497, 528-532 (2007).

with other public and private agencies, institutions, and organizations having related responsibilities … information pertaining to air pollution and the prevention and control thereof.” *Id.* section 7403(b). The Act expressly authorizes the agency to develop “nonregulatory strategies … for preventing or reducing multiple air pollutants, including … carbon dioxide, from stationary sources, including fossil fuel power plants.” *Id.* section 7403(g). Taken together, these provisions both establish that the EPA has the authority and illustrate why the EPA would have good reason to continue coordinating and assisting in the development of CO_2 pollution prevention and control efforts of the states and local governments, even in light of the stay of the CPP.

The EPA has proceeded under a similar understanding of its authority when CAA rules have been judicially stayed pending review in the past.

For example, when the the Court stayed the Cross-State Air Pollution Rule (CSAPR), EME Homer City Generation, L.P. v. EPA, No. 11-1302 (D.C. Cir. December 30, 2011), the EPA issued two rules that made a number of revisions to the stayed rule. The EPA noted that its actions in revising the rule were “consistent with and unaffected by the Court’s Order staying the final

[CSAPR]. Finalizing this action in and of itself does not impose any requirements on regulated units or states.” *See* 77 FR 10324, 10326 (February 21, 2012). Indeed, the EPA undertook that rulemaking in part “in order to neutralize a key uncertainty facing successful and potentially rapid program implementation following the current stay, such that sources can rely on <u>immediate activation</u> of a [CSAPR] allowance market.” *Id.* at 10331 (emphasis added). In another set of revisions finalized in June of 2012, the EPA again took action making a number of important changes, including state emission budget adjustments and revision of set-aside accounts for new sources, while the stay of the rule was in effect. *See* 77 FR 34830 (June 12, 2012). Among other things, the EPA rejected a comment to revise the set-aside accounts for years for which the EPA had already recorded allowances in compliance accounts prior to the stay being issued. *Id.* at 34838-34839. The EPA explained that because the allowances were already recorded, they were freely available to their owners to be transferred or sold and may no longer be in the original owners’ accounts. The agency rejected the commenter’s expansive interpretation that the judicial stay meant “these allocations are no longer distributed for use.” *Id.* Rather, the stay meant, in the EPA’s view that “sources are not required to hold allowances for compliance at this time," but that did not mean the allowances themselves did not remain in circulation. *Id.*

Similarly, when the the Court stayed the NO_X SIP Call, issued under authority of CAA section 110(k)(5), Michigan v. EPA, No. 98-1497 (D.C. Cir. May 25, 1999), the agency proceeded to institute direct federal regulation of the sources to achieve functionally the same result under CAA section 126(c). *See* Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport, 65 FR 2674, 2680 (January 18, 2000). In reviewing and upholding the EPA's direct federal regulation under CAA section 126, the Court addressed the issue of whether the EPA could proceed under CAA section 126 in light of the stayed NO_X SIP Call under CAA section 110. Noting that the "congruence" between the EPA's schedules for action under the separate provisions had been disrupted by its stay order, and that the conditions under which the EPA had originally deferred action under CAA section 126 were no longer present, the Court upheld the agency's authority to proceed under CAA section 126 and deferred to the agency's interpretation that the two provisions "operate independently" such that proceeding with regulation under section 126 was not unlawful. Appalachian Power Co. et al. v. EPA, 249 F.3d 1032, 1045-48 (D.C. Cir. 2000). To be clear, the EPA is not instituting direct regulation of affected EGUs in this action. Rather, the Court's analysis in Appalachian Power supports the agency's view that a stay does not affect its ability to conduct activities that are not in themselves dependent for their authority on the effectiveness of the stayed action.[6] The provision of these MRs is just such an action.

This action provides MRs that states may adopt, incorporate by reference, or otherwise use in the design of state plans. While the MRs provide states two approaches to plan design that the EPA has determined would be approvable as meeting the requirements of the CPP, the EPA is in no way requiring states to adopt either of the MRs. Thus, this action does not impose any requirements on states or affected EGUs. Many of the comments the EPA received on the proposed MRs urged the agency

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[6] *See also* Air Transp. Ass'n of Am. v. U.S. Dep't of Transp. et al., 613 F. 3d 206, 209 (D.C. Cir. 2010) (upholding Federal Aviation Administration's institution of airport congestion pricing while "slot auctions" regulation to solve the same congestion problem was judicially stayed pending review); NAACP, Jefferson County Branch v. Donovan, 737 F. 2d 67, 71-72 (D.C. Cir. 1984) (upholding agency authority to amend regulations bearing on the legality of an enjoined prior regulation).

to finalize them expeditiously in order to give states and stakeholders as much time as possible to consider them before state plan submittals are due. While these comments were made prior to the issuance of the stay of the CPP, the agency has continued to hear a desire from states and other stakeholders to have certainty regarding implementation options as soon as possible. By issuing these MRs now, the agency is also answering a request from those states who have said they wish to have additional information and resources from the agency now in order to continue working voluntarily on state plans to regulate CO_2 emissions from existing power plants. For instance, on April 28, 2016, environmental agency officials from fourteen states wrote to the EPA to request additional information and technical assistance related to the CPP, and they specifically requested that the EPA finalize the model rules.[7] Further, the provision of these MRs will put all states and stakeholders, even those who have decided to cease working on the development of a state plan while the stay is in effect, in the best possible position to begin working again on state plans once the stay is lifted.

[7] A copy of this letter has been placed in the docket for this action.

Although the CPP deadlines cannot be enforced while the stay remains in effect, at this point it is not clear whether and to what extent those deadlines will be tolled (*i.e.*, extended) once the stay is lifted. These issues were not addressed by the Supreme Court's stay orders and will need to be resolved when the stay is lifted. Some of the stay applicants expressly requested that all of the CPP deadlines be tolled for the period between the CPP's publication and the final disposition of their lawsuits. *See, e.g.,* Appl. of Util. & Allied Parties for Immediate Stay of Final Agency Action Pending Appellate Review 22. In its brief, the government interpreted that form of relief to be requested (either explicitly or implicitly) by all of the applicants, and it opposed the stay in part on the grounds that such relief would be "extraordinary and unprecedented." Mem. for Fed. Resps. in Opp. 3; *see id.* 70-71. In their reply brief, the twenty-nine state applicants clarified that they were only seeking a "straightforward" Administrative Procedure Act stay that would merely "temporarily divest [the Clean Power Plan] of enforceability," such that "the States need not comply with any of the [Clean Power Plan's] deadlines <u>that will occur during this litigation</u>." Reply of 29 States and State Agencies in Support of Appl. for Immediate Stay

29 (emphasis added). The states disagreed that granting the stay would necessarily require day-for-day tolling of every CPP deadline for the period between the CPP's publication and the conclusion of the lawsuit. *Id.* at 30. They stated that although such tolling "would be appropriate as a matter of basic fairness," "the exact shape of such an equitable disposition need not be decided today." *Id.* at 30 (emphasis added) (citing Michigan v. EPA, no. 98-1497, Docket 524995 (D.C. Circuit 1999), for an example of a case in which the Court decided whether and how to toll relevant deadlines after the challenged rule was upheld). The Supreme Court's orders granting the stay did not discuss the parties' differing views of whether and how the stay would affect the CPP deadlines, and they did not expressly resolve that issue. In this context, the legal effect of the stay on the CPP deadlines is ambiguous, and the question of whether and to what extent tolling is appropriate will need to be resolved once the validity of the CPP is finally adjudicated. It is at that point that the effect of the stay will be able to be assessed in light of all relevant circumstances.

Because it is currently unclear what adjustments, if any, will need to be made to implementation timing, the MRs continue to reflect the timing elements of the CPP as finalized. For instance, the compliance periods for the MRs remain as they were proposed and continue to track with the state plan interim step periods and final periods in the CPP (*e.g.*, the first MR compliance period starts on January 1, 2022). However, the agency recognizes that it may become necessary to adjust the timing elements in these MRs in concert with other timing elements of the CPP. If necessary, this will be addressed along with the resolution of other timing issues. The decision not to modify the timing elements of the MRs in this action should not be taken to indicate any particular view or intention on the part of the agency regarding how the timelines for the CPP overall may be impacted by the Supreme Court's stay.

B. What is the purpose of these model trading rules?

The EPA is finalizing two MRs (one that specifies a mass-based emission trading program and one that specifies a rate-based emission trading program) that a state can either adopt or tailor for inclusion in a state plan under the CPP. The EPA has designed these MRs so that their provisions meet the relevant requirements of the CPP. In the MRs proposal, the EPA stated that if one of the MRs is adopted by a state without any change, the state plan would be presumptively approvable. Commenters generally supported the concept that the MR state plans be considered presumptively approvable, and this generally remains the EPA’s view in this final rule. If a state adopts either one of these two MRs in its entirety in the state plan, then the state plan would be presumptively approvable with respect to those state plan elements. However, where there is a requirement of the CPP that the MRs do not address, a state must address it in order to have a fully approvable plan.

Thus, the agency uses the term “presumptively approvable” in recognition that a state plan submission must be accompanied by other materials in addition to MR regulatory provisions, and, as discussed below, certain other provisions or filings may be required to address other CPP state plan requirements. The requirements for state plans are set forth in the CPP and the CAA section 111(d) implementing regulations of 40 CFR part 60, subpart B. For instance, they include a formal letter of submittal from the Governor or his or her designee, evidence that the rule has been adopted into state law and that the state has necessary legal authority to implement and enforce the rule, and evidence that procedural requirements, including public participation under 40 CFR 60.23, have been met. *See also* 40 CFR 60.5875. CPP state plan submittals must include an identification of the affected EGUs in the state as well as an inventory of their CO_2 emissions for the most recent calendar year for which data are available prior to the submission of the plan. *See* 40 CFR 60.5740(a)(1). In addition, states must keep certain records and file certain reports and notifications with the EPA under 40 CFR 60.5865 and 60.5870, and state plans must include a description of the process, contents, and schedule for state reporting to the EPA about plan implementation and progress, as provided by 40 CFR 60.5740(a)(5). As discussed in section III.F of this preamble, states must also demonstrate in their state plan submittal that they have considered system reliability issues. *See* 40 CFR 60.5745(a)(7). Provisions to meet these CPP requirements are not included in the MRs.

Further, as explained below, the EPA is not finalizing certain discrete aspects of the mass-based MR as proposed. In particular, as explained in section IV below, the mass-based MR does not include provisions that specify an approach for allocating allowances, which a state must include in its state plan pursuant to 40 CFR 60.6815(b). Where a state plan includes a mass-based emission trading program, the CPP provides states with broad discretion in determining the allowance allocation approach and methods included in the state plan. Given the flexibility provided to states in the CPP to determine how to allocate allowances, the EPA has determined it would be inappropriate to finalize any particular allocation approach in the mass-based MR. The EPA believes that the inclusion of such provisions could be interpreted as the agency directing states toward a preferred approach, which it does not believe is appropriate given the different circumstances and policy objectives of individual states.[8]

The CPP established a presumptively approvable approach for addressing potential leakage through the regulation of new sources under state law.[9] In addition, states have broad

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[8] The EPA notes that the allocation requirements in the CPP are basic and, in general, simply require that a state plan specify how allowances will be allocated. *See* 40 CFR 60.5815. Determining the appropriate allowance allocation approach and method(s) as part of the design of a mass-based emission trading program -- while it involves important policy choices regarding the distribution of a tradable asset -– is not relevant to plan approvability under the CPP. The one exception is where a state uses allocation methods to address the CPP requirement to address potential emission leakage to new sources. *See* 40 CFR 60.5790(b)(5). This is discussed in section IV.G of the preamble.

[9] The EPA notes that the CPP provided “presumptively approvable” emission budgets for states that choose to address leakage by incorporating new fossil fuel-fired EGUs into their emission budget trading program as a matter of state law. Those emission budgets consist of the state’s mass goal plus a complement of additional allowances, called the “new source complement,” to provide a larger budget available to both existing affected and new fossil fuel-fired EGUs. *See* 40 CFR 60.5790(b)(5)(i).

discretion to fashion an approach to meeting CPP state plan requirements for addressing potential leakage where a state plan includes a mass-based emission trading program, pursuant to 40 CFR 60.5790(b)(5). Based on comments, the MR does not address further a presumptively approvable approach to leakage. Specifically, the agency is not providing a presumptively approvable allowance allocation approach as part of the mass-based MR for addressing potential leakage. States adopting the mass-based MR, therefore, must also address this plan requirement in their state plan submittal. To provide resources for state plan development, the EPA is providing a technical support document, "Leakage Requirement for State Plans using Mass-based Emission Budget Trading Programs" ("Leakage TSD"), located in the docket for this action. This document, which discusses and presents example approaches for meeting the CPP leakage requirement under the three options provided in the CPP, is discussed further in section IV.G of this preamble.

To further support state use of the MRs, the MRs were developed so that they can be adopted or incorporated by reference by a state with a minimum of changes that would be necessary to make the rule appropriate for use by a particular state. In this way, a state may adopt or incorporate by reference either of the MRs as its state plan, or as backstop emission standards in a state measures plan, with few, if any, adjustments.[10] A state may make changes to an MR, so long as its state plan meets all CPP requirements. Some commenters expressed concern that the MRs would limit states' flexibility under the CPP or even could mean that states that do not adhere to the MRs will have their plans disapproved. These concerns are unfounded. As explained in the CPP preamble, states have wide flexibility in the design of state plans. *See* 80 FR 64832, 64833 (October 23, 2015). The CPP establishes the requirements that states must meet in order to have their plans approved. The MRs simply provide two sample approaches that the EPA has determined, through this notice and comment rulemaking, meet the requirements of the CPP and are, therefore, considered presumptively approvable. However, these MRs are by no means the only approvable state plan designs. If a state chooses to tailor or modify an MR, such as by expanding the types of eligible resources that may be issued ERCs in a rate-based emission trading program, the EPA may still approve the plan. However,

[10] See section III.C below for a more detailed discussion of incorporating the MRs by reference and using a MR as a backstop.

the EPA would only do so after appropriate review of such provisions to determine whether they meet the applicable CPP requirements.

Functionally, the EPA’s determination of presumptive approvability with respect to these MRs means that, because the MRs have been finalized as plan designs that meet CPP requirements, at the time the EPA takes action on a state plan that has adopted one of the MRs, the EPA will not need to conduct an additional analysis of whether the MR provisions meet CPP requirements. At that time, it will be sufficient for the EPA to identify in its separate rulemaking for a state’s plan that the provisions in the state plan are the same as the provisions in one of the MRs that have been determined in this action meet CPP requirements. The EPA’s approval of a state plan, including a plan that adopts one of the MRs, will be the result of an independent notice-and-comment rulemaking process. The EPA’s finalization of the MRs here is without prejudice to the outcome of any particular state plan approval process. In accordance with CAA section 111(d), the implementing regulations in 40 CFR part 60 subpart B, and the CPP, the process for review and approval (or disapproval) of a state plan, whether based on one of the MRs or otherwise, will occur after a state makes its state plan submission.

While states are not required to adopt an MR, states may conclude that there are significant advantages to doing so. Use of the MRs by states would help to ensure consistency among state programs, which is useful for the potential operation of a broad-based emission trading program that spans multiple states and multi-state regions. As discussed at length in the CPP, individual EGUs operate less as isolated entities and more as components of a large interconnected system designed to integrate a range of functions that ensure an uninterrupted supply of affordable and reliable electricity while also, for the past several decades, maintaining compliance with air pollution control programs. Because emission reductions must occur at affected EGUs, a geographically broad emission trading program is particularly effective in allowing affected EGUs to operate in a way that achieves pollution control efficiently and without disturbing the overall electricity system of which they are a part and the critical functions that this system performs. In addition, consistency of requirements among state emission trading programs benefits not only affected EGUs, but also states in their roles as administrators of interstate emission trading programs.

C. What is the relationship between the final model trading rules and other EPA programs and rules?

1. The Clean Power Plan Emission Guidelines

On October 23, 2015, the EPA published a final rule establishing new source performance standards (NSPS) for carbon dioxide (CO_2) from fossil fuel-fired power plants under CAA section 111(b). *See* Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule, 80 FR 64510 (October 23, 2015) (codified at 40 CFR part 60, subpart TTTT). Simultaneously, the EPA published a final rule establishing EGs for state plans addressing CO_2 emissions from existing fossil fuel-fired power plants under CAA section 111(d). *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 FR 64662 (October 23, 2015) (codified at 40 CFR part 60, subpart UUUU) (also known as the “Clean Power Plan”). In the CPP, the EPA established: state-specific CO_2 goals for affected EGUs reflecting the CO_2 emission performance rates; CO_2 emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs -- fossil fuel-fired electric utility steam generating units and stationary combustion turbines; and guidelines for the development, submittal, and implementation of state plans that establish emission standards or other measures to implement the CO_2 emission performance rates, which may be accomplished by meeting the state CO_2 goals for affected EGUs.

On the same day that these final rules were published, the EPA also published a notice of proposed rulemaking, Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule, 80 FR 64966 (October 23, 2015). In that action, the EPA proposed a federal plan to implement the CPP for states and other jurisdictions that do not submit an approvable plan to the EPA. The proposal included two approaches to a federal plan: a rate-based emission trading program and a mass-based emission trading program. These proposals also separately constituted two proposed MRs that states could adopt or tailor for inclusion in a state plan under the CPP. In addition, the EPA proposed enhancements to the CAA section 111(d) implementing regulations related to the process and timing for state plan submissions and the EPA actions at subpart B of part 60, of title 40 of the Code of Federal Regulations, and an interpretation regarding when an existing source modifies or reconstructs in such a way that it meets the definition of a new source. The EPA also proposed an interpretation regarding the applicability of CAA section 111(d) to affected sources that later undertake a modification or reconstruction and proposed a necessary or appropriate finding for federal regulation under CAA section 301(d) for three areas of Indian country with affected EGUs.

In this action, the EPA is finalizing the two MRs that were proposed and published in the **Federal Register** on October 23, 2015.[11] The EPA is separately taking action to finalize changes to 40 CFR part 60, subpart B, the EPA's implementing regulations for CAA section 111(d), and to finalize an interpretation regarding when an existing source modifies or reconstructs in such a way that it meets the definition of a new source. The agency is not taking final action at this time with respect to the proposed federal plans, or the proposed necessary or appropriate finding for the three areas of Indian country. We

[11] As discussed in section III.I of this preamble, the EPA is also finalizing additions to the 40 CFR part 78 internal appeals procedures to include potential EPA decisions under the MRs.

provide more discussion on these two issues below.

2. The Proposed Federal Plan

The EPA is not taking any action at this time with respect to the proposed rate-based and mass-based federal plans. CAA section 111(d)(2) provides the EPA the same authority to prescribe a plan for a state in cases where the state fails to submit a satisfactory plan as the EPA would have under CAA section 110(c) in the case of failure to submit an implementation plan. As the EPA explained in the October 23, 2015, proposed rulemaking, finalization of the MRs does not constitute a final action with respect to a federal plan for the affected EGUs in any state. Rather, the proposed federal plan remains just that, a proposal. Therefore, in this action, the EPA is not responding to comments that relate solely to the proposed federal plan. Those comments will be considered and responded to, as appropriate, if and when the EPA takes action with respect to a federal plan for a particular state or states. As explained above, while the Supreme Court's stay of the CPP remains in effect, states are under no obligation to submit a state plan to the agency. Therefore, the legal prerequisite necessary for the EPA to promulgate a federal plan under CAA section 111(d)(2) — namely, the agency's action disapproving a required state plan submittal, or making a finding of failure to submit a state plan by a legally enforceable deadline – cannot be met while the stay is in effect.

3. Proposed Necessary or Appropriate Finding

The EPA proposed a necessary or appropriate finding under CAA section 301(d) for the EPA to implement a CAA section 111(d) federal plan for the affected EGUs located in three areas of Indian country. *See* 80 FR 65033 (October 23, 2015). These areas include lands of the Navajo Nation's reservation, lands of the Ute Tribe of the Uintah and Ouray Reservation, and lands of the Fort Mojave Tribe's reservation. The EPA is not taking action on that proposal at this time. Beyond the fact that the stay of the CPP is currently in effect, the agency notes that in general under the CAA, tribes with affected EGUs may, but are not required to, submit tribal plans to implement the CPP.

The EPA proposed carbon pollution EGs for existing EGUs in Indian country in a Supplemental Notice of Proposed Rulemaking. *See* 79 FR 65482 (November 4, 2014). The four facilities with affected EGUs located in Indian country that the EPA identified in the Supplemental Notice are: The South Point Energy Center, on the Fort Mojave Reservation geographically located within Arizona; the Navajo Generating Station, on the Navajo Indian

Reservation geographically located within Arizona; the Four Corners Power Plant, on the Navajo Indian Reservation geographically located within New Mexico; and the Bonanza Power Plant, on the Uintah and Ouray Indian Reservation geographically located within Utah. The CO_2 emission performance rates and equivalent CO_2 goals for affected EGUs in these areas were finalized along with those for affected EGUs located in the rest of the contiguous U.S. in the CPP, which, as explained above, is currently stayed.

The EPA received several comments opposing the proposed finding for the tribes arguing that it is neither necessary nor appropriate. In the case of the Navajo Nation, commenters point out that utilities operating on the Navajo Nation have already taken or will be taking steps to significantly reduce their CO_2 emissions from EGUs. Further, they enumerated other considerations such as lack of flexibility relative to states, economic consequences for the tribe, effects on water supply, and potential impacts for the state of Arizona that the EPA should weigh in its decision. The EPA has met with representatives from the Navajo Nation on several occasions to discuss their comments and better understand their concerns. At this time, the EPA is not taking action on the proposed necessary or appropriate finding as part of the final model trading rules, but intends to address it in the future.

4. The Clean Energy Incentive Program

The CEIP is a program that states have the option to adopt as part of a state plan if they wish to incentivize certain early emission reduction projects under the CPP. *See* 80 FR 64829-64831 (codified at 40 CFR 60.5737). The EPA included the CEIP in the CPP in response to the many comments the agency received supporting the early action crediting concept discussed in the CPP proposed rule, *see* 79 FR 34918-34919 (June 18, 2014). In the proposed federal plan and MRs, the EPA requested comment on a number of design details for the CEIP that had been identified in the preamble to the CPP, and also included provisions to implement the CEIP under the proposed federal plan and MRs. *See* 80 FR 65025-65026 (October 23, 2015). The agency proposed a rate-based and a mass-based approach to implementing the CEIP as part of the proposed federal plan. *See* 80 FR 65066-65067 (proposing a CEIP set-aside as part of a mass-based federal plan at 40 CFR 62.16235(e)); *id.* at 65092-65093 (proposing a rate-based CEIP program as part of a rate-based federal plan at 40 CFR 62.16431). The proposed federal plan CEIP provisions also served as proposed MR CEIP provisions that would be presumptively approvable if adopted in state plans. *See* 80 FR 64973 (October 23, 2015).

The EPA has determined to remove all CEIP-related provisions from this action finalizing the MRs, and has re-proposed optional example regulatory text for the CEIP as part of a separate proposal for public comment on a variety of CEIP design details. The Administrator signed a notice of proposed rulemaking of the CEIP design details on June 16, 2016, which was published in the **Federal Register** on June 30, 2016. *See* 81 FR 42940).[12] Therefore, the EPA is not finalizing any aspect of the CEIP in this action. The agency believes it is administratively simpler and more convenient for the public to be able to review and comment on the optional example regulatory text related to the CEIP in conjunction with all the other CEIP design details being proposed in that action. However, the MRs have been finalized in such a way that the optional CEIP example regulatory provisions could be readily incorporated.

5. Implications for New Source Review, Title V, and Other Programs

[12] *See also* https://www.epa.gov/cleanpowerplan/clean-energy-incentive-program.

In general, because the MRs are not effective unless they are incorporated into an approved state plan, this action does not have any direct implications for other CAA programs. If one of these MRs is incorporated into an approved state plan, the potential implications for New Source Review, title V, and other programs would likely be similar to those discussed in the notice of the October 23, 2015, federal plan and MRs proposal. *See* 80 FR 64984-64986. However, for the title V program, the EPA is making some changes to the relevant regulatory provisions in the MRs, as discussed in more detail below.

The MRs proposal included three main points regarding the title V program. First, title V permits for sources with affected EGUs will need to include any new applicable requirements that the approved state plan places on affected EGUs, including requirements under CAA section 111(d), as defined in the title V regulations at 40 CFR 70.2 and 71.2. Second, the proposed regulations included a provision stating that no title V permit revision shall be required for the allocation, holding, deduction or transfer of allowances once the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances have been incorporated in such permit. Third, pursuant to 40 CFR 70.7(e)(2)(i)(B) and

40 CFR 71.7(e)(1)(i)(B), we proposed that any changes that may be required to an operating permit with respect to the trading programs under 111(d) may be made using the minor permit modification procedures of the title V rules.

Various commenters on the title V program generally stated that states administering the MRs should not be required to incorporate as permit terms or conditions rule text that does not pertain directly to or does not impose any obligation on the title V facility. For example, some commenters stated that the allocation of allowances, establishment of set-asides, requirements for independent verifiers and the eligible resource requirements, all of which govern how states will administer the trading program, should not be included in the title V permit for an individual source. Regarding the proposed statement that no title V permit revision shall be required for the allocation, holding, deduction or transfer of allowances once the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit; many commenters were in favor of this statement. In terms of minor modifications, several commenters believe that the use of minor modifications of title V permits is the appropriate mechanism to make any changes that may be required to an operating permit with respect to the trading programs under 111(d). Another commenter stated that the EPA should explicitly state what types of changes the permitting authority could treat as minor modifications, justify those statements, and allow the public to comment on these changes before minor modifications are used to revise title V permits with 111(d) applicable requirements. Otherwise, the commenter believes, the potential for increases in emissions at sources under an emission trading program could impact already burdened communities without the opportunity for public comment since minor permit modifications under EPA-approved title V state programs are not subject to public notice requirements as are other title V permit modifications or revisions. *See* 40 CFR 70.7(h). Finally, other commenters were in favor of the EPA developing guidance to clarify what constitutes title V applicable requirements, with some of these commenters stating that the guidance should be similar but not identical to the Cross-State Air Pollution Rule (CSAPR) guidance as they see the CSAPR guidance as still too prescriptive.

Based on the comments received, the EPA is not finalizing in this action the proposed regulatory text stating that all requirements of this subpart (*i.e.,* Part 62 subpart MMM or Part

62 Subpart NNN) are applicable requirements and must be included in an affected EGU’s title V permit. The EPA is also not finalizing the regulatory text stating that any changes that may be required to an operating permit with respect to the trading programs under 111(d) may be made using the minor permit modification procedures of the title V rules.

The EPA acknowledges that some 111(d) plan requirements would be applicable requirements while other requirements that are a part of the approved state plan may not be title V applicable requirements under 40 CFR 70.2 and 71.2. The determination of what constitutes an applicable requirement should be made as a state is developing its plan or when revising a source's title V permit and would be subject to EPA review as part of approving the plan or as part of reviewing the title V permit. In addition, after review of comments and further consideration, the EPA acknowledges that a blanket authorization to use the minor modification procedures for any changes that may be required for an operating permit with respect to the 111(d) trading programs is not consistent with previous regulatory actions and guidance related to trading programs such as CSAPR. In general, states incorporate the applicable requirements of a trading program into existing title

V permits in accordance with the procedures in the approved operating permit program. Such procedures include the permit renewal provisions at 40 CFR 70.7(c) or 40 CFR 71.7(c), the reopening for cause provisions at 40 CFR 70.7(f) or 40 CFR 71.7(f), and the significant permit modification provisions at 40 CFR 70.7(e)(4) or 40 CFR 71.7(e)(3). After the trading program applicable requirements are included in the title V permit, title V allows the use of the minor permit modification procedures for permit modifications involving the use of economic incentives, marketable permits, emission trading, and other similar approaches, to the extent such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA. See 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B).

Therefore, the agency encourages states to identify those provisions that they consider title V applicable requirements as well as those changes that may be eligible to be made using minor modification procedures as they develop their state plans and submit those plans to EPA for approval, which would include public notice and comment. We believe this approach will provide states the flexibility necessary to identify the title V applicable requirements and permit modification procedures that best apply in the context of each state's plan and title V permitting program. The agency is not providing a presumptively approvable list of which changes to a title V permit may be so authorized. In addition and in anticipation of further interaction with states when they develop and submit state plans to EPA for approval, the EPA may issue guidance at an appropriate time if it is necessary to clarify title V applicable requirements and permit modification procedures in the context of the CPP.

Finally, we are finalizing the proposed statement that no title V permit revision shall be required for the allocation, holding, deduction or transfer of allowances once the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit. This provision is consistent with the existing title V regulations and we continue to believe that it provides the flexibility necessary to implement market-based programs such as the CAA Section 111(d) trading programs. Furthermore, this text is consistent with previous regulatory actions that contained such regulatory text (*e.g.*, CSAPR) as well as the comments received.

Regarding the potential for interactions with the NSR program, the proposal acknowledged, among other things, that it is conceivable that a source under a MR may choose, as a means of compliance with either a rate-based or mass-based approach, to undertake a physical or operational change to improve an affected EGU’s efficiency, and this could result in emissions increases that would trigger NSR under the NSR rules. However, the EPA continues to believe that these situations would be few. The agency did not propose any changes to the NSR rules in this action, and explicitly stated that such changes would be beyond the scope of this action. We requested comment on scenarios in which affected EGUs could become subject to NSR and ideas for harmonizing or streamlining the permitting process for such sources that is consistent with judicial precedent. *See* 80 FR 64985.

Based on the proposed preamble text, some commenters sought EPA clarification on whether heat rate improvements trigger NSR requirements or requested the EPA to make changes to the NSR regulatory provisions to ensure that these heat rate improvements do not trigger NSR permitting requirements and thus discourage plant efficiency improvements. Other commenters did not believe that EPA needs to develop new approaches to NSR for purposes of the MRs and opposed any relaxation of NSR requirements. Another commenter stated that the Clean Air Act does not authorize EPA to provide exemptions from otherwise-applicable NSR requirements.

In light of the case-specific nature of NSR-applicability determinations and the variability of the types of changes that might be made to improve an EGU's heat rate, it is not appropriate to conclude in the abstract if any particular heat rate improvement project would trigger NSR under the NSR regulations or not. Rather, each such project must be evaluated under the applicable NSR rules. In addition, we note that the MRs contain trading provisions that provide considerable flexibility to individual sources in meeting their obligations and do not require any specific source to make physical or operational changes in order to comply.

Regarding commenters that requested the EPA to make changes to the NSR regulatory provisions to ensure that heat rate improvements do not trigger NSR permitting requirements and thus discourage plant efficiency improvements, this is, again, beyond the scope of this action. The EPA notes, however, that it has previously attempted to promulgate exemptions from the NSR rules in order to remove potential regulatory disincentives to undertaking positive actions such as installing pollution controls, only to have these exemptions rejected by reviewing courts. The United States Court of Appeals for the District of Columbia Circuit in *New York v. EPA*, 413 F.3d 3, 40-42 (D.C. Cir. 2005), was clear that the EPA lacked the authority to exempt physical or operational changes that resulted in an NSR-triggering emissions increase from the NSR requirements, even if the EPA considered those projects environmentally beneficial. *Id.* The agency remains willing to continue working with states and affected EGUs to address specific NSR-related questions as they may arise.

III. Common Elements of the Final Model Trading Rules

A. Which EGUs would be affected under the MRs?

For the MRs, the definition of an affected EGU is identical to the definition in the CPP. *See* 40 CFR 60.5845, 60.5850; *see also* section IV.D in the CPP for a detailed explanation of which units are affected. To briefly summarize: an affected EGU according to the CPP is any steam generating unit (SGU), integrated gasification combined cycle (IGCC) unit, or stationary combustion turbine (SCT) that was in operation or had commenced construction on or before January 8, 2014,[13] and that meets certain criteria, which differ depending on the type of unit. In general, the criteria to be an affected EGU are as follows: a unit, if it is a SGU or an IGCC, must serve a generator capable of selling greater than 25 megawatts (MW) to a utility power distribution system; have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel); unless such unit is, and always has been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000MWh or less. If a unit is a SCT, the unit must meet the definition of a combined cycle or combined heat and power (CHP) combustion turbine; serve a generator capable of selling greater than 25 MW to a utility power distribution system; and have a base load rating of greater than 260 GJ/h (250 MMBtu/h).[14]

[13] January 8, 2014, is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

[14] Certain exclusions may apply. *See* 40 CFR 60.5850.

In the proposed Model Trading Rules, the EPA solicited comment on an alternative compliance pathway. This alternative compliance pathway (as detailed in the Alternative Compliance Pathway for Units that Agree to Retire Before a Certain Date Technical Support Document [“Alternative Pathway TSD”]) generally had support from commenters, particularly as a streamlined approach to compliance for smaller or marginal affected EGUs that may already be considering retirement. Consistent with the concepts outlined in the Alternative Pathway TSD, the EPA continues to believe that a state should consider including provisions to effectuate this approach in its plan. In essence, the approach would allow an affected EGU in a mass-based plan to make a commitment to retire on a date on or before December 31, 2029, so long as the amount of its emissions is removed from the total budget of the state’s mass-based emission trading program. While we believe this is a potential pathway, we have not included provisions in the mass-based model rule to effectuate this. In addition, the agency is deferring on methods to incorporate this approach into a rate-based emission trading program.

B. What is the compliance schedule?

The mass-based and rate-based MRs both include multi-year compliance periods that are consistent with the interim and final plan performance periods established in the CPP (two 3-year interim step periods followed by a 2-year interim step period during the interim performance period from calendar year 2022 through calendar year 2029, and successive 2-year final reporting periods during the final performance period beginning in calendar year 2030). These multi-year compliance periods are the same as those included in the proposal.

For the mass-based MR, a state evaluates compliance as of May 1 of the year after the last year of each multi-year compliance period (*i.e.*, the allowance transfer deadline is the May 1 following the end of a compliance period).[15] The May 1 date is appropriate, in the EPA’s view, because it provides a four-month window after the end of a compliance period to give owners

[15] The “allowance transfer deadline” is the deadline for transferring allowances that can be used for compliance in the previous compliance period to the compliance account of a facility with affected EGUs. For further information, see section IV.H of this preamble.

and operators time to ensure accurate CO_2 emissions data and acquire any necessary allowances for compliance. It also provides sufficient time for a state to determine whether each affected EGU in its state is in compliance with its emission standard and submit the required report to the EPA by the July 1 deadline in the CPP.[16]

For the rate-based MR, a state evaluates compliance as of June 1 of the year after the last year of each multi-year compliance period (*i.e.*, the ERC transfer deadline is the June 1 following the end of a compliance period).[17] The rate-based MR establishes a later compliance deadline than that for the mass-based MR in order to provide additional time for the issuance of ERCs for electricity generation or savings that occurred in the final year of the multi-year compliance period. This later timeframe still allows states ample time to evaluate compliance and submit the required report to the EPA by the July 1 deadline

[16] In accordance with the CPP, states must identify in a report to the EPA by July 1 following each performance period (i.e., each interim step period and final reporting period) whether affected EGUs are in compliance with their emission standards. *See* 40 CFR 60.5870.

[17] The “ERC transfer deadline” is the deadline for transferring ERCs that can be used for compliance in the previous compliance period to the compliance account of an affected EGU.

in the CPP. A state may wish to modify the rate-based MR and adopt a different ERC transfer deadline, depending upon the time it needs to assess compliance by each affected EGU and then develop and timely submit the July 1 report to the EPA.

The EPA received comments that supported the proposed multi-year compliance periods, favored annual compliance periods, and preferred multi-year compliance periods with intervening compliance requirements. Commenters generally explained that their preferred approach appropriately balanced compliance flexibility, administrative burden, and assuring timely compliance. The EPA is finalizing multi-year compliance periods as proposed because the EPA believes the approach best balances these considerations universally. The EPA acknowledges that individual states may find that different approaches better suit their particular circumstances, but this determination should be made by the state.

C. Process for State Adoption of Model Trading Rules

As discussed above, the EPA is finalizing the MRs as a tool for state plan development. One way that states may use the MRs is by adopting the provided regulatory text. States may choose to adopt the provided regulatory text as part of their state plans, including as a federally enforceable backstop for a state measures plan.

This section discusses methods for adoption of the MRs as part of a state plan - incorporation by reference (IBR) and duplication of the MR regulatory text – and also discusses use of the MRs as a federally enforceable backstop for a state measures plan. Because the EPA understands that a particular state’s law may influence its method of adoption of the MRs, this section includes a discussion of different methods of adoption.

Regardless of which approach a state chooses for adoption of a MR, once a state adopts the provisions of one of the MRs as a matter of state law, the state must follow the requirements of 40 CFR 60.27 and 40 CFR 60.5875 to submit those provisions to the EPA as part of the state’s plan submission. Once the EPA has a complete plan for a particular state (or states, in the case of a multi-state plan), it will evaluate whether the plan meets the requirements of the CPP.

1. State Plan Submittal Requirements

The requirements for state plan submittals are described in detail in section VIII of the preamble to the CPP. *See* 40 CFR 60.5745 and 80 FR 64843-64864. Each of the MRs is designed to meet the applicable requirements of the CPP. However, as the MRs do not address all the required components of a state plan under the CPP, state plans must include additional materials, as discussed above in section II.B.

2. Incorporation by Reference

A state may choose to adopt either the rate- or mass-based MR into its state regulations through IBR. Under this method, a state would promulgate text that cites to the provisions of the Code of Federal Regulations that the state intends to IBR.

States may choose to incorporate all the provisions related to each of the MRs finalized by the EPA in this rulemaking by referencing the entirety of 40 CFR part 62 subpart MMM for a mass-based state plan, or the entirety of 40 CFR part 62 subpart NNN for a rate-based state plan. In addition, states may choose to IBR subsections or individual provisions of the MRs.

States may also choose to incorporate the provisions of the MRs – either in whole or in part – as of a certain date. By providing that an IBR is as of a specified date, a state may have to adopt any subsequent changes to the MRs in separate rulemakings. If a state chooses to IBR a MR without specifying a particular date, the EPA would consider that state’s plan to automatically update to include any subsequent changes made by the EPA to the incorporated MR text.[18]

As discussed in section II.B above, states are not required to use the text of the MRs. Thus, a state may draft its own regulatory provisions, or modify or excise any piece of the finalized MR text that it does not wish to IBR and provide alternate text (assuming such alternate text meets CPP requirements). In some cases, it may be necessary for a state to provide changes to the MRs to adjust for state circumstances that are ministerial or otherwise do not have a material or substantive impact (for example, a state may need to change the numbering of sections and subsections as part of codification of MR text in state regulation). In other cases, a state may seek to make material or substantive replacements or changes to the MRs. In order to facilitate the EPA's review of the state's plan, the state could include in its supporting documentation a redlined version illustrating the changes to the model rules and an explanation of the changes, such as explaining whether such

[18] Some states may have legal restrictions on automatically-updating regulations. In such circumstances, a state plan that lacks an "as of date" clause could still be precluded from automatic updating by operation of state law. The EPA encourages states to identify any such state law, including judicial decisions, when it submits its state plan. In general, without such notification the EPA will assume such law does not exist.

changes are intended to be ministerial or substantive in nature. If the state's changes are substantive, such changes must meet the applicable requirements of the CPP. As discussed above in section II.B, material or substantive replacements or changes to the MRs would not be considered presumptively approvable. The EPA will act on state plans through a separate notice and comment rulemaking.

3. Other Methods of Adoption

In addition to incorporating the MRs by reference, a state may also directly adopt the regulatory text of one of the MRs. Under this method, a state would promulgate text that is an exact duplicate of the MR text finalized by the EPA.

As in the IBR context, states may choose to adopt directly into state regulation parts of the text of the MRs as finalized by the EPA, while changing other sections of the MRs. To the extent that a state chooses to alter the text of one of the MRs, the state may want to provide a redlined version comparing the state's regulations and the relevant MR as part of the state plan submittal documents, in order to facilitate the EPA's review of such changes.

While some substitutions or changes may materially or substantively change the MRs, other changes that a state could choose to make may be ministerial or otherwise not have a material or substantive impact. For example, substitution of a particular state's name for the word "state" in an MR would not substantively impact the MRs. Similarly, a state may need to change the numbering of sections or subsections of the MRs to be consistent with the state's previous or existing regulatory provisions. The state could provide the EPA with an explanation of changes the state may choose to make in their supporting documentation portion of the plan submittal, such as explaining whether such changes are intended to be ministerial or substantive in nature. If the state's changes are substantive, such changes must meet the applicable requirements of the CPP. By providing the appropriate supporting documentation as well as the rationale for such changes a state can further facilitate the EPA's review of the state's plan.

As further discussed in section II.B of this preamble, the EPA will act on state plans through a separate notice and comment rulemaking, and state plan submissions with material changes to the MRs will not be considered presumptively approvable.

4. Use of MRs as Backstop Emission Standards in a "State Measures" Plan

As discussed in the CPP and the MRs proposal, either a mass-based or rate-based MR could function as the federally enforceable “backstop” emission standards that the CPP requires to be included in “state measures” type state plans.

The conditions and requirements for the federally enforceable backstop emission standards in a state measures approach are discussed in detail in sections VIII.C.3.b and VIII.C.6.c of the preamble to the CPP. *See* 80 *FR* 64836-64837 and 64841-64843 (October 23, 2015). To summarize the requirements of the CPP, the federally enforceable backstop emission standards must fully achieve the CO_2 emission performance rates for affected EGUs, or the state’s interim and final rate-based or mass-based CO_2 emission goal for affected EGUs, if the state measures and any emission standards on the affected EGUs fail to achieve the intended level of CO_2 emission performance by affected EGUs. The state plan submittal must identify the federally enforceable emission standards for affected EGUs that would be used in the backstop, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards plan approach, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the CPP, 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). In addition, the backstop emission standards must make up for any shortfall in CO_2 emission performance by affected EGUs during a prior plan performance period that led to triggering of the backstop.

The CPP explicitly recognized that the backstop emission standards could be based on one of the MRs that the EPA is finalizing in this action. *See* 80 FR 64668 (October 23, 2015); *see also* 80 FR at 64975-64976 (October 23, 2015). As discussed in section III.C.2, above, the MRs are designed so that they can be adopted or incorporated by reference for use by states, and this includes their use as backstop emission standards for a state measures plan.

However, states will need to make some changes to the MRs in order to use them as backstop emission standards. For example, a state choosing to use the MRs as backstop emission standards will need to include modifications to make up for a shortfall in emissions performance in a state's prior plan performance period, as required by the CPP. *See* sections VIII.C.3.b and VIII.C.6.c of the CPP. The MRs do not provide provisions that would automatically adjust the emission standards to account for any prior emission performance shortfall (which is an option states have if designing their own backstop). While states could submit an appropriate revision to the backstop emission standards adjusting for the shortfall through the state plan revision process at a later date, the EPA recommends that states include a procedure for adjusting the emissions in the state plan submittal.

If a state chooses to use one of the MRs as a backstop, it could either IBR or provide an exact duplicate of the MR text, as described above. Further, in order to facilitate the EPA's review of the state's plan, a state should explain its intended use of the MR, along with the associated changes made to the MR, to ensure the MR is an effective backstop for that state.

D. Ready for Interstate Trading

The mass-based and rate-based MRs both provide tradable compliance instruments.[19] While structured as an individual state trading program, implemented under the legal authority of a single state, each of the MRs is designed to facilitate

[19] The mass-based MR includes the use of tradable CO_2 allowances (see section IV of this preamble). The rate-based MR includes the use of tradable emission rate credits (ERCs) (see section V of this preamble).

interstate trading of compliance instruments. Specifically, the MRs include provisions that enable their use as part of a trading-ready state plan. As discussed below, the trading-ready mechanism in the CPP provides a streamlined manner for states to adopt linked emission trading programs through individual state plans.

The CPP provides flexibility for states to choose to implement an interstate or intrastate trading program.[20] An interstate trading program allows affected EGUs to use for compliance a tradable compliance instrument issued in any other state participating in that same trading program. In contrast, in an intrastate trading program,[21] an affected EGU may only use for compliance a tradable compliance instrument issued by the state in which it is located.

Both the logic and historical experience of emission trading programs establish that a broader trading region (*i.e.*,

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[20] The CPP allows for states to implement a stand-alone intrastate trading program, linked individual programs through single-state plans (which effectively provides for an interstate trading program), or an interstate trading program through a multi-state plan.

[21] "Intrastate trading program," as used here refers to a single state program that is not linked to other state programs (either through program linkages established in a single state plan or through a multi-state plan).

one with a greater number of covered emission sources) provides greater opportunities for more cost-effective implementation of emission reduction measures compared with a smaller region (*i.e.*, one with a smaller number of covered emission sources). A trading program with broader geographic scope provides a greater diversity of affected EGUs with varying emission reduction opportunities and, thus, enhances the overall cost-effectiveness of the program (*i.e.*, the cost per unit of emission reduction).[22]

Each of the MRs provides an individual state component of a linked interstate trading program, using the trading-ready mechanism in the CPP for linking state programs. A trading-ready state plan is one where a state identifies the plan as “ready-for-interstate-trading” and the plan includes the use of an EPA-administered or EPA-designated tracking system. Upon approval of such a state plan, the state emission trading program would be linked to all other programs included in other approved ready-for-interstate-trading state plans that use the same or interoperable tracking system. As a result, the ready-for-

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[22] *See e.g.,* PJM Interconnection, EPA’s Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis (September 1, 2016); available at http://www.pjm.com/~/media/documents/reports/20160901-cpp-compliance-assessment.ashx.

interstate-trading mechanism provides a streamlined manner for states to adopt linked emission trading programs through individual state plans.

While each of the MRs is designed to be used as part of a ready-for-interstate-trading state plan, states could choose to modify a MR for use in a multi-state plan or for use in an individidual state plan with specified bilateral or multilateral linkages.[23] Each MR could also be modified for use in an individual state plan without linkages to other state trading programs. As explained above, a state plan that adopts one of the MRs would be ready-for-interstate-trading. Where a state adopts one of the MRs with a material change and intends for its state plan to be ready-for-interstate-trading, the EPA would need to determine through the state plan review process whether the state plan is in fact ready-for-interstate-trading. To this end, the EPA would evaluate whether the trading program specified in the state plan could be linked to trading programs in other approved state plans that are ready-for-interstate-trading, including plans that adopt a corresponding rate-based

[23] This would involve modest revisions to the trading-ready provisions in this MR to specify linkages among identified state programs.

or mass-based MR. Such a review would be necessary in order to ensure the integrity of the emission standards established in the state plans.

The ready-for-interstate-trading mechanism as it is applied to the rate-based and mass-based MRs is addressed in the respective sections of the preamble that discuss each MR.[24]

E. Tracking System Software, Administration, and Support

In the CPP, the EPA indicated that it was exploring options for providing tracking system support to states. This support could include, for example, development and administration of tracking systems that could be used by states to implement their mass- or rate-based emission trading programs. The EPA indicated that as part of this exploration it was conducting an initial scoping assessment of tracking system needs and functionality.[25]

The EPA received feedback from a number of states and stakeholders, prior to the proposal of the MRs, asking the EPA to provide support for the development and administration of tracking systems for both mass- and rate-based trading programs.

[24] For a discussion of the mass-based MR, see section IV of this preamble. For a discussion of the rate-based MR, see section V of this preamble.

[25] *See* 80 FR 64907.

Comments on the proposed MRs further underscored the desire of many states and stakeholders for the EPA to provide tracking system support to states. A number of commenters sought to have the EPA administer a national tracking system for both mass- and rate-based trading programs adopted by states under the CPP. Commenters also supported the ability for states to use existing tracking systems, such as those used to track renewable energy certificates used for compliance with state renewable portfolio standards (RPS). Many of these commenters asked for the capability to make state-administered tracking systems interoperable with an EPA-administered tracking system.

Based upon comments received, the EPA has decided to provide separate EPA-administered tracking systems for mass-based trading programs and for rate-based trading programs. The EPA-administered tracking systems for mass- and rate-based trading programs are the Allowance Tracking and Compliance System (ATCS) and the ERC Tracking and Compliance System (ERC-TCS), respectively. The phrase “EPA-administered” reflects the EPA’s role in providing the basic services required to support the ATCS and ERC-TCS, such as hosting the tracking system software, ensuring its security and ongoing operation, and providing technical support for users.

While the EPA will perform these administrative services for states that adopt one of these MRs or otherwise specify an EPA-administered tracking system in their state plan, these MRs and this preamble use the term “tracking system operator” to refer to the entity that will execute specific actions through the tracking system. As explained in the mass- and rate-based MRs, such actions include recording the allocation of allowances or issuance of ERCs, deducting allowances or ERCs from compliance accounts, and freezing accounts. These MRs define tracking system operator as the state, or an entity acting on behalf of the state, including the EPA. Certain tracking system functions could be carried out by either the state or the EPA, while other actions are more appropriately executed by the state alone or at the state’s discretion. A state adopting one of these MRs must determine whether the state, the EPA, or another entity will perform each tracking system function. In particular, a state adopting the mass- or rate-based MR must describe in its state plan submittal (either through a memorandum of understanding or some other documentation) whether the state, the EPA, or some combination thereof will execute the role of tracking system operator for each MR provision in which this term is used. With respect to certain tracking system functions, a state may choose to identify both the EPA and the state as the tracking system operator (so that both entities have the authority to execute the specified functions) while choosing to identify either only the state as the tracking system operator authorized to execute other functions, or identify the EPA as the tracking system operator authorized to execute certain functions upon a determination by the state. However the state chooses to document the assignment of functions to the tracking system operator, the state must provide the documentation as part of its state plan submittal.

Both EPA-administered tracking systems will provide tracking system functionality required by the CPP.[26] This functionality is explained in detail in the mass- and rate-based MRs, but it generally includes establishment of general accounts and compliance accounts, recording the allocation of allowances or issuance of ERCs in accounts, transfers between accounts, and deductions from compliance accounts for compliance demonstrations. The EPA's decision to provide EPA-administered tracking systems provides states the support sought by

[26] *See* 40 CFR 60.5810 (ERC tracking system requirements); *id.* at 60.5820 (allowance tracking system requirements).

commenters. While the EPA is committed to supporting states by providing these tracking systems, nothing requires a state to use the EPA-administered tracking system in its state plan. States have the flexibility to specify the use of a different tracking system in a state plan, so long as it meets CPP requirements.

Unlike with the mass-based MR, a state that adopts the rate-based MR, which specifies the ERC-TCS, will need to provide a state ERC document management and approval system that keeps track of all information supporting the state evaluation of resource eligibility and ERC issuance. This includes eligibility applications, EM&V plans, monitoring and verification reports, related independent verifier verification reports, and state approval or denial actions related to applications and submittals. The state-maintained ERC document management and approval system also must ensure appropriate communication protocols to make this information available to the ERC-TCS in an electronic, internet-based format.[27] Section V.D.2 below

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[27] Section IV below details the state's program administration role under a mass-based state plan that uses the EPA ATCS. Section V.D below details the state's program administration role under a rate-based state plan that uses the EPA ERC-TCS.

discusses in more detail the roles of the state and the EPA under the rate-based MR, as well as the relationship between the ERC-TCS and the state ERC document management and approval system.

As part of its tracking system scoping assessment, the EPA is publishing a tracking system white paper. This white paper, titled “Clean Power Plan Tracking Systems White Paper,” discusses the role of tracking systems, the elements of tracking system administration, the infrastructure needed to support interoperability of tracking systems, and the range of implementation services that the EPA performs through the EPA tracking systems to support implementation of the Acid Rain Program and Cross-state Air Pollution Rule.

Commenters asked for the EPA to provide more guidance about how it will assess the suitability of a tracking system used to administer a trading program included in a state plan, including the EPA process and requirements for identifying tracking systems that could be used in a ready-for-interstate-trading state plan and requirements for tracking system interoperability.[28] As part of the scoping assessment process, the EPA sought feedback on EPA designation of other tracking systems that could be used in a state plan that is ready for interstate trading as well as on the system protocols that would be needed to support tracking system interoperability.

F. How do these model trading rules consider “remaining useful life?"

Each of the MRs, if adopted by a state, adequately takes into consideration the remaining useful life of affected EGUs, as permitted by the CPP. Under CAA section 111(d)(1), all EGs must permit states, in applying a standard of performance to any particular existing source, to consider the remaining useful life of the source, among other factors. 42 U.S.C. 7411(d)(1). In the CPP, the EPA explained how the EGs satisfy this provision. *See* 80 FR 64869-64874 (October 23, 2015). While the agency will reiterate its position and rationale in the CPP here to provide background for this discussion, the EPA is not reopening the agency’s conclusions or rationale that the CPP EGs satisfy the CAA section 111(d)(1) requirement to permit the

[28] A ready-for-interstate-trading state plan must use an EPA-administered or EPA-designated tracking system.

consideration of remaining useful life and other factors. This topic is before the Court on the petitions for review of the CPP in State of West Virginia et al. v. U.S. EPA, No. 15-1363 (and consolidated cases) (D.C. Cir. filed October 23, 2015). Although it is obvious that the Court's decision could impact the EPA's interpretation of the remaining-useful-life provision and the EPA's view that the MRs adequately take into consideration remaining useful life, the EPA remains confident that the CPP will be upheld, including the appropriate application of the remaining useful life provision in the CPP.

The EPA explained that rather than specify performance rates that each individual affected EGU is to achieve, the CPP provided "collective performance rates for two classes of affected EGUs . . ., 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." *See* 80 FR 64870 (October 23, 2015). The CPP also noted that the EPA had established "reasonable rather than maximum possible implementation levels for each building block." *See* 80 FR 64871 (October 23, 2015). The EPA further explained that an emission trading program to implement this type of reasonable, collective performance rate (or equivalent goal) would adequately and inherently consider the remaining useful life of each affected EGU, because with trading, an affected EGU with a limited remaining useful life can avoid the need to implement long-term emission reduction measures and can instead purchase tradable instruments such as allowances or ERCs. *See* 80 FR 64734-64735 (October 23, 2015).[29] In addition, the agency noted other aspects of the CPP that permitted the consideration of remaining useful life, such as the fact that the interim performance period would not begin until 2022, and then would allow a phase-in period until 2030, allowing more lead time in state plans for regulated entities. 80 FR 64872. Finally, the agency found that the CPP further permitted consideration of remaining useful life by defining national performance rates for affected EGUs that make

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[29] "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." 80 FR 64871. "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 [or allowances] than the second facility." Id.

it easier for states to set up interstate trading regimes; by clearly defining the requirements for mass-based and rate-based trading programs to ensure their integrity; and by providing information on potential allocation approaches for mass-based trading. *See* 80 FR 64871 (October 23, 2015).

Because the CPP provides ample flexibility for states and sources to design appropriate compliance pathways in the ways described above, the EPA further concluded that facility-specific factors do not warrant adjustments to state goals or the uniform sub-categorized CO_2 emission performance rates. *See* 80 FR 64873 (October 23, 2015). The CPP nonetheless authorized states to set differential emission standards on affected EGUs, but required additional demonstrations in such instances to ensure the emission performance rates or equivalent state goal is met. *See* 40 CFR 60.5745(a)(5)(ii) (October 23, 2015).

The EPA set forth its legal interpretation of the remaining useful life provision of CAA section 111(d)(1) in the CPP. *See* 80 FR 64873-64874 (October 23, 2015); *see also* CPP Legal Memorandum 30-46. Among other things, the EPA noted that for CAA section 111(d) EGs other than the CPP, this provision has been implemented through the variance provision in the EPA implementing regulations. *See* 40 CFR 60.24(f). The agency explained why the CPP implements the remaining useful life provision in CAA section 111(d)(1) differently, and why this is allowed under CAA and the EPA implementing regulations, as well as relevant case law. The EPA pointed out that the agency's approach under the CPP was consistent with its application of a similar provision in the visibility program of the CAA under section 169A (while recognizing that the two provisions need not be interpreted in the same way). *See* 80 FR 64873-64874 (October 23, 2015). In the CPP Legal Memorandum, the EPA also discussed the legislative history of the remaining useful life provision in CAA section 111(d)(1). Legal Memorandum 33-36. Again, the agency recites this information by way of background, and this discussion in no way reopens the conclusions or approach to permitting consideration of remaining useful life the EPA finalized in the CPP.

In the notice for the proposed federal plan and model trading rules, the EPA proposed that both of the proposed mass-based and rate-based emission trading programs meet the requirement in CAA section 111(d)(2) that a federal plan shall take into consideration, among other factors, remaining useful life of the sources in the category of source to which such standard applies. *See* 80 FR 64982-64984 (October 23, 2015). The agency is taking no final action at this time with respect to the proposed federal plan. The EPA recognizes that under the general approach of the October 23, 2016, proposal, unless otherwise noted, references to the federal plan encompassed the MRs. *See, e.g.* 80 FR at 64973 (October 23, 2015) (explaining that the proposed federal plans and the proposed MRs take the "same approaches" to implementation). Further, the EPA explained at proposal that both forms of emission trading programs (rate- and mass-) adequately and inherently considered remaining useful life by providing for trading and other flexibilities authorized in the CPP. These included: the use of an extended interim performance period, the ability to credit early action, the use of emissions trading, the use of multi-year compliance periods, and the ability to link to other federal or state plans to create larger, interstate emission markets. *See* 80 FR 64983 (October 23, 2015). In particular, the EPA proposed that by relying on either rate- or mass-based emission trading, the proposed federal plan capitalizes on the inherent flexibility available through market-based mechanisms. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total compliance cost 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 or allowances than the second facility. *Id.*

For these reasons, a state that adopts one of the MRs has adequately considered remaining useful life.[30] However, states should note that they are not required by CAA to consider remaining useful life. The CPP is consistent with this. While the CPP permits states to consider remaining useful life in a number of ways, it does not make consideration of remaining useful life a mandated element of a state plan that must be submitted to and approved by the EPA. Nonetheless, states may want to consider remaining useful life. For the reasons given in the proposed federal plan preamble and reiterated immediately above, the EPA believes that both of these MRs, in fact, do so.

The EPA received a number of comments on remaining useful life. Comments regarding the proposed federal plan's consideration of remaining useful life are outside the scope of

[30] As discussed in the Response to Comments document for this action, the EPA believes that the MRs' broad-based trading approach also inherently addresses "other factors" that may be facility-specific.

this action. Comments that take issue with the CPP’s approach to the remaining useful life provision are also outside the scope of this action, as explained at the beginning of this section. Such comments include those that argue that there must be EGU-specific variances or that the goals must be adjusted to take into consideration remaining useful life, that affected EGUs should not be subject to emission standards or should be subject to relaxed emission standards until all debt is recovered, that stranded assets (either in the facility or in recently installed pollution control technology) will occur as a result of the CPP, and that the CPP must make allowance for uniquely burdened entities such as municipal and rural cooperatives. For our detailed responses to those comments that were within the scope of this action, please see the Response to Comments document for this action.

G. How do these model trading rules ensure that electric system reliability is maintained?

This section reviews, without re-opening, the reliability features and requirements of the CPP, including explaining how they apply regardless of whether the state adopts an MR.

The EPA designed the CPP to provide flexibility to states in the design of their state plans, including a long planning and implementation horizon, and a wide range of options for states to use in their plans in order to achieve the CO_2 emission performance rates or state rate- or mass-based CO_2 goals for affected EGUs included in the CPP. Comments from state, regional and federal reliability entities, power companies, and others, as well as consultation with the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC), helped inform a number of changes made to the CPP to address electric system reliability. These CPP features, among others, reflect the EPA's commitment to ensuring that compliance by affected EGUs with their emission standards under state plans does not interfere with the industry's ability to maintain electric system reliability.

There are numerous safeguards within the bulk power system that serve to assure that system reliability is maintained. These safeguards are discussed in the preamble to the CPP. *See* 80 FR 64874-64879 (October 23, 2015). In addition, the EPA included a number of features in the design of the CPP that are intended to assure that the CPP, and state plans adopted to meet the CPP, will not interfere with the maintenance of electric system reliability.

First, there is significant flexibility in how the applicable CO_2 emission performance rates or the state rate- or mass-based CO_2 goals for affected EGUs are achieved under a state plan. This means that a state can design a plan that is appropriate for the differing characteristics of the electric grid within its state.

Second, the CPP provides ample time for a state to design a plan and to meet CPP emission reduction requirements while maintaining system reliability.

Third, the EPA requires that each state consider system reliability issues as a part of developing its state plan, and demonstrate to the EPA in its final state plan submittal that it has done so. *See* 40 CFR 60.5745(a)(7). This is discussed in the preamble to the CPP. *See* 80 FR 64876-64877 (October 23, 2015).

Fourth, the CPP provides a mechanism for states to seek a state plan revision, which is something that could be done in order to address changes in circumstances that could have system reliability impacts if not accommodated in the state plan. 80 FR 64877; 40 CFR 60.5785.

Fifth, the CPP provides a reliability safety valve to temporarily modify emission standards for a reliability-critical affected EGU or EGUs if necessary to provide generation if an unforeseen emergency requires an immediate response to maintain system reliability. 40 CFR 60.5785(e); 40 CFR 60.5870(g). The reliability safety value is discussed in section III.F.1 below and in the preamble to the CPP. *See* 80 FR 64877-64879 (October 23, 2015).

Finally, the EPA, along with DOE and FERC, agreed to jointly monitor the implementation of the CPP to help ensure continued reliable electricity generation and transmission. *See* 80 FR 64879 (October 23, 2015).

The preamble to the CPP explains that access to compliance instrument (ERC or allowance) trading in a state program design supports the maintenance of electric system reliability. *See* 80 FR 64878 (October 23, 2015). This is because an emission trading program does not mandate a specific level of CO_2 emission performance or CO_2 emissions for each affected EGU, which could in effect limit the operation of individual units.[31] Instead, the availability of trading under a state plan provides affected EGUs with ample flexibility to comply with emission standards

[31] For a mass-based emission budget trading program, the emission standard for an affected EGUs is the requirement to surrender CO_2 allowances in a number equal to reported CO_2 emissions. For a rate-based emission trading program, the emission standard for an affected EGU is the requirement to achieve a CO_2 emission rate on an adjusted basis considering the use of surrendered ERCs by the affected EGU.

while meeting both routine and critical electric system reliability needs. The ability to trade to acquire allowances or ERCs provides an important tool for an affected EGU that must run to meet a critical reliability need, and to do so while still complying with its emission standard in a state plan. The EPA believes that access to trading is enhanced by the existence of these MRs, which provide states with a roadmap for designing a state plan with either a rate-based or mass-based emission trading program.

1. Is the “reliability safety valve” available in the model trading rules?

The EPA is clarifying here that the reliability safety valve (RSV) included in the CPP is available to states, regardless of whether a state chooses to adopt one of the MRs for its state plan. The RSV included in the CPP establishes a process for a state to come to the EPA during an immediate, unforeseen, emergency situation that requires an affected EGU or EGUs to deviate from the original emission standards in the state plan, in order to maintain electric system reliability. *See* 40 CFR 60.5785(e). Under these circumstances, the state must notify the EPA that the affected EGU or EGUs need to temporarily operate under a modified emission standard in order to respond to an unforeseen emergency situation that threatens electric system reliability. The RSV is established in the CPP and is a mechanism available outside the state plan. The RSV is available directly through the CPP and operates as a type of temporary state plan revision, which can be invoked, according to the process specified in the CPP, when necessary to maintain electric system reliability in extreme emergencies.[32]

In the preamble to the CPP, the EPA indicated that it does not anticipate that affected EGUs operating under emission standards in the form of an emission trading program would meet the criteria for use of the RSV, but the EPA did not entirely rule out the possibility. Those criteria include: 1) the event creating the reliability emergency is unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event; 2) the relief provided is for affected EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face some form of failure; and 3) the affected EGU or EGUs in question would be subject to the requirements of a state plan that imposes

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[32] For a further explanation and discussion of the RSV, *see* the CPP at 40 CFR 60.5785(e) and the preamble to the CPP at 80 FR 64877-64879.

emission constraints such that the affected EGU or EGUs' operation in response to the reliability emergency resulted in levels of emissions that violated those emission constraints. States with plans that allow for emission trading of either ERCs or allowances are not likely to experience an event that meets these three criteria because an affected EGU that needs to continue operating to prevent a severe system reliability disruption would have the opportunity to purchase allowances or ERCs to maintain compliance with its emission standard.

In the proposed federal plan, the EPA stated that it was not proposing to include a RSV as part of a federal plan. The agency based this proposed approach in part on the fact that the federal plan was proposed to be either a rate- or mass-based emission trading program, and therefore, the flexibility needed to address an unanticipated, emergency reliability event is already included in the design of the program. While the EPA did take comment on whether the RSV should be available in states subject to a federal plan, the EPA did not explicitly propose to preclude the use of the RSV by a state that adopts one of the MRs.

Multiple commenters expressed concerns that the proposal did not make the RSV available to states that adopt one of the

MRs. These commenters may have misunderstood the EPA's approach to the RSV. To be clear, the CPP allows for the use of the RSV by any state, including those that may adopt one of the MRs in its state plan. It is at least theoretically possible to envision a scenario in which each of the criteria the EPA identified in the CPP for utilizing the RSV could be met, regardless of state plan type. However, given the experience of other emission trading programs, the EPA does not anticipate that use of the RSV will be necessary, given the inherent compliance flexibility of an emission trading program approach. In any case, the RSV is available to states directly through the CPP as a type of temporary plan revision, regardless of whether or not a state adopts one of the MRs, and, therefore, a state need not include reference to the RSV in its originally-submitted state plan. Finally, the RSV functions to provide an adjustment to the federally-enforceable emission standard in a state plan, but the EPA acknowledges that this does not necessarily address the adjustment of requirements as a matter of state law. States—particularly those considering an approach that is less flexible than an emission trading program—may want to consider if there are any obstacles in their state laws to utilizing the RSV to request a short-term state plan modification in the event of a reliability emergency. States may wish to consider adjustments to their state laws that will allow them to more readily use the RSV in an emergency situation.

2. Must a state that adopts one of the model trading rules demonstrate that it has considered reliability?

In the preamble to the CPP, the EPA enumerated features of the CPP that support the electric industry’s ability to maintain electric system reliability, as described above. These features of the CPP apply regardless of whether a state adopts one of the MRs. One of these CPP features is that a state must demonstrate, in its final plan submission, that it considered electric system reliability issues in the course of developing its state plan. *See* 40 CFR 60.5745(a)(7). The EPA describes in the CPP preamble that consultation with the relevant independent system operator (ISO) or regional transmission organization (RTO), or other planning authority, would be a “particularly effective way” for a state to demonstrate that it considered electric system reliability when developing its state plan. *See* 80 FR 64877 (October 23, 2015). However, a state may choose to consider reliability in some other way, as long as it documents what it has done to consider electric system reliability in its final state plan submission.[33]

Some commenters expressed uncertainty as to whether the requirement that states demonstrate that they have considered reliability applied to states that adopt one of the model rules. The CPP requirement that a state must demonstrate that it considered reliability issues in the course of developing its state plan applies regardless of the type of plan a state submits, including a state plan that includes adoption of one of the MRs. Therefore, a state adopting either of the MRs should also include in its plan submission a demonstration that it has considered reliability issues. The fact that the state is adopting a trading program can be part of that demonstration. Beyond the adoption of a trading program, the demonstration performed by each state as part of its final state plan submittal will vary depending on how a state chooses to consider reliability. Because this required demonstration is documented in the supporting materials submitted in conjunction with a state plan, it is outside the scope of the MRs. As a result, the

[33] In the CPP preamble, the EPA stated, "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." 80 FR 64877 n.868.

MRs do not include regulatory text regarding this state plan requirement.

H. Use of Qualified Biomass in State Plans that Incorporate the Model Trading Rules

This section reviews, without reopening, the treatment of biomass as finalized in the CPP, and the comments that the EPA received related to the use of biomass in the MRs. This section also explains how states can incorporate the use of qualified biomass in a state plan that adopts one of the MRs, if a state elects to propose that qualified biomass may be used by affected EGUs as a compliance strategy for meeting emission standards included in a state plan.

The CPP provides flexibility to states in the design of their state plans, including the use of qualified biomass (defined in the CPP as a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere) as a compliance strategy for affected EGUs. As reflected in the CPP, 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, and many states already use diverse strategies to promote the use of different kinds of biomass to enable net carbon benefits while realizing their unique economic, environmental, and energy goals. 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. The process and considerations for the use of qualified biomass in state plan submissions are discussed in the CPP.[34]

In the MRs proposal, the EPA requested comment on a number of questions related to the role of biomass in the MRs. Specifically, the agency requested comment on: the inclusion of qualified biomass in the MRs; the types of qualified biomass feedstocks that should be specified in the MRs (if any); the inclusion of a pre-approved list of qualified biomass feedstocks in the MRs; how this list might be amended over time; and methods for entities to demonstrate that they are using feedstocks from the preapproved list. The agency also requested comment on: if biomass is included in the final MRs, whether generation of electricity using qualified biomass should be an

[34] See the preamble to the CPP at section VIII.I.2.c, 80 FR 64884-64887 (October 23, 2015).

eligible resource for issuance of ERCs in the rate-based MR; the treatment of qualified biomass co-firing at affected EGUs; methods of measurement for the associated biogenic CO_2 emissions from qualified biomass use; and EM&V requirements for tracking the use of qualified biomass.

The EPA received a broad range of comments on the use of qualified biomass in the MRs from a variety of states, as well as industry and other stakeholder groups. These comments provided rationales both supporting and opposing the inclusion of biomass in the MRs. Some commenters supported co-firing of qualified biomass with fossil fuels at affected EGUs as a compliance strategy, arguing that its use would expand renewable fuel use while extending the life of current coal plants. These commenters also asserted that qualified biomass should be eligible for the issuance of ERCs or allocation of allowances under the MRs. Other commenters opposed the inclusion of qualified biomass in the MRs and recommended that if it were included in the MRs, that the MRs must have strict sustainability requirements for qualified biomass. Commenters also addressed different methods of measurement for the associated biogenic CO_2 emissions from qualified biomass use. Some argued that all biomass feedstocks should be considered ‘‘carbon neutral,’’ while others asserted that biomass use will increase CO_2 emissions and should not be considered carbon neutral/low carbon.

Commenters also both supported and opposed identification of specific biomass feedstock types that could be considered qualified biomass in the MRs, including EPA provision of a pre-approved list of qualified biomass feedstocks. Some commenters also expressed concern regarding proposed EM&V requirements for biomass and offered recommendations on EM&V provisions for tracking the use of qualified biomass. Several commenters asserted that states should be able to determine how qualified biomass can be used in their state plans, as some states already have programs and practices that differ in their approaches to the use of biomass.

The diversity of comments received on the proposed MRs helped inform the EPA’s assessment of the role of biomass in the MRs. As the proposed MRs did not include biomass as a compliance option and as the comments received on the proposal reflect a broad range of disparate and in many cases conflicting statements, and due to the rapidly evolving state of the science associated with the use of biomass and resulting biogenic CO_2

emissions at stationary sources,[35] the EPA has not included provisions in the MRs that address the use of qualified biomass. The EPA notes that states retain flexibility under the CPP to include qualified biomass in a state plan submittal.

While the MRs do not directly provide for the use of qualified biomass, the use of qualified biomass can be proposed in a state plan submission where the state is adopting one of the MRs. Specifically, a state opting to use one of the MRs in its state plan could add provisions to the MR addressing the use of qualified biomass. Such provisions related to the use of qualified biomass as part of an amended MR would not be presumptively approvable and would be subject to EPA review and approval. For states electing to propose the use of qualified biomass in a rate-based or mass-based emission trading program, such provisions could be added to the rate-based MR or mass-based MR in ~~a~~ new subsections as needed to reflect the

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[35] Science Advisory Board peer review of the EPA’s 2014 draft Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources (https://yosemite.epa.gov/sab/sabproduct.nsf/LookupWebProjectsCurrentBOARD/3235dac747c16fe985257da90053f252!OpenDocument&TableRow=2.2#2).

requirements for qualified biomass as identified in the CPP.[36] The CPP provides the relevant information regarding considerations and required elements for the use of qualified biomass in state plans, including how state plans must demonstrate that proposed biomass feedstocks can be considered qualified biomass.[37]

I. Use of CO_2 Capture and Storage under the Model Trading Rules

The model trading rules provide for the use of CO_2 capture and storage as a compliance option for affected EGUs. Provided that certain requirements are met, as specified in each of the MRs, the CO_2 that is captured and stored is not included in reported CO_2 emission totals that are used to assess compliance with a mass-based or rate-based emission standard.

Both the mass-based MR and the rate-based MR include provisions that specify requirements for affected EGUs that capture and store CO_2.[38] These provisions specify that the owner or operator of an affected EGU must report CO_2 capture in

[36] See the preamble to the CPP at section VIII.I.2.c, 80 FR 64884-64887 (October 23, 2015).

[37] See the preamble to the CPP at section VIII.I.2.c, 80 FR 64884-64887 (October 23, 2015).

[38] These provisions are included in the mass-based MR at § 62.16360(e) and in the rate-based MR at § 62.16555(f).

accordance with 40 CFR 98, subpart RR, if injection of captured CO_2 occurs on-site at the affected EGU. The owner or operator of an affected EGU may also transfer captured CO_2 to an affected EGU or facility that reports in accordance with the requirements of 40 CFR 98, subpart RR, if injection occurs off-site. In both instances, the owner or operator of an affected EGU must also report captured CO_2 in accordance with 40 CFR 98, subpart PP.

J. Use of 40 CFR Part 78 Administrative Appeals Process Related to EPA Actions

The EPA is finalizing several additions to 40 CFR part 78 in order to clarify the EPA's internal administrative appeals process to the extent that it applies to the EPA's role under the MRs. In the October 23, 2015, notice, the EPA proposed adding a list of actions that the Administrator might take in the implementation of either a rate- or mass-based federal plan to the existing administrative appeals procedures the EPA has used for other emission trading programs under the CAA. The agency also requested comment on whether these procedures should be made available to any actions of the Administrator under the comparable state regulations approved as a part of a state plan under the CPP. Most commenters generally supported making the changes to 40 CFR part 78, and some commenters, in response to the agency’s request for comment, further supported providing similar treatment to any administrative actions by the Administrator under state plans.

The additions that are being made to 40 CFR part 78 in this action are a matter of internal process and procedure for the EPA, and are applicable with respect to the MRs only to the extent that the EPA itself may play some role in the implementation of state plans that incorporate the MRs or comparable state regulations. The degree to which the EPA would play any such administrative role will depend on the scope of the agency’s activities in assisting a state in the implementation of a state plan. For instance, the state and the EPA may voluntarily choose to enter into an agreement for the use of an EPA tracking system and for EPA to administer all or a portion of the tracking system. As explained in section VI of this preamble, the MRs identify the EPA as the tracking system administrator for the EPA tracking system specified in each MR, though states can modify these aspects of an MR if they wish. Ultimately, the agency’s role and the degree of its involvement in assisting a state in the implementation of its state plan will be determined by state plan design choices and the extent to which the EPA agrees to assist in state plan implementation.

Nonetheless, the agency believes it is appropriate to finalize these changes to 40 CFR part 78 now in preparation for any potential future role that it might have in assisting states with the implementation of their state plans. This is consistent with use of 40 CFR part 78 under existing emission trading programs administered by the EPA, where states may choose through a SIP to elect to participate in the agency’s trading program in order to meet CAA requirements. In the Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR), 40 CFR part 78 is the appropriate process for administrative review of an EPA action, even in the case of a SIP. *See e.g.* 40 CFR 96.308. The critical question in determining whether a party should invoke Part 78 is whether it is the state or the EPA that is making the decision in question. Where a state has chosen to rely on the EPA for some portion of the administration of an emission trading program, then such decisions of the Administrator are appropriately appealable through the process of 40 CFR part 78. 40 CFR part 78 does not apply to actions or decisions of states in the implementation of the MRs included in state plans. It only applies to the decisions of the EPA.

The agency encourages states to consider using an administrative appeals process for state actions in the implementation of state plans, similar to the 40 CFR part 78 process the EPA uses. While an administrative appeals process is not a requirement of the CPP, and it does not need to be included in a state plan, states may find it beneficial to use such a process to handle party-specific dispute resolution in the administration of CPP state plans. As the agency explained at proposal, use of administrative appeals can be beneficial by providing efficiency in dispute resolution and avoiding the need for recourse to judicial litigation. Many states may already have state-level administrative appeals processes under existing environmental programs administered by state agencies. It may be appropriate, and relatively simple, for a state to make modest additions to the existing state laws or regulations governing state-level administrative appeals that are similar to the additions to 40 CFR part 78 the EPA is finalizing.

As proposed, the EPA provided a list of actions under the MRs in 40 CFR part 78 that would be appealable under 40 CFR part 78. The agency is finalizing that list, in 40 CFR part 78, with some modest adjustments. However, the list finalized in 40 CFR part 78 for actions taken under both of the MRs is merely illustrative. As provided in 40 CFR 78.1(a), any “final decision” of the Administrator under one of the covered programs is appealable under 40 CFR part 78. The lists of specific actions contained in 40 CFR part 78.1(b) are non-exhaustive lists of the primary types of decisions the EPA anticipates would be appealable.[39] These lists address to some extent commenters’ requests that the EPA provide guidance or clarity on what types of actions are considered agency “final decisions.”

While commenters generally supported the proposed changes to 40 CFR part 78, some raised potential concerns. Some commenters cautioned that a formal appeals process can be “stilted” and that there should be more informal ways to resolve disputes before recourse to 40 CFR part 78 becomes necessary. The agency’s experience with existing programs has been that many potential issues can be, and usually are, resolved in the

[39] 40 CFR part 78 would not apply where the EPA is carrying out a purely ministerial task, such as distributing allowances according to the direction of a state. In such instances, the EPA action would not properly be considered a “final decision” of the Administrator. The lists added to 40 CFR part 78 identify a wide range of illustrative actions that could potentially constitute a “final decision” of the Administrator properly appealable under 40 CFR part 78, depending on the nature of the state plan and the role of the EPA in implementing it. Nonetheless, whether such actions constitute “final decisions” of the Administrator for purposes of 40 CFR part 78, as opposed to a decision of the state, requires a context-specific analysis.

first instance by working with the relevant program staff managing the program or administering the tracking system. The provisions of 40 CFR part 78 do not preclude such informal issue resolution from occurring. Other commenters suggested that the list of actions added to Part 78 should not be exhaustive. The EPA agrees, and as explained above, the final list of added actions in 40 CFR part 78 is merely illustrative and non-exhaustive.

Some commenters said that their states already have effective state appeals processes and opposed any effort to limit or change that process via a federal process. As discussed above, 40 CFR part 78 does not interfere with state processes for review of state actions. Other commenters asked for clarification of how 40 CFR part 78 could be used to resolve interstate disputes over ERCs and/or allowance allocations. 40 CFR part 78 is only applicable to the actions of the EPA. While the agency anticipates that it may be able to play some informal role in the resolution of interstate disputes under the MRs, if the decision in question is not one made by the EPA, then 40 CFR part 78 does not apply. As discussed above, the EPA encourages states to review and consider potentially modifying, as appropriate, their existing administrative appeals procedures to include state actions under the MRs.

Some commenters suggested making changes to the Part 78 process, such as by maintaining a list of “interested persons” to be contacted when issues affecting them may arise. Other commenters said it may be unclear when an action is a “final decision” and that this, or other potential inefficiencies in the process under 40 CFR part 78, could frustrate timely implementation. In general, changes to Part 78 beyond the addition of potential EPA actions under the two MRs are beyond the scope of this action. In the agency’s experience, 40 CFR part 78 has been invoked rarely, and the agency has generally been able to resolve party-specific disputes under existing programs covered by 40 CFR part 78 in a manner that did not undermine the effectiveness or timely implementation of those programs. As experience with the implementation of emission trading programs under the CPP develops, the agency will continue to consider how the administrative appeals process is functioning and whether it is contributing to timely and efficient implementation while avoiding the need for litigation.

IV. Mass-Based Model Trading Rule

A. Overview

This section provides an overview of the mass-based MR. The following sections discuss the key components of this MR, including compliance periods; emission budgets, allowance trading and banking; allowance allocation; trading program operations and compliance; and monitoring, reporting, and recordkeeping requirements for affected EGUs. The regulatory provisions for the mass-based MR are being codified in 40 CFR part 62, subpart MMM. State plans that adopt these MR provisions are presumptively approvable, as discussed in section II.B above.

The mass-based MR is in the form of a mass-based emission budget trading program for affected EGUs (also referred to as an “allowance system”). A mass-based emission budget trading program establishes an overall cap on emissions for a group of sources. Emission allowances are issued in an amount up to the established emission budget. Each source must meet an emission standard that limits the amount of its emissions to the amount of allowances it surrenders. An emission allowance represents a limited authorization to emit a specified amount of a pollutant and does not constitute a property right. Emission allowances are tradable. In this MR, each allowance authorizes the emission of one short ton of CO_2 by an affected EGU.

The mass-based MR is structured as an individual state trading program that would be submitted as part of a state plan that is ready for interstate trading. This MR, therefore, provides an individual state component of a linked interstate trading program, using the trading-ready mechanism in the CPP for linking state programs.[40] If states adopt this MR as part of a state plan that is ready for interstate trading, affected EGUs may use for compliance allowances from the emission budget of any state in the group of trading-ready states participating in the interstate program.[41]

In this MR, after each compliance period the owner or operator of any facility with affected EGUs must hold in the facility's compliance account CO_2 allowances for deduction equal

[40] A trading-ready state plan is one where a state identifies the plan as ready-for-interstate-trading and the plan includes the use of an EPA-administered or EPA-designated tracking system. Upon approval of such a state plan, the state emission trading program would be linked to all other programs included in other approved trading-ready state plans that use the same EPA-administered or EPA-designated tracking system.

[41] This MR includes provisions that establish this linkage among programs in approved trading-ready state plans. Through minor modifications, this MR could also be adapted for use by states taking other approaches. For example, this MR could be adapted for use as a state trading program that is not connected to other states, or an interstate trading program implemented through specified bilateral or multilateral linkages with other states or as part of a program implemented through a multi-state plan.

in number to the quantity of the reported CO_2 emissions of the affected EGUs during the compliance period. This allowance-holding and deduction requirement constitutes the emission standard for an individual affected EGU subject to an emission budget trading program. The owner or operator of a facility with affected EGUs or other entities that participate in the allowance market may buy, sell, or otherwise transfer allowances to or from other owners or operators of other affected EGUs or other entities that participate in the allowance market.

The design of the mass-based MR draws upon more than two decades of state and EPA experience implementing mass-based emission budget trading programs. Over the past decade multiple states have designed and implemented mass-based emission budget trading programs for CO_2 and other GHGs, and the EPA considered the experience gained through those programs in the design of this MR.[42] In addition, the EPA has more than twenty years of experience administering mass-based trading programs, including

[42] For information about these state programs, see http://www.rggi.org; and http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

the Acid Rain Program (ARP) sulfur dioxide (SO_2) trading program under title IV of the CAA, as well as the NO_X Budget Trading Program, Clean Air Interstate Rule (CAIR), and Cross-State Air Pollution Rule (CSAPR) under the "good neighbor" provision of CAA section 110(a)(2)(D)(i)(I).[43]

A mass-based trading program typically provides environmental certainty at lower cost than other policy mechanisms because it assures a specified emission outcome while maximizing compliance flexibility available to individual affected EGUs. The ability to trade allowances provides a mechanism through which emission reduction actions are taken where and when it is most economic to do so. In addition, such programs can provide temporal flexibility through the ability to bank allowances for future use, which creates an incentive to make emission reductions earlier than required if it is economic to do so.[44] Mass-based trading programs are relatively simple to operate and have historically enjoyed very high (near 100 percent) rates of compliance; these factors reduce administrative time and cost.

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[43] *See* http://www.epa.gov/airmarkets.

[44] Banked allowances can be held for use in compliance in a future compliance period, or sold in the market at a later date.

The mass-based MR includes regulatory provisions necessary to implement a mass-based trading program while meeting requirements in the CPP. However, the MR does not include an approach for allocating allowances, which a state must include in a state plan pursuant to 40 CFR 60.6815(b). The EPA has decided not to include the proposed allocation provisions in the final MR. Because each state choosing to include a mass-based trading program in its state plan has full flexibility to determine how it will allocate allowances, the EPA has determined it is unnecessary to suggest that any one approach is presumptively approvable.[45] A state adopting the mass-based MR, therefore, also must include an approach and method(s) for allocating allowances in its state plan submittal. See section IV.F of this preamble for further discussion.

In addition, because states have broad discretion to fashion an approach for meeting the CPP requirement to address potential “leakage” to new fossil fuel-fired sources pursuant to

[45] The EPA notes that the allowance allocation provisions in the proposed MR were primarily developed by the agency for use in the context of a federal plan, but also served as proposed allocation provisions for a model rule. Given the flexibility provided in the CPP, the EPA has determined that it is not warranted to finalize allowance allocation provisions in the final MR.

40 CFR 60.5790(b)(5), the mass-based MR does not include provisions that address this CPP requirement. As discussed above, the EPA is not finalizing allowance allocation provisions in the MR, some of which were proposed to address the CPP leakage requirement. States adopting this MR, therefore, must include in the state plan submittal an approach to address potential leakage, consistent with the requirement in the CPP. States have broad discretion to fashion an approach for meeting CPP requirements to address potential leakage to new fossil fuel-fired sources pursuant to 40 CFR 60.5790(b)(5). This topic is discussed further in section IV.G of this preamble.

The proposed MR also functioned as a proposed federal plan and, as such, contained a proposed general allocation approach and an approach to addressing potential leakage through allowance allocation. The federal plan remains a proposal. The decision not to finalize in the MR either the proposed general allowance allocation approach or the proposed allocation provisions for meeting the CPP requirement to address potential leakage does not reflect any judgment on the part of the EPA regarding those proposed approaches for a federal plan.

The EPA emphasizes that its decision not to finalize allowance allocation provisions was made in part to avoid the perception that an allowance allocation approach in a final MR would be more favored by the agency in the course of state plan review than an alternative allowance allocation approach proposed by a state. The EPA believes it is important from a policy standpoint to emphasize state discretion and deliberative processes for assessing different allocation options that may be used.

The mass-based MR is an emission-budget trading program for affected EGUs only. States may choose to address the CPP leakage requirement by modifying this MR to incorporate new sources[46] or through allowance allocation-based leakage mitigation strategies. States may also address the CPP leakage requirement through other state plan approaches. See section IV.G below for further discussion of options to address the CPP leakage

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[46] Appendix A of the Leakage TSD in the docket includes example regulatory text that could be used by a state to modify this MR, if it chooses to include new sources under state law as part of its emission budget trading program, as a means to meet the CPP requirement to address potential leakage. This regulatory text includes optional emission budgets that were specified and finalized as a presumptively approvable method for addressing the leakage requirement in the CPP, for states that choose to include new sources in an emission budget trading program under state law.

requirement.

This MR provides one specific example of a mass-based trading program.[47] A state may choose to include a mass-based trading program in its state plan that differs from this MR, as long as it meets the requirements in the CPP. States may choose to adopt the entire mass-based MR, or to adopt only certain provisions. States may choose to tailor or modify this MR, in which case the EPA would conduct appropriate review of such provisions as part of its review of a state plan, in order to determine that all requirements of the CPP are met. See section II.B of this preamble for further discussion.

The EPA received many comments on the proposed mass-based MR from a wide range of stakeholders. Comments strongly supported finalization of a mass-based MR and provided constructive feedback on the MR design elements that the agency proposed and for which it requested comment. This input has been

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[47] The EPA is aware of at least one organization, the National Association of Clean Air Agencies (NACAA), which has independently developed example regulatory text. The EPA has not evaluated whether this approach meets CPP requirements, and would only evaluate this approach through notice and comment rulemaking. *See* NACAA, Implementing EPA's Clean Power Plan: Model State Plans (May 2016), available at http://www.4cleanair.org/NACAA_Model_State_Plans.

incorporated into a number of provisions in the mass-based MR. As noted previously, comments related solely to the proposed federal plan are out of scope of this action and will be addressed, as appropriate, if and when the EPA promulgates a federal plan for a state following a finding that the state has failed to submit an approvable plan. The rest of this section addresses specific topics related to the mass-based MR. The agency notes throughout changes it has made to the proposal and how it has addressed or incorporated specific feedback received in comments.

B. Compliance Periods

The MR includes multi-year compliance periods that are consistent with the plan performance periods in the CPP (two 3-year interim step periods followed by a 2-year interim step period during the interim performance period from calendar year 2022 through calendar year 2029, and successive 2-year final reporting periods during the final performance period beginning in calendar year 2030). These multi-year compliance periods are the same as those included in the proposal, which were supported by many commenters. If a state chooses, it could amend the model rule to implement shorter compliance periods.

The agency proposed that compliance would be evaluated after the last year in each compliance period and that no intervening compliance requirements would be included. The EPA also requested comment on the inclusion of intervening compliance requirements, such as requiring affected EGUs to surrender a portion of the allowances necessary to meet their compliance obligation annually. Many commenters preferred no such intervening compliance requirements. A few commenters preferred inclusion of intervening requirements, with the rationale that this would provide early warning of potential noncompliance while retaining the flexibility of multi-year periods.

A multi-year compliance period without intervening compliance requirements provides greater compliance flexibility to affected EGUs and reduces administrative burden. The EPA believes that the multi-year approach included in the proposed MR strikes a reasonable balance between providing flexibility and reducing adminstrative burden while assuring that any noncompliance can be addressed in a timely fashion. Therefore, the EPA is finalizing this MR to maintain this multi-year compliance approach. The compliance periods included in this MR meet the requirements of the CPP.[48]

In this MR, a state evaluates compliance as of May 1 of the year after the last year of each multi-year compliance period (*i.e.*, the allowance transfer deadline is May 1 following the end of a compliance period).[49] The EPA proposed May 1 as the allowance transfer deadline and a number of commenters supported this approach. The May 1 date is appropriate, in the EPA's view, because it provides a four-month window after the end of a compliance period to give owners and operators time to ensure accurate CO_2 emissions data and acquire any necessary allowances for compliance. At the same time, May 1 is two months before the deadline of July 1 in the CPP for states to periodically report to the EPA on the status of the implmentation of their state plans, as specified at 40 CFR 60.5870. As part of this report, states must include their affected EGUs' compliance status with emission standards in the state plan (*see* 40 CFR 60.5870(b)(1)),

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[48] *See* 80 FR 64662, 64864 (October 23, 2015).

[49] The "allowance transfer deadline" is the deadline for transferring allowances that can be used for compliance in the previous compliance period to the compliance account of a facility with affected EGUs. For further information see section IV.H of this preamble.

and May 1 provides a two-month window for states to assess affected EGU compliance prior to the state reporting deadline.

C. Emission Budgets

In the CPP, the EPA established mass-based CO_2 goals for all states, for interim and final plan performance periods that align with the compliance periods included in this MR, and those mass-based CO_2 goals are the emission budgets used in this MR.[50] As a result, the emission budgets in this MR meet the requirements of the CPP.[51] Table 1 provides the CO_2 emission budgets established for states under this MR. Note that the emission budgets in Table 1 are annual amounts. For example, Alabama's budget is 66,164,470 short tons of CO_2 for each of the three years in the first interim step period.

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[50] The CPP includes mass-based CO_2 goals for the affected EGUs in each state for three interim step periods (2022-2024, 2025-2027, 2028-2029) followed by successive two-year final periods (2030-2031, and successive two-year periods). Mass-based CO_2 goals for states are established in Table 3 to subpart UUUU of part 60. The interim step goals during the interim plan performance period are specified in the preamble to the CPP at Table 13, 80 FR 64825 (October 23, 2015).

[51] *See* 80 FR 64662, 64890 (October 23, 2015). Under the CPP, states have discretion to establish CO_2 emission budgets that differ from the mass-based CO_2 goals for the interim step periods, provided the cumulative total of the established CO_2 emission budget over the full 8-year interim plan performance period is equal to or less than the state mass-based CO_2 goal for the interim plan performance period.

Table 1. Mass-based MR Annual CO_2 Emission Budgets

(Short Tons)

	Annual Budgets 2022-2024	Annual Budgets 2025-2027	Annual Budgets 2028-2029	Annual Budgets 2030-2031 and later
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835

Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584

New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah*	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111

Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

* Excludes affected EGUs located in Indian country within the state.

The EPA proposed that allowances would be denominated in short tons. A number of commenters supported the use of short tons while others preferred metric tons (*e.g.*, to facilitate potential future international linkages).[52] Denominating allowances in short tons is compatible with the mass-based CO_2 goals for states that the EPA promulgated in the CPP (which are in short tons) and the MR reporting requirements for affected EGUs (which require reporting of CO_2 emissions in short tons). This MR maintains the denomination of allowances in short tons.

D. Allowance Trading

The mass-based MR provides tradable allowances, each of which authorizes one short ton of CO_2 emissions from an affected

[52] The potential to link state programs that denominate CO_2 allowances in short tons with state programs that denominate CO_2 allowances in metric tons is discussed below in section IV.D.

EGU. While structured as an individual state trading program, implemented under the legal authority of a single state, this MR is designed to facilitate interstate allowance trading. Specifically, this MR includes provisions that enable its use as part of a trading-ready state plan.

The CPP provides flexibility for states to choose to implement an interstate or intrastate trading program.[53] An interstate trading program allows affected EGUs to use for compliance an allowance issued in any other state participating in that same trading program. In contrast, in an intrastate trading program,[54] an affected EGU may only use for compliance an allowance issued by the state in which it is located.

While this MR is designed to be used as part of a trading-ready state plan, states can choose to modify this MR for use in

[53] The CPP allows for states to implement a stand-alone intrastate trading program, linked individual programs through single-state plans (which effectively provides for an interstate trading program), or an interstate trading program through a multi-state plan.

[54] “Intrastate trading program” as used here refers to a single state program that is not linked to other state programs (either through program linkages established in a single state plan or through a multi-state plan).

a multi-state plan, or for use in an individual plan with specified bilateral or multilateral linkages.[55] See section III.D above for a discussion of the trading-ready state plan mechanism and other options for state plans that would also facilitate interstate trading.

The EPA structured the proposed mass-based MR as regulatory provisions for an individual state trading program. In the proposal, the agency also noted that the design of this MR would facilitate linking of individual state programs, and by extension, interstate trading of allowances. Commenters expressed broad support for finalizing MRs that would facilitate the linking of individual state programs and interstate trading. In particular, commenters expressed their support for MRs that could be submitted as part of a trading-ready state plan. The ability to link programs using this MR, and the trading-ready state plan mechanism, are discussed further in section III.C above.

While the EPA intended that the proposed MR could be submitted as a program linked with other states, including

[55] This would involve modest revisions to the trading-ready provisions in this MR to specify linkages among identified state programs.

through a trading-ready state plan, the proposed rule text itself did not include the provisions necessary to effectuate these linkages. In this MR, the EPA has included provisions for submission of this MR as part of a trading-ready state plan. These provisions indicate that allowances issued by other trading-ready states are usable for compliance by affected EGUs subject to the state program.[56]

Some commenters supported the ability for linking emission budget trading programs that denominate CO_2 allowances in short tons with programs that denominate CO_2 allowances in metric tons. The CPP allows a state to choose the amount of CO_2 emissions authorized by an allowance under its state plan (*e.g.*, whether an allowance is denominated in short tons or metric tons of CO_2). The CPP also does not preclude state plans from providing for trading across linked mass-based trading programs that use

[56] These regulatory provisions indicate that allowances allocated by other states with approved trading-ready state plans that use the same EPA-designated tracking system as the one specified in the state's approved state plan may be used for compliance. The EPA-designated tracking system specified in an approved trading-ready state plan could include an EPA-administered tracking system, or one or more EPA-designated tracking systems. If more than one tracking system is identified, those tracking systems would need to be interoperable for such a trading-ready state plan to be approvable.

allowances denominated in different units of measurement (*e.g.*, short-ton allowances and metric-ton allowances). This MR does not include provisions that would be necessary to effectuate trading across such linked programs; states may allow such trading, and if they do so, must include provisions for it in their state plan submittals, including provisions for conversion of units. The EPA would conduct appropriate review of such provisions as part of its review of a state plan, in order to determine whether all requirements of the CPP are met.[57]

E. Allowance Banking

Allowance banking is a form of temporal flexibility where unused allowances from a current or past compliance period can be used for compliance in a future compliance period. Experience with state and federal mass-based emission budget trading programs shows that banking provides incentives to reduce emissions earlier than required when it is economic to do so, and also provides significant compliance flexibility to affected

[57] *See* 40 CFR 60.5825. These provisions should include appropriate safeguards to avoid non-compliance by affected EGUs due to errors in converting between units of measurement. Considerations include stipulation of which parties do the conversion, at what point the conversion occurs, and tracking-system design.

EGUs. The EPA proposed to allow unlimited allowance banking in this MR. Many commenters supported unlimited banking, with some noting that prohibiting banking can create a perverse “use them or lose them” incentive (*i.e.*, an incentive to increase emissions, or defer emission reduction actions, in a current compliance period and use up current allowances because they wouldn’t have value in future compliance periods if banking were prohibited).[58]

The mass-based MR allows for unlimited banking, meaning current vintage allowances may be banked for use in any future compliance period.[59] For example, to demonstrate compliance with

[58] Banking is appropriate, in particular, for a trading program addressing GHG emissions, as the primary objective is a reduction in cumulative GHG emissions over time, rather than ensuring specified emission levels during relatively short periods of time.

[59] In this MR, each allowance is assigned a vintage that corresponds to a calendar year. All of the allowances that comprise the emission budget for each compliance period are assigned a vintage that corresponds to one of the years in that compliance period. For instance, for the first compliance period, each allowance will be assigned a vintage of one of the following years: 2022, 2023, or 2024. Each allowance authorizes the emission of one short ton of CO_2 during the compliance period that includes the allowance’s vintage year (*i.e.*, the current compliance period) or a later (future) compliance period.

the allowance surrender requirement for the compliance period that comprises the years 2025 through 2027, the owner or operator of an affected EGU may use allowances of vintages 2022, 2023, 2024, 2025, 2026, and 2027. As a further example, for the compliance period that comprises the years 2030 and 2031, an affected EGU may use allowances of vintages 2022 through 2031. There is no restriction on the use of banked allowances, including from the interim plan period (2022 through 2029) into the final plan period (2030 and thereafter). This approach is consistent with the CPP, which allows for allowance banking without limitation.[60]

The CPP prohibits allowance borrowing, where allowances from a future compliance period are used for compliance in a current period.[61] Consistent with this prohibition, the mass-based MR also prohibits borrowing. The EPA notes that the multi-

[60] *See* 40 CFR 60.5815(e).

[61] Allowance borrowing would occur if an allowance were used for compliance in a compliance period prior to the one that includes the allowance’s vintage year. For example, if an allowance has been assigned a vintage of 2025, it may not be used for compliance in the first compliance period, 2022-2024. *See* 40 CFR 60.5815(f).

year compliance periods included in this MR inherently provide for temporal flexibility within each multi-year compliance period (*e.g.*, during the first compliance period a vintage 2024 allowance could be used to cover a ton of CO_2 emitted in 2022).[62] This temporal flexibility provided through a multi-year compliance period allows affected EGUs and states to address potential short-term issues, such as temporary increases in electricity demand or localized reliability considerations due, for instance, to outages of generating units.

F. Allowance Allocation

1. Overview

In a mass-based trading program, policymakers may choose from a number of different methods for allowance allocation, including auction, direct allocation (*i.e.*, distribution at no cost to the recipient), and direct sale.[63] Allowances may be allocated solely to affected EGUs, or to other entities as a state may determine in its state program. Allowances are

[62] In practice, this effectively provides for a dynamic similar to borrowing within a compliance period.

[63] As commonly used, the term "allocation" refers to a method used by an administering agency to distribute allowances to affected entities and other market participants under an emission budget trading program.

allocated in an amount up to the applicable emission budget. Once allocated, allowances can then be traded among affected EGUs and other market participants.

As part of the proposed mass-based federal plan, the EPA included an allocation approach that would directly allocate most of the allowances to affected EGUs based on historical generation data. The historical-generation based allocation approach in the mass-based federal plan proposal also served as an example allocation method in the context of the proposed mass-based MR.

More significantly, however, the CPP provides states with broad discretion in the choice of allowance allocation approaches.[64] Indeed, a number of commenters on the proposed MR recommended that the EPA not include any allocation approach in this MR, because it could be interpreted as the default allocation for states, even if this was not the EPA's intent. Consistent with the flexibility and broad discretion provided to states on allowance allocation in the CPP, and in response to

[64] The EPA notes that the allocation requirements in the CPP are basic – specifically, that a state plan specify how allowances will be allocated. *See* 40 CFR 60.5815(b). This includes the method(s) used to allocate allowances, which includes the timing of allowance allocation.

many commenters, the EPA has decided not to include an allocation approach in this MR. The EPA has determined it is unnecessary to suggest that any particular allocation approach is presumptively approvable through inclusion of a specified approach in this MR, given that, as the EPA indicated in the proposed MR, the agency believes that states are generally well positioned to design their own allocation approaches. States can take into account a wide range of considerations and tailor decisions about allowance allocation to the particular characteristics and priorities of their state and stakeholders. In fact, as discussed below in section IV.F.3, many states have designed their own allocation approaches under other emission budget trading programs addressing GHG emissions and criteria pollutants.

The EPA also proposed three set-asides of allowances for this MR. An allowance set-aside is a policy mechanism whereby a portion of the allowances from an emission budget are reserved from the general allocation approach and distributed for a specific policy purpose. Along with its decision not to finalize an allocation methodology, the EPA has decided not to finalize any allowance set-aside approaches in this MR. However, the EPA has designed the structure of this MR’s regulatory text to be readily capable of including a Clean Energy Incentive Program (CEIP) set-aside, if a state using this MR chooses to implement the CEIP.

The EPA originally included a CEIP set-aside in the federal plan proposal and in this MR proposal on October 23, 2015. The CEIP set-aside would reserve a portion of allowances from the emission budgets of the first compliance period for allocation to qualifying recipients under the optional Clean Energy Incentive Program (CEIP). The EPA has decided to remove the CEIP set-aside provisions from this action and has re-proposed CEIP-related aspects of the mass-based MR, including the CEIP set-aside, in the Clean Energy Incentive Program Design Details proposed rule published on June 30, 2016.[65]

The second and third set-asides that the EPA originally included in the federal plan proposal and this MR proposal were designed to address the requirement in the CPP that state plans including mass-based emission trading programs address potential

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[65] *See* the Clean Energy Incentive Program Design Details proposal at 81 FR 42940 (June 30, 2016). In that action, the EPA also proposed to remove the existing language from 40 CFR 60.5815, paragraph (c) of the CPP, which pertained to EM&V requirements for the CEIP allowance set-aside, and to clarify and consolidate the EM&V requirements for eligible CEIP projects in the CEIP action.

leakage to new sources. These proposed set-asides included an output-based allocation set-aside for affected NGCC units and a set-aside to encourage the deployment of renewable energy (RE) resources. The EPA is not finalizing these set-asides in this MR for the reasons discussed in section IV.G below.

Under the CPP, the allowance allocation provisions included in a state plan must provide that the state will only allocate allowances from its established emission budget (*i.e.*, the total number of allowances allocated may not exceed the emission budget established in the approved state plan).[66] A state's allocation approach can provide that the total amount of allowances distributed is less than the applicable mass-based CO_2 goal for a state.[67] In order to meet requirements in the CPP, a

[66] *See* 40 CFR 60.5790(b)(1), which requires a state plan using an emission budget trading program to specify the emission budget for such program. *See also* 80 FR 64834-64835 (October 23, 2015).

[67] A state's allowance allocation approach can provide that the total amount of allowances allocated is less than the applicable mass-based CO_2 goal, pursuant to the reserved authority of states to set emission standards more stringent than federal standards under CAA section 116. A state may also include allocation provisions where a certain portion of allowances are withheld and only allocated in the case of certain events. For example, a state may choose to withhold unallocated allowances from under-subscribed allowance set-asides (*e.g.* to roll them into a future

state’s allocation provisions must specify, prior to the beginning of the compliance period, the method(s) that will be used to allocate allowances, which includes the timing and process for the allocation of allowances.[68]

If a state includes in its state plan an allowance allocation strategy to address the leakage requirement in the CPP, the EPA would conduct appropriate review of such provisions as part of its review of a state plan, in order to determine whether all requirements of the CPP are met. See section IV.G of this preamble for further discussion of the CPP requirements to address potential leakage to new sources.

2. Timing of Allocations

The EPA proposed in the mass-based federal plan and MR to determine the historical data-based allocations once, before the first compliance period, with no updating. The EPA proposed to allocate these allowances (*i.e.*, to record them in tracking system accounts) for one compliance period at a time prior to the start of each compliance period. A number of commenters supported that timing approach.

year’s set-aside), or to hold allowances in reserve as a cost-management mechanism.

[68] *See* 40 CFR 60.5815.

Because the timing of allocation may depend on the choice of allocation approach and methods made by a state – and because the EPA is not including an allocation approach in this MR – the EPA has not included allocation timing provisions in this MR.

Although the EPA is not finalizing an allocation approach in this MR, some discussion of allocation timing options and a clarification regarding the allocation timing requirements in the CPP at 40 CFR 60.5815(b) may be helpful for states as they consider allocation approaches as part of the development of a state plan. Basing allocation methods on non-updating historical data allows for allowance allocation prior to the beginning of each compliance period. However, many commenters recommended allocation approaches that could involve allocation after the start of a compliance period. For instance, many commenters recommended auctions as a preferred allocation approach. Several commenters cited the auctions used in the existing CO_2 and GHG emission budget trading programs implemented by the Regional Greenhouse Gas Initiative (RGGI) participating states and California, respectively. The RGGI and California auctions are conducted quarterly and offer current-vintage allowances for sale.[69] A commenter noted that quarterly auctions provide for frequent price discovery.[70]

The CPP provides states with broad flexibility to choose allocation approaches. States may choose auctions or other allocation approaches that depend on activity that occurs during compliance periods. When an allocation approach based on historical data is used, the EPA believes there are benefits to allocating allowances as early as practicable and in advance of the start of a compliance period. However, the CPP does not require that all allowances for a compliance period be allocated prior to the start of that period. Under 40 CFR 60.5815(b), a state must include in its state plan "provisions for allocation of allowances" for each compliance period prior to the beginning of the compliance period. This provision in the CPP requires a state to specify the allowance allocation method in its state plan, prior to the beginning of a compliance period. As a result, even if a state allocation method(s) allocates

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[69] For more information, *see* http://www.rggi.org/market/co2_auctions; and http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm. The RGGI and California auctions also offer some future-vintage ("advance") allowances.

[70] Auctions provide a periodic assessment of the market value of allowances, supplementing secondary allowance market price data.

allowances periodically during a compliance period, affected EGUs and other parties will have notice of the state’s allocation approach at the time of final state plan approval. This provision does not mean, however, that all allowances of a vintage that falls within a respective compliance period must be distributed prior to the beginning of that compliance period.

3. Allocation Approaches States Have Used

The EPA received significant comment recommending that it not provide an allowance allocation method or methods as presumptively approvable in a mass-based MR. Commenters noted that a MR allowance allocation methodology may suggest an EPA-endorsed default approach for states and could be perceived as limiting the flexibility provided to states in the CPP. Commenters also pointed to states’ experience with allowance allocation in previous programs as evidence of states’ ability and preference to identify allocation methods that work best for their circumstances. Many states have had success designing their own allowance allocation approaches. In addition, the EPA received wide-ranging comment on allowance allocation methodologies, ranging from support for historical generation- or emissions-based allocation to allowance auctions. The EPA also received comments suggesting allocation to only affected

EGUs, all generating units, load-serving entities (LSEs), and other entities.

In the proposal, the EPA itself recognized a wide variety of allocation approaches.[71] Although the EPA is not finalizing an approach to allowance allocation approach as part of this MR, this section surveys several examples from existing programs that may be of interest to states.

Under the RGGI of the Northeast and Mid-Atlantic states, which covers the electric power sector, the vast majority of allowances are allocated by participating states through joint quarterly auctions and the auction proceeds are used for consumer benefit purposes, primarily to accelerate deployment of end-use energy efficiency and mitigate electricity ratepayer impacts.[72] While individual RGGI participating states determine the use of their auction proceeds, and states have dedicated funding to a wide variety of programs, the majority of proceeds are used for funding demand-side energy efficiency (demand-side-

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[71] *See* 80 FR at 65015-65029.

[72] *See* Regional Greenhouse Gas Initiative, "Overview of RGGI CO_2 Budget Trading Program", at 4, available at http://www.rggi.org/docs/program_summary_10_07.pdf.

EE) programs, RE programs, and low-income ratepayer support.[73]

The RGGI participating states have noted that market barriers to least-cost demand-side EE options may not always be overcome by an allowance price signal alone, and related changes to retail electricity prices due to factors such as high implicit consumer discount rates, principal-agent market failures, or capital rationing. Evaluation of the RGGI program suggested that the allowance allocation method of periodic auctions and reinvestment of auction proceeds to consumer benefit programs contributed to a positive economic outcome of the program.[74] In particular, the RGGI participating states have found that investing auction proceeds in demand-side EE can lower both retail electricity bills and system costs by reducing electricity demand, lessening the need for additional system

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[73] *See* Regional Greenhouse Gas Initiative, "Investment of RGGI Proceeds Through 2013" (April 2015), available at http://rggi.org/docs/ProceedsReport/Investment-RGGI-Proceeds-Through-2013.pdf.

[74] *See* "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States", The Analysis Group (November 2011), available at http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/economic_impact_rggi_report.pdf.

infrastructure and decreasing wholesale electricity prices.[75]

Under the California mass-based emission budget trading program, which covers multiple sectors in addition to the electric power sector, the allowance allocation approach involves a combination of direct distribution of allowances to local electric distribution companies (LDCs), natural gas suppliers, and other covered entities, as well as quarterly state-run auctions.[76] The ratio of direct allocations to auctioned allowances is also adjusted over time. The proceeds from the auctions are used to promote RE, demand-side EE, advanced vehicles, and waste reduction.

In previous emission trading programs for criteria air pollutants, the EPA has noted that states have the flexibility to determine allowance allocation method(s) and utilize

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[75] Similar results could be achieved by allocating allowances directly to entities, such as local electricity distribution companies (LDCs), which would then reinvest proceeds from the sale of allowances in public benefit programs that deploy DS-EE and renewable energy measures.

[76] *See* California Air Resources Board, "Allowance Allocation", available at http://www.arb.ca.gov/cc/capandtrade/allowanceallocation/allowanceallocation.htm.

flexibility in regard to the use of direct allocation and auctions, frequency of allocations, methods for allocating allowances, and the use of allowance set-asides. States have regularly taken advantages of these flexibilities. For example, Kentucky set-aside 5 percent of its NO_X Budget Trading Program allowances for auction using a secondary market broker.[77] Alabama used a historical heat input approach for allocation in its CAIR SIP that ceased allocations to retired units sooner than in the CAIR MR and made those allowances available to new units.[78] In its CAIR SIP, New York established an allowance set-aside for demand-side EE and RE that was filled by unallocated allowances (*e.g.*, unused allowances from the new-unit set-aside).[79]

In some instances, states have also chosen to withhold and not allocate small portions of their emission budgets in order to meet certain policy objectives. For example, a number of the RGGI participating states have established small allowance set-asides from which a state retires allowances based on documented

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[77] 401 KAR 51:160. NOx requirements for large utility and industrial boilers; available at http://www.lrc.state.ky.us/kar/401/051/160.htm

[78] ADEM Admin. Code r. 335-3-x-xx; available at http://www.adem.state.al.us/alEnviroRegLaws/files/Division3.pdf

[79] 6 CRR-NY 243.6; 244.6; and 245.6, Energy efficiency and renewable energy technology account (2007) (amended 2015).

voluntary RE purchases by electricity ratepayers. These allowance set-asides are designed to preserve marketer and consumer claims in states with CO_2 emission budget trading programs that voluntary purchases of RE displace carbon-intensive generation and avoid CO_2 emissions.

The variety of allowance allocation approaches used in previous and current programs illustrates various states' interest and experience in designing their own allowance allocation methodologies. Furthermore, state public processes allow for the public to provide input on proposed state allocation approaches, providing transparency and increasing the likelihood of public support for the emission budget trading program. For example, research shows that the method of allocating allowances can have an impact on the overall cost of the program, as well as who bears the cost.[80] Experience with existing programs has shown that states have used allowance

[80] Palmer et al., *Allowance Allocation in a CO_2 Emissions Cap-and-Trade Program for the Electricity Sector in California*, Resources for the Future (October 2009). Available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-DP-09-41.pdf.

allocation methods to further various environmental and policy goals. For example, allocation methods have been used to mitigate potential electricity ratepayer impacts, protect low-income customers, and reduce the environmental burden on historically disproportionately impacted communities.[81]

In addition, a number of organizations have convened workshops with states and published papers on CPP state plan design, including allowance allocation approaches for mass-based plans, and provided multiple overviews and studies of different allocation approaches. As a result, there is a wealth of available information and analysis of different allocation approaches that could be utilized by states in designing the allocation methods included in a state plan that uses this MR.[82]

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[81] Gattaciecca et al., *Protecting the Most Vulnerable: A Financial Analysis of Cap-and-Trade's Impact on Households in Disadvantaged Communities Across California*, UCLA Luskin Center for Innovation (April 2016). Available at http://innovation.luskin.ucla.edu/sites/default/files/FINAL%20CAP%20AND%20TRADE%20REPORT.pdf.

[82] *See e.g.*, Franz Litz and Brian Murray, "Mass-Based Trading under the Clean Power Plan: Options for Allowance Allocation", (Nicholas Institute at Duke University, March 2016), available at https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_16-04_0.pdf.

G. Addressing Potential Leakage

The CPP requires that state plans using a mass-based emission budget trading program address the potential for leakage to new fossil fuel-fired EGUs. The CPP defines leakage as a larger incentive for generation shifts from affected existing fossil fuel-fired EGUs to new non-affected fossil fuel-fired EGUs that would occur under a mass-based emission budget trading program, as compared to any such incentives that might occur under application of the subcategory-specific CO_2 emission performance rates established in the CPP. This larger incentive for generation shifts from existing to new sources under an emission budget trading program is inconsistent with the degree of emission limitation achievable through the application of the BSER and could also result in increased overall CO_2 emissions. This unique potential for leakage under mass-based emission budget trading programs that only apply to existing sources is inconsistent with how the EPA applied the BSER and the assumptions the agency used for calculating the equivalent state mass CO_2 goals for affected EGUs. Therefore, this potential for leakage must be addressed in a state plan. Failure to adequately address potential leakage in a state plan could undermine the equivalence of the state mass-based CO_2 goals to the subcategory-specific CO_2 emission performance rates that the EPA established in the CPP.[83]

In the Leakage TSD[84], the EPA reiterates and discusses the need for the CPP requirement to address potential leakage in a state plan and provides example state plan approaches to address potential leakage. The CPP specified that states must demonstrate in their state plan that their specified approach sufficiently addresses leakage, and the Leakage TSD suggests example assessments for leakage that can be used in a state plan leakage demonstration.[85]

A number of stakeholders have conducted analyses of the CPP, with a focus on the potential nationwide CO_2 emission reduction implications of various state plan implementation decisions and approaches. These analyses show ongoing trends that may mitigate leakage potential, such as low natural gas

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[83] *See* 80 FR 64822 and 80 FR 64887-64888 (October 23, 2015).

[84] Technical Support Document: Leakage Requirement for State Plans using Mass-Based Emission Budget Trading Programs.

[85] The exception to this requirement is if the state includes new non-affected fossil fuel-fired EGUs as a matter of state law using the EPA-provided mass CO_2 emission budget that includes the state mass-based CO_2 goal for affected EGUs plus its state-specific new source complement finalized in the CPP. This is discussed further below.

prices and deployment of new zero-emitting generation and demand-side EE. The EPA believes that states can leverage these ongoing trends to meet the leakage requirement by demonstrating there are existing or planned measures in place to address leakage. Additionally, given these analyses, the EPA expects that depending on state-specific circumstances, states may not need much more than their existing or planned measures to address potential leakage. The Leakage TSD helps further elucidate the different paths available under the CPP for addressing potential leakage in a state plan, including how a state could leverage ongoing trends reflected in these recent analyses.

The CPP specifies the following options for state plans to address potential leakage[86]:

- Option 1. Regulate new non-affected fossil fuel-fired EGUs as a matter of state law in conjunction with emission standards for affected EGUs in a mass-based plan. If a state adopts an EPA-provided mass CO_2 emission

[86] *See* 80 FR 64887-64888 (October 23, 2015).

budget that includes the state mass-based CO_2 goal for affected EGUs plus its state-specific new source CO_2 emission complement finalized in the CPP, this option could be presumptively approvable.[87]

- Option 2. Use allowance allocation-based methods in a state plan that counteract incentives to shift generation from affected EGUs to unaffected fossil fuel-fired EGUs.
- Option 3. Provide a custom demonstration in a state plan, supported by analysis, that emission leakage is unlikely to occur due to particular state characteristics or state plan design elements that address and mitigate the potential for emission leakage.

The federal plan proposal and the MR proposal included an allowance allocation-based approach to address potential leakage, specifically through establishing an output-based allocation set-aside for affected NGCC units and a set-aside for generation from new (post-2012) RE generating capacity.[88] The

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[87] The EPA also recognized that states could adopt a new source emission complement different than that provided in the CPP, so long as it was accompanied by sufficient projections and analysis conducted by the state and subject to EPA's review for approvability. 80 FR at 64889.

[88] *See* 80 FR 65019-65025 (October 23, 2015).

agency requested comment on the inclusion of these set-asides and different aspects of the structure of these two set-asides. The EPA also specified that this approach was proposed in part because it would be the EPA’s responsibility to address potential leakage when implementing a federal plan and this approach was within the EPA’s authority.

The EPA received significant comment on how all three of the specified options in the CPP could be applied in the context of this MR and state plans, as well as other comments on the issue of potential leakage and ideas for potential solutions. Many commenters suggested a variety of analytical approaches for addressing potential leakage and demonstrating the effectiveness of different approaches. Commenters generally sought greater clarity from the EPA on how different approaches under the three CPP options could be applied and sufficiently demonstrated in state plans. The EPA received similar feedback from states during outreach meetings about state plan development.

In response to the many comments the EPA received on how to meet the CPP requirement to address potential leakage, the agency has decided not to finalize allowance allocation provisions in the mass-based MR to meet the CPP leakage requirement.[89] Instead, the EPA is providing the Leakage TSD, located in the docket for this action, which discusses example approaches for meeting the CPP leakage requirement under the three options provided in the CPP. This document also provides additional information about how states can make a satisfactory demonstration in a state plan that they have met the CPP requirement for addressing potential leakage. This document reflects in many ways the valuable input the EPA received from commenters on approaches to addressing potential leakage, and the agency expresses its appreciation for the analysis and thoughtfulness of commenters in their consideration of this issue.

Many commenters expressed support for the first CPP option for addressing potential leakage - regulating new non-affected fossil fuel-fired EGUs as a matter of state law. This approach most directly addresses concerns about leakage, because it includes new non-affected fossil fuel-fired EGUs under the same emission budget trading program as affected EGUs. Doing so

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[89] The EPA notes that the CPP provides “presumptively approvable” emission budgets, those consisting of the state’s mass goal plus its new source complement, for states that choose to address leakage by incorporating new fossil fuel-fired EGUs into their emission budget trading program as a matter of state law.

ensures that existing affected and new fossil-fuel fired EGUs face the same signal to reduce CO_2 emissions and removes the economic incentive for leakage to new fossil fuel-fired EGUs, as it is defined in the CPP. Other commenters expressed concerns about the viability of this option in their state. As discussed above, the CPP includes a presumptively approvable new source complement for each state that would add those short tons to the state mass-based CO_2 goal for affected EGUs to yield a larger emission budget for new and existing sources together.[90] The CPP does not, however, provide MR text that would operationalize the inclusion of new sources in an emission budget trading program included in a state plan.

Commenters requested that the EPA provide MR text for the implementation of a mass-based emission budget trading program that incorporates new sources under the program as a matter of state law, using the new source complement for each state in the CPP. While the EPA is not providing that language in the MR being finalized in this action, the EPA has provided example regulatory text that states could use to operationalize the new source complement in their state plans. This example regulatory

[90] *See* 80 FR 64888, Table 14.

text is provided in Appendix A of the Leakage TSD and the agency has provided instructions for states to readily incorporate that language into a state plan that uses this MR, should they choose to do so. This example regulatory text includes, for each state, the emission budgets finalized as presumptively approvable in the CPP that is equal to a state's mass-based CO_2 goal for affected EGUs plus new source complement.[91]

Regarding the second CPP option for addressing potential leakage - use of allowance allocation-based approaches - the EPA received a large number of comments on the approach in the proposed MR. Commenters suggested a wide variety of other allowance allocation-based approaches that could address the potential for leakage, with a significant disparity in approaches. A number of commenters had varying concerns with the structure of the proposed approach, including the types of electric generation receiving allowances, the allowance distribution method, and the level of electric generation incentive provided. Many commenters cited specific aspects of their state that caused them to prefer a different approach.

[91] The CO_2 emission budgets in Appendix A of the Leakage TSD are identical to those provided in the CPP at Table 14 of the preamble (80 FR at 64888-64889).

After consideration of these comments, the EPA has decided not to finalize an allowance allocation-based approach to address potential leakage in this MR. The wide-ranging comments that the EPA received indicate that it would be inappropriate to select a presumptively approvable allowance allocation approach to address potential leakage, given the wide range of potentially effective allowance allocation approaches states could adopt. The EPA recognizes that there is a wide disparity of viewpoints on how allowance allocation-based leakage mitigation approaches should be structured and that many states would be unlikely to simply adopt the proposed allocation approach without change. In this circumstance, the usefulness of providing states a presumptively approvable allocation approach for addressing potential leakage is substantially diminished. The EPA further notes that the allowance allocation provisions to address the CPP leakage requirement in the proposed MR were primarily developed by the agency for use in the context of a federal plan. Given the flexibility provided in the CPP, the EPA has determined that finalizing allowance allocation provisions in the final MR that address the CPP leakage requirement is not warranted.

The EPA co-proposed the allocation approach addressing potential leakage in both the federal plan and the mass-based MR. The EPA is taking no action with respect to the proposed mass-based federal plan, including how allowance allocation would be handled in that plan, thus the output-based set-aside for affected NGCC units and RE set-aside and all other aspects of the proposed federal plan remain as the agency’s proposal. The EPA’s decision not to finalize an allocation approach in this MR does not mean that the EPA may not conclude later that the allocation approach and set-asides that it proposed, or similar or modified approaches, could ultimately be finalized as appropriate in the context of a federal plan for a particular state or states. The choice not to include this option in this MR does not reflect an agency view or intention with respect to addressing potential leakage in any potential federal plan that may be promulgated in the future.

As specified in the CPP, states have the option to offer a custom allowance allocation-based approach in a state plan to address potential leakage. In the Leakage TSD, the agency provides a discussion about ways that a state could demonstrate in a state plan that a custom allocation-based approach sufficiently addresses potential leakage.

Regarding the third CPP option for addressing potential leakage – a custom demonstration in a state plan that leakage is unlikely to occur – many commenters also requested that the EPA clarify how states can demonstrate in a state plan that particular state circumstances and policies can mitigate the potential for leakage. The EPA evaluated many of the approaches suggested in comments, and recognizes the value of many of these potential approaches. At the same time, the EPA determined that it could not satisfactorily conclude it would be useful to finalize any of these approaches specifically as presumptively approvable. Indeed, the very idea of a "custom" approach is inimical to defining an approach that is presumptively approvable. In addition, many of the approaches suggested in comments are outside the scope of a MR, as they would be implemented through complementary state measures. However, the EPA does believe it can provide support to states by providing examples of potentially approvable approaches. In the Leakage TSD, the agency provides examples of custom demonstrations, including considerations for and discussion of ways that a state could support custom demonstrations using credible analysis.

H. Allowance Tracking and Compliance System Provisions

The final mass-based MR, like the proposed rule, includes provisions that meet the tracking system requirements in the

CPP. In general, these provisions align with provisions in current EPA mass-based emission trading programs that use the EPA’s allowance tracking and compliance system (ATCS), which is an electronic system that currently supports allowance surrender, transfer, and tracking activity under the Acid Rain Program and CSAPR.

The final mass-based model trading rule designates the EPA-administered ATCS as the allowance tracking and compliance system. The EPA received many comments supporting this approach. States could choose to use other tracking systems to administer a mass-based emission budget trading program that uses this MR, as long as the tracking system used by a state meets CPP requirements for tracking systems. See section III.E for discussion of EPA tracking system support for state plans.

The phrase “EPA-administered” reflects the EPA’s role in providing the basic services required to support the ATCS, such as hosting the tracking system software, ensuring its security and ongoing operation, and providing technical support for users. While the EPA will perform these administrative services for states that adopt the MR, or otherwise specify an EPA-administered tracking system in their state plan, the MR and this preamble use the term “tracking system operator” to refer to the entity that will execute specific actions through the tracking system. As explained in the MR, such actions include recording the allocation of allowances and deducting allowances from compliance accounts. This MR defines tracking system operator as the state, or an entity acting on behalf of the state, including the EPA. Certain tracking system functions could be carried out by either the state or the EPA, while other actions are more appropriately executed by the state alone or at the state's discretion. A state adopting one of these MRs must determine whether the state, the EPA, or another entity will perform each tracking system function. In particular, a state adopting the mass- or rate-based MR must describe in its state plan submittal (either through a memorandum of understanding or some other documentation) whether the state, the EPA, or some combination thereof will execute the role of tracking system operator for each MR provision in which this term is used.[92]

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[92] With respect to certain tracking system functions, a state may choose to identify both the EPA and the state as the tracking system operator (so that both entities have the authority to execute the specified functions) while choosing to identify either only the state as the tracking system operator authorized to execute other functions, or identify the EPA as the tracking system operator authorized to execute certain functions upon a determination by the state.

However the state chooses to document the assignment of functions to the tracking system operator, the state must provide the documentation as part of its state plan submittal.

The primary role of a tracking system is to provide an efficient means for affected EGUs to comply with requirements under an emission budget trading program, and for states to assess affected EGU compliance with their emission standards.[93] As was proposed, this MR includes provisions related to use of an electronic allowance tracking system to track allowances held by affected EGUs, as well as allowances held by other market participants (entities and individuals that do not have a compliance obligation under the program).

An allowance tracking system tracks a number of additional actions and information, including the allocation of all CO_2 allowances; holdings of CO_2 allowances in compliance accounts (*i.e.*, facility-level accounts for affected EGUs) and general accounts (*i.e.*, accounts for other entities, such as financial companies and brokers); deduction of CO_2 allowances for

[93] Under an emission budget trading program included in a state plan, the emission standard for an individual affected EGU is the requirement to hold and surrender allowances in a number equal to reported CO_2 emissions during a compliance period.

compliance purposes; and transfers of allowances between accounts.

1. Compliance and General Accounts

This MR includes provisions that address allowance accounts, which describe two types of tracking system accounts: compliance accounts, one of which the tracking system operator will establish for each facility with an affected EGU upon receipt of a complete certificate of representation for the facility; and general accounts, which can be established by any entity upon receipt by the tracking system operator of a complete application for a general account.

a. Compliance Accounts, Designated Representatives, and Certificates of Representation*.*

A compliance account is the account in which any allowances used by an affected EGU for compliance with its emission standard must be held.

This MR includes provisions for the establishment of a compliance account for each facility with one or more affected EGUs. A single compliance account is established for all affected EGUs at that facility. Using facility-level, rather than EGU-level compliance accounts, provides the owners and operators of an affected EGU more flexibility in managing allowances used for compliance. Facility-level compliance accounts do not jeopardize the environmental goals of a mass-based emission budget trading program MR and can facilitate compliance. In practice, a facility-level compliance approach avoids situations where an individual affected EGU holds insufficient allowances in a compliance account - and thus is in violation of allowance-holding requirements - even though other affected EGUs at the same facility have sufficient allowances in their compliance accounts so that all the affected EGUs at the facility, taken together, meet the allowance-holding requirement. Facility-level compliance is consistent with requirements for mass-based emission trading programs in the CPP, and is consistent with the approach used in EPA-administered mass-based trading programs.[94]

This MR establishes procedures for certifying, authorizing, and changing the designated representative of the owners and operators of an affected EGU. In addition, this MR establishes procedures for certifying, authorizing, and changing an

[94] *See* 80 FR 64892. The EPA has adopted facility-level compliance in previous emission budget-trading programs including the ARP, *see* 70 FR 25162, at 25296-98 (May 12, 2005); the CAIR FIP, *see* 71 FR 25328, at 25365 (April 28, 2006); and the CSAPR, *see* 75 FR 45210, at 45323 (August 2, 2010).

alternate representative for the designated representative. These MR provisions are patterned after provisions concerning designated representatives and alternate designated representatives in EPA-administered mass-based trading programs. The EPA is finalizing these procedures in this MR as proposed.

In this MR, a designated representative is the individual authorized to represent the owners and operators of each affected EGU in all matters pertaining to the mass-based trading program. One alternate designated representative can be selected to act on behalf of the designated representative, and thus the owners and operators of an affected EGU. Actions of both the designated representative and the alternate designated representative will legally bind the owners and operators of an affected EGU. Because the actions of the designated representative and alternate designated representative legally bind the owners and operators of the affected EGU, the designated representative and alternate designated representative must submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators of the affected EGU and was authorized to act on their behalf.

The designated representative and alternate designated representative are authorized to act on behalf of the owners and operators of an affected EGU upon receipt by the tracking system administrator of a complete certificate of representation. This document, in a format prescribed by the tracking system operator, includes: specific identifying information for the affected EGU and for the designated representative and alternate designated representative; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate designated representative. All submissions (*e.g.*, monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU must be submitted, signed, and certified by the designated representative or alternate designated representative. Upon receipt of a complete certificate of representation, the tracking system operator will establish a compliance account in the tracking system for each facility with an affected EGU involved.

To change the designated representative or alternate designated representative, a new certificate of representation must be received by the tracking system operator. A new certificate of representation must also be submitted to reflect changes in the owners and operators of an affected EGU. However, even in the absence of such a submission, new owners and operators of an affected EGU are still bound by the existing certificate of representation.

In addition to the flexibility provided by allowing an alternate designated representative to act for the designated representative (*e.g.*, in circumstances where the designated representative might be unavailable), the designated representative and alternate designated representative may delegate authority to agents to make electronic submissions. Such agents can electronically submit documents, which are specified by the designated representative and alternate designated representative.

These provisions addressing designated representatives and alternate designated representatives provide the owners and operators of affected EGUs with flexibility in assigning responsibilities under the mass-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the mass-based trading program.

b. General Accounts and Authorized Account Representatives.

General accounts can be used by any person, group, or organization for holding or trading allowances. However, allowances cannot be used for compliance with an emission standard so long as the allowances are held in a general account. Allowances that are used for compliance must be held in a compliance account as of the compliance deadline, as discussed below in section I.

To open a general account, a person must submit an application for a general account, which is similar in many ways to a certificate of representation. The application includes, in a format prescribed by the tracking system operator: the name and identifying information of the authorized account representative and the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate authorized account representative. The authorized account representative and alternate authorized account representative are authorized to represent all persons with an ownership interest in the allowances in the general account upon receipt of a complete application by the tracking system operator.

This MR includes provisions for changing the authorized account representative and alternate authorized account representative of a general account, the requirement to update the general account application to take account of changes in the persons having an ownership interest in allowances held in the general account, and provisions for delegating authority to make electronic submissions. These provisions are substantially identical to those applicable to comparable matters for designated representatives and alternate designated representatives for a compliance account.

2. Recordation of Allowance Transfers

This MR includes provisions that specify the process for transferring allowances from one account to another. Allowances may be transferred by submitting a transfer form providing, in a format prescribed by the tracking system operator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring designated representative or authorized account representative (or alternate representative).[95] If a transfer form containing all the required information is submitted to the

[95] While the MR provisions specify the use of a form to execute an allowance transfer, these provisions are designed to be executed in an electronic tracking system, including the use of an electronic signature.

tracking system operator, and the transferor account includes the allowances identified in the form, the tracking system operator will record the transfer by moving the allowances from the transferor account to the transferee account within five business days of the receipt of the transfer form.[96]

3. Error Correction

As in the proposal, this MR provides that the tracking system operator can, at its discretion and on its own motion, correct any type of error that it finds in an account in the allowance tracking system. In addition, this MR provides that the tracking system operator can review any submission under the mass-based emission budget trading program, make adjustments to the information in the submission, and deduct or transfer

[96] Under current EPA-administered trading programs, a participant may submit an allowance transfer request to the EPA using a paper form. In practice over 95 percent of all allowance transfers in current EPA-administered programs are submitted electronically by account representatives and recorded in real time in the EPA-administered ATCS. While this MR provides up to five days to record a submitted allowance transfer, the EPA anticipates allowance transfer submissions will use a process similar to those in current EPA-administered trading programs, which allows account representatives to submit allowance transfer requests through an electronic tracking system, allowing the transfers to be recorded in real time.

allowances based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA, including the ARP and CSAPR.[97]

This MR includes provisions specifying an administrative appeals procedure, as a means of resolving disputes that may arise in the course of administration of the program. The scope of these administrative appeals procedures includes corrections of errors in an allowance tracking system. These provisions are addressed above in section III.J.

I. Compliance with Emission Standard

Under this MR, once a compliance period ends (*e.g.*, by 11:59 pm on December 31, 2024, for the first compliance period), the owner or operator of a facility with affected EGUs has a window of opportunity following the end of the compliance period to evaluate reported CO_2 emissions and obtain any allowances that might be needed to cover CO_2 emissions from the affected EGUs during the compliance period. For example, the allowance transfer deadline for the first compliance period is 11:59 pm on

[97] *See* 40 CFR 72.96, 73.37, 97.427, and 97.428.

May 1, 2025. At that time, sufficient allowances must be in the compliance account for a facility to cover all of the CO_2 emissions from the affected EGUs at that facility during the preceding compliance period.[98] Each allowance under the mass-based MR authorizes the emission of one short ton of CO_2. To be usable for compliance, an allowance must be of a vintage that falls within the compliance period or a past compliance period.[99] Each owner or operator must hold, as of the allowance transfer deadline, in its facility compliance account, enough allowances usable for compliance to authorize the total reported CO_2 emissions of the affected EGUs at the facility for the

[98] While the CPP allows for compliance with a mass-based trading rule to be demonstrated at the facility level, and this model rule does so, a state has the discretion to structure a program by which compliance is demonstrated at the level of the affected EGU. "Facility level" in this context simply means all of the affected EGUs at a given facility.

[99] For example, to demonstrate compliance with the allowance surrender requirement for the compliance period that comprises the years 2025 through 2027, the owner or operator of an affected EGU may use allowances of vintages 2022, 2023, 2024, 2025, 2026, and 2027.

compliance period.[100,101] The designated representative for a compliance account has the option to identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, allowances will be deducted from a compliance account on a first-in, first-out basis.[102] Deducting allowances of different vintages may have tax and accounting implications for the owner

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[100] Allowances must be held in the compliance account as of the allowance transfer deadline, or a properly submitted allowance transfer must have been executed as of the allowance transfer deadline, such that sufficient allowances will be held in the compliance account after the transfer is recorded.

[101] The CPP requires a state plan that allows for facility-level compliance under a mass-based emission budget trading program to include provisions that specify the process for determining the compliance status of each affected EGU at a facility, if insufficient allowances are held in a facility compliance account to cover the CO_2 emissions from each of the affected EGUs located at a facility. *See* 40 CFR 60.5825(b)(1). If a state submitted this MR as part of its state plan, 62.16220(e)(2) makes clear that each affected EGU at a facility would be in non-compliant status if there were insufficient allowances in a facility compliance account, as of the allowance transfer deadline, to cover the total reported CO_2 emissions for all affected EGUs at the facility.

[102] Allowances that were first deposited in the compliance account through an allocation to an affected EGU at the facility will be the first to be deducted from the account by a state, in the order of recordation. Deduction of these allocated allowances will be followed by deduction of any allowances transferred to the compliance account, in the order of recordation.

or operator of an affected EGU, so having a default deduction method provides the owner or operator with certainty regarding which allowances will be deducted for compliance. Allowances that are deducted for compliance will be moved to a retirement account.

The CO_2 emissions that are used to evaluate whether sufficient allowances are held in a facility compliance account as of the allowance transfer deadline are the monitored and reported CO_2 emissions of the affected EGUs located at the facility during the compliance period. Section J below discusses the CO_2 emissions monitoring and reporting provisions for affected EGUs in this MR.

If a facility compliance account does not hold sufficient allowances for compliance by all affected EGUs at the facility, as of the allowance transfer deadline, then the facility is in violation[103] of the CAA and may be subject to enforcement under section 113, or 304 of CAA and/or under the approved state plan.

[103] As discussed above, if a state submitted this MR, the EPA would interpret these MR provisions to specify that each affected EGU at a facility would be in non-compliant status if there were insufficient allowances in a facility compliance account, as of the allowance transfer deadline, to cover the total reported CO_2 emissions for all affected EGUs at the facility.

In addition, consistent with existing programs, the EPA is finalizing in this MR a provision whereby the owner or operator of the affected EGUs must transfer into the facility compliance account, for deduction, two allowances for every short ton of excess CO_2 emissions (*i.e.*, for violating the emission standard).[104,105] These allowances may be of a past vintage (*i.e.*, allowances from an annual emission budget that falls within the compliance period when excess CO_2 emissions occurred or a past compliance period), or of a vintage year of the subsequent compliance period immediately after the compliance period in which the excess CO_2 emissions occurred. The mandatory requirement to submit a number of allowances equal to two times the amount of any excess CO_2 emissions for the prior compliance period is an ongoing obligation and the facility will be in

[104] "Excess emissions" are defined in this MR as any ton of CO_2 emissions from an affected EGU at a facility that exceeds the CO_2 emission limitation for the facility for a compliance period (*i.e.*, any ton of CO_2 emissions that is not authorized through an allowance available for deduction in the facility's compliance account).

[105] While the CPP does not prescribe such provisions addressing excess emissions, the CPP does require that emission standards adopted in a state plan must be enforceable. *See* 40 CFR 60.5775(f). These provisions are included to help address the enforceability of state emission standards imposed through adoption of this MR.

violation every day from the first day of the compliance period until compliance is achieved.

In addition, the owner or operator of an affected EGU with excess CO_2 emissions may be subject to civil penalties and other relief for each violation in accordance with the CAA, as well as the mandatory two-for-one allowance deduction requirement, with each ton of unauthorized CO_2 emissions constituting a separate violation of the CAA, and each violation being calculated daily, from the first day of the compliance period when the excess CO_2 emissions occurred and until the date compliance is achieved.

A number of commenters recommended eliminating the automatic two-for-one allowance deduction requirement for excess CO_2 emissions, and instead advocated relying on the existing enforcement provisions under section 113 of the CAA to approach each violation on a case-by-case basis. These commenters claimed this automatic deduction requirement for unauthorized CO_2 emissions was excessive. Other commenters suggested increasing the amount of the automatic allowance deduction for excess CO_2 emissions to four allowances for every one ton of excess CO_2 emissions, in conjunction with any civil penalties and other relief in accordance with sections 113 or 304 of the CAA and/or the approved state plan. These commenters argued that a two-for-one automatic deduction may not be sufficient to deter non-compliance under at least some allowance market scenarios. The EPA has determined that this MR includes a reasonable approach that will help to ensure compliance. The EPA maintains that it is important to include a requirement for an automatic deduction of allowances in a total amount that exceeds the amount of any excess CO_2 emissions, in order to provide a strong financial disincentive for non-compliance. This automatic requirement for the deduction of two allowances for every one ton of excess CO_2 emissions provides a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance is a significantly more expensive option than compliance.[106] Such automatic deductions have been successfully used in prior EPA-administered programs, including CAIR and CSAPR, as well as state programs.

J. Monitoring, Reporting, and Recordkeeping Requirements for Affected Electric Generating Units

Under the mass-based MR, monitoring and reporting requirements for affected EGUs are consistent with those

[106] The automatic deduction requirement cannot be avoided, regardless of any explanation for the excess CO_2 emissions provided by the owners or operators of the affected EGU.

established in the CPP. The requirements for the use of data that is already being monitored and reported under other EPA programs is an effort to ensure efficient and timely reporting for affected EGUs.

In the mass-based MR affected EGUs must monitor and report their CO_2 emissions for use in determining compliance with the emission standards. The emissions data must be monitored according to the applicable 40 CFR part 75 provisions specified in this MR and be reported to the EPA using the Emissions Collection and Monitoring Plan System (ECMPS), while monitoring and reporting of net energy output is consistent with the requirements that were established in the CPP. Under this MR, quarterly reporting is required for hourly CO_2 emissions and energy generation data, with each quarterly report due 30 days after the last day in the calendar quarter (*i.e.*, the 30th of April, July, October, and January). The reporting must be in accordance with 40 CFR 75.60, and additionally, the use of 40 CFR part 75 certified monitoring methodologies is required. Commenters were supportive of the requirement to monitor and report CO_2 emissions in accordance with 40 CFR part 75 to provide consistent reporting and minimize reporting costs.

The RGGI, ARP, MATS, and the mass-based MR all require continuous emissions monitoring systems (CEMS) to be installed and certified in accordance with 40 CFR part 75. The RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. Thus, many affected EGUs in states that adopt the mass-based MR will generally have no changes to their CO_2 monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates that there are fewer than 50 affected EGUs covered by the CPP that are not subject to the Acid Rain Program (ARP).[107] These affected EGUs will have to purchase and install additional CEMS and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of the CPP.[108] Several of the affected EGUs not subject to the ARP are subject to the MATS program and therefore, will have already installed stack flow rate and/or CO_2 monitors in order to comply with the MATS rule. Like the ARP rules, these can be used to meet the requirements in this MR.

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[107] Reporting of CO_2 emissions is already required for EGUs subject to the ARP.

[108] Approximately 10 of these affected EGUs are coal-fired, with the remainder being gas- and oil-fired that would qualify for an excepted monitoring methodology.

The CEMS used to comply and report data for MATS may be used to generate and report CO_2 emissions data, consistent with the requirements in this MR, without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate CO_2 mass emissions or CO_2 emission rate under this MR.

The same monitors and data collected may be used for multiple purposes, such as RGGI, ARP, MATS, and this MR. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 ensures cost-efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

Consistent with the requirement in the CPP, the mass-based MR requires the monitoring of net energy output through the use of a monitoring system that meets the ANSI Standard No. C12.20. The reporting of the net energy output data is through ECMPS, along with all of the monitored CO_2 emissions data.

The mass-based MR requires the use of substitute emissions data if there is invalid emissions data during an hour of operation, as specified under 40 CFR part 75. This is necessary for a complete data picture for a mass-based program when compliance is determined, as missing data can cause under-reported emissions. If this provision was not included there would be incorrect representation of total CO_2 emissions and an incorrect number of allowances needed by an affected EGU to comply with its emission standard.

In addition to hourly data, this MR requires reporting to the tracking system operator of the data required for the compliance determination for an affected EGU. This MR requires this data to be reported through the ATCS to help facilitate streamlined and efficient reporting by affected EGUs. Data that must be reported under this MR include the allowances surrendered by the affected EGUs at a facility and the cumulative CO_2 mass emissions of affected EGUs at a facility during the compliance period.

In the proposal, the EPA took comment on this MR requirement for monitoring and reporting of CO_2 mass emissions and net energy output for the year before the initial compliance period begins (*i.e.*, to commence January 1, 2021). The purpose for this was to allow time for affected EGUs to ensure that reporting was ready prior to the beginning of the first compliance period. This MR includes this provision for early reporting. In this MR, only monitoring and reporting is required beginning in 2021 – compliance with an enforceable emission standard only commences on the compliance period schedule that is detailed in section III.B of this preamble.

Consistent with the proposal, the recordkeeping requirements in this MR reflect the recordkeeping requirements in the CPP. This includes the requirement for the owners and operators of affected EGUs to keep records of data used for demonstrating compliance for five years. For the first two years, those records must be kept onsite at an affected EGU. In addition, all of the recordkeeping requirements that apply under 40 CFR part 75 would apply under this MR for the data that are submitted through ECMPS.

V. Rate-Based Model Trading Rule

A. Overview

The rate-based model trading rule (MR) provides model regulatory text for a state plan that applies both the subcategorized EPA interim step CO_2 emission performance rates and final period CO_2 emission performance rates, established in the CPP, as emission standards for affected EGUs. This MR also provides for interstate trading of emission rate credits (ERCs) and contains provisions necessary for a ready-for-interstate-trading state plan. This MR is one option for state plan design, and states retain the full range of plan design options provided by the CPP.[109] This section of the preamble explains the regulatory provisions of the rate-based MR, which are codified in subpart NNN of 40 CFR part 62.

The EPA received many comments on the proposed rate-based MR from a wide range of stakeholders. Comments generally supported finalization of a rate-based MR and provided constructive feedback on the design elements proposed and for which the EPA requested comment. Having carefully considered all of the input offered through comments, the EPA is finalizing model regulatory text for a rate-based trading program. If a state adopts this rate-based MR in its entirety in the state plan, then the state plan would be presumptively approvable with respect to the covered elements, as explained further in section II.B.[110] At the same time, states retain the flexibility to

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[109] A state could, for example, develop a mass-based state plan or a rate-based state plan designed for achievement of the state's rate-based goal. CPP preamble section VIII.C. (State Plan Approaches), 80 Fed. Reg. at 64,832-37.

[110] For a detailed discussion of how states can use the model trading rules when developing a state plan, as well as the concept of presumptive approvability, see section II.B above.

tailor a state plan to individual state circumstances and needs by modifing this MR or developing a different plan approach provided for in the CPP. A state, for instance, could modify this MR by identifying a different tracking system or including additional eligible resources.[111]

The rate-based MR includes provisions that enable a state plan that is ready for interstate trading. It includes provisions, for example, that apply both the subcategory-specific EPA interim step CO_2 emission performance rates and final period CO_2 emission performance rates, established in the CPP, as emission standards for affected EGUs; identify the EPA-adminstered ERC tracking and compliance system (ERC-TCS) as the instrument tracking system; and allow in-state affected EGUs to use in a compliance demonstration ERCs that were issued by another state with an EPA-approved trading-ready state plan that uses the ERC-TCS or an interoperable tracking system.[112] By including such provisions, this MR facilitates development of rate-based state plans that allow for interstate trading of ERCs

[111] Section II.B above discusses state options for using or modifying the rate- and mass-based model trading rules (MRs).

[112] Section III.C above discusses in more detail the relationship between ready-for-interstate-trading state plans and these model rules.

and supports an ERC trading market. Section III.D discusses in more detail the EPA’s decision to finalize MRs that can be used in a ready-for-interstate-trading state plan and the utility of MR provisions for states that decide not to develop a ready-for-interstate-trading state plan.

The rest of this section V explains, in detail, various provisions of the regulatory text that comprise the rate-based MR. Section V.B explains the compliance periods and use of the subcategory-specific CO_2 emission standards for affected EGUs. It also explains the requirement for each affected EGU to demonstrate compliance by achieving an adjusted CO_2 emission rate — a rate based upon the stack CO_2 emission rate and any ERCs surrendered by the affected EGU — that is less than or equal to its rate-based CO_2 emission standard. This MR includes the same emission standards for the interim step periods and final reporting periods as in the proposed rate-based MR and established in the CPP.

Section V.C explains accounting methods for ERC issuance to affected EGUs and specifies the types of resources eligible for ERC issuance under this MR (“eligible resources”). Affected EGUs earn ERCs for operating below their emission standards, and existing natural gas combined cycle (NGCC) units also earn Gas-

Shift ERCs (GS-ERCs) for incremental generation. ERCs can only be issued for MWh of qualifying electricity generation or savings from affected EGUs or eligible resources generated in or after 2022.[113] Eligible resources under this MR rule include RE technologies (*i.e.*, wind, solar, geothermal, hydro, wave, and tidal), nuclear power generators, non-affected combined heat and power (CHP) units (including certain waste heat to power (WHP) units), and demand-side EE projects, programs, and measures. For these eligible resources, this MR includes eligibility requirements consistent with the CPP. For example, eligible resources must have been installed or have increased capacity on or after January 1, 2013.

Section V.D summarizes the CPP requirements for an ERC tracking system and explains how provisions in the rate-based MR comport with those requirements. This MR specifies the EPA-administered ERC Tracking and Compliance System (ERC-TCS) as the ERC tracking system and refers to the tracking system operator as the entity that executes various actions through the ERC-TCS.

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[113] *See* 40 CFR 60.5800. As explained below, the one exception to this rule is for generation or savings from eligible projects under the Clean Energy Incentive Program (CEIP). *See* Clean Energy Incentive Program Design Details; Proposed Rule, 81 FR 42940 (June 30, 2016).

Tracking system operator is defined as the state or its designated agent, which could include the EPA. In the state plan submittal, the state will need to identify whether the state, EPA, or a designated third party will execute the role of tracking system operator for each MR provision in which this term is used. States have the discretion to modify this MR to specify a tracking system other than the ERC-TCS. This section also explains that even if a state adopts this MR and designates the ERC-TCS, the state will need to establish its own system and processes for receiving and evaluating eligibility applications, M&V reports, independent verifier verification reports, and other submittals, documents, and information related to ERC issuance. In addition, the state must maintain these documents and other information in a state ERC document management and approval system that makes them available to the ERC-TCS in an electronic, internet-based format. The discussion then covers the roles of compliance accounts and general accounts and describes rate-based MR provisions related to each.

Section V.E describes provisions for ERC issuance to affected EGUs and eligible resources. This includes provisions that cover the required contents of ERC eligibility applications and monitoring and verification (M&V) reports, as well as the timing for submission and state review of these submittals. This section also elaborates on evaluation, measurement, and verification (EM&V) plan requirements for each type of eligible resource included in the rate-based MR, as well as requirements related to independent verifiers. It then explains the provisions that address the improper issuance of ERCs.

Section V.F explains rate-based MR provisions related to the transfer, trading, and banking of ERCs. The rate-based MR includes provisions necessary for a state plan to be ready for interstate trading, which would allow affected EGUs to use ERCs in compliance demonstrations that are issued by certain other states with compatible state plans that are ready for interstate trading.[114] Consistent with the CPP, this MR provides for ERC banking but prohibits ERC borrowing.

Section V.G addresses rate-based MR provisions related to compliance, including the particulars of when and how affected EGUs demonstrate compliance with their emission standards. In short, an affected EGU’s adjusted CO_2 emission rate for a

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[114] Issues related to this MR and ready-for-interstate-trading state plans are discussed in more detail in sections III.D and V.F.1. To be linked, the CPP requires, among other things, that ready-for-interstate-trading state plans use the same EPA-designated or EPA-administered tracking system. 80 FR 64892.

compliance period must be at or below its emission standard for that compliance period. The only ERCs that can be used when calculating an adjusted emission rate are those held in the affected EGU’s compliance account as of the ERC transfer deadline, which is specified in this MR as the June 1 following the applicable compliance period. An affected EGU that does not comply with its emission standard must provide two ERCs for every one additional ERC needed to achieve its emission standard. This section also addresses cases where an affected EGU uses improperly issued ERCs for a compliance demonstration.

Section V.H covers CO_2 emissions and energy output monitoring, reporting, and recordkeeping requirements for affected EGUs.

B. Subcategorized Rates and Achievement of Emission Standards

1. Compliance Periods and Subcategorized Rates

The CPP allows states to design state plans that adopt federally enforceable rate-based emission standards for affected EGUs expressed as a rate of CO_2 mass emissions per MWh of net energy output. In addition, the CPP establishes nationally uniform subcategory-specific CO_2 emission performance rates and EPA interim step CO_2 emission performance rates for affected EGUs in two subcategories: natural gas-fired stationary combustion turbines (*i.e.*, natural gas combined cycle units, or NGCC units) and fossil fuel-fired steam-generating units (*i.e.*, utility boilers and IGCC units).[115]

As with the proposed rate-based MR, the compliance periods for affected EGUs in this MR mirror the multi-year interim step periods and the 2-year final reporting periods of the CPP. Under the rate-based MR, affected EGUs must achieve emission standards that span interim step period 1 (2022 to 2024), interim step period 2 (2025-2027), interim step period 3 (2028-2029), and 2-year final reporting periods (2030-2031, 2032-2033, etc.). Section III.B above includes further discussion of the MR compliance periods.

For the interim step compliance periods, the proposed rate-based MR used the EPA interim step CO_2 emission performance rates established in the CPP as emission standards for affected EGUs. For the final reporting periods, the proposal used the final period CO_2 emission performance rates as emission standards for affected EGUs. The proposal also sought comment on other options for emission standards, such as using a state’s rate-based CO_2

[115] For simplicity, affected utility boilers and IGCC units will collectively be called “steam generating units.”

goal. After careful consideration of comments received, the EPA is finalizing a rate-based MR that uses the proposed emission standards. Most commenters preferred this approach to a rate-based model rule that applies emission standards at the level of a state’s rate-based goal, though some preferred the latter approach. Commenters favored the approach finalized in this MR on the grounds that it promotes broader trading markets that can lead to more cost-effective emission reductions, as opposed to fractured, state-by-state trading markets. In addition, commenters liked that the approach finalized in this MR applies consistent emission standards for EGUs of the same type, across states that adopt this MR. A handful of commenters encouraged the EPA to leave states the option of designing a state plan that applies an identical emission standard for affected EGUs, even if the final MR includes emission standards as proposed. Nothing in this MR narrows the state-plan-design flexibility provided in the CPP. Section II.B above explains that this MR can be tailored or modified by states that choose a rate-based trading program design different than the one finalized in this MR.

Table 2 below provides the subcategory-specific rate-based emission standards included in this MR for each compliance period. These values are identical to the interim step rates and final period rates established in the CPP[116] and proposed for this MR. A state plan adopting this MR need not include a demonstration that the emission standards are adequate to achieve the CO_2 emission performance rates for the interim and final period.[117]

Table 2. Emission Standards for Affected EGUs

Subcategory	**2022-2024 Emission Standard**	**2025-2027 Emission Standard**	**2028-2029 Emission Standard**	**Final Period Emission Standard**
Fossil Fuel-Fired Electric Steam Generating Units	1,671*	1,500	1,380	1,305
Stationary Combustion Turbines	877	817	784	771

* Values represent lbs. of CO_2 emissions per MWh of generation

[116] U.S. EPA, Clean Power Plan Final Rule Technical Documents, Data File: Goal Computation Appendix 1-5, Appendix 4, https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

[117] The requirements of 40 CFR 60.5745(a)(5)(ii) do not apply to a state plan that adopts this MR (specifically, the emission standards finalized in this MR).

2. Achievement of Emission Standards

The rate-based MR requires each affected EGU to meet a rate-based emission standard established at the applicable level described above in section V.B.1.[118] Consistent with the CPP, an affected EGU achieves its rate-based CO_2 emission standard if its adjusted CO_2 emission rate over the applicable compliance period is less than or equal to its emission standard for that period.[119] An affected EGU that does not already operate with a reported CO_2 emissions rate at or below its emission standard can take steps to improve its reported CO_2 emission rate.[120] In

[118] In accordance with the CPP, compliance under the rate-based MR is evaluated at each individual EGU. *See* 40 CFR 60.5740(a)(2), 60.5770 (applying emission standards to each affected EGU). The CPP allows affected EGUs subject to a mass-based state plan to demonstrate compliance on a unit- or facility-wide basis. *See* 40 CFR 60.5825(a)-(b).

[119] Section V.G below and 40 CFR 62.16420(c) provide the formula used to calculate the adjusted emission rate of an affected EGU. Section VIII.K.1.a of the CPP preamble also explains the general accounting approach for adjusting an affected EGU's CO_2 emission rate.

[120] CPP Preamble section VIII.I (describing emission reduction actions that may be taken at affected EGUs).

addition, the unit can use ERCs to adjust its reported CO_2 emission rate.[121]

An ERC is a tradable compliance instrument that represents, for compliance purposes, one zero-emission MWh of energy generated or saved that may be used to adjust the reported CO_2 emission rate of an affected EGU for the purpose of demonstrating compliance with a rate-based emission standard under the CPP.[122] For each ERC surrendered by an affected EGU for its compliance demonstration, one MWh is added to the denominator of its reported CO_2 emission rate. This results in an adjusted CO_2 emission rate that is lower than its reported CO_2 emission performance rate. For example, assume an affected steam-generating unit with CO_2 emissions of 2 billion pounds and

[121] See section V.G below for a detailed explanation of the reported CO_2 emission rate.

[122] An ERC must meet the requirements of 40 CFR 60.5790(c). While ERCs have zero associated emissions for compliance demonstration purposes, they can be generated by low-emitting affected EGUs. Section V.C.2 below explains the calculation of ERCs issued to an affected EGU that operates below its emission standard. Section V.C.3 explains the accounting methodologies used to determine the amount of ERCs that a non-affected CHP or WHP generating unit may be issued as a low or zero-emitting resource.

electric generation of 1 million MWh during a compliance period. The affected EGU's reported CO_2 emission rate is 2,000 lb/MWh (2,000,000,000 lb CO_2/1,000,000 MWh = 2,000 lb/MWh). When complying with its rate-based emission standard, the affected EGU submits 333,334 ERCs, representing 333,334 MWh of electricity generation and/or savings.[123] Adding 333,334 MWh of generation to the reported MWh generation of the affected EGU results in an adjusted CO_2 emission rate of 1,500 lb CO_2/MWh (2,000,000,000 lb CO_2/1,333,334 MWh = 1,500 lb CO_2/MWh). The affected EGU achieves compliance if its adjusted CO_2 emission rate of 1,500 lb CO_2/MWh is at or below its emission standard.

C. Emission Rate Credit Mechanism

1. Overview

This section addresses rate-based MR provisions for ERC issuance to affected EGUs and eligible resources. It also identifies eligibility requirements for eligible resources and the specific types of eligible resources included in this MR.

Section V.C.2 discusses the accounting methods provided in

[123] Requirements for the issuance of ERCs and a further discussion of how ERCs are used in compliance with rate-based emission standards are addressed in section VIII.K.2 of the CPP preamble.

this MR for the issuance of ERCs to affected EGUs. Section V.C.2.a explains the accounting method used for issuance of ERCs to an affected EGU when its reported CO_2 emission rate is below its emission standard for a specified time period. The number of ERCs issued to steam generating units and combustion turbines depends upon the difference between their respective subcategory-specific CO_2 emission standards and the individual unit's reported CO_2 emission rate, as well as the amount of generation at that reported emission rate. Next, subsection V.C.2.b describes the accounting methodology in this MR used for issuance of GS-ERCs to credit incremental generation by affected NGCC units. Consistent with the CPP, only steam generating units can use GS-ERCs for compliance.[124]

Section V.C.3 explains the eligibility requirements for a resource to qualify for ERC issuance. This MR provides for ERC issuance to the following types of eligible resources that are installed or that increased capacity on or after January 1,

[124] Section VIII.K.2.a of the CPP preamble explains in more detail the relationship between NGCC incremental generation and GS-ERCs.

2013:[125] renewable electric generating technologies that use wind, solar, geothermal, hydro, wave, or tidal energy; nuclear power; non-affected CHP, including WHP; and demand-side EE.[126] Section V.C.3 also discusses ERC issuance to eligible resources located outside the United States and in areas of Indian country without affected EGUs. Finally, this section explains the ERC accounting methodologies for issuance of ERCs to non-affected CHP units, including certain WHP units.

2. ERC Issuance to Affected Electric Generating Units

a. <u>Performance Below Applicable Emission Standards.</u>

Under the rate-based MR, an affected EGU is issued ERCs for operating at a CO_2 emission rate below its rate-based emission standard. More specifically, ERCs are quantified in MWh and the number of ERCs issued is based upon the difference between an affected EGU's reported CO_2 emission rate (in CO_2 lb/MWh) and its emission standard, as well as on the amount of generation realized. The number of ERCs that may be issued to an affected

[125] *See* 40 CFR 60.5800(a)

[126] Section V.C.3 addresses state modification of this MR to include categories of eligible resource not finalized in this MR.

EGU that operates below its applicable emission standard is calculated using the following formula.[127]

$$\text{ERCs} = \frac{(\text{EGU standard} - \text{EGU operating rate})}{\text{EGU standard}} * \text{EGU generation}$$

The value for the term "EGU operating rate" (*i.e.*, reported CO_2 emission rate) is determined by applying the CO_2 emissions and MWh of net energy output reported using the Emissions Collection and Monitoring Plan System (ECMPS). For steam generating units, the term "EGU standard" refers to the emission standard for steam generating units listed in Table 2.; for combustion turbines, it is the emission standard for combustion turbines listed in Table 2. "EGU generation" refers to the MWh of generation over the applicable period.

In addition to receiving ERCs for generating below its emission standard, an affected NGCC unit can be issued GS-ERCs for incremental generation. The following section explains the method for crediting incremental generation from affected NGCC

[127] As explained in section V.G.1 below, this formula is also used to calculate the number of ERCs needed in a compliance demonstration.

units through the issuance of GS-ERCs.

b. Incremental NGCC Generation

The CPP requires a state that allows affected EGUs to use ERCs for compliance to include in its state plan the accounting methods and process for ERC issuance to affected EGUs. More specifically, for a state that applies emission standards that are not equal for all affected EGUs (such as the subcategorized emission standards in this MR), this includes requirements for the accounting and crediting of increased generation from affected EGUs that meet the definition of a stationary combustion turbine (*i.e.*, an NGCC unit, for practical purposes) on the presumption that such increased NGCC generation replaces generation from higher emitting steam generating units.[128] To fulfill these requirements, the rate-based MR includes provisions for crediting the increased generation from an affected NGCC unit through the use of GS-ERCs denominated in MWh. GS-ERCs are calculated by comparing the reported CO_2 emission rate of that affected NGCC unit to the emission standard for steam generating units.

[128] *See* 40 CFR 60.5795. The preamble to the CPP describes the parameters that a state plan accounting method must address.

In the proposed rate-based MR, the EPA provided a method of calculating GS-ERCs that would have credited all NGCC generation on a pro rata basis that reflects expected incremental NGCC generation to 75 percent capacity.[129] The EPA requested comment on an alternative method of calculation in which only NGCC generation over a certain generation threshold each year would be eligible to receive GS-ERCs.[130] The EPA received various comments on the proposal regarding GS-ERCs, including both the proposed pro rata methodology and the alternative incremental-generation methodology. Many commenters supported the incremental-generation methodology and viewed it as ensuring a more accurate basis for crediting incremental NGCC generation.

After review of the comments, the EPA has decided to finalize the alternative incremental-generation accounting methodology using an annual generation threshold, rather than the proposed pro rata methodology. Under this incremental-generation methodology, affected NGCC units are issued GS-ERCs for MWh of incremental generation beyond an annual generation

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[129] *See* 80 FR at 64991. *See* Section IV.C.2 of the proposal preamble for further discussion of the proposed GS-ERC methodology.

[130] *See* 80 FR at 64994.

threshold calculated for each unit. This annual generation threshold is calculated by applying the appropriate regional interconnection annual average capacity factor of NGCC units to the generating capacity of the unit that seeks issuance of GS-ERCs. The EPA has determined that the finalized methodology allows for better representation of actual emission performance and consistency with the Building Block 2 methodology used in setting the BSER of the CPP when compared to the proposed methodology. This is because the finalized calculation methodology more precisely reflects the emission reduction that Building Block 2 represents, which is emission reduction achievable by generation shifts from steam generating units to NGCC units. Under the incremental-generation method, GS-ERCs are only issued for actual increases in generation at an affected NGCC unit. Under the proposed pro rata methodology by contrast, ERCs would be issued based upon projected levels of incremental generation. As a result, the pro rata method would risk over crediting or under crediting NGCC units’ operation in practice due to an assumption of incremental operation. Thus, the methodology in this MR more directly measures and appropriately credits actual incremental generation by affected NGCC units.

The provisions for the calculation and issuance of GS-ERCs in the rate-based MR include four distinct calculation steps. As step one, the EPA has calculated the average regional baseline NGCC capacity factors for affected NGCC units in each of the electricity interconnections that were used in calculation of Building Block 2 of the CPP for the calendar year of 2012: the Eastern interconnection, Texas interconnection, and Western interconnection. The EPA calculated these values by dividing the total regional generation by affected NGCC units, in MWh, for 2012, by the total potential regional generation (net summer capacity multiplied by hours in the year) of the NGCC fleet for 2012, operating at full capacity. Those values are shown in Table 3. Using this capacity factor baseline allows affected NGCC units to generate GS-ERCs under the same metric that was used in Building Block 2 in the CPP, such that their operational choices in a compliance setting may be recognized in the same fashion as associated emission reduction potential was quantified in Building Block 2 that informed the quantification of the CO_2 emission performance rates in the CPP.

Table 3. – Regional NGCC Capacity Factors

Regional electricity interconnection	2012 regional net summer capacity (MW)	2012 total regional generation (MWh)	Regional NGCC capacity factor (percent)
Eastern	149,948	734,535,157	55.8

Western	46,522	198,374,376	48.5
Texas	30,912	137,182,895	50.5

Step two requires determining the threshold of MWh that the affected EGU must exceed in a calendar year before it is able to generate GS-ERCs for the given year. This unit-specific annual generation threshold is the product of the regional capacity factor from step 1 (divided by 100 in order to convert from percentage), the unit’s individual net summer capacity,[131] and the number of hours in the applicable calendar year. The net summer capacity of an NGCC unit is used in the calculation to provide consistency with the methodology in Building Block 2 of the CPP. A calendar year typically has 8760 hours, but leap years have 8784 hours. The equation is:

$$MWh_{threshold} = \frac{CF_{regional}}{100} \times \text{Net Summer Capacity} \times \text{Hours in the Year}$$

Where:

$MWh_{threshold}$	=	Unit specific threshold operation (MWh-net).
$CF_{regional}$	=	Regional capacity factor according to Table 3.
Net Summer	=	Affected EGU’s net summer capacity in MW.

[131] Net summer capacity is used to be consistent with the calculation of Building Block 2 in the CPP.

Capacity

Hours in the Year = Hours in the applicable calendar year.

The third step is calculating the GS-ERC emission factor, which is based upon an affected NGCC unit's CO_2 emission rate compared to the steam generating unit CO_2 emission standard during a corresponding compliance period. The GS-ERC emission factor represents the degree that the affected NGCC unit performs better than the steam generating unit EGU emission standard, because that is the emission rate of the generation that it is presumed to have replaced. This step produces the emission factor used to calculate the number of GS-ERCs to be issued for MWh of generation beyond the unit-specific annual generation threshold established in step 2. The equation in this step is as follows:

$$\mathrm{EF_{GS-ERC}} = 1 - \frac{\text{EGU emission rate}}{\text{Steam Generating Unit Emission Standard}}$$

Where:

$EF_{GS\text{-}ERC}$	=	GS-ERC Emission Factor.
EGU emission rate	=	Affected EGU's reported CO_2 emission rate (lb/MWh-net).
Steam generating unit emission standard	=	Steam generating unit emission standard for the corresponding compliance period (lb/MWh-net).

The fourth and final step in calculating GS-ERCs for an affected NGCC after it has exceeded its unit-specific generation threshold is to apply the GS-ERC emission factor (calculated in the third step) to the incremental MWh of generation (calculated in the second step). The equation representing this calculation is as follows:

$$\text{GS-ERCs} = \left(\sum \text{MWh}_{\text{total}} - \text{MWh}_{\text{threshold}}\right) * \text{EF}_{\text{GS-ERC}}$$

Where:

GS-ERCs	=	Calculated GS-ERCs (MWh-net).
$\text{MWh}_{\text{total}}$	=	Total net energy output generation of the affected NGCC unit during the applicable calendar year.

This final step in the GS-ERC calculation process is the basis for calculating the number of GS-ERCs to be issued by a state to an affected NGCC unit. Similar to ERCs issued to eligible resources, issued GS-ERCs are denominated in MWh. However, unlike ERCs issued to eligible resources, GS-ERCs may only be used for compliance by affected steam generating units. The requirements and processes for issuance of ERCs to affected EGUs are discussed more in section V.E.2 below.

The EPA received a number of comments on the calculation of

GS-ERCs. The majority of commenters support the EPA finalizing a crediting action that most accurately represents emissions reductions achievable through actions similar to those used under Building Block 2. Some commenters stated that under the proposed pro rata approach there was an inaccurate and perverse issuance of ERCs because of the issuance of ERCs for every MWh produced. If this were allowed to happen, GS-ERCs could be issued to units that did not actually change operation to increase their utilization. This would mean that there were no real environmental benefits achieved in those ERCs being awarded. Under the alternate approach in the proposal, the incremental-generation methodology, the ERCs being credited more accurately represent the environmental benefit from the NGCC operation. This desire for accuracy in calculating and crediting of ERCs is something that commenters overwhelmingly supported. Commenters' overwhelming support for the alternative methodology buttresses the EPA's decision to finalize it.

Additionally, commenters supported the application of unit specific metrics to accurately determine how many GS-ERCs a unit would be awarded. The EPA agrees with the commenters that unit-level metrics could be applied to accurately reflect calculation and crediting GS-ERCs. This is why the EPA is finalizing the use of regional characteristics from 2012 for each unit within that region combined with the unit summertime capacity to calculate the unit-specific generation threshold for issuance of GS-ERCs. The EPA believes that this methodology both achieves the EPA’s and commenters’ desire for increased accuracy and will help add stability for GS-ERC calculation and crediting by all units within a given region.

3. Eligible Resources for Emission Rate Credit Issuance

a. Eligibility Requirements

The CPP allows for the issuance of ERCs to resources other than affected EGUs that can substitute for generation from affected EGUs or avoid the need for generation from affected EGUs in or after 2022. Such resources must meet specific requirements finalized in the CPP in order to be eligible for ERC issuance.[132] For the rate-based MR, the EPA proposed and is

[132] *See* 40 CFR 60.5800; CPP Preamble Sec. VIII.K.1(2), 80 Fed. Reg. at 64,896-64899 (October 23, 2015). All requirements state plans must meet regarding ERCs (including state plan requirements for eligible resources) were finalized in the CPP. These foundational requirements were neither re-proposed nor reopened in the rate-based MR. The MRs set forth provisions that meet the CPP requirements for ERCs, but do not themselves set

now finalizing eligibility requirements consistent with those in the CPP.[133] Eligible resources may be issued ERCs only for qualifying MWh of electricity generated or saved in or after 2022.

Consistent with the CPP and proposed rate-based MR, the final rate-based MR requires that to be issued ERCs, eligible resources must be connected to the U.S. electricity grid and installed after the year 2012. This date of installation applies to new installed generating capacity, an increase in installed capacity, or newly installed electrical savings measures.[134] These requirements align with comments requesting maximum flexibility within the requirements of the CPP. This MR also includes provisions that identify categories of resources eligible for ERC issuance and specify geographic requirements for eligible resources as required by the CPP.

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any requirements regarding ERCs other than for states choosing to adopt the rate-based MR.

[133] Eligible resources may be issued ERCs only for the quantified and verified MWh of electricity generation or savings that they produce in 2022 and subsequent years.

[134] *See* 40 CFR 60.5800(a)(1). These foundational requirements were neither re-proposed nor reopened in the rate-based MR.

The CPP identifies categories of eligible resources and gives each state the flexibility to determine which categories to include in its state plan. A state may add an eligible resource category that is not specified in the CPP, subject to EPA approval based on the requirements specified in the CPP.[135] In addition to identifying categories of eligible resources, a state plan must specify accounting methods for the issuance of ERCs for electric generation or savings for each category of eligible resource.[136]

This MR specifies the following categories of eligible resources: RE (wind, solar, geothermal, hydro, wave, and tidal), nuclear, non-affected CHP (including WHP), and demand-side EE. Consistent with the CPP, this MR includes ERC accounting methodologies for each of these categories of eligible resources. This MR only includes categories of eligible resources for which the EPA could finalize a sufficiently specified, widely applicable quantification method supported by

[135] *See* 40 CFR 60.5800(a)(4)(vii).

[136] *See* 40 CFR 60.5830, 60.5835. For qualified biomass, waste-to-energy, and carbon capture and utilization (CCU), additional requirements apply, *see* 40 CFR 60.5800(d). For a discussion of accounting issues associated with each of the eligible-resource categories, *see* the preamble to the CPP at 80 FR 64,899-903.

public comments. This is consistent with comments that requested the widest possible array of resources be eligible under this MR, while providing a rate-based MR that includes accounting methodologies. A state may modify this MR by adding other eligible resource categories, provided the state plan includes a viable associated accounting method and meets other CPP requirements.

A state, for example, could add qualified biomass as an eligible resource in its state plan, provided plan provisions addressing biomass (*e.g.*, an ERC accounting methodology) meet CPP requirements.[137] The framework of this MR can be used by a state even with the addition of other categories of eligible resources. For instance, a state plan that includes additional categories of eligible resources can add those categories to section 62.16435(a)(5) of the rate-based MR. Accounting methods for ERC issuance that apply to those additional categories of eligible resources, where relevant, as well as other related requirements, can be specified in section 62.16455 of the rate-based MR. As discussed in section II.B above, any additions or

[137] Issues associated with biomass generally are discussed in section III.G above.

revisions to this MR are subject to substantive review against applicable statutory and regulatory requirements, including requirements in the CPP, by the EPA through notice and comment as part of its action on a state plan.

In addition to provisions that address categories of eligible resources, the rate-based MR includes provisions to meet geographic requirements in the CPP for eligible resources located in states with a rate-based state plan, states with a mass-based state plan, areas of Indian country without affected EGUs, and in Canada and Mexico. Comments generally requested maximum flexibility for geographic eligibility, within the parameters of the CPP. This MR includes geographic eligibility requirements that are consistent with the CPP and provide flexibility to states. In addition, they minimize the likelihood of ERC issuance to an eligible resource whose generation does not substitute for generation in a rate-based state.[138] In general, the approach in this MR supports a broader ERC trading market, can help reduce compliance costs, and provides market liquidity. However, states have the choice under the CPP to establish narrower geographic eligibility requirements.

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[138] *See* 80 FR 64913

Under this MR, an ERC may be issued to an eligible resource located in any state with a rate-based state plan, provided the eligible resource belongs to one of the categories of eligible resources described above. The eligible resource need not be located in the state to which the representative for the eligible resource applies for ERC issuance.

Further, an ERC may be issued to an eligible resource located in a state with a mass-based state plan or in Indian country that does not have affected EGUs and is not located within the borders of a rate-based state,[139] provided the eligible resource uses one of the following RE resources: wind, solar, geothermal, hydro, wave, or tidal. In addition, the electricity generation from the RE resource must be demonstrated to be delivered to the grid with the intention to meet load in a state with a rate-based state plan. The state with a rate-based plan to which the power is intended to be delivered does not have to be the state from which the representative for the eligible resource seeks ERC issuance. This is generally consistent with

[139] The application of these provisions in the rate-based model rule does not extend to areas of Indian country with affected EGUs. In such areas, the extent of crediting ability would depend on the nature of any tribal or federal plan for those areas under the CPP.

both the requirements of the CPP and comments requesting flexibility to the extent allowable under the CPP for resources located in a mass-based state.

Consistent with the CPP, this MR also provides that ERCs may be issued to eligible resources located in areas of Indian country that do not have affected EGUs and that are located within the borders of rate-based states.[140] All types of eligible resources are included in this authorization for these areas of Indian country located within the borders of rate-based states, including demand-side EE. Eligible resources in these areas of Indian country are not subject to a demonstration of delivery to meet load in a rate-based state, which is required for eligible resources in mass-based states, Indian country without affected EGUs not located within the borders of a rate-based state, or outside of the United States.[141] The electricity generation does not have to be delivered to the state from which the

[140] The application of these provisions in the rate-based model rule does not extend to areas of Indian country with affected EGUs. In such areas, the extent of crediting ability would depend on the nature of any tribal or federal plan for those areas under the CPP.

[141] Where the Indian country is located within the borders of a rate-based state, then all eligible resources in such areas, if grid-connected, can reasonably be assumed to be likely to meet load in a state with a rate-based plan. *See* 80 FR 64898.

representative for the eligible resource seeks ERC issuance.

Some stakeholders have expressed concern that a state with a rate-based plan could refuse to issue ERCs to otherwise eligible resources located in Indian country. Some stakeholders are concerned that if this were to occur, project providers would choose to develop eligible projects in the issuing state with the rate-based plan rather than in Indian country. To address this concern, this MR provides that the issuing state will give the same consideration to eligible resources on tribal lands as that given to other resources located inside or outside the state, such as when evaluating eligibility applications and M&V reports. This protects against the issuing state placing different requirements on an otherwise eligible resources on the basis that the resources are located in Indian country.

Under the CPP, an ERC may be issued to an eligible resource located outside of the United States under certain circumstances. Commenters requested clarification of the types of electric generating resources that may be located outside of the United States and be eligible under this MR, particularly as it applies to RE resources. This MR specifies that an ERC may be issued to an eligible resource located in Canada or Mexico, provided the resource uses one of the following RE resources:

wind, solar, geothermal, hydro, wave, or tidal. Electricity generation from the renewable resource must be connected to the U.S. grid and must be demonstrated to be delivered with the intention to meet load in a state with a rate-based state plan. The electricity generation does not have to be delivered to the state from which the representative for the eligible resource seeks ERC issuance.

Some commenters requested clarification of options for demonstrating that electricity generation is delivered to meet load in a state with a rate-based state plan. This MR specifies that ERCs may be issued to eligible resources that are RE resources located in mass-based states, areas of Indian country without affected EGUs that are not located within the borders of a rate-based state, Canada and Mexico, so long as they demonstrate that the electricity generation from the eligible resource was delivered to the grid to meet load in a state with a rate-based state plan. Such eligible resources have flexibility in how they make this demonstration. Examples of possible demonstrations of delivery of electricity generation include a power purchase agreement or a power delivery contract, but are not limited to these methods.

b. ERC Issuance Methodology for Non-Affected Combined Heat and Power (CHP) and Waste Heat-to-Power (WHP) Generating Units

The rate-based MR includes non-affected CHP units as a category of eligible resource that may be issued ERCs.[142] In order to include non-affected CHP units as an eligible resource, a state plan must provide accounting methods for the issuance of ERCs to such eligible resources.[143] Accordingly, this MR provides accounting methods for the issuance of ERCs to non-affected CHP units, as described below.

In this MR, there are two types of non-affected CHP units. The first type is referred to as “non-affected CHP units” and consists of “topping cycle” CHP units in which fuel is used to generate electricity and then waste heat from the electricity

[142] Certain CHP units may be affected EGUs and subject to regulation under a state plan. This section only addresses CHP units that are not subject to a CO_2 emission standard under a state plan, which are referred to as “non-affected CHP units” in this section.

[143] While the CPP did not specify an accounting method for non-affected CHP units, it did reference the parameters that an accounting method included in a state plan must meet. The CPP also noted that the accounting approach in the final rate-based MR could be a presumptively approvable approach. See 80 FR 64902.

generation process is recovered to provide useful thermal output (UTO).[144] For the purpose of ERC issuance, a non-affected CHP unit (*i.e.*, a CHP unit that does not meet the applicability criteria of section 62.16410) is an electric generating unit that uses a steam-generating unit or stationary combustion turbine to produce electric (or mechanical output) and UTO from the same primary energy. This type of non-affected CHP unit includes units that combust supplemental fuel in the heat recovery steam generator to create additional useful output. Section V.C.3.b.(1) discusses the ERC issuance accounting method under this MR for determining the number of ERCs that may be issued to this type of non-affected CHP unit.

The second type of non-affected CHP unit consists of waste heat-to-power (WHP) units. A WHP unit is defined in the MR as a unit where UTO is provided to an industrial or other process and the waste heat that cannot be used by the process is recovered and used to generate electricity without the combustion of supplemental fuel. Section V.C.3.b.(2) explains the ERC issuance accounting method in this MR for determining the number of ERCs

[144] The definition for useful thermal output (UTO) is consistent with that in the CPP under section 60.5880.

that may be issued to WHP units.

Both ERC issuance accounting methods address the fact that non-affected CHP units will or may emit CO_2, and therefore need an accounting methodology to determine the portion of total MWh of electricity generation for which ERCs may be issued and the number of ERCs that such generating units may be issued.[145]

The ERC issuance accounting methods finalized in this MR are substantially similar to the proposed methods. One change is the addition of a limit on the total number of ERCs that may be issued to a non-affected CHP unit. This limit is based on the electric generation capacity of the non-affected CHP unit when operated at its full design capacity in terms of useful thermal output and without the use of supplemental fuel. This limit has been introduced to remove perverse incentives to combust additional fuel in the heat recovery steam generator, in order to generate additional electricity for which ERCs could be issued in the absence of such a limit.

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[145] This is necessary because an ERC is deemed to have zero associated CO_2 emissions for compliance purposes. 80 FR 64908 (October 23, 2015); 60.5790(c)(2)(ii). The CPP requires a state plan to include accounting methods to determine the portion of electricity generation from non-affected CHP units and WHP units for which ERCs may be issued. 80 FR 64902-64903 (October 23, 2015).

(1) <u>ERC Issuance Accounting Methodology for Non-Affected CHP Units</u>

This section discusses the accounting method in this MR for the issuance of ERCs to the type of non-affected CHP units that does not include WHP units. The ERC issuance accounting methodology identifies the CO_2 emissions associated with the electricity generated by the CHP unit and then determines how many ERCs can be issued for the CHP unit’s electricity generation. The number of ERCs that may be issued to a non-affected CHP unit for a reporting period are derived as follows:

$$\text{ERCs} = \left(1 - \frac{\text{CHP}_{nae}\text{CO2 Emission Rate}}{\text{Reference CO2 Emission Rate}}\right) * \text{CHP}_{na}\text{Electricity Generation}$$

Where:

ERCs	=	The number of ERCs that may be issued for electricity generation by the non-affected CHP unit for the reporting period.
CHP_{nae} CO_2 Emission Rate	=	The non-affected CHP unit’s electricity generation CO_2 emission rate (in CO_2 lb/MWh).
Reference CO_2 Emission Rate	=	The applicable emission standard in Table 2 in the MR (Emission Standards for Affected EGUs), as described below.

CHP_{na} Electricity Generation	=	The non-affected CHP unit's reported net electricity generation (in MWh).[146]

The number of ERCs that may be issued for the non-affected CHP unit's electricity generation takes into consideration the CHP unit's electricity generation CO_2 emission rate and compares it to a reference CO_2 emission rate. This comparison is used in order to calculate a proration factor that is applied to the CHP unit's electricity generation. The proration factor is applied to determine the portion of the CHP unit's electricity generation that is deemed to be CO_2 emission-free for the purpose of ERC issuance.

(a) *Determining a non-affected CHP unit's electricity generation CO_2 emission rate.*

The ERC isuance accounting method specifies the method for calculating a non-affected CHP unit's electricity generation CO_2 emission rate, which represents the CO_2 emissions attributable to

[146] "Reported net electricity generation" refers to the electricity generation reported during an M&V report period, in accordance with requirements specified in the EM&V plan for the non-affected CHP unit. MR EM&V requirements for eligible resources that are non-affected CHP units are discussed in section E.3.d.(2) and specified in section 40 CFR 62.16455(e).

the generation of electricity and does not include CO_2 emissions associated with generation of UTO by the non-affected CHP unit. The rate is calculated by deducting a non-affected CHP unit's CO_2 emissions deemed to be attributable to its reported UTO from its total reported CO_2 emissions and then dividing the remaining CO_2 emissions by the non-affected CHP unit's total reported electricity generation. Determining the CO_2 emissions attributable to the non-affected CHP unit's UTO is based on the estimated CO_2 emissions from an assumed replacement thermal energy unit (RTEU)(e.g., a boiler or process heater)[147] that would have provided the same amount of UTO in the absence of the CHP unit. In other words, if the CHP unit had not been built, the same UTO would have been generated another way. The non-affected CHP unit's CO_2 emissions attributable to UTO are those emissions that would have been emitted by the RTEU.

The MR provides a methodology for calculating the estimated CO_2 emissions for an RTEU by taking into consideration the heat input to an RTEU, the RTEU's thermal efficiency, and the CO_2 emission intensity of the fuel used by the RTEU. To calculate

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[147] Process heater means a device use to transfer heat indirectly to a process material or to a heat transfer material for use in a process unit, instead of generating steam.

the total heat input for the assumed RTEU, the RTEU must be specified in the EM&V plan for the eligible non-affected CHP unit. This MR specifies thermal efficiency values for an assumed RTEU based on fuel type and also specifies CO_2 emission factors for the fuel combusted in the RTEU, which are the default CO_2 emission factors referenced in Table C-1 in the EPA's GHG Reporting Program rule, 40 CFR 98. Using this information, the CO_2 emissions from the assumed RTEU are calculated using equations specified in the MR.

(b) *Determining a non-affected CHP unit's reference CO_2 emission rate.*

The reference CO_2 emission rate used in the accounting method is the applicable emission standard for the applicable compliance period in Table 1 of this subpart that corresponds to the reporting period for the non-affected CHP unit. For a non-affected CHP unit that uses a stationary combustion turbine, the reference CO_2 emission rate is the emission standard for stationary combustion turbines in Table 1 of this subpart. For a non-affected CHP unit that uses a steam generating unit, the reference CO_2 emission rate is the emission standard for steam generating generating unitsin Table 1 of this subpart.

(2) ERC Issuance Accounting Methodology for WHP Units

The MR defines a WHP unit as a type of non-affected CHP unit and provides a unique ERC issuance accounting methodology for WHP units. This definition of WHP unit includes generating units where fuel is combusted to provide UTO to an industrial, institutional, or commercial process. The remaining heat (i.e., waste heat) from that process is recovered and used to generate electricity, and no additional fuel is combusted in the course of generating electricity. A unit is not considered a WHP unit under this MR in cases where fossil fuel combustion occurs in the heat exchanger of a unit in the process of capturing waste heat, in order to raise the waste heat exhaust temperature to generate electricity.

For purposes of ERC issuance, a non-affected CHP unit that is defined as a WHP unit under the MR is a unit where only waste heat is used to generate electricity and no supplementary firing of fuel occurs. Given this definition of a WHP unit, a WHP unit can be assumed to have a CO_2 emission rate of zero CO_2 emissions per MWh of electricity generation. Thus, this MR provides for ERC issuance based simply on the WHP unit's reported net electricity generation (MWh) (subject to the same limit on total electricity generation for which ERCs may be issued that applies for all non-affected CHP units, as discussed above in section (1)).

(3) Comments on Accounting Methods for Non-Affected CHP Units

This section summarizes key comments received on the proposed ERC issuance accounting methods for non-affected CHP units and WHP units. The EPA proposed and requested comment on a number of elements of the proposed ERC issuance accounting methods for non-affected CHP units and WHP units, as described below. The EPA also sought comment on the appropriate reference CO_2 emission rates for use in both ERC issuance accounting methods.

(a) *Comments on the accounting method for non-affected CHP units.*

The EPA requested comment on inclusion of an acounting method in the final rate-based MR based on a proposed accounting framework. Commenters supported the proposed general framework of the ERC issuance accounting method. A number of commenters sought additonal clarity on the types of CHP units to which the accounting method applies and about technical elements of the accounting method. In response to these comments, this MR clarifies the applicable type of non-affected CHP units to which the accounting method applies and includes technical revisions to a number of elements of the accounting method. The EPA recognizes the potential environmental benefits of non-affected

CHP units not covered in this MR. Accordingly, a state may modify this MR to include other types of non-affected CHP units as an eligible resource, along with associated ERC issuance accounting methods. Such proposed provisions would be subject to review and approval by the EPA as part of its review of a state plan submittal.

(b) *Comments on the the accounting method for WHP units.*

The EPA sought comment on a number of elements of the ERC issuance accounting method for WHP units. The EPA requested comment on the acounting method that applies when fossil fuel combustion is used to supplement waste heat at a WHP unit, in order to determine the portion of electricity generation by a WHP unit that may be issued ERCs. The EPA also solicited comment on other potential accounting methods for WHP that may differ from the proposed accounting framework.

A number of commenters sought additional clarity on the types of WHP units to which the proposed accounting method applies. In particular, some commenters suggested that the acounting method should apply to a broad set of WHP units, such as WHP units that use mechanical waste heat in addition to WHP units that use waste heat in the form of steam. A number of commenters also asked for additonal clarity about technical elements of the accounting method.

In response to these comments, this MR specifies that WHP is treated as a type of non-affected CHP unit and identifies the type of WHP unit to which the accounting method applies. In addition, it includes technical revisions from proposal to a number of elements of the accounting method to improve clarity.For multiple reasons, the EPA has decided not to include WHP units where excess heat is recovered from combustion turbines as an eligible resource in the MR. The definition of a stationary combustion turbine in the section 111(b) NSPS includes the turbine engine and any heat recovery unit. Separating out the heat recovery unit from the combustion turbine for the purposes of defining a WHP unit under the MR is potentially complicated and would be inconsistent with the approach used to determine applicability for affected EGUs under the section 111(b) NSPS and the CPP. If the MR allowed the heat recovery steam generator of a non-affected combustion turbine to be considered a WHP unit, this could potentially provide a perverse incentive to construct small combined cycle units with lower overall efficiency.

Non-affected combustion turbines that recover heat from the turbine exhaust may still meet the definition of a non-affected CHP unit in the MR, even if they do not meet the definition of a WHP unit. The agency also notes that a state may choose to include these types of units as an eligible resource in a state plan, provided state provisions meet CPP requirements, including provision of an appropriate ERC-issuance accounting method. States retain the ability to modify this MR to include other types of WHP units, and associated ERC issuance accounting methods, in their state plan submittals. Such proposed provisions must meet CPP requirements and are subject to review by the EPA as part of its review of a state plan submittal.

The EPA has also decided not to include heat recovery from mechanical drive (e.g., compressor) combustion turbines as a WHP unit in the MR. The EPA has determined that inclusion of such applications as a WHP unit would provide a perverse incentive to install a less efficient combustion turbine engine and compressor to maximize waste heat for electricity generation.

(c) *Comments on the CO_2 reference rates used in the accounting methods.*

In the proposed MR, the reference CO_2 emission rate is the applicable CO_2 emission standard rate for an affected EGU. The EPA received several comments on the selection of the appropriate reference CO_2 emission rate to which the non-affected CHP unit electricity generation CO_2 emission rate is compared.

Commenters suggested using several different reference rate approaches instead of the reference rate approach used in the proposed MR. Some commenters asserted that the reference rate should be based instead on the CO_2 emissions that are avoided from affected EGUs due to the electricity generation from non-affected CHP units and WHP units. Commenters suggested a number of different approaches for calculating the assumed avoided CO_2 emissions from affected EGUs that results from electricity generation by non-affected CHP units and WHP units. Some commenters suggested basing the reference rate on the average CO_2 emission rate of all generating units in a state or region during a specified period of time, rather than the CO_2 emission standards for affected EGUs in a state. Commenters also suggested that the reference rate be based on the average or marginal CO_2 emission rate for fossil fuel-fired EGUs in a state or region.

The EPA notes that the suggested alternative approaches for a reference rate do not align with the definition of an ERC in the CPP. In particular, these comments presume that an ERC represents an increment of avoided CO_2 emissions, while an ERC is defined in the CPP as a MWh of electricity generation or savings with zero associated CO_2 emissions for compliance purposes, 80 FR 64908. The reference rate approaches suggested by commenters would result in the calculation of different reference rates in different states or regions, based on the assumed avoided CO_2 emissions from affected EGUs that result from CHP or WHP generation. As a result, an identical CHP unit would be issued a different number of ERCs for the same amount of electricity generation, depending on where the CHP unit is located. For the resons outlined above, the EPA has determined that it is appropriate to finalize the proposed reference rate approach.The EPA notes that the final accounting method applied for non-affected CHP units and WHP units in the MR is consistent with the basic accounting approach applied in the CPP for all entities that may be issued ERCs, including affected EGUs and eligible resources.[148]

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[148] Application of the reference CO_2 emission rates used for non-affected CHP units and WHP units, based on the CO_2 emission standards for affected EGUs, is consistent with the accounting treatment applied for other eligible resources, both non-emitting and emitting. For example, application of the same reference CO_2 emission rate to non-emitting RE and DS-EE eligible

D. Emission Rate Credit Tracking System Functions and Operations

1. Overview

This section explains how provisions in the rate-based MR comport with CPP requirements for an ERC tracking system and discusses the designation of the ERC-TCS as the ERC tracking system in this MR. This section then explains the function of compliance accounts and general accounts and describes the rate-based MR provisions related to compliance accounts and general accounts that address designated representatives, alternate designated representatives, certificates of representation, authorized account representatives, and alternate authorized account representatives.

2. Functions and Administration of the ERC Tracking System

The CPP requires a state plan that includes a rate-based trading program to include provisions specifying an ERC tracking system.[149] The EPA will provide an ERC tracking system that

resources would result in calculation of a proration factor of 1 using the method described for non-affected CHP units (*i.e.*, all quantified and verified MWh would be counted when determining the total MWh of electricity generation or savings for which ERCs may be issued). In addition, the accounting methods for issuance of ERCs to affected EGUs under the CPP incorporate the use of a reference rate based on the applicable CO_2 emission standards for affected EGUs.

[149] *See* 40 CFR 60.5810.

states with rate-based trading programs can utilize, and this MR identifies the EPA-administered ERC Tracking and Compliance System (ERC-TCS) as the ERC tracking system. Commenters asked EPA to support states that include a rate-based trading program in their state plan by providing an ERC tracking system. The EPA is committed to supporting states by providing the ERC-TCS, but nothing requires a state to choose this tracking system. States have the flexibility to specify a different tracking system in a state plan, so long as the tracking system meets CPP requirements.

The EPA will administer the ERC-TCS by providing basic services required to support the tracking system. These services include hosting the tracking system software, ensuring its security and ongoing operation, and providing technical support for users. Administration of the ERC-TCS by the EPA, as described here, is distinct from actions performed in the tracking system by the tracking system operator that are necessary to implement the rate-based trading program specified in the MR. This MR uses the term “tracking system operator” to refer to the entity that will execute specific actions through the tracking system, as prescribed in the MR. For this MR, such actions include, but are not limited to, the recordation of ERCs in tracking system accounts, deduction of ERCs used for compliance, and revocation of ERCs based upon misstatement or error.

This MR defines “tracking system operator” as the state, or an entity acting on behalf of the state, including the EPA. Certain tracking system functions could be carried out by either the state or the EPA, while other actions are more appropriately executed by the state alone or at the state’s discretion. A state adopting one of these MRs must determine whether the state, the EPA, or another entity will perform each tracking system function and specify that determination in its state plan submittal, as explained in section III.E above. Where this MR uses the term “state” as the actor, the EPA intends to not offer to perform this function needed to run an ERC trading program. For example, the state or its designated agent, not including the EPA, will receive and process eligibility applications, M&V reports, and independent verifier verification reports. In addition, the state or its agent, not the EPA, will develop and maintain an ERC document management and approval system, as explained below.

In addition to the EPA’s “Clean Power Plan Tracking Systems White Paper” that accompanies this MR package, the EPA explored the tracking system scoping assessment referenced in the CPP. The white paper is intended to educate stakeholders about the tracking systems in general as well as to stimulate discussion about tracking systems in the context of the CPP. States can use this white paper and any other products that may result from the tracking system scoping assessment to inform their decisions about tracking systems and which entities (*e.g.*, the state, the EPA, or another actor) will perform various actions in the tracking system. This scoping assessment is further addressed in section III.E above.

The ERC-TCS will provide the recordation, documentation, and public-access functions needed in an instrument tracking system for ERCs. As required by 40 CFR 60.5810(a)(1), it will ensure that ERCs are properly tracked from issuance to retirement in order to provide an accurate and verifiable means for affected EGUs to comply with requirements under a rate-based emission trading program and for states to assess compliance by affected EGUs. The ERC-TCS will electronically track the recordation of ERC issuance, holdings, transfers between accounts, deductions for compliance demonstrations, and retirements. It also will assign each ERC a unique identifier and ensure that it is traceable through the ERC tracking system back to the affected EGU or eligible resource for which it was issued. The ERC-TCS will provide public access to a record of ERC ownership, dates of ERC transfers among accounts, account holder information, origin of ERCs, and identification of ERC type (*i.e.,* whether it is an ERC issued to an eligible resource or a GS-ERC).

Section 60.5810(a)(2) of the CPP requires that an ERC tracking system document and provide electronic, internet-based public access to all information that supports state approval of eligible resources and the issuance of ERCs as well as have the capability to generate reports based on such information. This includes, for each ERC, supporting documents and information, such as an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports. The EPA does not anticipate the ERC-TCS providing functionality for state processing and maintenance of documents and information related to eligible resources or ERC issuance. The ERC-TCS, however, will possess the capability to facilitate electronic, internet-based public access to reports with this information, when connected with a state-maintained ERC document management and approval system that contains all information supporting the state evaluation of resource eligibility and ERC issuance.

Therefore, to meet the requirements of 40 CFR 60.5810(a)(2), the state plan must ensure that the state ERC document management and approval system and appropriate communication protocols will make available to the ERC-TCS in an electronic, internet-based format, documentation of eligibility applications for eligible resources, monitoring and verification reports, related independent verifier verification reports, and state approval or denial actions related to applications and submittals.

In order to meet the requirements of 40 CFR 60.5810(a), the state plan must include the necessary provisions for an ERC tracking system. Therefore, a state utilizing the ERC-TCS must identify in its state plan the state-maintained ERC document management and approval system in addition to the ERC-TCS. Accordingly, the rate-based MR provisions identify the ERC-TCS and a state-maintained “ERC Document Management and Approval System.” State plan provisions should retain the term “ERC Document Management and Approval System” if the state system is identified with the same name. If the state ERC document management and approval system is identified by a different name, then the state should replace this MR term with the name of the state’s system. A state that adopts this MR must demonstrate in the supporting documentation for its state plan submittal that the state-maintained ERC document management and approval system will adequately maintain the appropriate documents and information on an ongoing basis. In addition, the ERC document management and approval system must provide the ERC-TCS electronic, internet-based access to this information. To ensure the integrity of the rate-based trading program, the state’s ERC document management and approval system must have appropriate compatibility with the ERC-TCS.[150] When a state plan adopts this MR and provides adequate supporting documentation, the state plan will meet the CPP requirements for an ERC tracking system.[151] If a state adopting this MR fails to identify a state-maintained ERC document management and approval system that will adequately maintain all information supporting the state evaluation of resource eligibility and ERC issuance and that appropriately connects with the ERC-TCS, the ERC-TCS would

[150] Under the CPP, emission standards in a state plan must be quantifiable, verifiable, non-duplicative, and permanent. A tracking system meeting the requirements of the CPP helps assure the integrity of a rate-based approach that includes an emission trading program, therefore, assuring a state plan using such an approach provides for the implementation and enforcement of rate-based emission standards in accordance with section 111(d). 80 FR 64,904.

[151] As described above, some states also may need to change MR provisions to accurately identify the state ERC document management and approval system.

not be capable of providing all the functions required by 40 CFR 60.5810 for an ERC tracking system, and the state’s plan may be subject to disapproval on that basis. The EPA anticipates coordinating closely with states on these issues during the development of state plans that utilize the ERC-TCS in order to ensure that at the time of state-plan submittal, a state plan using the ERC-TCS provides all of the ERC tracking system functions required in the CPP.

3. Compliance Accounts and General Accounts

The rate-based MR includes provisions that govern two types of tracking system accounts: compliance accounts and general accounts. The following subsections explain the purpose and establishment of each account type, as well as procedures and responsibilities for account representatives.

a. *Compliance Accounts, Designated Representatives, and Certificates of Representation.*

The rate-based MR includes provisions for the establishment of a compliance account for each affected EGU. A compliance account is the account in which any ERCs used by an affected EGU for compliance with its emission standard must be held. As explained in section V.F below, in order for an affected EGU to use an ERC for compliance with its emission standard, the ERC must be held in that affected EGU's compliance account by the ERC transfer deadline. After the ERC transfer deadline, ERCs are deducted from compliance accounts to complete the compliance process.[152]

Provisions in this MR establish procedures for certifying, authorizing, and changing the designated representative of the owners and operators of an affected EGU. In addition, they establish procedures for certifying, authorizing, and changing an alternate representative for the designated representative. These MR provisions are patterned after provisions governing designated representatives and alternate designated representatives in existing EPA-administered mass-based trading programs. The EPA is finalizing procedures related to account representatives as proposed.

In the rate-based MR, a designated representative is the individual authorized to represent the owners and operators of each affected EGU in all matters pertaining to the rate-based trading program. The designated representative, for example,

[152] Section V.G below discusses the ERC transfer deadline and compliance processes in more detail.

submits official information about affected EGUs to the tracking system operator, transfers ERCs out of a compliance account and into another account,[153] ensures the compliance account holds sufficient ERCs by the ERC transfer deadline, and conducts any designation of which allowances in the compliance account will be surrendered and in what order.

One alternate designated representative can be selected to act on behalf of the designated representative and, by extension, the owners and operators of an affected EGU. Actions of both the designated representative and the alternate designated representative will legally bind the owners and operators of an affected EGU. Because the actions of the designated representative and alternate designated representative legally bind the owners and operators of an affected EGU, the designated representative and alternate designated representative are required to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators of the

[153] Technically, the designated representative submits a transfer request and then the tracking system operator records the transfer. *See* 40 CFR 62.16525, 62.16530. In practice, transfers occur instantaneously when conducted electronically through the ERC-TCS.

affected EGU and was authorized to act on their behalf.

The designated representative and alternate designated representative are authorized to act on behalf of the owners and operators of an affected EGU upon receipt by the tracking system operator of a complete certificate of representation. While the certificate of representation may take a form prescribed by the tracking system operator, it must include the following information: specified identifying information for the covered source and covered EGUs at the source and for the designated representative and alternate designated representative; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate designated representative. All submissions (*e.g.*, monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU must be submitted, signed, and certified by the designated representative or alternate designated representative. Upon receipt of a complete certificate of representation, the tracking system operator will establish a compliance account in the ERC-TCS for the appropriate affected EGU.

A new certificate of representation is required in order to change the designated representative or alternate designated representative. A new certificate of representation also must be submitted to reflect changes in the owners and operators of an affected EGU. Even in the absence of such a submission, however, new owners and operators of an affected EGU are bound by the existing certificate of representation.

In addition to the flexibility provided by allowing an alternate designated representative to act for the designated representative (*e.g.*, in circumstances where the designated representative might be unavailable), the designated representative and alternate designated representative may delegate to agents the authority to make electronic submissions. Such agents can electronically submit documents that are specified by the designated representative and alternate designated representative.

Provisions addressing designated representatives and alternate designated representatives provide the owners and operators of affected EGUs with flexibility in assigning responsibilities under the rate-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the rate-based trading program.

b. General Accounts and Authorized Account Representatives.

The rate-based MR includes provisions for the establishment of general accounts. ERCs issued to an eligible resource are issued into the general account specified for the eligible resource. General accounts can be used by any person, group, or organization for holding or trading ERCs. In order for an ERC in a general account to be used in a compliance demonstration, it must be transferred out of the general account and into the appropriate compliance account for an affected EGU before the ERC transfer deadline.

Consistent with the proposal, this MR provides that to open a general account, a person must submit an application for a general account, which is similar in many ways to a certificate of representation. The tracking system operator specifies the form of the application, but the application must include the following: an identifying name for the account; the name and identifying information of the authorized account representative and the alternate authorized account representative; the names of all persons with an ownership interest with respect to ERCs held in the account; and certification language and signatures of the authorized account representative and alternate authorized account representative. Upon receipt of a complete application for a general account, the tracking system operator will establish a general account in the ERC-TCS for the applicant.

The authorized account representative and alternate authorized account representative are authorized to represent all persons with an ownership interest in the ERCs held in the general account. The authorized account representative, for example, can transfer ERCs out of a general account and update account information.

This MR includes provisions for changing the authorized account representative and alternate authorized account representative of a general account and delegating authority to make electronic submissions. Provisions also require updates to the general account application to reflect changes in the persons having an ownership interest in ERCs held in the general account. These provisions are substantively identical to those applicable to comparable matters for designated representatives and alternate designated representatives for a compliance account.

4. Error Correction

As in the proposal, this MR provides that the tracking system operator can, at its discretion and on its own motion, correct any type of error that it finds in an account in the

ERC-TCS. In addition, this MR provides that the state can review any submission under the rate-based trading program and make adjustments to the information in the submission. The tracking system operator has the authority to deduct or transfer ERCs based on such adjusted information. These provisions are a standard feature of other trading programs administered by the EPA, including the ARP and CSAPR.[154] . The administrative appeals procedures in 40 CFR part 78 apply to disputes regarding decisions by the EPA when administering a tracking system or executing tracking system functions on behalf of the state. The scope of these administrative appeals procedures includes corrections of errors in the ERC-TCS. Administrative appeals procedures are addressed above in section III.J.

E. Emission Rate Credit Issuance Process and Requirements

1. Overview

Section V.E.2 describes the process provided in the rate-based MR for issuance of ERCs to affected EGUs and eligible resources. For eligible resources, the ERC issuance process includes an eligibility application, monitoring and verification reports, independent verifier verification reports, and the

[154] *See e.g.* 40 CFR 72.96, 73.37, 97.427, and 97.428

actual issuance of ERCs. Section V.E.2 also addresses situations where ERCs are improperly issued to affected EGUs or eligible resources. The discussion continues in section V.E.3 with an explanation of EM&V plans and EM&V requirements for the categories of eligible resources specified in this MR. Section V.E.4 then describes accreditation and other issues associated with independent verifiers.

This MR provides that each ERC will have a unique identifier that indicates the issuing state, type of ERC (*e.g.*, GS-ERC[155]), the number of the ERC, vintage year, and type of affected EGU or eligible resource for which the ERC was issued. For an ERC, “vintage” refers to the calendar year in which the MWh on which issuance of the ERC is based occurred. For example, if an ERC is issued in 2023 for MWh electricity savings that occurred in 2022, the ERC would be assigned a 2022 vintage.

This MR provides the requirements for ERC issuance explained below, and others, in order to ensure that the rate-

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[155] GS-ERCs are distinguished from generic ERCs through the use of the ERC identifier, because while all affected EGUs can use generic ERCs in a compliance demonstration, only steam-generating units can use GS-ERCs.

based emission standards on the affected EGUs are quantifiable, verifiable, non-duplicative, permanent, and enforceable. Consistent with the EPA's views on the regulatory scope of the CPP,[156] the EPA does not view these requirements as federally enforceable under the CAA against entities other than the affected EGUs.[157] As the provisions related to the ERC issuance process in the model rule make clear, affected EGUs may only use for compliance ERCs from eligible resources that have been issued according to the requirements of the model rule. The use of invalid ERCs for compliance may subject an affected EGU to CAA enforcement action. In addition, when the requirements of the model rules for ERC issuance have not been met, the issuance of ERCs to a particular eligible resource may be suspended, ERCs may be revoked, and accounts may be frozen, among other administrative consequences.

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[156] *See* 80 FR at 64783 (October 23, 2015).

[157] This does not preclude the potential for federal or state enforcement against criminal or civil violations of other federal or state statutes that could potentially occur in the context of a rate-based trading program, such as instances of fraud.

2. Issuance of ERCs to Affected Electric Generating Units and Eligible Resources

This section discusses rate-based MR provisions related to the issuance of ERCs to affected EGUs and eligible resources. These provisions address applicable CPP requirements related to the issuance of ERCs.[158] The CPP requires a state plan to include certain administrative provisions necessary to implement a program, but it does not prescribe specific provisions that a state must adopt for inclusion in a plan. The rate-based MR includes provisions necessary to meet CPP requirements as well as provisions related to timing and other administrative processes the EPA believes would facilitate an efficiently functioning program, ensure program integrity, and promote market liquidity.

Section V.E.2.a describes provisions for issuance of ERCs to affected EGUs. Section V.E.2.b describes provisions related to the issuance of ERCs to eligible resources, including requirements for the eligibility application, monitoring and verification reports, independent verifier verification reports,

[158] *See e.g.,* 60 CFR 60.5790 (state plan requirements); 60 CFR 60.5805 (process for issuance of ERCs).

and the mechanics of ERC issuance. Finally, subsection V.E.2.c describes provisions for error correction and other actions by the state in the event ERCs are improperly issued to affected EGUs or eligible resources.

The rate-based MR provisions discussed in this section generally are consistent with the proposal. These provisions include some changes from those proposed in response to comments and to ensure that the provisions fully align with the CPP. The EPA, for example, adjusted the ERC transfer deadline and specified the timing provisions for the issuance of ERCs in order to provide for more frequent issuance than was proposed. The EPA also made a number of minor technical changes in the interest of clarity and ease of program implementation.

a. Issuance of ERCs to Affected EGUs.

As discussed in section V.C.2.a, an affected EGU may be issued ERCs for operating at a CO_2 emission rate below its emission standard. In addition, affected NGCC units may be issued GS-ERCs, as discussed in section V.C.2.b. The rate-based MR specifies the process for the issuance of ERCs (including GS-ERCs) to affected EGUs, as described below.

To be issued ERCs, each affected EGU must submit an eligibility application to the state via the ERC-TCS. Affected

EGUs can be issued ERCs only after state approval of the eligibility application. The rate-based MR specifies the necessary contents of an eligibility application: information about the affected EGU included in its certificate of representation, identification of the compliance account into which issued ERCs will be transferred, documentation of the final CO_2 emission monitoring plan submitted under 40 CFR part 75, documentation of the energy output monitoring plan, the accounting method for calculating ERCs or GS-ERCs that may be issued to the affected EGU, a request by the designated representative for the affected EGU that it be determined eligible for the issuance of ERCs, and an attestation that all information in the application is true, accurate, and complete. Within 60 days of receipt of a complete eligibility application, the state will make a determination on an eligibility application or request additional information about the application. Otherwise, the eligibility application automatically will be deemed approved 60 days after receipt of a complete application. If the eligibility application is approved, the state registers the affected EGU in the ERC document management and approval system. Once so registered, the affected EGU is eligible to be issued ERCs, provided all applicable requirements continue to be met.

States may determine their own processes for evaluating eligibility applications for affected EGUs. In circumstances where a state adopts this MR, the EPA may possess almost all information required for the eligibility application. Depending upon the state’s decision about EPA’s role as tracking system operator for various tracking system functions, the EPA may already have information included in the certificate of representation and the compliance account information for the affected EGU maintained in the ERC-TCS. In addition, the MR requires that CO_2 emissions and net energy output data for the affected EGU be submitted to the EPA through ECMPS, and the MRs specify the accounting methods for issuing ERCs to affected EGUs. As a result, the EPA explored whether the ERC-TCS can be used to help streamline submission of eligibility applications by consolidating information submitted to the EPA that is required for submission of an eligibility application. Under this MR’s monitoring and reporting provisions, an affected EGU must have an approved monitoring plan and report CO_2 emissions and energy output to the EPA quarterly.[159]

Monitoring data must be reported directly to the EPA via the Emissions Collection and Monitoring Plan System (ECMPS); the data submitted to ECMPS will be transferred to the ERC-TCS.[160] Because each affected EGU is subject to this MR's monitoring and reporting requirements for both CO_2 emissions and energy output under 40 CFR part 75, once an eligibility determination is made by the state, based on its approval of an eligibility application, there is no further submittal process required for the issuance of ERCs to an affected EGU.[161]

In the event there are material changes to the information in an approved eligibility application, the designated representative for the affected EGU must submit an updated eligibility application to the state for approval. This includes, for example, changes to the affected EGU's CO_2 emission

[159] Section V.H below explains the monitoring and reporting provisions of this MR in more detail.

[160] This process is similar to that used in existing state programs. For instance, the EPA currently provides CO_2 emissions data through an automated process to the states participating in the Regional Greenhouse Gas Initiative (RGGI).

[161] This is in contrast to the process for ERC issuance to eligible resources, which requires submission of an M&V report.

monitoring plan and the accounting method for calculating GS-ERCs. The affected EGU cannot be issued ERCs for generation that occured after the material change until the updated eligibility application is approved by the state. Depending upon the nature of the material change, ERCs may be issued for generation that occurred after the material change but before approval of the updated eligibility application, provided all relevant requirements for ERC issuance are met.

ERCs will be recorded in an affected EGU's compliance account on either a quarterly basis or an annual basis, depending on the type of ERC. For an affected EGU that operates at a CO_2 emission rate below its emission standard, the tracking system operator will record the appropriate number of ERCs in the compliance account for the affected EGU within 60 days following the quarterly deadline for reporting valid CO_2 emissions and energy output data for the previous calendar quarter pursuant to 40 CFR part 75 (i.e., January 30, April 30, July 30, and October 30) or EPA publication of these data, whichever is later. The tracking system operator will record any GS-ERCs based upon valid CO_2 emissions data from a certified part 75 monitoring system and valid net energy output data for a full prior calendar year within 60 days following the fourth quarter reporting deadline of January 30 or EPA publication of these data, whichever is later. In practice, if an affected NGCC unit reports valid data for a full calendar year by the fourth quarter reporting deadline of January 30,[162] the tracking system operator will record GS-ERCs in the affected EGU’s compliance account by no later than 60 days following this deadline.

b. Issuance of ERCs to Eligible Resources.

The MR specifies the process for the issuance of ERCs to eligible resources.[163] This process aligns with the required two-step process and related requirements established in the CPP. Under the CPP, in the first step, a potential ERC provider (*i.e.*, a resource that may qualify as an eligible resource) submits an eligibility application for a qualifying program or project to the state. The state or its agent then reviews the application to determine whether the potential ERC provider meets eligibility requirements for the issuance of ERCs. Section V.E.2.b(1) identifies the required contents of the eligibility application, the need for application review by an independent verifier, and the timeline for state review of an eligibility

[162] Meaning the affected NGCC unit had reported valid data for each calendar quarter during the calendar year.

[163] *See* 40 CFR 60.5805(a).

application.

After the ERC provider has implemented the eligible resource program or project approved in step one, it may undertake the second step of the process in order to be issued ERCs. In this section step, the ERC provider must periodically submit an M&V report to the state documenting the MWh of electricity generation or energy savings resulting from the eligible resource. These results are quantified according to the EM&V plan approved as part of the eligibility application in step one and verified by an accredited independent verifier. The independent verifier must submit its verification assessment in a report that accompanies the M&V report submitted to the state. The state then reviews the M&V report and determines the number of ERCs (if any) that should be issued. Finally, the tracking system operator records the appropriate number of ERCs in the tracking system account registered to the ERC provider, and the tracking system operator records the ERCs into the account specified.[164] Sections V.E.2.b(2)-(4) describe requirements for

[164] 80 FR 64906-907 (detailing further the two-step process for ERC issuance). If the state designates the EPA to perform the service of recording ERCs into general accounts, the state would direct the EPA to record the number of ERCs that the state has determined appropriate for the eligible resource at hand.

this second step for ERC issuance, including those related to monitoring and verification reports, independent verifier verification reports, and ERC issuance.

(1) Eligibility Application.

An eligibility application allows the state to evaluate whether a resource is eligible to be issued ERCs for MWh of electricity generation or savings that occur in 2022 or later. Under this MR, the authorized representative for a potential eligible resource may submit an eligibility application at any time after establishing a general account.[165] An eligibility application may be submitted even prior to the beginning of the first compliance period, which begins on January 1, 2022. Such pre-compliance-period program activity can support market liquidity by providing market participants with information about the expected future supply of ERCs, based on the resources that have been determined eligible by a state.[166]

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[165] An initial M&V report may accompany an eligibility application, for a resource that is already installed or has already been implemented. However, an M&V report is not considered valid for the purposes of review by a state until a state has determined that a resource is eligible.

[166] These eligible resources will be registered in the state-administered document review and management system, along with the approved eligibility applications, each of which provides a detailed description of the eligible resource.

Provisions of this MR specify that the state will review a complete eligibility application within 90 days of receipt. An eligibility application must be submitted in a form prescribed by the state and include the following:

- Identification of the authorized account representative for the general account into which ERCs will be recorded, and identification of the account;[167]
- Identification of the eligible resource and specific information about the resource;
- Identification of the owners or operators of the eligible resource, as applicable;[168]

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[167] In this MR, the authorized account representative for this identified general account is the legal representative for the eligible resource. Rate-based MR provisions for the establishment of a general account and identification of an authorized account representative are discussed in section V.D.3 above.

[168] In the context of an eligibility application, "owner or operator" refers to the parties that have a financial interest in the eligible resource and/or are responsible for its operation. This may differ depending on the type of eligible resource. For example, identification of the owner or operator of an eligible RE or nuclear generating resource would be similar to the identification of such parties for an affected EGU. For a DS-EE resource, an "owner or operator" could involve different types of parties, such as an EE program administrator or an energy service company implementing an EE project at a

- Demonstration that the resource meets all applicable eligibility requirements;
- A certification that the resource has not submitted an eligibility application to be issued ERCs under any other state or multi-state program;
- An evaluation, measurement and verification (EM&V) plan;[169]
- A verification report from an accredited independent verifier;[170]
- An authorization for the state to physically inspect the eligible resource;

building or facility. In many cases, the “owner or operator” of such an eligible resource may not be the owner or operator of the building or facility where EE projects and/or measures are installed.

[169] For a resource to be eligible, the EM&V plan must meet all applicable requirements for the resource established in this MR. EM&V plans and EM&V requirements are discussed in section V.E.3 below.

[170] While considered part of an eligibility application, the independent verifier verification report must be submitted separately to a state by the accredited independent verifier. This MR specifies this submittal process for verification reports.

- An attestation indicating all information in the application is true, accurate, and complete.[171]

In the event there are material changes to the information in an approved eligibility application, the authorize account representative for the eligible resource EGU must submit an updated eligibility application to the state for approval. This includes, for example, changes to the eligible resource’s EM&V plan. The eligible resource cannot be issued ERCs for electricity generation or savings that occured after the material change until the updated eligibility application is approved by the state. Depending upon the nature of the material change, ERCs may be issued for electricity generation or savings that occurred after the material change but before approval of the updated eligibility application, provided all relevant requirements for ERC issuance are met.

A number of commenters raised issues related to what party or parties would receive ERCs issued for electricity generation or savings by a respective eligible resource under the MR. In

[171] Under the CPP, states may require other information to be provided in an eligibility application. While this MR preserves this ability for states, it does not include any additional specific information requirements beyond what the CPP requires.

particular, many commenters observed that a number of different parties may have a financial or other interest in an eligible resource (and the ERCs issued to the eligible resource) and advocated that certain parties rather than others should be entitled to the ERCs issued to a respective eligible resource.

Consistent with the proposal, the final MR does not address such contractual issues or other agreements among private parties. Rather, the MR specifies that the authorized acount representative for a general account submits an eligibility application for an eligible resource and that any ERCs issued to the eligible resource will be recorded in the identified general account. Part of the application process for the establishment of a general account requires identification of all parties that have an ownership interest in the ERCs held in the account. Further, these account-establishment provisions specify that the authorized account representative is authorized to take actions on behalf of all parties with an ownership interest in the ERCs held in the account and that these parties are bound by such actions.

This approach is consistent with that taken in other emission trading programs, including EPA-administered programs and state programs. In response to these comments, the final MR clarifies that the authorized account representative for the general account identified in an eligibility application for an eligible resource is the party that represents the eligible resource in all submittals and all other matters under the rate-based trading program.

(2) Monitoring and Verification Reports.

The rate-based MR provides for a rolling ERC issuance process, rather than a single annual issuance date as proposed. This adjustment is in response to comments requesting that the rate-based MR facilitate more frequent ERC issuance in order to promote market liquidity, as well as the EPA's assessment that such a process would provide for more effective implementation of a rate-based emission trading program. The authorized representative for an eligible resource may submit an M&V report at any time.[172] A state will make a determination that each M&V report is administratively complete, after which the M&V report

[172] An initial M&V report may accompany an eligibility application, for a resource that is already installed or has already been implemented. However, an M&V report is not considered valid for the purposes of review by a state until a state has determined that a resource is eligible.

will be made publicly available by the state.

The state then will determine, within 50 days of receipt of the complete M&V report, the number of ERCs to be issued to the eligible resource.[173] This determination will be publicly accessible in the state ERC document management and approval system and through the ERC-TCS. Under this MR, an M&V report may cover a reporting period that ranges from one calendar quarter to 24 months in length.[174] The EPA believes that the 50-day review timeframe will provide sufficient time for state review of M&V reports. Upon completion of the state’s review of an M&V

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[173] If the state designates the EPA to perform the service of recording ERCs into general accounts, the state would provide to the EPA the number of ERCs issued to the eligible resource and the tracking system account number for the eligible resource.

[174] This approach allows the authorized representative for the eligible resource to determine the optimum timeframe and schedule for submission of an M&V report, considering the time needed for independent verification of MWh data and related transaction costs incurred in developing and submitting an M&V report. For example, eligible resources with simpler EM&V plans (and, presumably, lower transaction costs), such as eligible resources where electricity generation is metered and that are already reporting data to meet state RPS requirements, may select to submit M&V reports on a quarterly basis. Eligible resources with more complex EM&V plans or smaller eligible resources that generate or save less MWh may choose to submit M&V reports less frequently. Such resources may incur higher transaction costs per MWh of electricity generation or savings if required to submit M&V reports on a quarterly or annual basis.

report, the tracking system operator will, within 10 days, record the appropriate number of ERCs in the ERC-TCS account identified by the state. If the state is the tracking system operator for the recordation of ERCs, this 10-day time period commences upon completion of the state's review of the M&V report. If the state designates the EPA or another entity other than the state as the tracking system operator for the recordation of ERCs, this 10-day time period will commence upon its receipt of ERC issuance information from the state.

This timeframe enables the preparation and submittal of an M&V report for MWh generation or savings that occur during the last calendar quarter of a compliance period, and it ensures state review of that M&V report and subsequent issuance of ERCs prior to the June 1 ERC transfer deadline for affected EGUs.[175] For example, if an ERC provider submits an M&V report by March 1 following the end of a compliance period, the state will determine, within 50 days, the appropriate number of ERCs to be

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[175] The ERC transfer deadline is the date by which ERCs must be held in an affected EGU's compliance account for deduction as part of its compliance demonstration. This MR includes an ERC transfer deadline for affected EGUs of June 1 following the end of a compliance period. Section V.F discusses the ERC transfer deadline and related concepts in more detail.

issued to the eligible resources on the report. The tracking system operator then will record the appropriate number of ERCs into the eligible resource’s general account within 10 days, so that the whole process would be completed by no later than May 1. This provides a 30-day window between the date of ERC issuance (May 1) and the ERC transfer deadline (June 1) for selling the ERCs and transferring them into compliance accounts prior to the ERC transfer deadline.[176]

In addition to timing provisions, the rate-based MR specifies the required content of an M&V report. While M&V reports will be submitted in a form prescribed by the state, they must include the following:

- Documentation that the electricity-generating resource or energy-saving measures or practices were installed or implemented consistent with the description in the approved eligibility application (applies to first submitted M&V report);

[176] The EPA notes that ERCs may be banked without limitation. As a result, even if an M&V report were submitted too late for ERCs to be issued prior to the ERC transfer deadline for the previous compliance period, those ERCs would be usable for compliance in the current compliance period and future compliance periods.

- Identification of the time period covered by the report (reporting period);
- Description and documentation of how the relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan in the approved eligibility application were applied during the reporting period to determine the documented MWh of electricity generation or savings in the report;
- Documentation (including data) of the quantified and verified MWh of electricity generation or savings during the reporting period;
- Documentation of any change in ownership interest of the eligible resource (from that in the approved eligibility application); and
- An attestation indicating all information in the application is true, accurate, and complete.

(3) Independent Verifier Verification Reports.

This MR specifies requirements and content for all independent verifier verification reports (also referred to this preamble and the rate-based model rule regulatory text as a “verification report”) that are included as part of an eligibility application or an M&V report. Verification report content differs depending upon whether the report is a part of an eligibility application or M&V report. This MR also requires that verification reports be submitted in a form prescribed by the state.

All verification reports must include a verification statement that sets forth the findings of the verifier, based on its assessment of the eligibility application or M&V report. The statement must include an assessment of whether the submittal includes any material misstatements or material data discrepancies and whether the submittal conforms with applicable requirements established in this MR. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier’s assessment. The statement must also include an attestation that the statements and information in the verification report are true, accurate, and complete.

The required contents of a verification report for an eligibility application must describe the review conducted by the accredited independent verifier and provide the accredited independent verifier’s assessment of each of the following:

- The eligibility of the resource, in accordance with eligibility requirements established in this MR;[177]
- The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another state plan;[178]
- The eligible resource exists or will be implemented in the manner described in the eligibility application;
- The EM&V plan for the eligible resource meets all applicable requirements established in this MR;
- Sufficient disclosure of any mandatory or voluntary programs to which data are reported relating to the eligible resource; and
- Any other information, as required by the state.

In addition to these required contents of a verification report, the verifier must review any other information that it

[177] This must include an analysis of the adequacy and validity of the information submitted to demonstrate the resource meets all applicable eligibility requirements.

[178] In practice, this verification component assesses whether the resource has been submitted under another state's rate-based emission trading program or whether another party has submitted the resource under the state's rate-based trading program (*i.e.*, whether the resource has been submitted more than once, either to multiple state programs or to a single state program).

finds, in its professional opinion, is necessary to assess the adequacy and validity of the information and data included in the eligibility application. The verification report must describe any such additional information that was reviewed and include a description of the verifier's assessment of this information where relevant.

The verification report for an M&V report must describe the review conducted by the accredited independent verifier and provide the accredited independent verifier's assessment of each of the following:

- The adequacy and validity of the information and data submitted to quantify MWh of electricity generation or electricity savings during the period covered by the report, as well as all supporting information and data identified in the EM&V plan and M&V report;
- Electricity generation or savings were quantified and verified in accordance with the EM&V plan for the qualified eligible resource;
- Evaluation of whether all electricity generation or savings data are within a technically feasible range for the specific eligible resource (determined through a quality assurance and quality control check of the data);

- The M&V report meets all applicable requirements of this MR; and
- Any other information, as required by the state.

In addition to this information, the verifier must include in the report the verifier's review of any other information that in the verifier's professional opinion is necessary to assess the adequacy and validity of the information and data included in the M&V report. The verification report must describe any such additional information that was reviewed and include a description of the verifier's assessment of this information where relevant. Associated rate-based MR requirements for independent verifiers, such as those related to accreditation and conflicts of interest, are discussed below in section V.E.4.

(4) Issuance of ERCs.

Provisions of this MR specify the process for issuance of ERCs to an eligible resource. Based on its review of a complete M&V report, the state will determine the number of ERCs to be issued to the eligible resource for quantified and verified MWh of electricity generation or savings during the period addressed by the report. Based upon this determination, the tracking system operator will record the appropriate number of ERCs in the general account for the eligible resource identified in the approved eligibility application. ERCs may be issued to the eligible resource in an amount up to the MWh documented in the M&V report and approved by the state. The state may determine that fewer ERCs should be issued than the quantified and verified MWh in the M&V report for cause, if it finds material discrepancies or misstatements in the M&V report that impact the total quantified and verified MWh of electricity generation or savings contained in the report. The state will document any such discrepancies as part of its ERC issuance determination, and this information along with documentation of the number of ERCs issued will be maintained in the the state ERC document management and approval system and made publicly available through the ERC-TCS.

c. *Improperly Issued ERCs and Error Correction.*

The rate-based MR includes provisions to address circumstances where ERCs have been improperly issued to eligible resources and affected EGUs.[179] States have the authority to

[179] The CPP requires a state plan to "include provisions that address requirements for revocation or adjustment that apply if an ERC issued by the State is subsequently found to have been improperly issued." *See* 40 CFR 60.5790(c)(3).

revoke approval of an eligibility application in the event of error or mistatement in the eligibility application. In the event approval is revoked for an affected EGU, the tracking system operator will deduct ERCs from the affected EGU’s compliance account in a number sufficient to offset the ERCs issued to the affected EGU based upon the invalid eligibility application. Alternatively, the tracking system operator can reduce the number of ERCs issued to the affected EGU in the future in order to offset the number of ERCs issued to the affected EGU based upon the invalid eligibility application.

In the event approval is revoked for an eligible resource, that resource would no longer be an eligible resource and would not be eligible to be issued ERCs.[180] If that resource already has been issued ERCs based on the error or misstatement in the eligibility application, the the tracking system operator will deduct ERCs from the eligible resource’s general account in a number sufficient to offset the ERCs issued to the eligible resource based upon the invalid eligibility application.

[180] The eligible resource could resubmit a new, corrected eligibility application. If the resubmitted new eligibility application was approved by the state, the eligible resource would again be qualified for the issuance of ERCs.

Alternatively, the tracking system operator can reduce the number of ERCs issued to the eligible resource in the future in order to offset the number of ERCs previously issued to the eligible resource based upon the invalid eligibility application.

In the event ERCs have been issued to an affected EGU based upon error or misstatement of quantified MWh of electricity generation, the tracking system operator will deduct ERCs from the compliance account held by the designated representative of the affected EGU. The tracking system operator will revoke ERCs in an amount necessary to correct the error or misstatement. In the event that the compliance account of the affected EGU holds an insufficient number of ERCs to correct the error or misstatement, the designated representative must surrender for deduction to the tracking system operator a number of ERCs necessary to correct the error or misstatement.

In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for an eligible resource for which ERCs have been issued, the state will address the error or misstatement by subtracting the appropriate number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In effect, fewer ERCs are issued for the next M&V report in order to compensate for ERCs previously issued improperly.

A final M&V report refers to the M&V report that covers the last reporting period of the final crediting period for an eligible resource, which is established in the EM&V plan included in the approved eligibility application for the eligible resource. When ERCs have been issued to an eligible resource based upon a final M&V report that contains an error or misstatement of quantified MWh of electricity generation or savings, the consequence explained above of reducing qualifying MWh from the M&V report for the subsequent reporting period is not necessarily possible, because there would not be a subsequent M&V report. In such a case, the tracking system operator will deduct ERCs in an amount necessary to correct the error or misstatement from the general account held by the authorized account representative of the eligible resource. If the general account of the eligible resource contains an insufficient number of ERCs to correct the error or misstatement, the authorized account representative must submit to the state within 30 days a number of ERCs necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the state. Under the proposed approach, only the authorized account representative would be prohibited from further participation in the program. The approach finalized here holds the eligible resource in addition to the authorized account representative accountable for submitting an M&V report that contains an error or misstatement of quantified MWh of electricity generation or savings. The finalized approach prevents an eligible resource from merely changing the authorized account representative and then continuing participation in the program.

The tracking system operator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if ERCs have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The tracking system operator also may freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which ERCs have been issued.

Freezing a general account will prevent transfer of ERCs out of the account.

3. Evaluation, Measurement, and Verification Requirements

a. <u>Overview</u>

This section describes the evaluation, measurement, and verification (EM&V) requirements for the categories of eligible resources specified in the rate-based MR. These EM&V requirements are consistent with the structural requirements established in the CPP for EM&V for eligible resources. The EM&V provisions of this MR specify requirements that must be applied when developing an EM&V plan for a specific eligible resource in order for an ERC to be issued. An EM&V plan must detail how MWh of electricity generation or savings for the eligible resource will be quantified and verified in M&V reports submitted for an eligible resource. M&V reports are the basis for state issuance of ERCs and must demonstrate that the MWh of electricity generation or savings were quantified and verified in accordance with the EM&V plan in the approved eligibility application. As discussed in section V.E.2.b, an EM&V plan is included in the eligibility application for an eligible resource.

In addition to the EM&V requirements in this MR, the EPA is separately releasing final EM&V guidance for demand-side EE eligible resources. This guidance elaborates on applying the EM&V requirements of this MR when developing an EM&V plan for several different types of demand-side EE programs, projects, and measures.

The following subsections describe the EM&V requirements for the eligible resources included in this MR, which include RE generating units, nuclear energy generating units, non-affected combined heat and power (CHP) generating units, waste heat to power (WHP) generating units, and demand-side EE programs, projects, and measures.

b. Overall Approach to EM&V

In the CPP, the EPA indicated that its approach to EM&V is guided by certain principles, including that EM&V requirements should accomplish the following:

- Leverage existing industry best practices for purposes of ERC issuance, recognizing the context in which EM&V is applied as part of a rate-based emission trading program;[181]
- Avoid excessive interference with current EM&V conducted at

[181] In particular, the EPA noted that the level of EM&V rigor necessary for ensuring the integrity of a rate-based emission trading program may differ from that necessary to ensure effective expenditure of electricity ratepayer dollars through a utility- or state-administered energy efficiency program.

the state and utility level that is robust, transparent, and working well;

- Maintain flexibility to accommodate industry change, technology improvement, and innovation in EM&V approaches and protocols over time; and
- Strike a reasonable balance between EM&V rigor and accuracy and the level of effort and cost involved in EM&V.[182]

The majority of commenters agreed with these principles and the approach to EM&V taken in the proposed rate-based MR. As a result, the EM&V provisions in this MR largely align with those that were proposed and aim to meet these principles. At the same time, the EPA received many useful comments related to specific EM&V provisions for different categories of eligible resources. In light of these comments, this MR includes revisions to some technical aspects of the proposed EM&V requirements. These comments and revisions are noted in the relevant subsections

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[182] In particular, the EPA has considered the level of EM&V effort and cost required in the context of smaller eligible resources, such as small RE generating units and DS-EE measures deployed through EE programs, where the individual energy generation or savings impact of an individual energy generating unit or energy efficiency measure is relatively small and programs deploy a large number of individual energy generating units or energy efficiency measures in many locations.

that follow.

c. Renewable Energy and Nuclear Energy EM&V Requirements

(1) EM&V Requirements for Renewable Energy Resources.

This MR includes EM&V requirements for eligible renewable energy resources and their composite generating units. An EM&V plan for an eligible renewable energy resource must document how all electricity generation will be quantified and verified. The CPP requires that for all eligible renewable energy resources of any nameplate capacity, each EM&V plan must specify that electricity generation be physically measured on a continuous basis. This section explains provisions that cover meter specifications, meter location, verification processes, and aggregation specifications.

The EPA sought comment on meter specifications, particularly the appropriateness of the proposed rate-based MR requirement to use a “revenue quality” meter. Commenters broadly supported the use of revenue quality meters for larger nameplate capacity renewable energy resources in the physical measurement of generation. Commenters indicated that alternative metering approaches, such as integrated “onboard” inverter meters, could be used to physically measure generation data for smaller renewable energy resources located behind retail customer utility meters, and in doing so reduce the EM&V cost burden for smaller projects when compared to the use of revenue quality meters. The EPA also sought comment on the proposed rate-based MR definition of a revenue quality meter. Commenters broadly supported the accuracy in measurement requirements of the ANSI C-12 standard as an appropriate definition of a revenue quality meter, but some commenters favored a definition that allows for alternative equivalent standards.

In response to comments, the EPA is finalizing in this MR three classes of metering specifications based on the nameplate capacity of renewable energy resources for which different metering requirements apply. The measurement requirements defined under this MR takes into account common metering instrumentation practices and the corresponding cost burden that higher accuracy meters may impose on renewable energy resources as noted by commenters. This MR requires that for renewable energy resources with a nameplate capacity of 5 MW or more, all electricity generation must be physically measured with a meter that meets or exceeds the American National Standards Institute No. C-12.20, American National Standard for Electricity meters – 0.2 and 0.5 Accuracy Class, or an equivalent standard of performance and measurement accuracy. For renewable energy resources with a nameplate capacity of 30 kW or more and less than 5 MW, all electricity generation must be physically measured with a meter that meets or exceeds the American National Standards Institute No. C-12.1, American National Standard for Electric Meters - Code for Electricity Metering, or an equivalent standard of performance and measurement accuracy. In response to comments, for renewable energy resources with a nameplate capacity less than 30 kW, this MR allows for an alternative metering approach that does not require that the meter meet a revenue quality standard or definition. Under this alternative approach, renewable energy resources less than 30 kW may use an alternative meter provided the meter meets a +/-5 percent or better accuracy in measurement of actual generator output and the EM&V plan demonstrates that a higher accuracy meter is not otherwise available to the renewable energy resource. For any nameplate capacity renewable energy resource, where the resource has an installed meter that exceeds the minimum accuracy of measurement requirements, the resource must use the higher accuracy meter.

This MR requires that each EM&V plan must specify quality assurance procedures for how each alternative meter will be validated to meet and maintain at least a +/-5 percent accuracy in measurement; how generation data will be collected and validated by an independent third-party[183] that is not affiliated with the owner or operator of the renewable energy resource; and the safeguards that will be put in place to ensure that the meter(s) and generation data measurements are not improperly manipulated or adjusted from actual generation measurements. EPA notes that some alternative meters, such as “onboard” inverter meters, may allow users to manipulate or manually set the reported generation levels of the meter. In response to this observation, this MR requires that an EM&V plan for renewable energy resources of less than 30 kW must specify two requirements. First, an EM&V plan must specify that an independent third-party will validate physical metering measurements by comparing measured generation at the renewable

[183] An “independent third-party” as used in this EM&V section is an entity that is not be affiliated with the owner or operator of the renewable energy resource or the representative for the eligible resource that includes the generating unit. This “independent third-party” is materially different and distinct from an accredited independent verifier”, which is authorized by the state to review M&V reports and render its opinion on the validity of the generation data and information in an M&V report and whether it meets the relevant regulatory requirements.

energy resource to a calculated generation estimate based on the technical potential of the renewable energy resource, using publicly available methodologies and calculators, such as the National Renewable Energy Laboratory's PV Watts[184] for solar. Second, an EM&V plan must specify that the lesser of the two values will be reported as the metered generation data. The second requirement provides assurance against manipulation of metered electricity generation data and places a cap on the reported physical electricity generation data equal to the estimated technical generation potential of an eligible renewable energy resource.

The EPA also sought comment on the appropriate meter locations for renewable energy resources. The EPA received comments that physical measurement can occur at various places between the renewable energy generating unit and the point where eligible generation is delivered to meet consumer load (*e.g.*, interconnection or bus bar). This means that physical measurement may take place as far from the point where eligible generation is delivered to meet consumer load as an onboard

[184] National Renewable Energy Laboratory PV Watts Calculator, http://pvwatts.nrel.gov/

inverter meter for retail consumer sited generating units. In response to comments, this MR explains the intent of the appropriate location of generation measurement and accommodates renewable energy resources of all types and nameplate capacities that are interconnected to the transmission and distribution grid, as well as generators located behind retail customer utility meters. These MR provisions also ensure that accurate measurement of electricity generation is applied toward ERC issuance for renewable energy resources that are customer-sited behind a retail utility meter and potentially serve on-site customer load that would otherwise be served by electricity from the grid.

Meter placement requirements in an EM&V plan must be designed to ensure accurate measurement of the amount of electricity generation that is delivered to the grid and/or used to serve on-site customer load. For all eligible renewable energy resources of any nameplate capacity, this MR requires that measurement of the AC generation be taken at the point of the grid interconnect. For retail-customer sited RE resources, this must be the nearest practical point to the bus bar, and no further from the bus bar than the DC/AC inverter serving the renewable energy resource. Reported AC generation measurement must represent the electricity generation of the eligible renewable energy resource net of any non-customer-load.[185] For eligible renewable energy resources that are sited behind an individual retail customer utility meter, all electricity generation from the renewable energy resource, including that which is used to meet on-site customer load, net of any non-customer load, is eligible for ERC issuance.[186]

The EPA sought comment on data verification processes,

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[185] Non-customer loads include, but are not limited to, station service, auxiliary loads, and parasitic loads. It also includes any in-facility electricity use by the generating unit itself that is necessary for the generation of electricity, such as electricity used by pumps, fans, electric motors, condensers, pollution control equipment, monitoring and control equipment, and any other electricity used in the operation of the eligible resource. Electricity generation from an eligible resource that is used to meet non-customer load is not eligible for ERC issuance and any reported electricity generation data must be net of non-customer loads. In practice, eligible resources must physically measure electricity generation at the nearest point to where the net electricity generation is delivered to the grid to serve consumer load, and must not include any gross electricity generation used to meet non-customer loads (*i.e.*, station service, auxiliary loads, parasitic loads, etc.).

[186] For a retail customer-sited generating resource, this is the electricity generation that in practice serves to replace generation from affected EGUs, as it is the generation that is either supplied to the grid or not supplied from the grid to meet on-site customer load.

including whether eligible generation data should go through a control area accounting or settlement process. Commenters supported this requirement for projects that report to a control area operator, but comments also noted the need to accommodate alternatives for generation from renewable energy resources that do not go through a control area operator. In response to comments, this MR requires each EM&V plan to specify that all electricity generation data that are collected and electronically telemetered from the renewable energy resource to a control area operator[187] will be verified through a control area accounting or settlement process that occurs on at least a monthly basis. If a renewable energy resource of any nameplate capacity does not report generation data to a control area operator and that is verified through a control area accounting

[187] A control area operator is an electric power system, or a combination of electric power systems, to which a common automatic generation control is applied to match the power output of generating units within the area to demand. Control area operators typically operate generating capacity to meet area demand, monitor actual interchange (electric energy flowing between control areas), and can dispatch generating resources to ensure that actual interchange equals scheduled interchange. Generators within control area operator geography generally report MWh generation data, which is verified and financially settled through an established accounting and settlement process.

or settlement process on at least a monthly basis, the EM&V plan must describe how generation data will be manually collected and validated by an independent third-party that is not affiliated with the owner or operator of the generating unit or the representative for the eligible renewable energy resource that includes the generating unit. Each EM&V plan must specify how manually collected generation data will be validated and verified for the purpose of ERC issuance. Renewable energy resources less than 30 kW may submit a petition to the state to self-report generation data and the approved petition must be included in the EM&V plan. In addition, an EM&V plan must specify certain minimal requirements for self-reported generation data for the purpose of ERC issuance. Based on comments received pertaining to the cost burden concerns for reporting of generation data for smaller generating units, renewable energy resources less than 30 kW that do not generate at least 1 MWh each month to enable monthly reporting may instead report generation data on an annual basis for that annual reporting period. Renewable energy resources, however, must be evaluated each subsequent annual reporting period for whether they still meet the insufficient monthly generation threshold of one MWh that allows for annual reporting of generation.

Provisions of this MR allow for several renewable energy generating units that share a singled grid interconnection to be considered a single eligible renewable energy resource as long as the multiple generating units are of the same resource type (*i.e.*, multiple wind farm turbines that share the same grid interconnection). The measured electricity generation from two or more independently metered generating units that share the same grid interconnection may be summed to arrive at a total generation amount for the eligible renewable energy resource. Such eligible renewable energy generators must be subject to a single EM&V plan.

The EPA sought comment on the requirements for allowing generation data to be aggregated, what types of characteristics projects should share in order to be aggregated and what the appropriate threshold for aggregation should be. Commenters generally supported aggregation and the maximum individual project threshold of 150 kW, but commented that the proposed 1 MW total aggregated nameplate capacity threshold was too small. In response to comments, this MR allows for the measured generation from separately interconnected renewable energy resources of less than 150 kW to be aggregated and subject to a single EM&V plan. This includes renewable energy resources and their composite generating units to be at different locations or facilities. Also in response to comments, separately metered renewable energy generating units may be aggregated as a single eligible renewable energy resource if the aggregated individual generating units do not exceed a total aggregated nameplate capacity of 10 MW and the individual generating units share essential generating characteristics, such as resource type (*i.e.*, either all solar or all wind resource generating units), the same level of grid[188] interconnection, and located in the same state. In addition, each renewable energy resource must be separately metered using a meter that meets the same performance and accuracy requirements and is subject to the same maintenance and quality assurance procedures. All of the essential shared generating characteristics of the aggregated renewable energy generating units that comprise a single eligible renewable energy resource must be documented in each EM&V plan.

This MR allows for generation from eligible renewable energy resources to quantify transmission and distribution (T&D)

[188] Aggregations must be made of generation units that interconnect at either the transmission or distribution, or customer sited level.

losses for the purpose of ERC issuance. Only the portion of net generation from the renewable energy resource used to meet coincident onsite retail-customer load that otherwise would have been met by the electric grid is eligible for ERC issuance. The EM&V plan must specify the method and appropriate T&D loss factor used for determining the T&D losses, as well as the method used for determining the eligible portion of generation used to serve coincident onsite retail-customer load. MR provisions that detail the required methodology for estimating the T&D loss factor are discussed in subsection V.E.3.f of the EM&V section.

(2) EM&V Requirements for Nuclear Power Resources.

The rate-based MR includes EM&V requirements for nuclear power resources and their composite generating units. An EM&V plan for a nuclear power resource that is an eligible resource must document how all electricity generation will be quantified and verified. For all eligible nuclear power resources, each EM&V plan must specify that generation data will be physically measured on a continuous basis and be measured by a meter that meets the American National Standards Institute No. C12.20, American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Class, or a metering standard of equivalent accuracy.

EPA sought comment on the appropriateness of having nuclear power resources meet the same EM&V requirements as renewable energy resources. Commenters noted that nuclear power resources did not need to meet the same level of EM&V requirements due to the highly regulated nature of nuclear power industry and due to the existing requirements for measurement and verification of generation currently used. In response, this model rule requires that nuclear power meet several EM&V requirements that define the measure and validation of electricity generation from nuclear power resources for the purpose of ERC issuance.

For all eligible nuclear power resources, measurement of electricity generation must be taken at the nearest practical point to the grid interconnect, or at the point of the grid interconnect, such that the total reported generation measurement represents the total generation net of electricity used by the generating unit(s) in the generation of electricity such as station service, auxiliary load, and parasitic loads.[189]

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[189] Non-customer loads include, but are not limited to, station service, auxiliary loads, and parasitic loads and includes any electricity used by the generating unit itself that is necessary for the generation of electricity, such as electricity used by

Multiple eligible nuclear power generating units that share a single grid interconnection may be considered a single eligible nuclear energy resource and be subject to a single EM&V plan. The measured electricity generation from two or more independently metered nuclear power generating units that share the same grid interconnection may be summed to arrive at the total generation for the eligible nuclear power resource.

An EM&V plan must specify that all electricity generation data that are collected and electronically telemetered from the nuclear energy resource to a control area operator will be verified through a control area accounting or settlement process that occurs on at least a monthly basis.

d. *Non-affected CHP and WHP EM&V Requirements*

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pumps, fans, electric motors, condensers, pollution control equipment, monitoring and control equipment, and any other electricity used in the operation of the generating unit. Electricity generation from an eligible resource that is used to meet non-customer load is not eligible for ERC issuance and any reported electricity generation data must be net of non-customer loads. In practice, eligible resources must physically measure electricity generation at the nearest point to where the net electricity generation is delivered to the grid to serve consumer load, and must not include any gross electricity generation used to meet non-customer loads (*i.e.* station service, auxiliary consumption, parasitic loads etc.).

(1) EM&V Requirements for Non-affected CHP Units

The rate-based MR includes EM&V requirements for eligible non-affected CHP units the scope of which address data elements necessary to apply the ERC issuance accounting method for non-affected CHP units discussed in section V.C.3.b.(1).[190] The EM&V requirements specifically address monitoring and reporting of CO_2 emissions, electricity generation, and heat input using methods specific to the non-affected CHP generating unit size and fuel type. The EM&V requirements in the final MR are based primarily on established practices for measuring and reporting CO_2 emissions and energy output by non-affected CHP units, including WHP units. These requirements maintain rigor and simplicity while minimizing the associated cost burden. The final requirements meet the same objectives and where requirements have not been in place, non-affected and WHP requirements have been based on RE requirements to ensure consistency across the final MR.

There are general EM&V requirements that apply to all non-affected units of all generating capacity. There are also

[190] The EM&V requirements apply to non-affected CHP units that are eligible resources for the issuance of ERCs. These are fossil fuel-fired EGUs that are not subject to the CPP.

specific requirements that depend upon whether it has an electric generating nameplate capacity greater than 1 MW or less than or equal to 1 MW. There are useful thermal output requirements that apply to non-affected CHP units that are not WHP units.

(a) *Non-affected CHP units with an electric generating nameplate capacity greater than 1 MW.*

An EM&V plan for a non-affected CHP unit that fits this category must specify the requirements for monitoring and reporting of CO_2 emissions and heat input. These requirements in an EM&V plan must be the same as those specified for affected EGUs in 40 CFR 62.16540. An EM&V plan must specify that all electricity generation will be physically measured with a meter that meets or exceeds the standard of performance and measurement accuracy in the American National Standards Institute No. C-12.20, American National Standard for Electric Meters - 0.2 and 0.5 Accuracy Class. A petition may be submitted to the state, as part of an EM&V plan, to use a meter that meets an alternative equivalent standard for performance and measurement accuracy, and the petition, if approved, must be included in the approved EM&V plan.

The EM&V plan must specify CO_2 emission monitoring and reporting requirements that are consistent with the monitoring and reporting requirements that apply for affected EGUs.

(b) *Non-affected CHP units with an electric generating nameplate capacity less than 1 MW*

The EPA has finalized that for a non-affected CHP unit that falls within this sub-category must submit an EM&V plan that specifies a method for measuring and reporting of CO_2 emissions and heat input for approval by the state. The EM&V plan must specify requirements for quarterly reporting of heat input by fuel type and specify how CO_2 emissions will be calculated based on reported heat input. The EM&V plan must also specify how manually collected data will be validated and verified.

All electricity generation must be physically measured with a meter that meets or exceeds the standard of performance and measurement accuracy in the American National Standards Institute No. C-12.1, American National Standard for Electric Meters - Code for Electricity Metering. A petition may be submitted to the state, as part of an EM&V plan, to use a meter that meets an alternative equivalent standard for performance and measurement accuracy and the petition, if approved, must be included in the approved EM&V plan.

This MR allows for separately metered and interconnected non-affected CHP and WHP units that fall within this sub-category to be aggregated as a single eligible resource and subject to a single EM&V plan. According to the MR, non-affected CHP units must be aggregated with non-affected CHP units, and WHP units must be aggregated with WHP units. Units at different locations or facilities can be aggregated. Separately metered generating units may be aggregated as a single eligible resource if the aggregated individual generating units do not exceed a total aggregated nameplate electric generating capacity of 25 MW and the individual generating units share essential characteristics, such as sharing a common fuel type and sharing the same level of grid[191] interconnection. In addition all aggregated units must be located in the same state.Further, each generating unit must be metered using a meter that meets the same performance and accuracy requirements and is subject to the same maintenance and quality assurance procedures. All of the essential shared generating characteristics of the aggregated

[191] Aggregations must only be made of generation units that interconnect at either the transmission or distribution, or customer-sited level.

non-affected CHP and WHP units that comprise a single eligible resource must be documented in the EM&V plan.

(c) *Non-affected CHP units that are not a WHP unit*

An EM&V plan must specify the process that will be used to monitor and report useful thermal output. The measurement of useful thermal output in the form of steam involves the measuring of steam pressure and steam flow (and in the case of superheated steam, steam temperature). An EM&V plan must specify the operation and calibration of equipment that measures pressure, temperature and steam flow leaving the non-affected CHP unit and that measures the temperature and flow of returning condensate, or the pressure, temperature and steam flow of returning steam. Furthermore, the requirements for monitoring and reporting useful thermal output of a non-affected CHP unit that are specified in an EM&V plan must be demonstrated to meet a minimum +/- 5 percent accuracy in measurement[192] over the operation of the measurement period and the EM&V plan must detail how this requirement will be met. An EM&V plan must specify the method for selection and application of appropriate

[192] The total accuracy in measurement is the sum of the uncertainties of the flow, temperature, pressure sensors and calculation uncertainty.

thermal measurement instrumentation to ensure the minimum measurement accuracy is achieved. An EM&V plan must specify how the useful thermal output data will be validated by an independent third-party that is not affiliated with the owner or operator of the generating unit or the representative for the eligible resource that includes the generating unit.

(d) *All non-affected CHP units or WHP units of any electric generating nameplate capacity*

For all non-affected units, electricity generation data must be measured with the meter with the highest available measurement accuracy that meets the metering requirements of paragraphs (c)(1) to (c)(3) of this section. The measured electricity generation from two or more independently metered generating units may be summed where the generating units share the same grid interconnection.

For all non-affected units, measured electricity generation data must represent only generation that serves load that otherwise would have been served by the grid if not for the output of the generating unit. All electricity generation data must be net of any non-consumer load-related losses or any electricity used by the generating unit in the generation of electricity, such as auxiliary loads or parasitic load. All electricity generation data must be net of any generation used to supply the ancillary equipment used to operate a generating unit ("station service") or parasitic load on the generating unit's side of the point of interconnection with the grid.

For all non-affected units, the generation data must be measured at the nearest practical point to a generating unit's grid interconnection, or bus bar interconnection for retail-customer sited resources, meaning at the point of delivery in which the AC output of the generating unit can be isolated from the grid or differentiated from other sources of generation.

For all non-affected units, the generation data must be measured at the nearest practical point to the generating unit's grid interconnection, or bus bar interconnection for retail-customer sited resources, meaning at the point of delivery in which the AC output of the generating unit can be isolated from the grid or differentiated from other sources of generation.

For generating units interconnected to a transmission system and with on-site loads other than non-consumer loads, such as station service, the EM&V plan must demonstrate that the metering approach used is capable of distinguishing between other on-site loads and non-consumer loads, such as station service.

An EM&V plan must specify that all electricity generation data that are collected and electronically telemetered from the generating unit to a control area operator[193] will be verified through a control area accounting or settlement process that occurs on at least a monthly basis. If a generating unit of any nameplate capacity does not report generation data to a control area operator, the EM&V plan must describe how generation data will be manually collected and validated by an independent third-party that is not affiliated with the owner or operator of the generating unit or the representative for the eligible resource that includes the generating unit.

This MR allows for generation from eligible non-affected CHP units to quantify transmission and distribution (T&D) losses for the purpose of ERC issuance. Only the portion of net

[193] A control area operator is an electric power system, or a combination of electric power systems, to which a common automatic generation control is applied to match the power output of generating units within the area to demand. Control area operators typically operate generating nameplate capacity to meet area demand, monitor actual interchange (electric energy flowing between control areas), and can dispatch generating resources to ensure that actual interchange equals scheduled interchange. Generators within control area operator geography generally report MWh generation data, which is verified and financially settled through an established accounting and settlement process.

generation from the renewable energy resource used to meet coincident onsite retail-customer load that otherwise would have been met by the electric grid is eligible for ERC issuance. The EM&V plan must specify the method and appropriate T&D loss factor used for determining the T&D losses, as well as the method used for determining the eligible portion of generation used to serve coincident onsite retail-customer load. MR provisions that detail the required methodology for estimating the T&D loss factor are discussed in subsection V.E.3.f of the EM&V section.

(2) EM&V Requirements for WHP units

The rate-based MR includes EM&V requirements for WHP units the scope of which address data elements necessary to apply the ERC issuance accounting method for WHP units discussed in section V.E.[194] Specifically, WHP units must monitor and report electricity generation and the final MR specifies EM&V requirements for measuring and reporting of electricity generation identical to those required for non-affected CHP units, which are discussed above in Section V.C.

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[194] The ERC issuance accounting method for WHP units is discussed in section V.C.2.

(3) Comments on EM&V requirements for non-affected CHP units and WHP units

The EPA requested comment on all proposed metering, measurement, and verification requirements for non-affected CHP units and WHP units, including the appropriateness of their use for CHP units and with respect to the size of a CHP unit. The EPA also requested comment on any additional necessary EM&V requirements for non-affected CHP units and WHP units. Several commenters mentioned a need for further clarity and presentation in the proposed EM&V requirements for non-affected CHP units and WHP units. The EPA has clarified ambiguity in the proposed EM&V requirements and provided separate MR requirements that apply to non-affected CHP units and WHP units and these requirements are described in sections 4. and 5.

The EPA also took comment on whether the proposed EM&V provisions for non-affected CHP units (the use of the low mass emission monitoring and reporting provisions of 40 CFR 75.19) with a nameplate electric generating capacity less than or equal to 25 MW are appropriate for such units and whether any other methods may be more appropriate.

After review, the EPA has determined that the low mass emissions methodology in 40 CFR 75.19 is not appropriate to apply to all non-affected CHP units smaller than 25 MW, as some of those units combust fuel other than natural gas and/or distillate fuel oil. Instead, the final MR specifies that an EM&V plan for all units with an electric generating nameplate capacity greater than 1 MW must include requirements for monitoring and reporting of CO_2 emissions, heat input, and net energy output that are consistent to those requirements that apply for affected EGUs. This approach still allows for flexibilities for units that solely combust liquid and/or gaseous fuels to use the methodology found in Appendix D of Part 75. However, this approach retains the requirements for a CO_2 or O_2 CEMS for units that combust solid fuels that are consistent with those that apply for affected EGUs.

The EPA has decided, therefore, to finalize different EM&V requirements for non-affected CHP units with an electric generating nameplate capacity less than or equal to 1 MW. For such units, an EM&V plan must specify a method, for approval by the state, for measuring and reporting of CO_2 emissions and heat input. The EM&V plan must specify requirements for quarterly reporting of heat input by fuel type and specify how CO_2 emissions will be calculated based on reported heat input. An EM&V plan must specify how manually collected data will be validated and verified.

Many commenters requested clarification that all non-affected CHP units are allowed to account for avoided T&D system losses for electricity generation used on-site, arguing that avoiding T&D losses are a significant benefit common to CHP resources. The final MR specifies requirements for calculating an avoided T&D loss factor that may be applied to customer-sited non-affected CHP units and WHP units.

e. Demand-side Energy Efficiency EM&V Requirements

This rate-based MR includes EM&V requirements for eligible demand-side EE resources, which are described below. An EM&V plan for an eligible EE resource must document how all electricity savings from the implementation of the eligible EE resource will be quantified and verified. Electricity savings must be quantified either after the electricity savings have occurred or as the savings are occuring on a real-time basis. The rate-based MR specifies that eligible EE resources may include an EE project or measure as well as an EE program. An EE measures is a single technology, energy-use practice or behavior that, once installed or operational, reduces electricity usage at a particular end-use, facility, premises, or piece of equipment located behind a retail utility meter at a customer site. An EE project consists of a combination of multiple measures, technologies, or energy-use practices in a single such end-use, facility, or premises, whereas an EE program is an organized activity sponsored and funded by a particular entity to promote the adoption of one or more EE projects or EE measures across multiple end-uses and facilities.

In conjunction with this rate-based MR, the EPA is finalizing EE EM&V guidance in order to provide supplemental technical information to support the development and implementation of an EM&V plans, consistent with the EM&V requirements in the MR. The EE EM&V guidance is applicable to all demand-side EE programs, projects, and measures addressed in an EM&V plan.

(1) <u>Common Practice Baseline.</u>

The proposed MR defined EE savings as the difference between normalized[195] electricity usage after an EE program, project, or measure is implemented, and a “common practice baseline” (CPB). The EPA proposed the CPB as a means of

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[195] Normalized electricity usage means usage that has been adjusted to account for the effects of independent variables unrelated to the EE program, project or measure that impact energy use, such as weather or building occupancy.

establishing a framework for baseline determination, applicable across various types of demand-side EE projects and measures, that ensures that quantified and verified electricity savings are additional to levels of EE improvement that would naturally occur or otherwise be expected absent the existence of an eligible EE resource. The EPA’s draft EE EM&V guidance provided examples and definitions of CPBs for different types of EE projects, EE measures, and EE implementation strategies (*e.g.*, retrofit, replace-on-failure, new construction). In response to the proposed MR, commenters requested further clarification of the CPB definitions and applicability. The EM&V provisions in this rate-based MR, as well as the accompanying EE EM&V guidance, address these comments and include updated information to help EE providers identify and implement an appropriate CPB.

An EM&V plan must specify the CPB that will be applied for each EE project or EE measure that comprises the eligible EE resource, and it must provide sufficient documentation and evidence to demonstrate the appropriateness of each applied CPB. An EM&V plan must document why a particular CPB was selected and include an analysis of the appropriateness of that CPB for the EE project(s) or EE measure(s) addressed in the EM&V plan.

This MR defines a CPB, as applied to a specific EE project or EE measure, as the level of energy performance that would occur under the more energy-efficient of the following: (a) the technology or condition required by applicable federal, state, or local building code or product standard, if any; or (b) the expected technology, operating conditions, or practices that would have existed for the market at the time of implementation or likely subsequent replacement within the life of the EE project or EE measure, in the absence of the EE project or EE measure. This definition of a CPB is consistent with the definition of CPB in the proposed MR and the principles for EM&V in the CPP. It also establishes an approach to baseline determination that can be applied consistently across the various types of eligible EE resources and thereby maintain the integrity of a rate-based emission trading program. A CPB, as defined in the rate-based MR, ensures that ERCs are only issued to eligible EE resources that result in electricity savings relative to the level of electricity use that would naturally occur or that result in a level of EE that is better than the level of EE already required by existing laws or regulations.[196]

(2) Protocols and Guidelines Used to Quantify EE Savings

The use of one or more EM&V protocols or guidelines to quantify energy savings is a routine practice among EE implementers. Such documents establish definitions, prescribe appropriate procedures, and generally govern the application of EM&V methods used to quantify energy savings. These protocols and guidelines have been developed at the national, regional, and state levels to support utility-administered EE programs and public- and private-sector energy-savings performance contract projects throughout the country.

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[196] As established in an EM&V plan for an eligible EE resource, an applied CPB may change over the course of the effective useful life (EUL) of an EE project or EE measure. To illustrate, a CPB for an EE lighting retrofit program could specify that the CPB for EE measures installed during a program year is energy use equivalent to the average energy performance of typical lighting technologies installed for the applicable end-use within the last five years. As lighting technology improves over time, the quantified value of the CPB will also change. For this reason, an EM&V plan must specify the process by which the applied value of a CPB will be reviewed at least every 3 years and updated as necessary. An updated value of a CPB must be applied to all EE projects or EE measures addressed in an EM&V plan that are installed or that begin operating after such an update occurs.

The proposed MR included the requirements that an EM&V plan specify which protocols and guidelines would be used to inform the application of the EM&V method(s) used to quantify savings, and also describe how such protocols and guidelines would be applied. The proposed MR recognized that these protocols and guidelines offer flexibility to EM&V practitioners to consider how they are applied in practice, consistent with the unique features of the EE project or EE measure. Commenters generally agreed with this approach. The final rate-based MR retains the requirement that all electricity savings must be quantified using methods that adhere to one or more best-practice EM&V protocols or guidelines[197] and that an EM&V plan must include a detailed description of how such documents will be applied. An EE provider may continue to apply the protocols or technical guidelines that they are already using, provided that they meet the requirements of this MR.

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[197] "Best practice" means that the protocol or technical guideline is identified in the EE EM&V guidance issued by the EPA, or that it has gone through a rigorous and credible development and vetting process that includes review by EM&V experts and other stakeholders representing multiple affected organizations and interests, and has been approved by the state for use in an EM&V plan.

(3) Applied Methods Used to Quantify Savings from EE Programs and Projects.

The proposed MR included requirements for the selection and application of one or more EM&V methods for use in quantifying electricity savings from EE projects and EE measures. The proposed requirements were intended to reflect widely-applied best practices, in which utilities, private companies, and other EE providers select from a range of EM&V approaches, depending on factors such as the type of EE resource, magnitude of expected electricity savings, and EM&V budget.

The proposed MR identified three examples of best-practice EM&V approaches, including direct measurement and verification applied to individual EE projects or measures, the use of deemed savings values for specific EE measures, and comparison group approaches such as randomized control trials (RCT).[198] The

[198] Direct measurement and verification EM&V methods use site-level metering and measurement as the basis for quantifying electricity savings. In contrast, the deemed savings EM&V method involves applying pre-specified per-unit savings values or formulas to verified counts of installed EE measures. The comparison group EM&V method quantifies EE savings based on facility-level electricity usage data for a group of facilities

proposed MR also acknowledged the ongoing evolution of best practice for applied EM&V methods, including efforts to incorporate new data collection and analysis techniques.[199] Consistent with the proposal, the rate-based MR provides flexibility to select one or more applied EM&V methods. This MR includes three key requirements pertaining to how such methods must be applied.

First, the applied EM&V method(s) specified in an EM&V plan for an eligible EE resource must fall into one or more of the broad categories of prevailing EM&V approaches, as defined in best-practice protocols or technical guidelines. The three types of acceptable EM&V approaches allowed in this rate-based MR are

participating in an EE program and a group of facilities not participating in the EE program.

[199] In response, several commenters observed that EM&V approaches involving the automated analysis of large quantities of real-time interval billing or other electric system data, if applied in an appropriate manner, are consistent with industry best-practice methods and are therefore a robust and credible form of quantification. For consideration in an EM&V plan under this MR, EE providers using an automated EM&V approach would need to specify that such an approach is consistent with one or more of the three categories of EM&V methods described below, and meets the other applicable requirements in this section.

direct measurement and verification applied to individual EE projects or measures, the use of deemed savings values or formulas for specified EE projects or measures, and the use of comparison group approaches.[200]

Second, the applied EM&V method(s) in an EM&V plan must be appropriate to the unique characteristics of the EE project or measure(s) as defined in industry-standard protocols or technical guidelines.

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[200] If an EM&V plan specifies the use of a deemed savings approach, several additional requirements apply: (a) The EM&V plan must document why the use of each deemed savings value and formula is appropriate for each EE project or EE measure addressed in the EM&V plan; (b) The deemed savings values and formulas must be documented in a freely available database or spreadsheet (which may be known as a technical resource manual (TRM)) that is accessible on a public Web site, specifies the conditions for which each deemed savings value or formula may be applied, and specifies the source of each deemed savings value or formula; (c) Deemed savings values or formulas must be applied in a manner that quantifies electricity savings relative to the appropriate CPB for each EE project or EE measure, and for an EE project must also be applied in a manner that accounts for the interactions between individual EE measures that comprise the EE project; and (d) An EM&V plan must specify a process for reviewing the deemed savings values and formulas at least every three years, updating them as necessary to reflect more recent and/or accurate data, and applying them to all EE projects or EE measures addressed in an EM&V plan that are installed or begin operating after such an update occurs.

Third, the applied EM&V method(s) in an EM&V plan must include a methodology for adjusting electricity usage values to account for the effects of independent variables (weather, occupancy, production rates, etc.) that can affect energy usage and the associated energy savings values, and must explain how the quantified value of electricity savings will be adjusted to account for the effects of such independent variables for the average conditions of the independent variables over the EUL[201] of the EE project or EE measure in the EM&V plan.

(4) EM&V Requirements Related to Interactive Effects.

The EPA's proposed MR required that EM&V plans specify how "double counting" will be avoided through the use of tracking and accounting procedures to ensure that the same MWh of electricity savings is not claimed more than one time. The types of potential double counting scenarios were listed in the proposed MR. Based on public comment received, this rate-based MR includes similar provisions for addressing such double counting scenarios. However, in an effort to clarify how EE providers can implement such provisions, this rate-based MR

[201] EUL is a conservatively-specified estimate of the average duration of time over which EE savings from an EE project or an EE measure can reasonably be expected to occur.

defines double counting as a form of “interactive effects,” which may occur among EE projects and/or EE measures and which may affect the value of quantified electricity savings.

This MR identifies three types of interactive effects that must be addressed in an EM&V plan. The first is “other-system effects,” in which an EE measure designed to reduce the electricity use of one system also affects the electricity use of another system (*e.g.*, a lighting measure that also reduces cooling loads and increases heating loads). The second is “multi-measure effects,” in which more than one EE measure is installed in the same facility at the same time, affecting the same energy-using system(s). The combined effect of the EE measures on electricty savings is different (usually less) than the sum of individually quantified electricity savings for each measure by itself (*e.g.*, joint installation of building shell improvements and cooling system upgrades). The third is “EE program overlap,” in which a particular EE project or EE measure is influenced or encouraged by more than one EE program, and the electricity savings resulting from that project or measure might improperly be counted partly or wholly by more than one program if the program overlap is not addressed. This MR specifies that electricity savings from a single EE project or EE measure may be apportioned to more than one EE program (for example, if that project or measure is jointly funded), but the total savings claimed for that EE measure across all programs must not exceed the actual measured savings (*e.g.*, where an EE program focused on changing consumer behavior results in greater participation in existing EE rebate programs and the same electricity savings for certain projects or measures are potentially attributed to both programs).

(5) EM&V Requirements Related to Independent Variables that Affect Electricity Usage.

The EPA proposed that EM&V plans must specify how major changes in independent variables that affect electricity usage and the value of quantified electricity savings (but that are not directly related to the EE project or EE measure, such as weather, building occupancy, and production levels) must be accounted for. The EPA received public comments confirming that such "normalization" of energy usage is a routine and fundamental aspect of quantifying energy savings. As a result, this MR specifies that an applied EM&V method must describe how electricity usage data will be adjusted to account for the effects of independent variables, where appropriate. Applied EM&V methods must additionally ensure that this adjustment utilizes the average conditions of independent variables over the effective useful life (EUL) of the EE project or EE measure.[202]

(6) EM&V Requirements Related to Verification.

Consistent with provisions in the proposed MR and public comments received by the EPA, this rate-based MR includes a requirement for each EM&V plan to document the best-practice approaches that will be used to verify electricity savings from the EE resource addressed in the EM&V plan.[203] This includes the requirement to verify that the EE resource is installed and operating, recognizing that the applicable best-practice approaches vary by the type of EE project or EE measure.

For an EE program consisting of the installation of multiple EE projects or EE measures at different locations, the EM&V plan must specify the process that will be used to verify the quantity of each type of EE project or EE measure that is installed and operating during the period of time for which the

[202] MR provisions addressing the effective useful life (EUL) of EE projects and EE measures is discussed in section V.E.3.e.(7).

[203] As used here, the term “verify” refers to confirmation that equipment was installed, rather than verification activities conducted by an accredited independent verifier.

EM&V plan applies. For EE projects that may become partially operational (for example, if a fraction of the component EE measures fails over time), the EM&V plan must specify the process that will be used to verify what portions of the EE project are installed and operational during the period of time for which the EM&V plan applies.

In the case of EE projects or EE measures intended to influence consumer behavior, the EM&V plan must specify the process that will be used to verify that the projects or measures continue to have the intended effect on consumer behavior during the period of time for which the EM&V plan applies.

Additionally, each EM&V plan must specify the best-practice processes and techniques will be used to conduct quality assurance and quality control of all data used to quantify electricity savings.

(7) Effective Useful Life (EUL) of EE Projects and EE Measures.

An EUL is an estimate of the duration of electricity savings of individual EE projects and EE measures, in years. The proposed MR specified that an EM&V plan must include EUL values for individual EE project and EE measures, as determined using best-practice procedures (*e.g.*, annual verification assessments, persistence studies, deemed estimates of an EUL, or a combination of all three). In response, commenters noted that the proposal lacked details about the appropriate values for such EULs and how such values could be determined in practice. Therefore, for the rate-based MR, the EPA is establishing the specific requirement that each EM&V plan must indicate whether a pre-specified EUL[204] or an annually verified EUL will be applied for each EE project and EE measure addressed in the EM&V plan, and include a demonstration of why that EUL appraoch is appropriate for the specific EE project or EE measure addressed in the EM&V plan.

If an annually verified EUL is applied, an EM&V plan must specify that the quantity of installed EE measures still in place and operating will be determined each year, via empirical

[204] Pre-specified EULs for EE equipment installation or operational and behavioral improvements must be established based on: (a) a recent applicable persistence study, conducted according to industry best practices and meeting statistical accuracy criteria, (b) an applicable EUL value documented in a freely available database or spreadsheet that meets the applicable requirements for determining a deemed savings value or formula, discussed above, and/or (c) an independent third-party laboratory lifetime testing protocol. If none of these information sources is available for establishing a pre-specified EUL, EE providers must use the annually verified EUL approach.

data collection, for which electricity savings are claimed. With an annually verified EUL, the explicit determination of a pre-specified EUL in an EM&V plan is not required. However, the EM&V plan must include a methodology for empirical data collection to be used to determine the number of EE projects and EE measures that remain installed and operating at the end of each preceeding reporting period.

The EPA believes that the pre-specified EUL option will typically be simpler to implement than the annually verified EUL option and is therefore likely to be selected in most cases. However, in cases where it is not possible to pre-specify an EUL based on the requirements above, or where annual EM&V methods are already being applied for other purposes, such as a performance contract implemented by a private energy service company, EE providers may prefer to use annual verification of EULs. Annual verification of EULs also may be preferred if an EE provider believes the EE measure life will exceed the applicable pre-specified EUL.

(8) Measurement accuracy.

Measurement accuracy refers to the relationship between the true value of energy savings and an estimate of the value. The proposed MR required that EM&V plans specify how the accuracy of quantified MWh savings values would be assessed, including the rigor of the methods used to control the types of error[205] inherent to the applied EM&V methods. As part of this accuracy requirement, it was proposed that the quantified savings values have at least a 90 percent confidence interval whose end points are no more than +/-10 percent of the estimate. Commenters generally agreed with these requirements but questioned whether the EPA intended for the accuracy measurements to apply to the total savings value or each individual source of potential bias and error.

For this rate-based MR, the EPA is retaining the requirement that an EM&V plan must specify how the accuracy of electricity savings will be assessed in the EM&V plan. Each EM&V plan must specify how measurement error will be controlled, as well as how the quantifiable random error will be quantified. The quantifiable statistical errors that must be considered include both sampling error and modeling or estimation error. For each reporting period, the total quantified electricity savings values must have a 90 percent confidence interval with

[205] This includes systematic error (also referred to as bias) that causes savings values to be consistently either overstated or understated, and random error that occurs by chance.

end points that differ from the quantified value by no more than +/-10 percent of that value. The difference between the end points and the estimate, as a percent of the estimate, is referred to as the relative precision. Thus, the requirement is for no more than 10 percent relative precision at 90 percent confidence. This requirement for statistical accuracy applies to the combined effect of all measurable sources of statistical uncertainty across the EE projects or EE measures addressed in an EM&V plan. It is not necessary to calculate an explicit 90 percent confidence interval for the total quantified electricity savings, as long as it can be shown using best-practice statistical methods that the confidence interval endpoints are each no more than 10 percent from the estimate.

(9) Calculation of Avoided Electricity Transmission and Distribution (T&D) Losses.

The proposed MR specified that quantified electricity savings from demand-side EE may be adjusted by using a T&D loss factor,[206] and that if such a factor is applied, it must be the

[206] T&D losses are the difference between the electricity generation required to serve a customer's load (measured at the EGU bus bar) and the customer's actual electricity usage (measured at the customer meter).

smaller of 6 percent of the calculated statewide annual average T&D loss rate (expressed as a percentage) calculated using the most recent data published by the U.S. EIA State Electricity Profile.

For the rate-based MR, T&D losses may likewise be included in the quantification of electricity savings for a demand-side EE resource. The method and rationale for making this adjustment is described in section V.E.3.f below.

f. Calculation of Avoided Electricity Transmission and Distribution (T&D) Losses.

The proposed MR indicated that quantified electricity savings may be adjusted by using a T&D loss factor for the purpose of ERC issuance. The final MR also allows for the quantification of avoided T&D losses for RE and non-affected CHP resources that are sited and interconnected on the retail-consumer side of the utility meter, or for electricity savings from demand-side EE measures, programs or projects. EPA received comment on the proposed approach for quantifying T&D losses for the purpose of ERC issuance. In response to these comments, the final MR establishes a common and shared methodoolgy for determining the appropriate T&D loss factor to be applied to eligible generation of an eligible behind the retail-consumer utilty meter resource or electricity savings from demand-side EE measure, program or project. The T&D loss factor methodology relies on publically available EIA-861 data, providing for the T&D loss factor to be based on local utility average, or in the absence of local utility data, a state average loss factor may be calculated. EM&V plans must specify the methodology and T&D loss factor used. For a retail-consumer sited RE and non-affected CHP resources the EM&V plan must specify the methodology for determining the proportion of generation used to meet coincident retail-consumer load. Generation that is delivered to the utlity side of the retail-consumer utility meter, or any electricity used by the generator in the generation of electricty, or electricity used to meet non-consumer loads, such as station service, auxilliary load and parasitic load is not eligible to be included in the quantification calculation for avoided T&D losses for the purpose of ERC issuance.

4. Independent Verification

As discussed in section V.E.2.b, any eligibility application and M&V report for an eligible resource must be accompanied by a verification report from an independent verifier. This MR includes provisions for the accreditation of independent verifiers by the state and the required conduct of independent verifiers. Provisions of this MR align with the requirements for independent verification established in the CPP for state plans.[207] The provisions specify the requirements and process for state accreditation of independent verifiers, including a detailed description of what constitutes independence. The provisions also specify the procedures that independent verifiers must follow in the course of the provision of verification services to avoid conflict of interest (COI), as well as the process for the revocation of accreditation status by a state in instances where a verifier fails to meet applicable MR requirements.

Provisions in this MR addressing independent verifiers are consistent with those proposed, although they contain some technical revisions. The remainder of this section describes these requirements for independent verifiers specified in this MR. These MR provisions provide the practical requirements for

[207] CPP requirements for independent verifiers are specified at sections 60.5805(i) and 60.5880 (definition of independent verifier), and are discussed in the CPP preamble at section VIII.K.2.b, 80 FR 64,906-907.

accreditation of independent verifiers and independent verifier conduct necessary to meet the structural requirements for independent verifiers established in the CPP.

a. <u>Verifier Accreditation Requirements.</u>

The rate-based MR stipulates that an independent verifier must have the necessary technical qualifications to provide verification services for the subject in question, as well as fulfill certain codes of conduct in providing verification services. Under this MR, only verifiers approved or accredited by a state may provide verification services related to ERC issuance pursuant to a state plan.[208] In addition, verifiers must have sufficient knowledge of the rate-based emission trading program MR, technical expertise, and knowledge of auditing, accounting, and information management practices, in order to perform verifcation services. This MR indicates that a state may recognize, in part, accreditation by an outside organization

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[208] In this section, the term “verifier” is used interchangeably to refer to both a “verification body” (<u>i.e</u>., a verification company or organization) and a “verifier,” which is an individual that is a principal or employee of a verification body.

where such outside accreditation demonstrates that MR requirements are met.[209]

In order to provide verification services to an eligible resource, an accredited verifier must demonstrate that it is independent. This MR includes provisions that stipulate that accredited independent verifiers may not provide verification services for any eligible resource for which they have a financial, management, or other interest.[210] Such relationships constitute a conflict of interest (COI). This MR also indicates that COI situations may also arise as a result of personal relationships among individuals representing an eligible resource and an accredited verifier. It also stiplulates that a verification report will not be accepted as part of an eligibility application or M&V report where the accredited verification body or any individual verifier has a COI with regard to the eligible resource that is the subject of the eligibility application or M&V report.

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[209] An illustrative example is American National Standards Institute (ANSI) accreditation under ISO 14065:2013 for GHG validation and verification bodies. More information is available at https://www.ansica.org/wwwversion2/outside/GHGgeneral.asp.

[210] This MR sets forth the circumstances consituting COI at 62.16475.

Under this MR, accredited verification bodies must have management protocols in place to identify and remedy any COI prior to provision of verification services to an eligible resource.

b. Verifier Accreditation Process.

This MR specifies the process for verifier accreditation. A prospective verifier must submit an application for verification to the state, in a form prescribed by the state. In the application, a prospective verifier must demonstrate that it meets the requirements for an accredited verifier, which are described above in subsection 4.a. In addition, an application for accreditation submitted by a prospective verifier must describe or demonstrate the following:

- The independent verifiers that will provide verification services, including lead verifiers, key personnel, and any contractors, or subcontractors (collectively, the accredited independent verification team),[211]

[211] Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the state may provide a verification report.

- The eligible resource categories for which the verifier is seeking accreditation,[212]
- Documentation that the verifier is not debarred, suspended, or proposed for debarment pursuant to federal government regulations,[213] and
- Documentation that the verifier holds, and will maintain, professional liability insurance for its direct employees and any other parties that it employs.[214]

c. Ongoing Verifier Conduct Requirements.

Prior to engaging in verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource for which it is providing verification services, and it must disclose to the state all necessary

[212] An accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

[213] Pursuant to the federal Government-wide Debarment and Suspension regulations, 40 CFR part 32, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

[214] A prospective verifier must document that it holds and will continue to maintain, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either Standard & Poor’s or Moody’s, specifically, AAA, AA, A or BBB for Standard & Poor’s, and Aaa, Aa, A, or Baa for Moody’s.

information for it to asess whether a potential COI exists. Independent verifiers may not provide verification services for an eligible resource prior to approval by the state.

This MR specifies that failure of an accredited verifier to identify and adequately address any COI prior to provision of verification services is grounds for revocation of accreditation. In addition, accreditation may be revoked in instances where an independent verifier is no longer qualified to provide verification services, for negligence in the course of providing verification services, or intentional misrepresentation of data in a verification report.

This MR also includes provisions indicating that a state may reject a verification report if the state determines that the verifier has a COI, as defined in this MR. In such a case, the eligibility application or M&V report that the verification report accompanies is deemed incomplete, and the submittal would not be reviewed by the state.

F. Emission Rate Credit Trading, Transfers, and Banking

1. Emission Rate Credit Trading and Transfers

The rate- and mass-based MRs, as explained in section III.D of this preamble, include provisions that facilitate the development of a state plan that is ready for interstate trading. The proposal signaled that the MRs would facilitate the linking of state trading programs and thus provide for interstate trading. Commenters conveyed broad support for this approach. In particular, they favored finalization of MR provisions that could be submitted as part of a ready-for-interstate-trading state plan.

The CPP requires that rate-based ready-for-interstate-trading state plans apply the EPA interim step CO_2 emission performance rates or the EPA CO_2 emission performance rates established in the CPP as emission standards and allow in-state affected EGUs to use ERCs issued by other states with EPA-approved trading-ready state plans that use the same designated tracking system and emission standards. In order to facilitate the development of state plans that are ready for interstate trading, rate-based MR provisions apply subcategory-specific EPA interim step CO_2 emission performance rates and final period CO_2 emission performance rates established in the CPP as emission standards for affected EGUs.[215] In addition, the rate-based MR

[215] The CPP also allows states to implement a multi-state rate-based emission trading program that uses a weighted average of individual state rate-based goals. However, such an approach would need to be implemented through a multi-state plan. *See* 40 CFR section 60.5750.

includes provisions specifying that ERCs issued by other states with an approved ready-for-interstate-trading state plan that use the ERC-TCS (or an interoperable tracking system) and apply the same emission standards as those in this MR can be used by in-state EGUs for compliance. Further, the rate-based MR specifies the ERC-TCS as the state's ERC tracking system. Designation of the ERC-TCS facilitates interstate trading because states that adopt the rate-based MR would default to designation of the same tracking system.[216] While ERC trading can occur among affected EGUs and eligible resources issued ERCs by states that adopt this MR, the CPP prohibits those affected EGUs and eligible resources from trading with affected EGUs or eligible resources issued ERCs by a rate-based state that uses emission standards different from those in this MR and with market participants in a mass-based trading program.[217]

[216] States that modify the rate-based MR or develop a state plan from scratch also can designate the ERC-TCS. Section III.E above explains that while the rate- and mass-based MRs are designed for ready-for-interstate-trading state plans, they may be useful to other types of state plans.

[217] Trading also can occur among market participants issued ERCs by states that adopt this MR and those issued ERCs by state that do not adopt this MR but use the ERC-TCS, apply the same emission standards, and meet other requirements for a compatible ready-for-interstate-trading state plan.

To effectuate ERC trading and the transfer of ERCs between accounts, this MR includes provisions that specify the process for transferring ERCs from one account to another. ERCs may be transferred by submitting a transfer form providing, in a format prescribed by the tracking system operator, the account numbers of the accounts involved; the serial numbers of the ERCs involved; and the name and signature of the transferring designated representative or authorized account representative (or alternate representative).[218] If a transfer form containing all the required information is submitted to the tracking system operator and the transferor account includes the ERCs identified in the form, the tracking system operator will record the transfer by moving the ERCs from the transferor's account to the transferee's account within five business days of the receipt of the transfer form.[219]

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[218] While MR provisions specify the use of a form to execute an allowance transfer, these provisions are designed to be executed in an electronic tracking system, including the use of an electronic signature.

[219] Under current EPA-administered trading programs, a participant may submit an allowance transfer request to the EPA using a paper form. In practice more than 95 percent of all transfers in current EPA-administered programs are submitted

2. Emission Rate Credit Banking

As in the proposal, the rate-based MR allows unlimited banking of ERCs within the interim plan performance period and final period, as well as from the interim plan performance period to the final period. This means an affected EGU that holds more ERCs than needed to achieve its emission standard for a particular compliance period may save (*i.e.*, bank) those ERCs for use in a compliance demonstration for a future compliance period.[220] An ERC will not expire after any duration of time.

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electronically by account representatives and recorded in real time in the EPA-administered ATCS. While the rate-based MR provides up to five days to record a submitted allowance transfer, the EPA anticipates ERC transfer submissions through the ERC-TCS will use a process similar to those in current EPA-administered trading programs, which allows account representatives to submit allowance transfer requests through an electronic tracking system, allowing the transfers to be recorded in real time.

[220] Under the rate-based MR, each ERC is assigned a vintage. For an ERC, “vintage” refers to the calendar year in which the MWh on which issuance of the ERC is based occurred. For example, if an ERC is issued for MWh electricity savings that occurred in 2022, the ERC would be assigned a 2022 vintage. (For an allowance used in a mass-based program, “vintage” refers to the emission budget year of the allowance.) Using a compliance period of 2030-2031 as an example (which aligns with the first final plan performance period), an affected EGU could use ERCs that have a vintage of 2030, 2031, or any prior year, to

Most commenters supported this overall approach to banking.

Consistent with the CPP,[221] ERC borrowing is prohibited under this MR. In practice, MR borrowing and banking provisions mean that the only ERCs an affected EGU can use to demonstrate compliance for the current period are those of a vintage during a current or prior compliance period.

G. Compliance Provisions

1. Compliance Demonstration

Rate-based MR provisions specify requirements for compliance demonstrations by affected EGUs. As finalized in the CPP, for an affected EGU subject to a rate-based emission standard to meet its compliance obligations, its adjusted CO_2 emission rate for the applicable compliance period must be at or below its emission standard.[222] An affected EGU's adjusted CO_2 emission rate represents its reported CO_2 emission rate combined with the number of ERCs deducted for compliance.

Consistent with the CPP and proposed rate-based MR, provisions of this MR specify that an EGU's reported CO_2 emission

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demonstrate compliance with its emission standard for the 2030-2031 compliance period.

[221] *See* 40 CFR 60.5790(c)(4).

[222] *See* 40 CFR 60.5790(c)(1).

rate for a compliance period reflects reported emissions and generation data for the compliance period. In particular, the reported CO_2 emission rate is calculated by summing the total measured CO_2 mass emissions, in units of pounds, for an affected EGU during a compliance period and then dividing it by the total net energy output, in units of MWh, for an affected EGU during the compliance period. This reported CO_2 emission rate is compared to the emission standard that the affected EGU is subject to during the corresponding compliance period. If the reported CO_2 emission rate for an affected EGU is no higher than its emission standard, the unit achieves its emission standard. If the reported CO_2 emission rate for an affected EGU exceeds its emission standard, ERCs are deducted from the affected EGU's compliance account in number sufficient to achieve an adjusted CO_2 emission rate equal to or below the emission standard. Section 62.16420 of this MR provides the following equation for determining whether an affected EGU is in compliance with its emission standard.

$$\text{Adjusted Emission Rate} = \frac{\text{Mass of CO2 emitted (lbs)}}{\text{MWh Generation} + \text{MWh ERCs} + \text{MWh GS} - \text{ERCs}}$$

To reiterate the example provided in section V.B.2 above, assume an affected steam generating unit with CO_2 emissions of 2 billion pounds, 1 million MWh of electric generation, and 333,334 ERCs in its compliance account. Applying these parameters yields the following:

$$1{,}500 \text{ lb CO2/MWh} = \frac{2{,}000{,}000{,}000 \text{ lb CO2}}{1{,}000{,}000 \text{ MWh} + 333{,}334 \text{ MWh ERCs} + 0 \text{ MWh GS} - \text{ERCs}}$$

The affected EGU achieves compliance if its adjusted CO_2 emission rate of 1,500 lb CO_2/MWh is at or below its emission standard.[223] Because only steam generating units and IGCC units can use GS-ERCs in a compliance demonstration, NGCC units will always have a zero value for “MWh GS-ERCs” in the above formula for calculating an adjusted emission rate.

The designated representative for an affected EGU must calculate the number of ERCs necessary to meet the affected EGU’s emission standard and transfer sufficient ERCs into the affected EGU’s compliance account by the ERC transfer deadline.

[223] Section VIII.K.1.a of the CPP preamble explains the general accounting approach for adjusting an affected EGU’s CO_2 emission rate.

To be usable for compliance, an ERC must be of a vintage from the current or a prior compliance period.

The number of ERCs that an affected EGU with a reported CO_2 emission rate in excess of its emission standard needs for compliance can be calculated using the following method.[224] Subtract the CO_2 stack emission rate of the affected EGU from the EGU's emission standard, and then divide this value by the EGU's emission standard. The resulting negative value represents how much the reported CO_2 emission rate of the affected EGU exceeds its emission standard. This negative value is weighted by multiplying it by the MWh electricity output from the affected EGU. The following formula generically expresses this calculation:

$$\text{ERCs} = \frac{(\text{EGU standard} - \text{EGU operating rate})}{\text{EGU standard}} * \text{ EGU generation}$$

[224] As explained in section V.C.2.a above, this method is also used to calculate the number of ERCs (but not GS-ERCs) an affected EGU may be issued for operating below its emission standard. A positive value represents the number of ERCs that may be issued to the affected EGU. A negative value, as explained here, represents the number of ERCs needed in a compliance demonstration.

As an example, assume a steam generating unit operating in the second interim compliance period subject to an emission standard of 1,500 lbs CO_2/MWh. The unit operates at 2,000 lbs CO_2/MWh and generates 1 million MWh over the compliance period. Inputing this information into the above formula would result in the following:

$$\text{ERCs} = \frac{\left(\frac{1{,}500\ \text{lbs/CO2}}{\text{MWh}} - \frac{2{,}000\ \text{lbs/CO2}}{\text{MWh}}\right)}{\frac{1{,}500\ \text{lbs/CO2}}{\text{MWh}}} * \ 1{,}000{,}000\ \text{MWh}$$

Solving this equation shows that in order to achieve the emission standard, the steam generating unit would need to surrender 333,334 ERCs (the calculated result is rounded to the nearest higher integer). This quantity of ERCs represents the quantity of MWh that need to be added to the denominator of the steam generating unit's reported CO_2 emission rate to achieve compliance with its emission standard. Total emissions (2 billion pounds of CO_2), divided by total generation (1,000,000 MWh + 333,334 ERCs = 1,333,334 MWh) equals the emission rate for compliance (1,500 lb/MWh).

Section V.B.1 above explains the compliance periods and emission standards established under the rate-based MR. In accordance with the CPP, states that adopt this MR must identify in a report to the EPA by July 1 following each reporting period (*i.e.* each interim step period and final reporting period) certain data and whether affected EGUs are in compliance with their emission standards, among other information.[225] The rate-based MR contains an ERC transfer deadline of the June 1st that immediately follows the end of each compliance period.[226] For example, the ERC transfer deadline for the first compliance period (2022 through 2024) is June 1, 2025. The ERC transfer deadline is the date by which each affected EGU must transfer into its compliance account enough ERCs to achieve its emission standard for the compliance period.

Under this MR, each affected EGU must submit to the state by June 15 following each compliance period a report that includes information about CO_2 emissions, generation, operating hours, and ERCs deducted for the prior compliance period.[227] The June 1 ERC transfer deadline and the June 15 affected EGU

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[225] *See* 40 CFR 60.5870.

[226] A compliance period refers to a discrete period of time for an affected EGU to comply with an emission standard. *See* 40 CFR 60.5880. A reporting period refers to a period of time for which state plan performance is reported. *See e.g.,* 40 CFR 60.5870(b)(1). Under this MR, reporting periods and compliance periods are identical.

[227] See section V.H below for further discussion of these reports.

reporting deadline provide the state time to determine, among other things, whether each affected EGU in its state is in compliance with its emission standard and to report this to EPA by the July 1 deadline. A state may wish to modify this MR and adopt an earlier or later ERC transfer deadline and affected EGU reporting deadline, depending upon the time it needs to assess compliance by each affected EGU and then develop and timely submit the July 1 report to the EPA.

The rate-based MR specifies that the tracking system operator will deduct ERCs used to meet an emission standard from the compliance account of the applicable affected EGU and moved to a retirement account, which ensures they cannot be used again. The designated representative for a compliance account has the option to identify specific ERCs to be deducted, but, in the absence of such identification or in the case of a partial identification, the tracking system operator will deduct ERCs from a compliance account on a first-in, first-out basis.[228]

[228] ERCs that were first deposited in the compliance account through issuance to an affected EGU will be the first to be deducted from the account by a state, in the order of recordation. Deduction of these issued ERCs will be followed by deduction of any ERCs transferred to the compliance account, in the order of recordation.

Deducting ERCs of different vintages may have tax and accounting implications for the owner or operator of an affected EGU, so having a default deduction method provides the owner or operator with certainty regarding which ERCs will be deducted for compliance.

This MR also contains provisions detailing monitoring and reporting requirements for CO_2 emissions and net energy output, which are necessary for compliance demonstrations and compliance assessments. These provisions are explained in section V.H. below.

2. Compliance Assessment and Penalty Provisions

As explained above, compliance is evaluated by comparing an affected EGU’s adjusted CO_2 emission rate to its emission standard. To address circumstances where an affected EGU’s adjusted CO_2 emission rate exceeds its emission standard, the EPA proposed rate-based MR provisions that would require the surrender of two ERCs for every ERC an affected EGU needed to achieves its emission standard but failed to hold in its compliance account by the ERC transfer deadline.

A number of commenters recommended eliminating the automatic two-for-one ERC deduction requirement for exceeding its emission standard and instead advocated for reliance on the existing enforcement provisions under section 113 of the CAA, which approach each violation on a case-by-case basis. These commenters claimed this automatic deduction requirement for exceeding the emission standard was excessive. Other commenters suggested increasing the amount of the automatic ERC deduction to four ERCs for every one the EGU failed to hold in its compliance account, in conjunction with any civil penalties and other relief in accordance with sections 113 or 304 of the CAA and/or the approved state plan. These commenters argued that a two-for-one automatic deduction may not be sufficient to deter non-compliance under at least some ERC market scenarios. The EPA received some comments acknowledging and supporting its position regarding long-standing CAA section 113 and 304 enforcement authorities.

The EPA is finalizing rate-based MR compliance assessment and penalty provisions as proposed because they constitute a reasonable approach that will help to ensure compliance. The rate-based MR requires the surrender of two ERCs for every ERC that the owners and operators of an affected EGU fail to hold in a compliance account by the ERC transfer deadline in order to comply with the affected EGU’s emission standard. This obligation is in addition to the ongoing requirement that affected EGUs meet emission standards for the compliance periods in which they operate. The ERCs owed under this requirement will be deducted from the affected EGU’s compliance account as soon as they are available in this account. The deduction of two ERCs for each ERC shortfall is in addition to any other recourse provided in sections 113(a)–(h) or section 304 of the CAA. This requirement to surrender two times the number of ERCs needed to make up the shortfall for a compliance period is an ongoing obligation that lasts until compliance is achieved.

The EPA maintains that it is important to include a requirement for an automatic deduction of ERCs in a total amount that exceeds the amount of ERCs the EGU failed to hold in order to provide a strong financial disincentive for non-compliance. This automatic requirement for the deduction of two ERCs for every one ERC the EGU failed to hold provides a strong incentive for compliance with the emission standard by ensuring that non-compliance is a significantly more expensive option than compliance.[229] Such automatic deductions have been successfully

[229] The automatic deduction requirement cannot be avoided, regardless of any explanation for the failure to meet the emission standard provided by the owners or operators of the affected EGU.

used in prior EPA-administered programs, including CAIR and CSAPR, as well as state programs.

3. Use of Improperly Issued ERCs in a Compliance Demonstration

The rate-based MR requirements for the issuance of ERCs, such as the state review of eligibility applications and M&V reports and the recording of ERC issuance through the ERC-TCS, provide safeguards to ensure the integrity of ERCs. Nevertheless, there may be circumstances where ERCs are issued that do not, in fact, represent eligible MWh as required in the CPP. Therefore, consistent with the CPP (40 CFR 60.5790(c)(3)), this MR provides that an ERC can be used by an affected EGU for a compliance demonstration only if it represents the one MWh of actual electricity generation or savings that it purports to represent and otherwise meets applicable requirements. As described in the CPP and proposed rate-based MR, it is critical to the integrity of an ERC, and the overall integrity of a rate-based emission trading program, that each ERC represents the actual MWh of electricity generated or saved that it purports to represent.

The proposed rate-based MR specified that, in the event that an affected EGU surrenders facially valid ERCs to meet its emission standard, but those ERCs are found to be invalid, the affected EGU may be subject to federal enforcement, pursuant to sections 113(a) – (h), 42 U.S.C. 7413(a)-(h), and section 304 of the Clean Air Act, 42 U.S.C. 7604. In addition, the United States, states, and other persons have the ability to enforce violations and secure corrective actions. The EPA received several comments in favor and in opposition to this approach. Those opposed suggested that an affected EGU that purchased and used an invalid ERC for compliance should not be liable for its use, but rather, the source of the invalid ERCs should be liable. Conversely, those in favor noted that the proposed approach sets forth clear and predictable lines of responsibility and a framework within which sellers and purchasers of ERCs can contract between themselves to further allocate responsibility. The EPA concurs that existing contract law provides a framework within which sellers and purchasers of ERCs can allocate responsibility between themselves, such that each party to the contract is able to protect its interests. Thus, after consideration of the comments, the EPA has decided to finalize the proposed approach in order to protect the environmental integrity of a rate-based plan in the event that ERCs are improperly issued and to further incentivize compliance by affected EGUs.

H. Monitoring, Reporting, and Recordkeeping Requirements for Affected Electric Generating Units

Monitoring, reporting, and recordkeeping requirements in this MR are consistent with those established in the CPP and substantively the same as those proposed. This MR includes requirements to use data that are already being monitored and reported under other EPA programs, in an effort by the EPA to promote efficient and timely reporting for affected EGUs.

In the rate-based MR, affected EGUs must monitor and report their CO_2 emissions and net energy output generation data for use in determining compliance with their subcategory specific emission standards. The emissions data must be monitored according to the applicable 40 CFR part 75 provisions and reported to the EPA using ECMPS. Monitoring and reporting of net energy output is consistent with the requirements established in the CPP. Under this MR, hourly emissions and generation data must be reported quarterly, with each quarterly report due 30 days after the last day in the quarter (*i.e.*, the 30th of April, July, October, and January). The reporting must be in accordance with 40 CFR 75.60. Commenters were supportive of the requirement to monitor and report CO_2 emissions in accordance with 40 CFR part 75 and thought it would provide consistent reporting and minimize costs.

Many affected EGUs in states that adopt the rate-based MR generally will have no changes to their CO_2 monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates there are fewer than 50 affected EGUs covered by the CPP that are not subject to the Acid Rain Program (ARP)[230] and thus will have to purchase and install additional continuous emissions monitoring systems (CEMS) and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this MR.[231] Several of the affected EGUs not subject to the ARP are subject to the MATS program and therefore already will have installed stack flow rate and/or CO_2 monitors in order to comply with the MATS rule, which are also necessary to meet rate-based MR requirements. The CEMS used to comply and report data for MATS may be used to generate and report CO_2 emissions data, consistent with the requirements in this MR, without having to install

[230] Reporting of CO_2 emissions is required for EGUs subject to the ARP.

[231] Approximately ten of these affected EGUs are coal-fired with the remainder being gas- and oil-fired units that will qualify for an excepted monitoring methodology.

duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate CO_2 mass emissions or a CO_2 emission rate under this MR.

The Regional Greenhouse Gas Initiative (RGGI), ARP, MATS and this MR all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this MR. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 ensures cost-efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs. The majority of the affected EGUs covered by this MR are already affected by the ARP and/or RGGI and will have minimal additional monitoring and reporting requirements.

Consistent with the requirement in the CPP, this MR requires the monitoring of net energy output through the use of a monitoring system that meets the ANSI Standard No. C12.20. The reporting of the net energy output data is through ECMPS, along with monitored CO_2 emissions data.

The rate-based MR requires the use of only those data that are valid and does not allow for any substitute data to be used when calculating CO_2 emissions and net energy output for an affected EGU. This is to ensure the CO_2 emission rates, which are calculated from the monitored data, reflect the actual representative emission rates of affected EGUs and do not incorporate any data where there is either invalid or missing emissions data and/or generation data.

In addition to reporting hourly CO_2 emission data and net energy output data through ECMPS, this MR, consistent with the CPP, requires that affected EGUs submit to the state through the ERC-TCS a report that includes information about CO_2 emissions, electricity generation, operating hours, and any ERCs used for compliance, per 40 CFR 60.5860(d).[232] Under this MR, this report must be submitted to the state by June 15 following each compliance period. A state, however, can modify this date to

[232] 40 CFR 62.16555(a)(2).

allow more or less time after submittal of this affected EGU report for the state to develop and submit the state report to the EPA by July 1 following each reporting period, as required by 40 CFR 60.5870.[233]

In the proposal, the EPA took comment on MR requirements for monitoring and reporting of CO_2 mass emissions and net energy output for the year before the initial compliance period begins (*i.e.*, to commence January 1, 2021). The purpose for this was to allow time for affected EGUs to ensure that approved monitoring systems are in place and working properly prior to the beginning of the first compliance period. This MR includes this provision for early reporting. In this MR, only monitoring and reporting is required beginning in 2021 — compliance with an enforceable emission standard would only commence on the compliance period schedule that is detailed in section III.B of this preamble.

Consistent with the proposal, the recordkeeping requirements in this MR reflect the recordkeeping requirements

[233] A compliance period refers to a discrete period of time for an affected EGU to comply with an emission standard. 40 CFR 60.5880. A reporting period refers to a period of time for which state plan performance is reported. *See e.g.,* 40 CFR 60.5870(b)(1). Under this MR, reporting periods and compliance periods are identical.

in the CPP. This includes the requirement for the owners and operators of affected EGUs to keep records of data used for demonstrating compliance for five years. For the first two years, those records must be kept onsite at an affected EGU. In addition, all of the recordkeeping requirements that apply under 40 CFR part 75 would apply under the MR for the data that are submitted through ECMPS.

VI. Public Access to Program Data and Market Oversight

The MRs establish the specific data elements and information that will be maintained in the EPA-administered tracking system or state ERC document management and approval system (per the rate-based MR) under a state plan that adopts the mass- or rate-based MR. The MRs also specify the information that will be made publicly available. These provisions include data that must be made publicly available pursuant to the CPP, as well as information not required to be made public under the CPP, but which the EPA believes will facilitate program transparency and market functioning.

All data maintained in an EPA-administered tracking system or state ERC document management and approval system will facilitate market oversight by states. Section VI.A below lists the data that is maintained in the ATCS, the ERC-TCS, or state

ERC document management and approval system in accordance with the final mass-based and rate-based MRs, respectively. Section VI.B below lists the data that must be made publicly accessible in accordance with the MRs. Section VI.C discusses market oversight and monitoring considerations for states and the role that tracking system data can play in facilitating market oversight and monitoring, in light of the data maintained in the tracking systems for mass-based and rate-based programs under the MRs.

A. Information Documented in Tracking Systems

The MRs specify the information that will be documented by the EPA-administered tracking systems and state ERC document management and approval systems, including the following:

- Account holder names and information
- Authorized account representative names and information[234]
- Information about qualifying eligible resources that may be issued ERCs (for rate-based program)
- Documentation of allowances or ERCs held in individual accounts

[234] This includes both designated representatives for compliance accounts and authorized account representatives for general accounts.

- Documentation of allowance or ERC transfers among accounts
- Documentation related to eligible resources (including eligibility applications, EM&V plans, monitoring and verification reports, and related independent verifier verification reports) (for rate-based program)
- Documentation of state approvals for eligible resources (for rate-based program)
- Documentation of ERC issuance to affected EGUs and eligible resources (for rate-based program)
- Documentation of allowance allocations (for mass-based programs)
- Documentation of allowance or ERC surrenders for demonstration of compliance by affected EGUs
- Compliance status of affected EGUs for a respective compliance period

All of the data and information that was included in the proposed MRs has been included in the MRs.

The EPA requested comment on whether allowance or ERC price information be collected through and maintained in the tracking systems for mass-based or rate-based MRs, as a component of possible market monitoring functions. *See* 80 FR 64977 (October 23, 2015). To be clear, market monitoring is not a CPP requirement for state plans. The EPA has decided not to include this requirement in the MRs. States, however, could include requirements for account holders to report the allowance or ERC price related to allowance or ERC transfers among accounts held by unaffiliated parties. For example, the RGGI participating states require price information to be reported, where applicable, at the time of an allowance transfer among accounts. This data is used for market oversight purposes by the independent market monitor for the RGGI participating states and is also made publicly available in aggregate form through tracking system public reports.[235]

In accordance with the MRs, most, but not all, of the data and information listed above is made publicly available through the tracking system in either raw or aggregated form, as described below.

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[235] *See*, for example, Annual Report on the Market for RGGI CO_2 Allowances: 2015, available at http://www.rggi.org/market/market_monitor. *See* RGGI CO_2 Allowance Tracking System (RGGI COATS) – Transaction Price Report. Public reports through the RGGI CO_2 Allowance Tracking System (RGGI COATS) are available at http://www.rggi.org/market/tracking/public-reporting.

B. Public Information Available in Tracking Systems

The MRs specify the data and information that the tracking systems for mass-based and rate-based programs must make available through public reports.[236] In accordance with the MRs, the following data, at a minimum, will be made available through public reports:

- Account holder names and information
- Authorized account representative names and information[237]
- Information about qualifying eligible resources that may be issued ERCs (for rate-based program)
- Documentation related to eligible resources (including eligibility applications, EM&V plans, monitoring and verification reports, and related independent verifier verification reports) (for rate-based program)
- Documentation of state approvals for eligible resources (for rate-based program)
- Documentation of ERC issuance to affected EGUs and eligible resources (for rate-based program)

[236] *See* final rate-based MR at 62.16515(h).
[237] This includes both designated representatives for compliance accounts and authorized account representatives for general accounts.

- Documentation of allowance allocations (for mass-based programs)
- Documentation of allowance or ERC surrenders and affected EGU demonstration of compliance with emission standards
- Compliance status of affected EGUs for a respective compliance period

There is certain information documented in the ATCS and ERC-TCS that the MRs do not specify will be made publicly available. However, this does not preclude a state that uses a MR from making this additional information publicly available at its discretion, notwithstanding the omission of this information in the list of data specified in the MRs. This includes data about allowance or ERC holdings in individual compliance and general accounts as well as allowance or ERC transfers among individual identified accounts.

Some commenters indicated that making such data available could create concerns related to market competitiveness and facilitate anti-competitive conduct by market participants. For example, providing public access to individual account holdings during the course of a compliance period could indicate to market participants whether a compliance entity is short or long with regard to allowance or ERC holdings in comparison to its reported CO_2 emissions or CO_2 emission rate, indicating the level of allowance or ERC demand among individual owners or operators of affected EGUs. Likewise, making individual allowance or ERC transfer data available to the public could provide market participants with insights into compliance and market procurement strategies employed by individual firms.

In reality, compliance entities could circumvent such holding and transaction reporting through the use of general accounts held by the trading arm of a company or through the use of third-party brokers. As a result, such reporting could actually increase the complexity of market oversight and monitoring if compliance entities generally attempt to shield themselves from allowance or ERC holdings and transaction reporting through the use of general accounts and brokers.

In response to these comments, the MRs do not indicate that such data will be made publicly available, although states remain free to make such information publicly available at their discretion, in either raw or aggregated form. The EPA notes that it provides public access to data about allowance holdings in individual accounts and allowance transfers among individual identified accounts for the emission trading programs that it administers, including the Acid Rain Program and Cross-state Air

Pollution Rule (CSAPR). Based on the operation of these programs, the agency has not seen indications that the provision of such information has adversely impacted market competitiveness or facilitated anti-competitive conduct by market participants. However, the agency also acknowledges that the circumstances for state-administered emission trading programs may differ from those that the EPA administers, which may warrant different approaches to provision of public data related to program operations.[238] As a result, the provisions in the MRs do not specify that such data will be made publicly available.

C. Market Oversight and Market Participation

1. Market Oversight

In the MRs proposal, the EPA sought comment on the provision of market oversight for both allowance and ERC markets. The EPA indicated that based on its experience in administering emission trading programs, it expected competitive markets to emerge for emission trading programs established

[238] For example, provision of public data on allowance holdings in individual identified accounts could present more of a concern about the potential for anti-competitive conduct in a program that distributes the majority of allowances through auction rather than free allocation.

through state plans, and that the potential for anti-competitive conduct and market manipulation was fairly low. However, the EPA also sought comment on potential design elements of a MR that could address any identified competitiveness or market power concerns. In the proposal, the EPA also indicated that it was evaluating options for providing oversight and monitoring of the allowance and ERC markets related to the emission trading programs established through state plans, which could include engaging with other federal and state agencies as appropriate, and potentially with third parties. The EPA also requested comment on appropriate market monitoring activities.

Many commenters advocated that the EPA provide market oversight and monitoring services to states, and asserted that it cannot be assumed that competitive markets will emerge that are free of manipulation or anti-competitive conduct. Some commenters also recommended that the EPA appoint an independent market monitor to provide market monitoring services to states.

The EPA intends to continue its evaluation of the potential for the agency to provide market oversight and monitoring services to states, as part of its overall assessment of implementation support for states. However, based on its initial assessment, the EPA believes that states are well positioned to conduct market oversight and monitoring of the primary and secondary allowance or ERC markets related to the emission trading programs they establish under state plans. States can tailor such oversight and monitoring to the specific aspects of their programs.[239] In the tracking system white paper, the EPA discusses data collection and access that could support potential market oversight by states and/or independent market monitors retained by states.

The EPA also notes that federal agencies such as the Commodity Futures Trading Commission (CFTC) and the Federal Energy Regulatory Commission (FERC) have authority to oversee related markets to monitor for potential market manipulation. This includes the authority to take enforcement action against market participants in the event of anti-competitive conduct in markets within their jurisdiction. The EPA intends to coordinate with its federal partner agencies in its continuing assessment of potential market oversight and monitoring considerations for

[239] For example, states that choose to auction allowances or are located in competitive wholesale electricity markets (*e.g.*, administered by an ISO or RTO) may find additional market monitoring services more useful than states with vertically integrated state-regulated electric utilities that choose to freely allocate allowances. *See e.g.* Potomac Economics, *Market Monitor Report for Auction 32*, June 3, 2016.

state plan emission trading program markets.

The EPA notes that the information that is required to be maintained in a tracking system under the MRs will support and facilitate market monitoring. See subsections VI.B and VI.C above for a description of the information that must be maintained in a tracking system under the MRs, as well as the information that the MRs specify will be made publicly available. In particular, tracking system data related to allowance or ERC holdings in individual accounts and allowance or ERC transfers among individual accounts is useful data for market monitoring. The MRs also require that a designated representative (for compliance accounts) or an authorized representative (for general accounts) report information on all of the parties that have an ownership interest in the allowances or ERCs held in an account, which may be useful in categorizing different market participants and monitoring market-related activities. To the extent that the EPA administers a tracking system for state programs, it intends to coordinate with states to facilitate monitoring of their programs through provision of access to tracking system data to entities responsible for market monitoring.

2. Limits on Market Participation

The EPA is finalizing its proposed approach placing no limits on who may participate in an emissions trading market under either of the MRs. A number of commenters recommended that the MRs limit market participation to entities that have an ownership interest in an affected EGU (*i.e.*, “compliance entities”). A number of commenters did not recommend barring non-compliance entities from participating in the allowance or ERC market, but advocated placing restrictions on their market participation. In particular, these commenters advocated that the MRs prohibit non-compliance entities from retiring allowances or ERCs, or holding these instruments for a period of more than three years. These commenters explained that retirement and/or indefinite holding of allowances or ERCs by non-compliance entities would effectively increase the stringency of state emission trading programs, with potentially adverse impacts. In contrast, a number of commenters strongly advocated placing no restrictions on the participation of non-compliance entities in allowance or ERC markets, arguing that their participation will increase market liquidity and facilitate better price discovery.

The EPA does not agree with the comments that would limit market participation to compliance entities, or limit the market participation of non-compliance entities. As a result, the EPA has not included such restrictions on the market participation of non-compliance entities in the MRs. The EPA’s experience is that participation by non-compliance entities, such as brokers, in allowance markets is important to ensuring a liquid market, and that the participation of a greater number of market participants enhances rather than threatens market competitiveness and promotes price discovery. In particular, a greater number of market participants reduces the potential for the exercise of market power. This could be a concern for some state emission trading programs, depending on the number of unaffiliated entities subject to the program. The benefits of open market participation have been borne out in the operation of EPA-administered emission trading programs, as well as the RGGI emission budget trading program and the trading program administered by California.[240] In addition, independent governmental entities have advised that open markets without

[240] *See*, Potomac Economics, *Annual Report on the Market for RGGI CO_2 Allowances: 2015*, available at http://www.rggi.org/market/market_monitor.

limits on participation increase market liquidity and price discovery, and actually reduce the potential for market manipulation and anti-competitive conduct.[241]

Further, the EPA notes that such prohibitions on market participation would be difficult for states to administer in practice, as it is often difficult to determine whether an entity is a compliance entity or a non-compliance entity. For example, some financial firms that primarily engage in allowance markets as liquidity providers also have ownership interests in regulated power plants and companies with regulated power plants often rely on trading subsidiaries to participate in allowance markets on their behalf.[242] As a result, in practice there are often "grey areas" when determining whether a company should be

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[241] *See e.g.,* Interagency Working Group for the Study on Oversight of Carbon Markets, *Report on the Oversight of Existing and Prospective Carbon Markets*, January 18, 2011; and Congressional Budget Office, *Evaluating Limits on Participation and Transactions in Markets for Emissions Allowances*, December 2010.

[242] These entities frequently participate in allowance markets through the use of general accounts and when relevant transfer allowances to individual compliance accounts prior to a compliance deadline.

considered a compliance or non-compliance entity.[243]

The EPA notes that all of the federal emissiontrading programs it administers pursuant to the CAA provide for non-compliance entities to participate in the allowance market, and non-compliance entities are also allowed to participate in the RGGI and California allowance markets.[244] While some non-compliance entities have participated in allowance markets with the purpose of purchasing allowances and then indefinitely holding or retiring them to provide additional environmental benefits, the number of allowances involved has been very small as a percentage of an allowance market. The vast majority of non-compliance entities participating in allowance markets, by volume, are liquidity providers, such as brokers and financial institutions. Therefore, in the agency's view, and based on its experience in the operation of other emission trading programs,

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[243] RGGI market monitor reports assess market participation by both compliance and non-compliance entities. However, these classifications are for market monitoring purposes, rather than placing restrictions on individual firms. More information is available at http://www.rggi.org/market/market_monitor.
[244] Under the RGGI and California programs, non-compliance entities may participate in both allowance auctions (the primary market where allowances are first distributed) and the secondary market (the market for allowances that have already been initially distributed – *i.e.*, trading).

the limitations on market participation requested by some commenters to be included in the MRs are not warranted as a means to prevent increased stringency and in fact may be counter-productive to the aims of market oversight and liquidity.

VII. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency has taken to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking, specifically those actions that have taken place post-proposal of the federal plan and MRs.

As we stated in the proposal for this rulemaking, climate change is an environmental justice (EJ) issue. Low-income communities and communities of color already overburdened by pollution are likely to be overburdened by, and less resilient to, the impacts of climate change. We continue to stress the importance of recognizing the unique burdens of climate change borne by low-income communities and communities of color, as well as We recognize that vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and by providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that could fall disproportionately on vulnerable communities. In addition, this rule will also reduce millions of tons of conventional air pollutants, which will further lead to better air quality and improved health in these same communities. In addition, this rule would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE, and these emission reductions include SO_2 and NO_x, which form ambient $PM_{2.5}$ and ozone, and HAP, such as mercury and hydrochloric acid. These reductions can lead to better air quality and improved health outcomes in these same communities. In the comment period for the CPP as well as for this rule-making, we heard from many commenters who recognize and welcome those benefits.

While the agency expects overall emission decreases as a result of this rulemaking, we continue to recognize that some EGUs may operate more frequently. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units, which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_x compared to higher-emitting steam units. The exact extent to which these MRs and the CPP influence a decrease overall emissions from the power sector is yet to be determined. This is because it is dependent on how a state implements its plan. We encourage states, as they develop their plans, to conduct assessments to consider these potential increases in emissions that may occur in low-income communities and communities of color.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in the development of this rulemaking. In this section, we discuss recommendations that EPA incorporated into this action so that communities are not disproportionatley impacted by the state plans.

A. Proximity Analysis

As stated in the proposal for this action, the EPA continues to be committed to ensuring that there is no disproportionate, adverse impact on vulnerable communities as a result of this proposed rulemaking. As such, we encourage the use of the proximity analysis provided in the CPP as a tool for identifying the socio-economic characteristics of areas in close proximity to affected EGUs.

The proximity analysis provides detailed socio-economic information on the communities located within a three-mile radius of each affected power plant in the U.S. Included in the analysis is information on the percentage of low-income and minority populations in proximity to facilities. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a three-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in a plant's air emissions may affect the air quality experienced by potentially vulnerable communities.

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

As stated in the Executive Order 12898 discussion located in section VIII.J of this preamble, The EPA believes that all communities will benefit from this proposed rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and the agency throughout the rulemaking process. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA has made it publicly available on its Clean Power Plan Communities Portal that will be linked to this rulemaking's Web site (http://www.epa.gov/cleanpowerplan). Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/. We also encourage states, as part of their state plan development, to do additional EJ analyses using local information.

B. Community Engagement in This Rulemaking Process

The EPA heard from vulnerable communities throughout the outreach process for the CPP that it is imperative for communities to have an understanding of how rulemakings that target climate change work. They expressed a desire to know how these rulemakings may benefit their communities and what the potential adverse impacts of the rules may be on their communities. We intend to provide communities with the information that they need to engage with the agency throughout the rule development process.

We received feedback from communities that public hearings, webinars, and in-person meetings are the most effective ways to engage with them and to provide them with the information they need to understand the rulemaking. In response to this feedback, multiple public hearings, webinars, and in-person trainings were conducted after publication of the proposed MRs.

Four public hearings were held on the proposal, each consisting of one panel over two days. A hearing was held in Pittsburgh, Pennsylvania, on November 12-13, 2015; in Denver, Colorado, on November 16-17, 2015; in Washington, DC, on November 18-19, 2015; and in Alanta, GA on November 19-20, 2015. These opportunities allowed the agency to hear concerns from community members, and to provide clarifications on the proposal.

We also held a national webinar for communities in December 2015 that provided an overiew of the propsed federal plan and model trading rules as well as the CEIP. This national webinar was followed by similar webinars in each EPA region (ten in total). Community members were given the opportunity to listen to a presentation and then ask clarifing questions. Our primary goal for the webinars was to provide a high level overview of the proposal to communities so they have an understanding of how the rulemaking may potentially affect their communities and to providethe contextual information they need to actively engage with the agency throughout the comment period.

As part of the outreach for the proposed federal plan and model trading rules, each EPA region held either an in-person meeting or a webinar, or both, for stakeholders, including communties, in December of 2015.

Lastly, we provided serveral in-person trainings on the proposed federal plan and model trading rules and the CEIP. In October of 2015, we hosted two in-person trainings, one focused on tribal concerns and was held in Las Vegas, Nevada, and one focused on EJ communities and was held in Port Arthur, Texas. A Workshop for Environmental Justice Communities on the CPP was held December 15-16, 2015 in Washington, DC, and two EPA Trainings for Tribal/Environmental Justice Communities on the CPP were held on Decemeber 7-8, 2015, and Decemeber 9-10, 2015, in Farmington, New Mexico and Tuba City, Arizona, respectively. In addition to these in-person meetings, we also held numerous conference calls and in-person meetings by request, all of which can be found in the docket for this rulemaking.

C. Providing Communities with Access to Additional Resources

1. Early-Action Program.

In the proposal for the federal plan and MRs we requested comment on whether a portion of early action set-asides should be targeted to RE projects that benefit low-income communities, how a low-income community should be defined as eligible under this set-aside, and how much of the set-aside should be designated for low-income communities. We also requested comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ, and, if so, in what manner, from the methods that are proposed. Subsequent to the proposal of the federal plan and MRs, we proposed additional design details for the CEIP. The CEIP reproposed many of the requirements realted to early-action set-asides that were initally proposed in the federal plan and model trading rules. Comments related to these provisions will not be addressed in this final action, as the early-action program will be addressed through the CEIP design details rulemaking, which has a Docket ID No. EPA-HQ-OAR-2016-0033.

2. Additional Resources on RE/EE for Communities

The EPA believes it is important to provide information and resources for low-income communities on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. The goal of these resources is to help low-income communities gain the benefits of this rulemaking. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills. One such project that the EPA has provided is a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures.

Additionally, the EPA will provide information on the Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[245]

We also note that there are many federal resources avaialable to help bring EE and RE to low-income communities. A detailed list of federal programs was provided in the proposed federal plan and model trading rules. *See*80 FR 65050 (October 23, 2015).

D. Co-Pollutants

Increasingly, state air agencies are considering multi-pollutant emission reduction strategies, such as EE and RE requirements, as compliance options for CAA plans and EPA encourages this multi-pollutant approach when assessing

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[245] http://www.epa.gov/power/.

compliance options for addressing GHG emissions during the development of state plans. Many states are already implementing cost-effective EE/RE requirements that reduce all types of power generation related emissions (including CO_2, NO_X, $PM_{2.5}$, SO_2, and HAP). Effectively assessing these approaches will require strong working relationships between state energy and environmental officials. As state public utility commissions and state energy offices implement, increase the stringency of, or adopt new EE/RE requirements, their expertise can assist air agencies to incorporate the NO_X emission impacts into stae plan develpoment and implementation.

The EPA discussed this approach more completely in the CPP and in an accompanying TSD titled “Incorporating RE and Demand-Side EE into State Plan Demonstrations.” States would be able to use EE/RE requirements as a compliance option in their state plans to meet the CPP’s CO_2 emission reduction targets for existing fossil-fired EGUs, and achieve a co-benefit of reducing NOx emissions that would be beneficial to managing ozone formation.

The EPA believes that in many cases it can be more cost-effective for states to develop integrated control strategies that address multiple pollutants rather than separate strategies for individual air quality programs. An integrated air quality control strategy that reduces multiple pollutants can help ensure that reductions are cost-effectively achieved and produce the greatest overall air quality benefits. The EPA has encouraged states to take a multi-pollutant approach to managing air quality to the greatest extent possible.

While the agency encourages states to develop multi-pollutant plans, it recognizes that certain factors can make such efforts challenging. For example, the NAAQS are to be reviewed every 5 years, and any revisions to the standards will lead to a series of implementation steps required by specific statutory schedules, and the timing for various pollutants may not coincide with the ultimate timing requirements for the development of state plans. In some cases program requirements and deliverables may not be coordinated easily, but in other situations there are good opportunities for conducting technical analyses and developing policy approaches that can have important health and environmental benefits while addressing multiple key air pollution issues at the same time, particularly for overburdened communities.

One such opportunity is the increased use of multi-pollutant assessments. A multi-pollutant assessment, or one-atmosphere modeling, is conducted with a single air quality model (such as CMAQ or CAMx) that is capable of simulating transport and formation of multiple pollutants simultaneously. For example, this type of model can simulate formation and deposition involving pollutants associated with $PM_{2.5}$, ozone and regional haze, and it can include algorithms simulating gas phase chemistry, aqueous phase chemistry, aerosol formation and acid deposition. This type of model can account for estimated changes in traditional air pollutant emissions resulting from programs (such as EE and RE programs) to reduce emissions of CO_2 and other GHGs. It could also include the formation and deposition of key air toxics and the chemical interactions that occur with these individual toxic species to produce $PM_{2.5}$ and ozone.

VIII. Statutory and Executive Order Reviews

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

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

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. This action raises novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket.

This action finalizes two MRs that states may adopt in state plans under the CPP. This action is not economically significant. These MRs have no associated burden, health or environmental risk, or cost associated with them because they are simply a model for states to use or adopt, at their option, in the development of a CPP state plan. This action does not impose requirements, and states are free to develop state plans that differ from the MRs so long as they meet the applicable statutory and regulatory requirements.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until approved by OMB.

This rule does not directly impose specific requirements on state and U.S. territory governments with affected EGUs. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. This rule does impose specific requirements on affected EGUs located in states, U.S. territories, or areas of Indian country.

The information collection activities in this final rule are consistent with those activities defined under the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (*i.e.*, the CPP) finalized on August 3, 2015. The information collection requirements in this final rule have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501 et seq. The ICR document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Aside from reading and understanding the rule, this action would impose minimal new information collection burden on affected EGUs beyond what those affected EGUs would already be subject to under the authorities of 40 CFR parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control numbers 2060–0626 and 2060– 0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This action provides MRs that states may adopt, incorporate by reference, or otherwise use in the design of state plans under the CPP. While the MRs provide states two approaches to plan design that the EPA has determined would be approvable as meeting the requirements of the CPP, the EPA is in no way requiring states to adopt either of the MRs. Thus, this action does not impose any requirements on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This final rule does not have federalism implications. The EPA believes, however, that this final rule may be of significant interest to state and local governments. Consistent with the EPA’s policy to promote communications between the EPA and state and local governments, the EPA consulted with state and local officials early in the process of developing the CPP to permit them to have meaningful and timely input into its development.

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

This action does not have tribal implications as specified in Executive Order 13175. There are no substantial costs imposed on tribes, and no actions taken that preempt tribal law. Thus consultation under, Executive Order 13175 is not required for this action.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of “covered regulatory action” in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not meet the definition in section 2-202.

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

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for the CPP which this action follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous United States in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards that are novel or new beyond what was finalized within the CPP.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections

VIII.F and VIII.G of this preamble, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council of the National Academies that the potential impacts of climate change raise EJ issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the United States.[246]

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

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

IPCC, 2014: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts —including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location), raising EJ concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the United States.

M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

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

In addition to reducing CO_2 emissions, the guidelines described by the CPP and consequently here would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_x, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[247] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to

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

have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[248] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emission reductions. The RIA for the CPP, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and EJ considerations section VII of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on vulnerable communities. The EPA consulted its May 2015, Guidance on Considering Environmental

[248] U.S. Environmental Protection Agency (U.S. EPA). 2009. Integrated Science Assessment for Particulate Matter (Final Report). EPA-600-R-08-139F. National Center for Environmental Assessment – RTP Division. December. Available on the Internet at http://www.cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.

Justice during the Development of Regulatory Actions, when determining what actions to take.[249] As described in section VII of this preamble (community and EJ considerations), the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section VII.A of this preamble. Additionally, as outlined in sections I and IX of this preamble the EPA has engaged meaningfully with communities throughout the development of the CPP and has devised a robust outreach strategy for continual engagement throughout this rulemaking.

These final MRs and the CPP, in conjunction, have taken into consideration the impacts that the CPP will with EJ in minority and low-income populations.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

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

List of Subjects in 40 CFR Part 60

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

List of Subjects in 40 CFR Part 62

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

List of Subjects in 40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control.

Dated: **[Date of signature]**.

Gina McCarthy,
Administrator.

List of Subjects in 40 CFR Part 60

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

List of Subjects in 40 CFR Part 62

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

List of Subjects in 40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control.

Dated: **[Date of signature]**.

Gina McCarthy,
Administrator.

PART 62--APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS

1. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

2. Add subpart MMM to read as follows:

Subpart MMM——Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units that Commenced Construction on or Before January 8, 2014

Sec.

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Definitions

Subpart MMM——Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units that Commenced Construction on or Before January 8, 2014

Introduction

§ 62.16205 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for a Greenhouse Gas Mass-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of implementing emission guidelines limiting GHG emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC) unit, or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases (GHG). The GHG emission limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) PSD and title V thresholds for greenhouse gases. (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected EGUs, the "pollutant that is subject to the standard promulgated under section 111 of the

Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

Applicability of this Subpart

§ 62.16210 Who is subject to this subpart?

(a) Owners or operators of an affected electric generating unit (EGU) located within a State that has adopted this subpart as a State plan, or portion of a State plan, which plan or portion has been approved by the Administrator and is effective under subpart UUUU of part 60 and part 62 of this chapter, are subject to this subpart.

(b) An affected EGU is any steam generating unit, IGCC unit, or stationary combustion turbine that meets the applicability requirements in §§ 60.5845 and 60.5850 of this chapter.

§ 62.16215 What requirements apply to affected EGUs that retire?

(a) Exemption. (1) Any affected EGU that is permanently retired as defined in § 62.16375 is exempt from §§ 62.16220(c)(1) [CO_2 Emissions Requirements], 62.16340 [Compliance Requirements], 62.16345 [Monitoring], 62.16360 [Reporting], and 62.16365 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section is effective on the first day of the compliance period immediately following the compliance period in which the retirement of the EGU took effect, as long as the requirements of paragraph (a)(3) and (b)(1) of this section are met.

(3) Within 30 days of the EGU's permanent retirement, the designated representative must submit a statement to the State, in a format the State may prescribe, which states that the EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) An EGU that becomes exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners or operators of an EGU exempt under paragraph (a) of this section must retain, at the EGU, records demonstrating that the EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the State. The owners or operators bear the burden of proof that the EGU is permanently retired.

(3) The owners or operators and, to the extent applicable, the designated representative of an EGU exempt under paragraph (a) of this section must comply with the requirements of the GHG Mass-based Trading Program accruing during any compliance periods for which the exemption is not in effect, including any requirements that apply after the exemption takes effect.

General Requirements

§ 62.16220 What emission standards and requirements must owners or operators and designated representatives comply with?

(a) Designated representative requirements. The owners or operators of an affected EGU must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16290 through 62.16300.

(b) Emission monitoring, reporting, and recordkeeping requirements. (1) The owners or operators, and the designated representative, of each affected EGU at the facility must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16345, 62.16360, and 62.16365.

(2) The emissions data determined in accordance with §§ 62.16345, 62.16360, and 62.16365 must be used to determine compliance with the CO_2 emission standard under paragraph (c) of this section. For each monitoring location from which mass CO_2 emissions are reported, the mass CO_2 emissions amount used in determining compliance must be the mass CO_2 emissions amount for the monitoring location determined in accordance with § 62.16345 and rounded to the nearest ton.

(c) CO_2 emission standard requirements (1) CO_2 emission standard. As of the allowance transfer deadline for each compliance period, the owner or operator, and designated representative for each affected EGU must hold, in the facility's compliance account CO_2 allowances available for deduction for such compliance period under § 62.16340(a) in an amount not less than the tons of total CO_2 emissions for such compliance period from all affected EGUs at the facility.

(2) Compliance periods. An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022 and for each compliance period thereafter.

(3) Vintage of CO_2 allowances held for compliance. (i) A CO_2 allowance may be held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period only if it is of a vintage year that corresponds to a year that falls within such compliance period or a prior compliance period.

(ii) A CO_2 allowance may be held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period only if it is of a vintage year that corresponds to a year that falls within such compliance period for which excess CO_2 emissions occured, a prior compliance period, or the compliance period immediately subsequent to the compliance period for which excess CO_2 emissions occurred.

(4) Allowance Tracking and Compliance System (ATCS) requirements. Each CO_2 allowance must be held in, deducted from, or transferred into, out of, or between ATCS accounts in accordance with this subpart.

(5) Limited authorization. A CO_2 allowance is a limited authorization to emit one ton of CO_2 during a compliance period. Such authorization is limited in its use and duration as follows:

(i) Such authorization must only be used in accordance with the GHG Mass-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the State or the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the State or tracking system operator determines is necessary or appropriate.

(6) Property right. A CO_2 allowance does not constitute a property right.

(d) Title V permit requirements. No title V permit revision will be required for any allocation, holding, deduction, or transfer of CO_2 allowances in accordance with this subpart, provided that the requirements applicable to such allocation, holding, deduction, or transfer of CO_2 allowances are already incorporated in such permit.

(e) Liability. (1) The owners or operators of each affected EGU are subject to federal enforcement pursuant to sections 113(a) – (h) and section 304 of the Clean Air Act for violations of any requirements of this subpart, and the United States, States, and other persons have the ability to enforce against such violations and secure appropriate corrective actions, and the owners or operators must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act. Each ton of excess CO_2 emissions and each day of such compliance period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) If total CO_2 emissions during a compliance period from the affected EGUs at a facility are in excess of the CO_2 emission standard set forth in paragraph (c)(1)(i) of this section, then the owners or operators of each affected EGU at the facility must hold in the compliance account the CO_2 allowances required for deduction under § 62.16340(e), and each day until the requisite number of CO_2 allowances are held for deduction shall

constitute a separate violation of this subpart and the Clean Air Act.

(3) Any provision of the GHG Mass-based Trading Program that applies to an affected EGU at a facility or the designated representative of an affected EGU at a facility will also apply to the owners and operators of such affected EGUs at the facility.

(f) Effect on other authorities. No provision of the GHG Mass-based Trading Program or exemption under § 62.16215 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved State plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16225 How is time computed under the Greenhouse Gas Mass-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the GHG Mass-based Trading Program, to begin on the occurrence of an act or event will begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the GHG Mass-based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the GHG Mass-based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16230 What are the administrative appeal procedures?

(a) The administrative appeal procedures for decisions of the Administrator under the GHG Mass-based Trading Program are set forth in part 78 of this chapter.

(b) [Reserved]

Emission Budgets and Allowance Allocation

§ 62.16235 What are the CO_2 emission budgets?

(a) The CO_2 emission budgets for the interim 3- and 2-year compliance periods during the years 2022 through 2029, and the final 2-year compliance periods for the years 2030-2031 and subsequent 2-year periods are specified in Table 1 of this subpart.

§ 62.16240 How are CO_2 allowances allocated?

[Reserved.]

§ 62.16245 What is the timing for allocation of CO_2 allowances?

[Reserved.]

Designated Representatives

§ 62.16290 How are designated representatives and alternate designated representatives authorized, and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16300, all affected EGUs at a facility shall have one designated representative, with regard to all matters under the GHG Mass-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the tracking system operator of a complete certificate of representation under § 62.16305:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner or operator of each affected EGU at the facility in all matters pertaining to the GHG Mass-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of each affected EGU at the facility shall be bound by any decision or order issued to the designated representative by the State or the tracking system operator regarding any such affected EGU at the facility.

(b) Except as provided under § 62.16300, each facility with affected EGUs may have one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of each affected EGU at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the tracking system operator of a complete certificate of representation under § 62.16305:

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of each affected EGU at the facility shall be bound by any decision or order issued to the alternate designated representative by the State or the tracking system operator regarding any such affected EGU at the facility.

(c) Except in this section, § 62.16375, and §§ 62.16295 through 62.16315, whenever the term “designated representative” is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16295 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16315 concerning delegation of authority to make submissions, each submission under the GHG Mass-based Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each facility and affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the facility or affected EGUs for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The tracking system operator will accept or act on a submission made for a facility with affected EGUs or an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16315.

<u>§ 62.16300 What are the processes for changing a designated representative, an alternate designated representative, the list of owners and operators, and affected EGUs at the facility?</u>

(a) <u>Changing a designated representative</u>. The designated representative may be changed at any time upon receipt by the tracking system operator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the tracking system operator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the affected EGUs at the facility.

(b) Changing an alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the tracking system operator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the tracking system operator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the affected EGUs at the facility.

(c) Changes in the list of owners and operators. (1) In the event an owner or operator of an affected EGU at the facility is not included in the list of owners and operators in the certificate of representation under § 62.16305, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the affected EGUs at the facility, and the decisions and orders of the State or the tracking system operator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of an affected EGU at the facility, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16305 amending the list of owners and operators to reflect the change.

(d) <u>Changes in affected EGUs at the facility</u>. Within 30 days of any change in which affected EGUs are located at a facility (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16305 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer

before initial installation) before being located at the facility, then the certificate of representation must identify, in a format prescribed by the tracking system operator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the facility.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the tracking system operator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, email address and facsimile transmission number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the facility.

§ 62.16305 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the following elements in a format prescribed by the tracking system operator:

(1) Identification of the facility, and each affected EGU at the facility, for which the certificate of representation is submitted, including facility name, facility category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each affected EGU, actual or projected date of commencement of commercial operation, identification number and net summer capacity of each generator served by each affected EGU, and a statement of whether the facility is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility and of each affected EGU at the facility.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of each affected EGU at the facility”; and

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the GHG Mass-based Trading Program on behalf of the owners and operators of each affected EGU at the facility and that each such owner or operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the State or the tracking system operator regarding the facility or unit.”

(iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected, to each owner and operator of the facility and of each affected EGU at the facility; and CO_2 allowances and proceeds of transactions involving CO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CO_2 allowances by contract, then CO_2 allowances and proceeds of transactions involving CO_2 allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the tracking system operator, documents of agreement referred to in the certificate of representation shall not be submitted to the tracking system operator. The tracking system operator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16310 What is the tracking system operator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16305 has been submitted and received, the tracking system operator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16305 is received by the tracking system operator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the tracking system operator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the State or the tracking system operator under the GHG Mass-based Trading Program.

(c) The State or the tracking system operator will not address or attempt to resolve any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

§ 62.16315 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative or alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the tracking system operator provided for or required under this subpart.

(b) In order to delegate authority to a natural person to make an electronic submission to the tracking system operator in accordance with paragraph (a) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the tracking system operator a notice of delegation, in a format prescribed by the tracking system operator, that includes the elements in paragraphs (b)(1) through (4) of this section.

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person to which such electronic submission authority is delegated (referred to in this section as an “agent”).

(3) For each such natural person to which such electronic submission authority is delegated, a list of the type or types of electronic submissions under paragraph (a) of this section for which authority is delegated to him or her.

(4) The following certification statements by such designated representative or alternate designated representative:

(i) “I agree that any electronic submission to the tracking system operator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16315(c) shall be deemed to be an electronic submission by me”; and

(ii) “Until this notice of delegation is superseded by another notice of delegation under § 62.16315(c), I agree to maintain an e-mail account and to notify the tracking system operator immediately of any change in my e-mail address unless all delegation of authority by me under § 62.16315 is terminated.”

(c) A notice of delegation submitted under paragraph (b) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the tracking system operator and until receipt by the tracking system operator of a superseding notice of delegation, if any, submitted by such designated representative or alternate designated representative, as appropriate. Such superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(d) Any electronic submission covered by the certification in paragraph (b)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (c) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping and Reporting

§ 62.16320 How are compliance accounts, retirement accounts, and general accounts established?

(a) Compliance accounts. Upon receipt of a complete certificate of representation under § 62.16305, the tracking system operator will establish a compliance account for the facility with affected EGUs for which the certificate of representation was submitted, unless the facility already has a compliance account. The designated representative and any alternate designated representative of the facility with affected EGUs shall be the authorized account representative and the alternate authorized account representative, respectively, of the compliance account.

(b) Retirement accounts. The tracking system operator will establish a retirement account, into which CO_2 allowances held in a compliance account for the affected EGUs at a facility are transferred for surrender by the designated representative of the affected EGUs at the facility, in order to demonstrate compliance with the applicable emission standards. The retirement account may be held by only the tracking system operator. Except for actions by the tracking system operator as provided for in § 62.16355 and § 62.16370, once a CO_2 allowance is retired, the CO_2 allowance shall no longer be transferable to another account in the ATCS or any other allowance tracking system.

(c) General accounts—(1) Application for a general account. (i) Any person on behalf of any enitity may apply to open a general account, for the purpose of holding and transferring CO_2 allowances, by submitting to the tracking system operator a complete application for a general account. Such application must designate one authorized account representative and may designate one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CO_2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the tracking system operator:

(A) Name, mailing address, e-mail address, telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons, and associated identifying information, subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: “I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the GHG Mass-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the State or the tracking system operator regarding the general account”; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the tracking system operator, documents of agreement referred to in the application for a general account shall not be submitted to the tracking system operator. The tracking system operator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the tracking system operator of a complete application for a general account under paragraph (c)(1) of this section, the tracking system operator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the tracking system operator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the GHG Mass-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to CO_2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the State or the tracking system operator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make electronic submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) Except in this section, whenever the term “authorized account representative” is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative or alternate authorized account representative of a general account may be changed at any time upon receipt by the tracking system operator of a superseding complete application for a general account under paragraph (c)(1) of this section.

Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative or alternate authorized account representative before the time and date when the tracking system operator receives the superseding application for a general account shall be binding on the new authorized account representative or alternative authorized account representative, as the case may be, and the persons with an ownership interest with respect to CO_2 allowances in the general account.

(ii)(A) In the event a person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the general account, and the decisions and orders of the State or the tracking system operator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to CO_2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the tracking system operator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the tracking system operator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the tracking system operator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the State or the tracking system operator under the GHG Mass-based Trading Program.

(iii) The State or the tracking system operator will not address or attempt to resolve any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative or alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the tracking system operator provided for or required under this subpart.

(ii) In order to delegate authority to a natural person to make an electronic submission to the tracking system operator in accordance with paragraph (c)(5)(i) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the tracking system operator a notice of delegation, in a format prescribed by the tracking system operator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person to which such electronic submission authority is delegated (referred to in this section as an “agent”);

(C) For each such agent to which such electronic submission authority is delegated, a list of the type or types of electronic submissions under paragraph (c)(5)(i) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the tracking system operator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iii), if any, shall be deemed to be an electronic submission by me”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iii), I agree to maintain an e-mail account and to notify the tracking system operator immediately of any change in my e-mail address unless all delegation of authority by me under § 62.16320(c)(5) is terminated.”

(iii) A notice of delegation submitted under paragraph (c)(5)(ii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the tracking system operator and until receipt by the tracking system operator of a superseding notice of delegation, if any, submitted by such authorized account representative or alternate authorized account representative, as appropriate. Such superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(iv) Any electronic submission covered by the certification in paragraph (c)(5)(ii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iii) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the tracking system operator a request to close the general account. Such request must include a correctly submitted CO_2 allowance transfer under § 62.16330 for any CO_2 allowances in the account to one or more other ATCS accounts.

(ii) If a general account has no CO_2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CO_2 allowances, then the tracking system operator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the tracking system operator receives a correctly submitted CO_2 allowance transfer under § 62.16330 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the tracking system operator good cause as to why the account should not be closed.

(d) Account identification. The tracking system operator will assign a unique identifying number to each general account established under paragraphs (a) through (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the tracking system operator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 62.16295(a) and 62.16315 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 62.16325 When will CO_2 allowances be recorded in compliance accounts?

The tracking system operator will record an allocation of CO_2 allowances in the appropriate ATCS account by the date 15 days after the date on which any allocation of CO_2 allowances to a recipient must be made in accordance with § 62.16240.

§ 62.16330 How must transfers of CO_2 allowances be submitted?

(a) An authorized account representative or alternate authorized account representative seeking recordation of a CO_2 allowance transfer must submit the transfer to the tracking system operator.

(b) A CO_2 allowance transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the tracking system operator:

(i) The account numbers established by the tracking system operator for both the transferor and transferee accounts;

(ii) The serial number of each CO_2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative or alternate authorized account representative of the transferor account and the date signed; and

(2) When the tracking system operator attempts to record the transfer, the transferor account includes each CO_2 allowance identified by serial number in the transfer.

§ 62.16335 When will CO_2 allowance transfers be recorded?

(a) Except as provided in paragraph (b) of this section, within five business days of receiving a CO_2 allowance transfer that is correctly submitted under § 62.16330, the tracking system operator will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CO_2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any CO_2 allowances of a vintage year that falls before such allowance transfer deadline will not be recorded until after the tracking system operator completes the deductions from such compliance account under § 62.16340 for the compliance period to which the allowance transfer deadline applies.

(c) Where a CO_2 allowance transfer is not correctly submitted under § 62.16330, the tracking system operator will not record such transfer.

(d) Within 5 business days of recordation of a CO_2 allowance transfer under paragraphs (a) and (b) of the section, the tracking system operator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CO_2 allowance transfer that is not correctly submitted under § 62.16330, the tracking system operator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16340 How will deductions for compliance with a CO_2 emission standard occur?

(a) Availability for deduction for compliance. CO_2 allowances are available to be deducted for compliance with an affected EGU's CO_2 emission standard for a compliance period only if the CO_2 allowances:

(1) Meet the requirements of section 62.16220(c)(3) (vintage year); and

(2) Are held in the compliance account for the affected EGU as of the allowance transfer deadline for such compliance period.

(b) Deductions for compliance. After the recordation, in accordance with § 62.16335, of CO_2 allowance transfers submitted by the allowance transfer deadline for a compliance period, the tracking system operator will deduct from each facility's compliance account CO_2 allowances available under paragraph (a) of this section in order to determine whether the affected EGUs at the facility meet the CO_2 emission standard for such compliance period, as follows:

(1) Until the number of CO_2 allowances deducted equals the number of tons of total CO_2 emissions from all affected EGUs at the facility for such compliance period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under paragraph (a) of this section remain in the compliance account.

(c) Identification of CO_2 allowances by serial number. The designated representative or alternate designated representative for a facility's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for CO_2 emissions or excess emissions for a compliance period in accordance with paragraph (b) or (e) of this section. In order to be complete, such request must be submitted to the tracking system operator by the allowance transfer deadline for such compliance period and include, in a format prescribed by the tracking system operator, the identification of the facility and the appropriate CO_2 allowance serial numbers.

(d) First-in, first-out. The tracking system operator will deduct CO_2 allowances under paragraph (b) or (e) of this section from the facility's compliance account in accordance with a complete request under paragraph (c) of this section or, in the absence of such request or in the case of identification of an insufficient number of CO_2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(1) Any CO_2 allowances that were allocated to the affected EGUs at the facility and not transferred out of the compliance account, in the order of recordation; and then

(2) Any CO_2 allowances that were allocated to any affected EGU or other entity and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(e) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a compliance period in which the facility has excess emissions, the tracking system operator will deduct from the facility's compliance account a number of CO_2 allowances equal to two times the number of tons of the facility's excess emissions. The CO_2 allowances deducted must be of a vintage year that corresponds to years that fall within: the compliance period for which excess emissions occurred, a prior compliance period, or the compliance period immediately subsequent to the compliance period for which excessemissions occurred.

(f) Recordation of deductions. The tracking system operator will record all deductions under paragraphs (b) and (e) of this section from the appropriate compliance account.

§ 62.16345 What monitoring requirements must the owner or operator comply with?

(a) The owner or operator of an affected EGU must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter. The owner or operator of an affected EGU must comply with the requirements of this section to monitor CO_2 emissions and net energy output at each affected EGU.

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(4) or (5) of this section. A complete data record is required, i.e., CO_2 mass emissions must be reported for each operating hour, therefore substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content,

fuel flow rate and/or gross calorific value (GCV) must be used in the calculations for any hour in which such substitute data values are required to be recorded; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire quarter or compliance period, as applicable.

(3) The owner or operator must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standard No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator of an affected EGU must calculate net energy output according to paragraphs (a)(6)(i)(A) and (B) of this section.

(4) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected EGU using the procedures in paragraphs (a)(4)(i) through (vi) of

this section, except as otherwise provided in paragraph (a)(5) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the affected EGU is equipped with emission controls that produce non-combustion CO_2 (e.g., from sorbent injection), then this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (e.g., carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) Calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis). CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV must be used in the calculations.

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

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

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(iii) of this section over the entire compliance period.

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

(5) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(4) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(5)(i) through (vi) of this section.

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

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) Determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(5)(ii) of this section and multiply it by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

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

(v) Sum all of the hourly CO_2 mass emissions values (lb) that were calculated according to procedures specified in paragraph (a)(5)(iii) of this section over the entire quarter or compliance period, as applicable.

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

(6) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standard No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or

operator of an affected EGU must calculate net energy output according to paragraph (a)(6)(i) of this section.

(i) For each operating hour of a compliance period that was used in paragraph (a)(4) or (5) of this section to calculate the total CO_2 mass emissions, the owner or operator must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(6)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, if there is no (i.e., zero) gross or net electrical output, but there is mechanical or useful thermal output, the owner or operator must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, the owner or operator must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output must be counted as zero for this calculation.

(A) The owner or operator must alculate P_{net} for an affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

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

Where:

P_{net} = Net energy output of the affected EGU in MWh.

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

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

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

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

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(6)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions as defined in § 62.16375, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions as defined in § 62.16375, as applicable) from any integrated equipment that is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

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

(B) If applicable to the affected EGU (for example, for a combined heat and power affected EGU), $(Pt)_{PS}$ must be calculated using the following equation:

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

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

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

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in § 62.16375 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

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

(ii) [Reserved]

(7) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(1) of this section share a common exhaust gas stack, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each affected EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net energy output for the common stack must be the sum of the hourly net energy output for all affected EGUs that are served by the common stack and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(8) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and the owner or operator elects to monitor in the ducts), the hourly CO_2 mass emissions and the "stack operating time" (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emission standard by summing the CO_2 mass emissions measured at the individual stacks or ducts for the affected EGU.

(b) [Reserved]

§ 62.16350 Can CO_2 allowances be banked for future use or transfer?

(a) A CO_2 allowance may be banked, for future use or transfer, in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under §§ 62.16240(b), 62.16335, 62.16340, 62.16355, or 62.16370.

§ 62.16355 How does the tracking system operator process account errors?

The tracking system operator may, at his or her sole discretion and on his or her own motion, correct any error in any ATCS account. Within 10 business days of making such correction, the tracking system operator will notify the authorized account representative for the account.

§ 62.16360 What are the reporting, notification and submission requirements for a designated representative of an affected EGU?

The designated representative of an affected EGU must prepare and submit reports according to paragraphs (a) through (e) of this section, as applicable.

(a)(1) The designated representative must meet all applicable reporting requirements and submit quarterly reports as required under subpart G of part 75 of this chapter and must include the following information, as applicable in the quarterly reports:

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

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour during the reporting quarter;

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

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

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

(2) At the end of each compliance period, by May 5th of the calendar year following the end of the compliance period, the designated representative of an affected EGU must submit a report to the State that includes the following:

(i) All hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack) at the facility, as specified in paragraphs (a)(2)(ii)-(iii) of this section;

(ii) For each affected EGU at the facility, the cumulative annual CO_2 mass emissions (tons) for each year of the compliance period, derived from the electronic emissions reports for the fourth calendar quarter of that year, submitted to EPA under § 75.64(a) of this chapter;

(iii) For each affected EGU at the facility, the sum of the cumulative annual CO_2 mass emissions values for the compliance period from paragraph (a)(2)(ii) of this section;

(iv) For each affected EGU at the facility, the net electric output and the net energy output (Pnet) values for each unit or stack operating hour in the compliance period;

(v) For each affected EGU at the facility, the sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period;

(vi) Identification of the emission standard for each affected EGU at the facility and demonstration that each affected EGU at the facility complied with its emission standard;

(vii) For the affected EGUs at the facility, a list of the CO_2 allowances surrendered to demonstrate compliance for the compliance period, including the date of surrender and the serial numbers of the surrendered CO_2 allowances.

(b) The designated representative of each affected EGU at the facility must make all submissions required under the GHG Mass-based Trading Program, except as provided in § 62.16315. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(c) The designated representative must submit all electronic reports required under paragraph (a)(1) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA; and must submit all electronic reports required under paragraph (a)(2) of this section using the ATCS.

(d) For affected EGUs under this subpart that are not in the Acid Rain Program, the designated representative must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(e) If an affected EGU captures CO_2 to meet the applicable emission standard, then the designated representative must report in accordance with the requirements of 40 CFR part 98, subpart PP, of this chapter and either:

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

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

(f) The designated representative must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to the affected EGUs at the facility.

§ 62.16365 What are the recordkeeping requirements?

The owner or operator of each affected EGU must maintain the records, as described in paragraphs (a)) and (b) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

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

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

(1) All CO_2 emissions monitoring information, in accordance with this subpart;

(2) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with, an affected EGU’s emission standard under § 62.16220 and any other requirements of the GHG Mass-based Trading Program;

(3) Data that is required to be recorded by 40 CFR part 75, subpart F, of this chapter; and

(4) Data with respect to any CO_2 allowances used by the affected EGU in its compliance demonstration, including all information, records, and reports relating to the surrender for deduction of CO_2 allowances for compliance under the GHG Mass-based Trading Program, including the unique serial identification number of each CO_2 allowance surrendered and the date of surrender.

§ 62.16370 What actions may the tracking system operator take on submissions?

(a) The State and the tracking system operator may review and conduct independent audits concerning any submission under the GHG Mass-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The tracking system operator may deduct CO_2 allowances from or transfer CO_2 allowances to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16375 What definitions apply to this subpart?

As used in this subpart, all terms not defined herin will have the meaning given them in the Clean Air Act and in subparts A, B, TTTT, and UUUU of part 60 of this chapter.

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Affected electric generating unit or affected EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that meets the applicability requirements in §§ 60.5845(b) and 60.5850 of this chapter.

Allocation or allocate means, with regard to CO_2 allowances, distribution of CO_2 allowances by the State, in accordance with the State allowance distribution methodology and process specified in §§ 62.16240 and 6216245, to:

(1) An affected EGU; or

(2) Any other entity specified by the State.

Allowance Tracking and Compliance System (ATCS) means the system administered by the EPA by which the tracking system operator records allocations, deductions, and transfers of CO_2 allowances under the GHG Mass-based Trading Program.

Allowance transfer deadline means, for a compliance period in a given year, midnight of May 1 (if it is a business day), or midnight of the first business day thereafter (if May 1 is not a business day), immediately after such compliance period and is the deadline by which a CO_2 allowance transfer must be submitted for recordation in a facility's compliance account in order to be available for use in complying with the facility's affected EGUs' CO_2 emission standard for such compliance period in accordance with §§ 62.16220 and 62.16340.

Alternate designated representative means, for each affected EGU at a facility, the natural person who is authorized by the owners and operators of all such affected EGUs at the facility, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the GHG Mass-based Trading Program. If the facility with affected EGUs is also subject to the Acid Rain Program, CSAPR NO_X Annual

Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CO_2 allowances held in the general account and means, for a compliance account, the designated representative.

Automated data acquisition and handling system (DAHS) means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Business day means a day that does not fall on a weekend or a federal holiday.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

<u>CO_2 allowance</u> means a limited authorization under this subpart to emit one short ton of CO_2 during a compliance period under the GHG Mass-based Trading Program, subject to all applicable limitations contained in this subpart. The State or the Administrator reserves the authority to terminate or limit, to the extent necessary or appropriate to implement any provision of the Clean Air Act, the limited authorization of a CO_2 allowance. A CO_2 allowance is a tradable compliance instrument originated by the State, or by another state that has adopted regulations that are included in a state plan designated by the state as ready-for-interstate-trading with the GHG Mass-based Trading Program and approved by the Administrator as such. Each CO_2 allowance is assigned an applicable calendar year identifier (vintage year), which corresponds to the emission budget year for which the CO_2 allowance was originated. CO_2 allowances are allocated, recorded, held, deducted, or transferred only as whole CO_2 allowances.

<u>CO_2 allowances held</u> means the CO_2 allowances treated as included in an Allowance Tracking and Compliance System (ATCS) account as of a specified point in time because at that time they:

(1) Have been recorded by the tracking system operator in the account or transferred into the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart.

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period by the CO_2 allowances available for deduction for the affected EGUs at a facility under § 62.16340(a) for such compliance period.

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means an ATCS account, established by the tracking system operator for a facility with affected EGUs under this subpart, in which any CO_2 allowance allocations to the affected EGUs at the facility are recorded and in which are held any CO_2 allowances available for use for a compliance period in complying with the affected EGUs' CO_2 emission standard in accordance with §§ 62.16220 and 62.16340.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024.

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027.

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

(4) Final compliance period.

Continuous emission monitoring system (CEMS) means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16345. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling

system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

<u>CSAPR NO_X Annual Trading Program</u> means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(a) of this chapter and in accordance with subpart AAAAA of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance

with § 52.38(a)(3), (4), or (5) of this chapter.

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(b) of this chapter and in accordance with subpart BBBBB of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.38(b)(3), (4), or (5) of this chapter.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(b) of this chapter and in accordance with subpart EEEEE of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.38(b)(6), (7), (8), or (9) of this chapter.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.39 of this chapter and in accordance with subpart CCCCC of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.39(d), (e), or (f) of this chapter.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.39 of this chapter and in accordance with subpart DDDDD of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.39(g), (h), or (i) of this chapter.

Deduct CO_2 allowances means permanently withdrawing CO_2 allowances by the tracking system operator from a compliance account (e.g., in order to account for compliance with the CO_2 emission standard).

Designated representative means, for each affected EGU at a facility, the natural person who is authorized by the owners and operators of all such affected EGUs at the facility, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the GHG Mass-based Trading Program. If the facility with affected EGUs is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1

Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

Emissions means air pollutants exhausted from an affected EGU or facility into the atmosphere, as measured, recorded, and reported to the tracking system operator by the designated representative, and as modified by the State or the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission budget means a statewide mass-based CO_2 emission budget specified in § 62.16235.

Excess emissions means any ton of CO_2 emissions from the affected EGUs at a facility during a compliance period that exceeds the CO_2 emissions limitation for the affected EGUs at a facility for such compliance period.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final 2-year compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

General account means an ATCS account established under this subpart that is not a compliance account or a retirement account.

Generator means a device that produces electricity.

GHG Mass-based Trading Program means a state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter, as a means of controlling CO_2 emissions.

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the tracking system operator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Indian country means "Indian country" as defined in 18 U.S.C. 1151.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) at the time of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) at the time of such completion as specified by the person conducting the physical change.

Net summer capacity means the maximum electricity 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.

Operate or operation means, with regard to an affected EGU, to combust fuel.

Operator means, for a facility that contains one or more affected EGUs or an affected EGU at a facility respectively, any person who operates, controls, or supervises the facility or the affected EGU at the facility and includes, but is not limited to, any holding company, utility system, or plant manager of such facility or affected EGU.

Owner means, for a facility that contains one or more affected EGUs or an affected EGU at a facility respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in one or more affected EGUs at a facility;

(2) Any holder of a leasehold interest in the facility or an affected EGU at the facility, provided that, unless expressly provided for in a leasehold agreement, “owner” does not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such facility or affected EGU; and

(3) Any purchaser of power from a facility or an affected EGU at the facility under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners and operators have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16215; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Receive or receipt of means, when referring to the tracking system operator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the tracking system operator in the regular course of business.

Recordation, record, or recorded means, with regard to CO_2 allowances, the moving of CO_2 allowances by the tracking system operator into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Submit means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any "submission" deadline shall be determined by the date of dispatch.

Ton means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the GHG mass-based trading program emissions limitations and reduction requirements, any remaining fraction of a ton equal to or greater than 0.50 ton is deemed to equal one ton and any fraction of a ton less than 0.50 ton is deemed not to equal any ton.

Tracking system operator means the State or an entity acting on behalf of the State, including the Administrator of the United States Environmental Protection Agency.

Valid means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Vintage year means the applicable calendar year identifier assigned to each CO_2 allowance, which corresponds to the emission budget year for which the CO_2 allowance was originated.

§ 62.16380 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit

CO_2—carbon dioxide

CPP—clean power plan

EGU-electric generating unit

GCV-gross calorific value

H_2O—water

hr—hour

IGCC-integrated gasification combined cycle

kg-kilogram

kW—kilowatt electrical

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt-hour

O_2—oxygen

PSD-prevention of significant deterioration

yr—year

Table 1 to Subpart MMM of Part 62—Annualized State CO_2 Emission Budgets for Affected EGUs (short tons)[1]

State	Interim period			Final period
	Step 1 2022-2024	Step 2 2025-2027	Step 3 2028-2029	2030-2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337

Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

[1] The values in this table are annual amounts; the total CO_2 emission budget for each multi-year compliance period is the annual value multiplied by the number of years in the compliance period.

3. Add subpart NNN to read as follows:

Subpart NNN—Greenhouse Gas Emissions Rate-based Model Trading Rule for Electric Utility Generating Units that Commenced Construction on or Before January 8, 2014

Sec.

Introduction

Applicability of this Subpart

General Requirements

Emission Rate Credit Issuance, Adjustment, and Revocation

Evaluation, Measurement and Verification Plans; Monitoring and Verification Reports; and Verification Reports

Designated Representatives

Monitoring, Recordkeeping, Reporting

Definitions

SUBPART NNN—GREENHOUSE GAS EMISSIONS RATE-BASED MODEL TRADING RULE FOR ELECTRIC UTILITY GENERATING UNITS THAT COMMENCED CONSTRUCTION ON OR BEFORE JANUARY 8, 2014

Introduction

§ 62.16405 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for a Greenhouse Gas (GHG) Rate-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of implementing emission guidelines limiting GHG emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC) unit, or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The GHG limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) PSD and Title V thresholds for greenhouse gases. (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to GHG emissions from affected EGUs, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

Applicability of this Subpart

§ 62.16410 Who is subject to this subpart?

(a) Owners or operators of an affected electric generating unit (EGU) located within a State that has adopted this subpart as a State plan, or portion of a State plan, which State plan or portion of a State plan has been approved by the Administrator and is effective under subpart UUUU of part 60 and part 62 of this chapter, are subject to this subpart.

(b) An affected EGU is any steam generating unit, IGCC unit, or stationary combustion turbine that meets the applicability requirements in §§ 60.5845 and 60.5850 of this chapter.

§ 62.16415 What are the requirements for retired affected EGUs?

(a) Exemption. (1) Any affected EGU that is permanently retired as defined in § 62.16570 is exempt from §§ 62.16420(c)(1) [CO_2 Emissions Requirements], 62.16535 [Compliance Requirements], 62.16540 [Monitoring], 62.16555 [Reporting], and 62.16560 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section is effective on the first day of the compliance period immediately following the compliance period in which the retirement of the

EGU took effect, as long as the requirements of paragraph (a)(3) and (b)(1) of this section are met.

(3) Within 30 days of the EGU's permanent retirement, the designated representative must submit a statement to the State, in a format that the State may prescribe, which states that the EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) An EGU that becomes exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners or operators of an EGU exempt under paragraph (a) of this section must retain, at the EGU, records demonstrating that the EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the State. The owners or operators bear the burden of proof that the EGU is permanently retired.

(3) The owners or operators and, to the extent applicable, the designated representative of an EGU exempt under paragraph (a) of this section must comply with the requirements of the GHG Rate-based Trading Program accruing during any compliance

periods for which the exemption is not in effect, including any requirements that apply in the compliance period in which the exemption takes effect.

General Requirements

§ 62.16420 What emission standards and requirements must owners or operators and designated representatives comply with?

(a) Designated representative requirements. The owners or operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16485 through 62.16495.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners or operators, and the designated representatives of affected EGUs must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16540, 62.16555, and 62.16560.

(2) The CO_2 emissions data determined in accordance with § 62.16540 must be used to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which CO_2 emissions are reported, the CO_2 emission rate used in determining compliance must be the CO_2 emission rate at the monitoring location determined in accordance with paragraph (c) of this section.

(c) CO₂ emission standard requirements. (1) As of the ERC transfer deadline for each compliance period, the owner or operator, and the designated representative, for each affected EGU must demonstrate compliance with the affected EGU's emission standard listed in Table 1 of this subpart, by calculating a CO_2 emission rate by factoring stack emissions and any ERCs into the following equation:

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

Where:

CO_2 emission rate	=	An affected EGU's calculated CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.
M_{CO2}	=	Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU. In the case of units that share a common emission stack and that have emissions that are not individually monitored pursuant to part 75 of this chapter, the measured CO_2 mass at the stack will be apportioned to each affected EGU based on net energy output. For any hour where one or more EGUs are not producing net energy output the apportionment will be based on operating time.
MWh_{op}	=	Total net energy output over the compliance period for an affected EGU in units of MWh.
MWh_{ERC}	=	ERC replacement generation for an affected EGU

denominated in units of MWh (ERCs are denominated in whole integers as specified in paragraph (c)(2) of this section). This summation includes any GS-ERCs, which are only available for use by an affected EGU that is a steam generating unit or IGCC unit.

(2) Except as provided in paragraph (c)(3) of this section, an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if it meets the requirements in (c)(2)(i) and (ii), as appropriate.

(i) An ERC qualifies if it:

(A) Has a unique serial identifier;

(B) Represents one whole MWh of actual electricity generated or saved with zero associated CO_2 emissions;

(C) Was issued for electricity generated or saved on or after January 1, 2022;

(D) Was issued to an eligible resource that meets the requirements of § 62.16435 or to an affected EGU that meets the requirements of § 62.16434, by the State (or by another state administrator of a linked GHG Rate-based Trading Program that is part of an EPA-approved state plan and applies the Table 1 rates as emission standards) through the ERC-TCS or an interoperable tracking system; and

(E) Has not been previously surrendered and retired for purposes of compliance with this subpart or any other state plan under subpart UUUU of part 60 of title 40 of the CFR.

(ii) If the ERC issued is a GS-ERC it must only be issued to an affected EGU classified as a stationary combustion turbine that meets the requirements of § 62.16434, by the State (or by another state administrator of a linked GHG Rate-based Trading Program that is part of an EPA-approved state plan and applies the Table 1 rates as emission standards) through the ERC-TCS or an interoperable tracking system.

(3) An ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if it represents electricity generation or savings that a state has relied on or is relying on to demonstrate achievement of any state measure pursuant to § 60.5780 of this chapter.

(4) ERC transfer deadline for a compliance account. (i) The ERC transfer deadline for an affected EGU is June 1 in the year following the last year in the compliance period.

(ii) As of the ERC transfer deadline for each compliance period, the owners or operators of each affected EGU must hold, in the affected EGU's compliance account, sufficient ERCs to demonstrate compliance with its applicable emission standard listed in Table 1 of this subpart pursuant to the requirement of paragraph (c)(1) of this section.

(d) Compliance periods. An affected EGU is subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022, and for each compliance period thereafter.

(1) Vintage of ERCs held for compliance. An ERC may be held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period only if it is of a vintage year that corresponds to a year that falls within such compliance period or a prior compliance period.

(2) ERC tracking and compliance system. Each ERC must be held in, deducted from, and transferred into, out of, or between ERC-TCS accounts in accordance with this subpart.

(3) Limited authorization. (i) Any use of an ERC by an affected EGU to meet an emission standard under paragraph (c)(1) of this section must comply with the requirements of the GHG Rate-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the State or the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the State or the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(4) Property right. An ERC does not constitute a property right.

(e) Title V permit requirements. No title V permit revision will be required for any issuance, holding, deduction, or transfer of ERCs in accordance with this subpart, provided that the requirements applicable to such issuance, holding, deduction, or transfer of ERCs are already incorporated in such permit.

(f) Liability. (1) The owners or operators of each affected EGU are subject to federal enforcement pursuant to sections 113(a) – (h) and section 304 of the Clean Air Act for violations of any requirements of this subpart, and the United States, States, and other persons have the ability to enforce against such violations and secure appropriate corrective actions, and the owners or operators must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act;

(2) If an affected EGU exceeds its emission standard in paragraph (c)(1)(i) during a compliance period based on its stack emissions and generation alone, and it did not hold sufficient ERCs to meet its emission standard by the applicable ERC transfer deadline, then:

(i) The owners or operators of the affected EGU must hold in the compliance account the ERCs required for deduction under § 62.16535(e); and

(ii) Each day until the requisite number of ERCs are held for deduction shall constitute a separate violation of this subpart and the Clean Air Act.

(3) If an affected EGU exceeds its emission standard because it obtained sufficient facially valid ERCs to meet its emission standard, but those ERCs were found to be invalid, then:

(i) The owners or operators of the affected EGU must hold in the compliance account the ERCs required for deduction under § 62.16535(e); and

(ii) Each day until the requisite number of ERCs are held for deduction shall constitute a separate violation of this subpart and the Clean Air Act.

(4) Any provision of the GHG Rate-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU shall also apply to the owners or operators of such affected EGU.

(g) Effect on other authorities. No provision of the GHG Rate-based Trading Program or exemption under § 62.16415 shall be construed as exempting or excluding the owners or operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable approved State plan, federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16425 How is time computed time under the Greenhouse Gas Rate-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the GHG Rate-based Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the GHG Rate-based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the GHG Rate-based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16430 What are the administrative appeal procedures?

(a) The administrative appeal procedures for decisions of the Administrator under the GHG Rate-based Trading Program are set forth in part 78 of this chapter.

(b) [Reserved]

Emission Rate Credit Issuance, Adjustment, and Revocation

§ 62.16434 What affected EGUs qualify for issuance of ERCs, and what amount of ERCs may they be issued?

(a) ERCs may only be issued to affected EGUs under the conditions listed in paragraphs (b) and (c) of this section.

(b) An Affected EGU may be issued ERCs if it emits CO_2 below its applicable emission standard, in the amount calculated using the following equation:

$$\text{ERCs} = \frac{(\text{EGU standard} - \text{EGU operating rate})}{\text{EGU standard}} * \text{EGU generation}$$

Where:

ERCs = Number of emission rate credits that may be issued to an affected EGU during an applicable calendar quarter rounded down to the nearest

		whole integer (MWh).
EGU emission standard	=	The emission standard the affected EGU must comply with during the applicable compliance period according to § 62.16420 (lb/MWh).
EGU emission rate	=	The affected EGU's CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).
EGU generation	=	Total net energy output generation of the affected EGU during the the applicable calendar quarter measured in accordance with § 62.16540 (MWh).

(c) A stationary combustion turbine that meets the definition of an affected EGU may be issued GS-ERCs for electricity generation during a given calendar year when the operation of the affected EGU exceeds the unit-specifc net energy output threshold. The number of GS-ERCs issued must be calculated in accordance with paragraphs (c)(1) through(3) of this section.

(1) To calculate the number of GS-ERCs:

$$\mathrm{GS-ERCs} = (\mathrm{MWh}_{\mathrm{total}} - \mathrm{MWh}_{\mathrm{threshold}}) * \mathrm{EF}_{\mathrm{GS-ERC}}$$

Where:

GS-ERC	=	Calculated GS-ERCs rounded down to the nearest whole integer (MWh).

MWh_{total}	=	Total net energy output generation of the affected EGU during the applicable calendar year measured in accordance with § 62.16540 (MWh).
$MWh_{threshold}$	=	Affected EGU's net energy output threshold operation calculated using the equation in paragraph (c)(2) of this section.
$EF_{GS\text{-}ERC}$	=	Value calculated using the equation in paragraph (c)(3) of this section.

(2) To calculate the net energy output threshold generation for the affected EGU:

$$MWh_{threshold} = \frac{CF_{regional}}{100} \times \text{Net Summer Capacity} \times \text{Hours in the Year}$$

Where:

$MWh_{threshold}$	=	Affected EGU's net energy output threshold operation to be used in the equation in paragraph (c)(1) of this section (MWh-net).
$CF_{regional}$	=	Regional capacity factor in percent according to Table 2 of this subpart.
Net Summer Capacity	=	Affected EGU's net summer capacity (MW).
Hours in the Year	=	Hours in the applicable calendar year.

(3) To calculate the GS-ERC emission factor for the affected EGU:

$$EF_{GS-ERC} = 1 - \frac{\text{EGU emission rate}}{\text{Steam Generating Unit Emission Standard}}$$

Where:

EF_{GS-ERC}	=	GS-ERC emission factor.
EGU emission rate	=	Affected EGU's reported CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh-net).
Steam generating unit emission standard	=	Steam generating unit emission standard for the corresponding compliance period as found in Table 1 of this subpart (lb/MWh-net).

(4) GS-ERCs may be used for compliance only by an affected EGU meeting the definition of a steam generating unit or IGCC unit. Notwithstanding any other provision of this subpart, GS-ERCs may not be used for compliance by an affected EGU that is a stationary combustion turbine.

§ 62.16435 What resources are considered eligible resources?

(a) Affected EGUs may only use for compliance ERCs issued to resources that qualify to be an eligible resource, by meeting each of the specified requirements in paragraphs (a)(1) through (5) of this section in addition to being approved by a State through an approved eligibility application.

(1) The electric generating resource is new or increased electrical generating capacity that was installed on or after January 1, 2013. If a resource had a nameplate capacity uprate,

then ERCs may be issued only for generation from the uprated generating capacity, which is the difference in generating capacity between the uprated nameplate capacity and the nameplate capacity prior to the uprate. ERCs may not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in capacity between the uprated nameplate capacity and the nameplate capacity prior to the uprate is eligible to be issued ERCs.

(2) The demand-side energy eficiency (EE) project(s) or measures that comprise an energy efficiency resource were installed or implemented on or after January 1, 2013.

(3) The resource is connected to, and delivers electricity to or saves electricity on, the electric grid in the contiguous United States.

(4) (i) The resource is located in this State or any other state whose affected EGUs are subject to rate-based emission standards pursuant to subpart UUUU of 40 CFR part 60, including

areas of Indian country that do not have any affected EGUs located within the borders of the State or such states; or

(ii) The resource is located in a state with mass-based emission standards under subpart UUUU of 40 CFR part 60 (including areas of Indian country that do not have any affected EGUs located within the borders of such a state), or Canada or Mexico, in which case the following additional requirements apply:

(A) The resource can demonstrate delivery (e.g., through a power purchase agreement or contract for delivery) of its electricity generation with an intent to meet load in this State or another state whose affected EGUs are subject to rate-based emission standards pursuant to subpart UUUU of 40 CFR part 60; and

(B) The resource is limited to those listed in paragraph (a)(5) (i) of this section.

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

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

(ii) Nuclear energy;

(iii) Non-affected CHP unit;

(iv) WHP unit; or

(v) A demand-side EE project or measure that saves electricity and where electricity savings are calculated on the basis of quantified ex post savings.

(6) The state will not prohibit an eligible resource from receiving ERCs or allowances on the basis that the resource is located in Indian country.

(b) An affected EGU cannot use ERCs issued to any resource that does not meet the requirements of this subpart in the compliance demonstration required under § 62.16420.

(c) No ERCs shall be issued to any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of part 60 of this chapter, except CHP units that meet the requirements of paragraph (a) of this section;

(2) EGUs that do not meet the applicability requirements of § 62.16410, except CHP units that meet the requirements of paragraph (a) of this section;

(3) Measures that do not reduce CO_2 emissions from affected EGUs, including, for example, GHG offset projects representing sequestration due to forestry and agriculture, direct air capture and storage or sequestration of GHGs, and crediting of

CO_2 emission reductions from vehicles as a result of vehicle electrification; and

(4) Any measure not approved by the Administrator to generate ERCs in connection with a specific State plan approved by the Administrator.

(d) Two or more renewable energy resources that are separately interconnected and metered may aggregate to form one eligible resource for the purposes of the eligibility application required in § 62.16445, the EM&V plan required in § 62.16455, and the M&V report required under § 62.16460 only when the provisions of paragraphs (d)(1) and (2) are met.

(1) The nameplate capacity of each separately interconnected and metered renewable energy resource is less than 150 kW, and the sum of the nameplate capacities of all aggregated renewable energy resources does not exceed 10 MW; and

(2) Each aggregation of the renewable energy resources meet the following essential generating characteristics requirements:

(i) Each renewable energy resource and its composite generating units are of the same renewable resource type;

(ii) Each renewable energy resource and it composite generating units are located in the same state;

(iii) Each renewable energy resource must share the same level of grid interconnection and be aggregated by interconnection level at either the retail-customer level or of the transmission, subtransmission, or distribution level;

(iv) The generation data of each renewable energy resource must be measured by meters of the same minimum level of measurement accuracy and be subject to the same maintenance and quality assurance procedures.

(3) Notwithstanding this provision, the following requirements will continue to apply for renewable energy resources that aggregate under an eligibility application, EM&V plan, and M&V report:

(i) For an eligiblity application § 62.16445(c)(2)(ii) must apply to all of the individual aggregated renewable energy resources; and

(ii) Monitoring as required in the EM&V plan must still apply to each individual aggregated renewable energy resource;

(e) Two or more non-affected CHP units may be aggregated to form one eligible resource for the purposes of the eligibility application required in § 62.16445, the EM&V plan required in §

62.16455, and the M&V report required under § 62.16460 only when the requirements of paragraphs (e)(1) and (2) are met.

(1) Each aggregation of non-affected CHP units must meet the following essential generating characteristics requirements:

(i) Each non-affected CHP unit is of the same non-affected CHP unit type;

(ii) Each non-affected CHP unit is located in the same state;

(iii) Each non-affected CHP unit must share the same level of grid interconnection and be aggregated by interconnection level at either the retail-customer level or of the transmission, subtransmission, or distribution level;

(iv) The generation of each non-affected CHP unit must be measured by meters of the same minimum level of measurement accuracy and be subject to the same maintenance and quality assurance procedures.

(2) In additon to the requirements of paragraph (e)(1), where two or more non-affected CHP units that are separately interconnected and metered are aggregated, the nameplate capacity of each separately interconnected and metered non-affected CHP unit must be less than 1 MW, and the sum of the

nameplate capacities of all such aggregated non-affected CHP units may not not exceed 25 MW.

(3) Notwithstanding this provision, the following requirements will continue to apply for non-affected CHP units that are aggregated under an eligibility application, EM&V plan, and M&V report:

(i) For an eligiblity application § 62.16445(c)(2)(ii) must apply to all of the individual non-affected CHP units; and

(ii) Monitoring and reporting as required in the EM&V plan must still apply to each individual aggregated non-affected CHP unit.

(f) A non-affected CHP unit that is an eligible resource may only be issued ERCs according to the requirements of paragraphs (f)(1) through (3) of this section.

(1) The electricity generation for which ERCs may be issued to a non-affected CHP unit, as calculated in accordance with paragraphs (f)(2) and (3) as applicable, may not exceed the lesser of the following two values:

(i) The non-affected CHP unit's reported net electricity generation during the relevant reporting period, as reported in accordance with the applicable EM&V plan as specified in § 62.16455(e); or

(ii) The maximum possible net electricity generation of the non-affected CHP unit for the the reported operating hours in the relevant reporting period, determined according to the applicable EM&V plan as specified in § 62.16455(e), without the use of supplemental fuel (e.g., supplemental firing in duct burners) and at the maximum possible useful thermal output of the unit (e.g., for a non-affected CHP unit with condensing steam turbines, the maximum possible net electric generation would be determined based on its electric generation at the maximum level of steam extraction and/or bypass).

(2) For a non-affected CHP unit that is not a WHP unit, the electricity generation for which ERCs may be issued may only be calculated according to the following equation:

$$\text{ERCs} = \left(1 - \frac{\text{CHP}_{nae}\text{CO}_2\text{ Emission Rate}}{\text{Reference CO}_2\text{ Emission Rate}}\right) \times \text{CHP}_{na}\text{Electricity Generation}$$

Where:

ERCs = The number of ERCs that may be issued for electricity generation by the non-affected CHP unit for the relevant reporting period.

CHP_{nae} CO_2 Emission Rate	=	The non-affected CHP unit's CO_2 emission rate attributed to electricity generation during the relevant reporting period, calculated according to paragraph (f)(2)(ii) of this section. If the CO_2 emission rate calculated in accordance with paragraph (f)(2)(ii) of this section is less than zero, a rate of 0 lb/MWh is applied. (lb/MWh)
Reference CO_2 Emission Rate	=	The applicable reference CO_2 emission rate as determined according to paragraph (f)(2)(i) of this section. (lb/MWh)
CHP_{na} Electricity Generation	=	The non-affected CHP unit's reported net electricity generation during the relevant reporting period, as determined according to paragraph (f)(1) of this section. (MWh)

(i) The reference CO_2 emission rate for a non-affected CHP unit is based on the electricity generating technology listed in either paragraph (f)(2)(i)(A) or (B) of this section.

(A) For a non-affected CHP unit that uses a stationary combustion turbine, the reference CO_2 emission rate is the emission standard for affected stationary combustion turbines in Table 1 of this subpart for the compliance period corresponding with the non-affected CHP unit's relevant reporting period.

(B) For a non-affected CHP unit that uses a steam generating unit, the reference CO_2 emission rate is the emission standard for affected steam generating units in Table 1 of this subpart for the compliance period corresponding with the non-affected CHP unit's relevant reporting period.

(ii) To calculate a non-affected CHP unit's CO_2 emission rate attributed to electricity generation use the following equation:

$$\mathrm{CHP_{nae}\ CO_2\ Emission\ Rate} = \frac{\mathrm{CO_2\ CHP}_{na} - \mathrm{CO_2\ CHP_t}}{\mathrm{CHP}_{na}\ \mathrm{Electricity\ Generation}}$$

Where:

CHP_{nae} CO_2 Emission Rate	=	The non-affected CHP unit's CO_2 emission rate attributed to electricity generation during the relevant reporting period. (lb/MWh)
CO_2CHP_{na}	=	The reported total CO_2 emissions from the non-affected CHP unit during the relevant reporting period. (lb)
CO_2CHP_t	=	The CO_2 emissions attributed to the non-affected CHP unit's useful thermal output during the relevant reporting period, calculated according to paragraph (f)(1)(iii) of this section. (lb)
CHP_{na} Electricity Generation	=	The non-affected CHP unit's reported net electricity generation during the relevant reporting period, as determined according to paragraph (f)(1) of this section. (MWh)

(iii) To calculate the CO_2 emissions attributed to the non-affected CHP unit’s useful thermal output use the following equation:

$$CO_2CHP_t = RTEU_{HI} \times EF_{Fuel} \times 2.2\ {}^{lb}/_{kg}$$

Where:

CO_2CHP_t	=	The CO_2 emissions (in lb) attributed to the non-affected CHP unit’s useful thermal output.
$RTEU_{HI}$	=	The total assumed heat input for the replacement thermal energy unit (RTEU) during the relevant reporting period, calculated according to paragraph (f)(1)(iv). (mmBtu)
EF_{Fuel}	=	The CO_2 emission factor for the fuel used by the replacement thermal energy unit, calculated according to paragraph (f)(1)(vi). (kg/mmBtu)

(iv) To calculate the assumed heat input for the replacement thermal energy unit use the following equation:

$$RTEU_{HI} = \frac{UTO}{RTEU_{RAE}}$$

Where:

$RTEU_{HI}$	=	The total assumed heat input for the replacement thermal energy unit (RTEU) during the relevant reporting period. (mmBtu)
UTO	=	The reported useful thermal output (UTO) from the non-affected CHP unit. (mmBtu)

$RTEU_{RAE}$ = The applicable representative annual efficiency of the replacement thermal energy unit, calculated according to paragraph (f)(1)(v) of this section. (dimensionless)

(v) To calculate the representative annual efficiency of the replacement thermal energy unit during the relevant reporting period use the following equation:

$$\mathrm{RTEU_{RAE}} = \frac{((\mathrm{HI}_C + \mathrm{HI}_P) \times .85) + (\mathrm{HI}_{NG} \times 0.80) + (\mathrm{HI}_{Other} \times 0.75)}{\mathrm{HI}_C + \mathrm{HI}_P + \mathrm{HI}_{NG} + \mathrm{HI}_{Other}}$$

Where:

$RTEU_{RAE}$ = The applicable representative annual efficiency of the replacement thermal energy unit (RTEU). (dimensionless)

HI_C = Heat input from the combustion of coal at the non-affected CHP unit during a reporting period. (mmBtu)

HI_P = Heat input from the combustion of petroleum at the non-affected CHP unit during a reporting period. (mmBtu)

HI_{NG} = Heat input from the combustion of natural gas at the non-affected CHP unit during a reporting period. (mmBtu)

HI_{Other} = Heat input from the combustion of other all fuels at the non-affected CHP unit during a reporting period. (mmBtu)

(vi) The fuel used by the replacement thermal energy unit is the fuel used by the non-affected CHP unit during the relevant reporting period. The CO_2 emission factor for the fuel used by the non-affected CHP unit is found in Table C-1 of Part 98 Subpart C of this chapter. If more than one fuel is used by the non-affected CHP unit during the relevant reporting period then a heat input weighted average CO_2 emission factor is calculated using the following equation:

$$EF_{Fuel} = \frac{\sum_{i=1}^{n} (\text{Fuel } i_{HI} \times \text{Fuel } i_{CO2\ EF})}{\sum_{i=1}^{n} \text{Fuel } i_{HI}}$$

Where:

EF_{Fuel}	=	The CO_2 emission factor for the fuel used by the replacement thermal energy unit (kg/mmBtu).
Fuel i_{HI}	=	The reported total heat input for the non-affected CHP unit during the relevant reporting period for fuel type *i*. (mmBtu)
Fuel i_{CO2EF}	=	The CO_2 emission factor for fuel type i, according to Table C-1 of Part 98 Subpart C of this chapter. (kg/mmBtu)
n	=	The total number of fuels combusted during the relevant reporting period.

(3) A non-affected CHP unit that is a WHP unit may only be issued ERCs for the unit’s net electricity generation (in MWh) during the relevant reporting period as determined according to paragraph (f)(1) of this section.

§ 62.16440 What is the process for revocation of qualification status of an eligible resource?

(a) If the State finds that a resource previously determined to be an eligible resource does not meet the requirements of § 62.16435, then the State will revoke the qualification of the resource as an eligible resource, so that it cannot be issued ERCs. In this case, the provisions of § 62.16450 may apply.

(b) The state may revoke the qualification of the resource as an eligible resource if the circumstances identified in paragraph (b)(i) or (ii) of this section occur. If the state revokes the qualification of the resource, the provisions of § 62.16450 may apply.

(i) Any instance of intentional misrepresentation in an eligibility application or monitoring and verification (M&V) report, or

(ii) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports or other submissions.

§ 62.16445 What is the process for the issuance of ERCs?

Affected EGUs may use for compliance only ERCs that have been issued to affected EGUs and eligible resources through the process, and that meet the requirements, in paragraphs (a) through (f) of this section.

(a) Eligibility application. To be eligible to be issued ERCs, the designated representative of an affected EGU or the authorized account representative of an eligible resource must submit an eligibility application as specified in paragraphs (b) and (c) of this section. Additionaly, for a designated representative the the requirements of § 62.16515 for submittal of a certificate of representation for an affected EGU must be met. The eligibility application must demonstrate that the requirements, as applicable, of § 62.16434 (for an affected EGU) or § 62.16435 (for an eligible resource) are met. If there is a material change in information submitted in the eligibility application then the affected EGU or eligible resource must re-submit an eligibility application to reflect the change.

(b) Eligibility application for an affected EGU. An eligibility application for an affected EGU must be submitted to the State through the ERC-TCS and must include the information in paragraphs (b)(1) through (7) of this section.

(1) Information about the affected EGU included in its account certificate of representation under § 62.16500, including the effective date for the certificate of representation.

(2) Identification of the affected EGU’s compliance account in the ERC-TCS.

(3) The submission date, submission ID and monitoring location(s) of the monitoring plan for the facility at which the affected EGU(s) is located, or for the affected EGU, as submitted under § 75.53 of this chapter.

(4) The accounting method for calculating ERCs and/or GS-ERCs that will be used for issuance of ERCs to the affected EGU.

(5) A statement certifying that the designated representative of the affected EGU is registering to receive any ERCs or GS-ERCs that may be issued to the affected EGU according to section 62.16434.

(6) The following statement, signed by the designated representative of the affected EGU:

“I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(7) Any other information required by the State.

(c) Eligibility application for an eligible resource. An eligibility application for an eligible resource must be submitted to the State, in a format prescribed by the State, and must include the following, as applicable:

(1) Identification of the authorized account representative for the eligible resource, including the authorized account representative's name, regular mail address, e-mail address, telephone number, and identification of the ERC-TCS account into which any ERCs issued for the eligible resource will be recorded. The authorized account representative specified in the eligibility application shall represent the eligible resource in all submittals and actions required by this section.

(2) The following information about the eligible resource, as applicable:

(i) Physical location and contact information for the owner or operator of the eligible resource, if different from the authorized account representative;

(ii) For an electric generating resource:

(A) For each generating unit that comprises the electric generating resource, generating unit prime mover and/or technology type; nameplate electric generating capacity; generating unit category (e.g., wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit identifications (EIA ORIS Code and Facility Registration System (FRS) Code, if applicable); the control area, balancing authority, indpendent system operator as defined in § 62.16570, or the regional transmission organization in which the generating unit is located (if applicable).

(B) For an electric generating unit with a nameplate capacity of 1 MW or more that is included as part of an electric generating resource, a copy of the most recent filing of the generating unit's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA-860.

(C) For an electric generating unit with a nameplate capacity of less than 1 MW that is included as part of an electric generating resource, the information that would be contained in a U.S. Energy Information Agency's Annual Electric Generator Report Form EIA-860.

(iii) For an energy efficiency resource, a detailed description of the demand-side energy efficiency project(s) and/or measures that comprise the resource, including: the parties installing or implementing the energy efficiency project(s) and/or measures, including lead contractor(s), subcontractors, and consulting firms (if different from the authorized account representative); electricity-using system(s), end-use(s), building or facility type(s) where the energy efficiency projects and/or measures are implemented or will be implemented; specifications of energy-saving equipment, materials, and/or practices implemented or to be implemented;; and additional technical specifications and documentation, as applicable.

(iv) For an energy efficiency program, the information in paragraph (c)(2)(iii) of this section plus a description of the program, including: overall approach or "logic" to the program, including assumptions about how EE projects or EE measures intalled or implemented as part of the program will achieve quantifiable electricity savings; and the delivery mechanism(s) of the program, which may include financial incentives or equipment rebates, dissemination of actionable information to electricity customers, and on-site audits paired with technical recommendations.

(3) For eligible resources with components at distributed locations, such as electric generating units or energy efficiency projects and/or measures at multiple residential, commercial, or industrial buildings, aggregated information about the location of electric generating units or energy efficiency projects and/or measures that constitute an eligible resource, provided that the eligibility application must attest that the accredited independent verifier and the State will have the ability to access information, upon request, specifying the location of each discrete electric generating unit, energy efficiency project, and/or energy efficiency measure that constitutes an eligible resource.

(i) Aggregation of multiple renewable energy electric generating units as a single renewable energy eligible resource must be in accordance with § 62.16455(c)(4).

(ii) Aggregation of multiple nuclear energy electric generating units as a single nuclear energy eligible resource must be in accordance with § 62.16455(d)(2).

(iii) Aggregation of multiple non-affected CHP units as a single non-affected CHP eligible resource must be in accordance with § 62.16455(e).

(iv) Aggregation of multiple WHP units as a single WHP eligible resource must be in accordance with § 62.16455(e).

(v) Aggregation of multiple energy efficiency projects and/or energy efficiency measures as a single energy efficiency eligible resource must be in accordance with § 62.16455(f)(4).

(4) Demonstration that the eligible resource meets all applicable eligibility requirements in § 62.16435.

(5) A certification that the eligibility application has been submitted to only one State or pursuant to a single EPA-approved multi-state plan where States are providing for joint issuance of ERCs pursuant to their individual State authority.

(6) An evaluation, measurement, and verification (EM&V) plan for the eligible resource that meets the requirements of § 62.16455, as applicable to the type of eligible resource.

(7) A verification report for the eligible resource from an accredited independent verifier that meets the requirements of §§ 62.16470 and 62.16475.

(8) An authorization that provides for the following: the State may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(9) The following statement, signed by the authorized account representative of the eligible resource:

"I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(10) Any other information required by the State.

(d) Registration of affected EGUs and eligible resources. The State will review the eligibility application for an affected EGU or eligible resource to determine whether the affected EGU or eligible resource meets the requirements of paragraph (a) through (c) of this section, and if it determines that the requirements are met, approve the eligibility application and register the affected EGU or eligible resource in the State ERC Document Management System. Once so registered, the affected EGU or eligible resource is qualified to be issued ERCs, provided all applicable requirements of this subpart continue to be met. If a State does not act on the eligiblity application for an affected EGU within 60 days of submittal of the eligibility application, then the eligiblity application is deemed to be approved and the affected EGU is qualified to be issued ERCs.

(e) M&V reports. For a qualified eligible resource, the authorized account representative must submit to the State an M&V report that meets the requirements of § 62.16460 prior to issuance of ERCs by the State. A M&V report may cover a period ranging from one calendar quarter to 24 months in length.

(f) Verification reports. For an eligible resource, the authorized account representative must include a verification report from an accredited independent verifier that meets the requirements of §§ 62.16470 and 62.16475 as part of each eligibility application and M&V report. While considered a part of the eligibility application and M&V report, the verification report must be submitted separately by the accredited independent verifier to the State in a format prescribed by the State.

(g) Issuance of ERCs. (1) ERCs and GS-ERCs may be issued by the State to an affected EGU provided that all requirements of this subpart are met for the affected EGU to be issued ERCs. ERCs will be issued by the State and recorded by the tracking system operator in the compliance account for the affected EGU within 60 days following the quarterly deadline for reporting valid CO_2 emissions and energy output data for the previous calendar quarter according to § 62.16555 or EPA publication of these data §, whichever is later. GS-ERCs are issued by the State annually and recorded by the tracking system operator in the compliance account for the affected EGU within 60 days of the fourth quarter reporting deadline of January 30 for reporting valid CO_2 emissions and energy output data according to § 62.16555 or EPA publication of these data, whichever is later.

(2) ERCs may be issued by the State to a eligible resource

based only on actual electricity generation or savings documented in an M&V report that meets the requirements of § 62.16460 and a verification report that meets the requirements of § 62.16465. The State will determine, within 50 days of receipt of a complete M&V report, the number of ERCs to be issued to the eligible resource and will make this determination publicly accessible through the ERC-TCS. Upon completion of its review of an M&V report, the tracking system operator will, within 10 days, record the appropriate number of ERCs in the ERC-TCS account identified by the State. Only one ERC will be issued for each verified MWh of electricity generation or savings.

(h) Tracking system. ERCs may be issued only through the ERC-TCS. The tracking system operator will ensure that the ERC-TCS has electronic, internet-based access to the State's ERC Document Management and Approval System.

§ 62.16450 What is the process for addressing error or misstatement, misrepresentation, or failure to meet requirements?

(a) In the event of error or misstatement, misrepresentation, or failure to meet the requirements of this subpart regarding quantified MWh of electricity generation or savings in an M&V report for which ERCs have been issued, the

State or the tracking system operator will adjust the number of ERCs issued in a subsequent reporting period to address such circumstances, by, for example, subtracting a number of MWh from the quantified and verified MWh in the M&V report for a subsequent reporting period. In the event that such circumstances occur in a final M&V report for an eligible resource, for which ERCs have been issued, the provisions of paragraph (b) of this section will apply. In the event that such circumstances occur for an affected EGU, for which ERCs have been issued, the provisions of paragraph (c) of this section will apply.

(b) In the event of error or misstatement, misrepresentation, or failure to meet the requirements of this subpart regarding quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which ERCs have been issued, the State or the tracking system operator will revoke ERCs from the general account of the eligible resource in an amount necessary to correct such circumstance. In the event that the general account of the eligible resource holds an insufficient number of ERCs to correct such circumstance, the authorized account representative must surrender for deduction to the tracking system operator within 30 days a number of ERCs necessary to correct such circumstance. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the State.

(c) In the event of error or misstatement, misrepresentation, or failure to meet the requirements of this subpart regarding quantified MWh of electricity generation for an affected EGU, for which ERCs have been issued, the State or the tracking system operator will revoke ERCs from the compliance account of the affected EGU, in an amount necessary to correct the error or misstatement. In the event that the compliance account of the affected EGU holds an insufficient number of ERCs to correct the circumstance, the designated representative must surrender for deduction to the tracking system operator a number of ERCs necessary to correct the error or misstatement.

(d) The State or the tracking system operator may freeze the general account of an eligible resource at any time if it has been determined that ERCs have been improperly issued, based on an error or misstatement, misrepresentation, or failure to meet the requirements of this subpart in an eligibility application or M&V report. The State or the tracking system operator may also freeze the general account of an eligible resource, pending investigation of potential error or misstatement, misrepresentation, or failure to meet the requirements of this subpart in an eligibility application or M&V report. Freezing a general account will prevent transfer of ERCs out of the account.

(e) If ERCs are issued to an affected EGU or resource that is found to be ineligible, then the State or the tracking system operator may take the actions in paragraphs (e)(1) through (3) of this section.

(1) Freeze the account of the affected EGU or resource, preventing any transfers of ERCs out of the account.

(2) Revoke and deduct ERCs held in the account of the affected EGU or resource, in a number equal to the number of ERCs improperly issued to the affected EGU or resource.

(3) In the event that the account of the affected EGU or resource holds a number of ERCs less than the number of ERCs improperly issued to the affected EGU or eligible resource, the designated representative of the affected EGU or the authorized account representative of the resource, that is found to be ineligible must acquire and surrender for deduction to the

tracking system operator within 30 days the number of ERCs necessary. Failure to meet this requirement will result in prohibition of the eligible resource and the authorized account representative, or the affected EGU and the designated representative, from further eligibility to be issued ERCs in the GHG Rate-based Trading Program, unless reauthorized at the discretion of the State.

(f) The State or the tracking system operator may temporarily or permanently suspend issuance of ERCs for an eligible resource or affected EGU pending investigation of potential error or misstatement, misrepresentation, or failure to meet the requirements of this subpart in an eligibility application, an M&V report or any other investigation with respect to the eligibility status of an eligible resource or affected EGU or their quantified MWh of electricity generation or savings.

Evaluation, Measurement and Verification Plans; Monitoring and Verification Reports; and Verification Reports

§ 62.16455 What are the requirements for evaluation, measurement and verification plans for eligible resources?

Affected EGUs may only use for compliance ERCs that have been issued to eligible resources according to the requirements for evaluation, measurement, and verification (EM&V) plans set forth in paragraphs (a) through (f) of this section.

(a) EM&V plan requirements. Any EM&V plan submitted as part of an eligibility application in support of the issuance of an ERC pursuant to this rule must meet the requirements of this section.

(b) General EM&V plan requirements. An EM&V plan must identify the eligible resource (including individual electric generating unit(s), energy efficiency project(s), and energy efficiency measures) addressed in the eligibility application and the reporting period that the EM&V plan covers. For an eligible energy efficiency resource, this period must not exceed the effective useful life of the energy efficiency project(s) and/or measures that comprise the eligible resource, as specified in paragraph (e)(9) of this section.

(c) EM&V plan requirements for renewable energy resources. An EM&V plan must specify the manner in which the electricity generated by individual renewable energy generating units that comprise eligible renewable energy resources will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the requirements listed in paragraphs (c)(1) through (11) of this section, as applicable.

(1) For a renewable energy resource with a nameplate capacity of 5 MW or more, the EM&V plan must specify that the generation data will be physically measured on a continuous basis using a meter that meets or exceeds the American National Standards Institute No. C12.20, American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Class. A petition may be submitted to the State to use a meter that meets an alternative equivalent standard for performance and measurement accuracy and the petition, if approved, must be included in the EM&V plan.

(2) For a renewable energy resource with a nameplate capacity of 30 kW or more and less than 5 MW, the EM&V plan must specify that the generation data will be physically measured on a continuous basis using a meter that meets or exceeds the American National Standards Institute No. C12.1, American National Standard for Electric Meters – Code for Electricity Metering. A petition may be submitted to the State to use a meter that meets an alternative equivalent standard for performance and measurement accuracy and the petition, if approved, must be included in the EM&V plan.

(3) For a renewable energy resource with a nameplate capacity of less than 30 kW, the EM&V plan must specify that the

generation data will be physically measured on a continuous basis using a meter that is accurate to within +/- 5 percent or better of the actual generation output, in accordance with the following subsections (i) through (ii).

(i) The EM&V plan must specify quality assurance procedures for how each meter will be validated to meet and maintain +/- 5 percent accuracy in measurement.

(ii) The EM&V plan must specify how electricity generation data will be collected and validated, and specify measures to ensure that the meter itself and any data measurements from it cannot be tampered with, adjusted or manipulated in any manner. At a minimum, such measures must include restrictions that would preclude the consideration of any physically measured generation beyond the technical potential of the eligible resource in ERC issuance. For example, such measures may include the following methodology: calculation of a maximum generation estimate based on the technical potential for the eligible renewable energy resource, based on an estimating methodology that is specified in the EM&V plan; comparison of the physically metered generation to the maximum generation estimate; and if the physically metered generation exceeds the maximum generation estimate, then only the amount of physically measured generation up to the maximum generation estimate may be considered in ERC issuance, whereas if the physically metered generation is lower than the maximum generation estimate, then only the physically metered generation may be considered in ERC issuance.

(4) For a renewable energy resource of any nameplate capacity, metered electricity generation data for each renewable energy resource must be associated with a single grid interconnection. A renewable energy resource and its total measured electricity generation may be comprised of two or more generating units associated with a single grid interconnection if the following provisions are met.

(i) All generating units are of the same resource type; and

(ii) The measured generation of the renewable energy resource must be physically measured, net of any non-consumer load-related losses or any electricity used by a generator unit in the generation of electricity, such as station service, auxiliary loads, or parasitic loads.

(5) For a renewable energy resource of any nameplate capacity that is using an installed meter that exceeds the metering requirements of paragraphs (c)(1) through (c)(3) of this section, as applicable, an EM&V plan must specify use of such a meter or a meter of equivalent accuracy.

(6) For a renewable energy resource of any nameplate capacity, the generation data must be measured at the nearest practical point to a generating unit’s grid interconnection, or bus bar interconnection for retail-customer sited resources, meaning at the point of delivery in which the AC output of the generating unit can be isolated from the grid or differentiated from other sources of generation.

(7) For a renewable energy resource of any nameplate capacity, any generation data that is electronically telemetered from the generator to its control area operator and validated at least monthly through a control area energy accounting or settlement process may be used to demonstrate a renewable energy resource’s generation levels. If the generating unit is not subject to a control area operator and to validation through a control area energy accounting or settlement process that occurs at least monthly, paragraphs (c)(7)(i) through (iii) of this section apply, as appropriate.

(i) The EM&V plan must specify how generation data will be collected by manual meter readings on a monthly basis and must specify how the data will be validated by a party unaffiliated with the owner or operator of the generating unit(s) of the renewable energy resource.

(ii) If the renewable energy resource generates less than 1 MWh of electricity on a monthly basis, then the metered generation data of each single interconnected renewable energy resource may be collected on an annual basis. In this case, the generation data must be collected by manual meter readings for that annual period and must be validated by a party unaffiliated with the owner or operator of the renewable energy resource and its composite generating units, and the EM&V plan must specify how these requirements will be met. Each renewable energy resource subject to this paragraph (7)(ii) must be evaluated in each subsequent annual period to determine whether the resource’s monthly output is less than 1 MWh and whether collection of electricity generation data on an annual basis may be continued.

(iii) If the generation data is measured by a meter pursuant to subsection (c)(3) of this section, a petition may be submitted to the state to allow for self-reporting of generation data. The petition, if approved, must be included in the EM&V plan. Under such an approved petition, each EM&V plan must specify, at a minimum: requirements of self-reporting; allowable limits for reporting cumulative meter readings; allowable frequency of self-reporting; the process for validating reported generation data; and must specify record keeping and submission requirements of metered generation for all self-reporting renewable energy resources and their composite generating units.

(8) For a renewable energy resource of any nameplate capacity, all generation data must be net of any non-consumer load-related losses or any electricity used by a generating unit in the generation of electricity such as station service, auxiliary loads, or parasitic loads, in accordance with the following provisions:

(i) All generation data must be net of any generation used to supply the ancillary equipment used to operate a generating unit (“station service”) or parasitic load on the generating unit’s side of the point of interconnection with the grid; and

(ii) For generating units interconnected to a transmission system and with on-site loads other than non-consumer loads, such as station service, the EM&V plan must demonstrate that the metering approach used is capable of distinguishing between other on-site loads and non-consumer loads, such as station service.

(9) Retail-customer sited renewable energy resources may quantify the avoided electricity transmission and distribution losses (in MWh) from eligible onsite renewable energy resources

that is used to serve coincident onsite retail-consumer load. For these renewable energy resources, the EM&V plan must specify the method and appropriate loss factor used in calculating the avoided transmission and distribution losses pursuant to subsection (g) of this section. Calculation of avoided transmission and distribution losses may only be applied to the electricity generation from renewable energy resources, as measured pursuant to paragraphs (c)(1), (c)(2) or (c)(3) of this section, that used to serve coincident onsite retail-consumer load. The EM&V plan must specify a method for determining the eligible proportion of generation used to serve coincident onsite retail-consumer load by the eligible renewable energy resource and its composite generating units.

(10) Any other requirements specified by the State.

(d) EM&V plan requirements for nuclear power resources. An EM&V plan must specify the manner in which the electricity generated by the eligible nuclear power resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (d)(1) through (7) of this section, as applicable.

(1) An EM&V plan must specify that for an eligible nuclear power resource of any capacity size, the generation data will be physically measured on a continuous basis using a meter that meets or exceeds the American National Standards Institute No. C12.20, American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Class. A petition may be submitted to the State to use a meter that meets an alternative equivalent standard for performance and measurement accuracy and the petition, if approved, must be included in the EM&V plan.

(2) The generation data for each eligible nuclear power resource must be associated with a single metered grid interconnection. A nuclear power resource and its total measured generation may be comprised of two or more individual nuclear power generating units associated with a single grid interconnection. The measured electricity generation from two or more independently metered nuclear power generating units may be summed that share the same grid interconnection.

(3) All generation data must be net of any electricity used by the generating unit in the generation of electricity such as station service, auxiliary loads, or parasitic loads, in accordance with the following provision:

(i) All generation data must be net of any generation used to supply the ancillary equipment used to operate a nuclear generating unit (“station service”) or parasitic load on the generating unit’s side of the point of interconnection with the grid.

(4) The generation data of a nuclear power generating unit must be measured at the nearest practical point to the generating unit’s grid interconnection, meaning at the point of delivery in which the AC output of the generating unit can be isolated from the grid, net of any electricity used by the generating unit in the generation of electricity, such as station service, auxiliary loads, or parasitic loads.

(5) For a nuclear power resource of any namplate capacity, the generation data must be electronically telemetered from the nuclear power resource or its composite generating units to its control area operator and validated through a control area energy accounting or settlement process that occurs at least monthly.

(6) Any other requirements specified by the State.

(e) EM&V plan requirements for non-affected CHP units. An EM&V plan for a non-affected CHP unit must specify the manner in which the CO_2 emissions, heat input, electricity generation, and useful thermal output of the non-affected CHP unit will be quantified, measured, and verified. The manner of quantification, measurement and verification must meet the requirements listed in paragraphs (e)(1) through (9) of this section, as applicable.

(1) For a non-affected CHP unit with an electric generating nameplate capacity greater than 1 MW, the EM&V plan must specify:

(i) The CO_2 emissions monitoring and reporting requirements, and heat input monitoring and reporting requirements in accordance with the requirements in § 62.16540.

(ii) Electricity generation must be physically measured on a continuous basis using a meter that meets or exceeds the American National Standards Institute No. C12.20, American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Class. A petition may be submitted to the State to use a meter that meets an alternative equivalent standard for performance and measurement accuracy, and the petition, if approved, must be included in the EM&V plan.

(2) For a non-affected CHP unit with an electric generating nameplate capacity less than or equal to 1 MW, the EM&V plan must specify:

(i) A method, for approval by the State, for monitoring and reporting of CO_2 emissions and heat input. The EM&V plan must specify requirements for quarterly reporting of heat input by fuel type and how CO_2 emissions will be calculated based on reported heat input.

(ii) Electricity generation must be physically measured on a continuous basis using a meter that meets or exceeds the American National Standards Institute No. C12.1, American National Standard for Electric Meters – Code for Electricity Metering. A petition may be submitted to the State to use a meter that meets an alternative equivalent standard for performance and measurement accuracy, and the petition, if approved, must be included in the EM&V plan.

(3) For a non-affected CHP unit of any nameplate capacity that is using an installed meter that exceeds the metering requirements of paragraph (e)(1)(ii) or (e)(2)(ii) of this section, as applicable, an EM&V plan must specify use of such a meter or a meter of equivalent accuracy.

(4) For all non-affected CHP units of any nameplate capacity, electricity generation must be measured at the nearest practical point to the generating unit’s grid interconnection, or bus bar interconnection for retail-customer sited resources,

meaning at the point of delivery in which the output of the generating unit can be isolated from the grid or differentiated from other sources of electricity generation.

(5) For non-affected CHP units of any nameplate capacity, any electricity generation data that is electronically telemetered from the generator to its control area operator and validated at least monthly through a control area energy accounting or settlement process may be used to demonstrate a non-affected CHP unit’s generation levels. If the non-affected CHP unit is not subject to a control area operator and to validation through a control area energy accounting or settlement process that occurs at least monthly, paragraph (e)(5)(i) of this section applies.

(i) The EM&V plan must specify how generation data will be collected by manual meter readings on a monthly basis and must specify how the data will be validated by a party unaffiliated with the owner or operator of the non-affected CHP unit(s).

(6) For all non-affected CHP units of any nameplate capacity, all generation data must be net of any non-consumer load-related losses or any electricity used by the generating unit in the generation of electricity, such as station service,

auxiliary loads or parasitic loads, in accordance with the following provisions:

(i) All generation must be net of any generation used to supply the ancillary equipment used to operate a generating unit ("station service") or parasitic load on the generating unit's side of the point of interconnection with the grid; and

(ii) For generating units interconnected to a transmission system and with on-site loads other than non-consumer loads, such as station service, the EM&V plan must demonstrate that the metering approach used is capable of distinguishing between other on-site loads and non-consumer loads, such as station service.

(7) Retail customer-sited non-affected CHP units may quantify the avoided electricity transmission and distribution losses (in MWh) from onsite non-affected CHP units that is used to serve coincident onsite retail customer load. For these non-affected CHP units, the EM&V plan must specify the method and appropriate loss factor used in calculating the avoided transmission and distribution losses pursuant to subsection (g) of this section. Calculation of avoided transmission and distribution losses may only be applied to the electricity generation from a non-affected CHP unit, as measured pursuant to

paragraphs (e)(1)(ii) or (e)(2)(ii) of this section, that is used to serve coincident onsite retail-consumer load. The EM&V plan must specify a method for determining the eligible proportion of generation used to serve coincident onsite retail-consumer load by the non-affected CHP unit(s).

(8) For non-affected CHP units that are not WHP units, the EM&V plan must specify that useful thermal output will be physically measured on a continuous hourly basis according to the procedures in § 62.16540(a)(5)(i)(B).

(i) An EM&V plan must specify the operation and calibration of equipment that measures pressure, temperature and steam flow leaving the CHP unit and that measures the temperature and flow of returning condensate, or the pressure, temperature and steam flow of returning steam. The useful thermal output of non-affected CHP units must be demonstrated to meet a minimum +/- 5 percent accuracy in measurement over the CHP’s operation during the measurement period and the EM&V plan must detail how this requirement will be met. An EM&V plan must specify the method for selection and application of appropriate thermal measurement instrumentation to ensure the minimum measurement accuracy is achieved. An EM&V plan must specify how the useful thermal output data will be validated and verified for the purpose of ERC issuance.

(ii) The EM&V plan must describe how the useful thermal output data will be manually collected and validated by an independent third-party that is not affiliated with the owner or operator of the non-affected CHP unit or the representative for the eligible resource that includes the non-affected CHP unit.

(9) Any other requirements specified by the State.

(f) <u>EM&V plan requirements for demand-side energy efficiency resources</u>. An EM&V plan for a demand-side energy efficiency ("EE") resource must specify how electricity savings from EE projects and/or EE measures that comprise the EE resource will be quantified and verified, in accordance with the requirements in paragraphs (f)(1) through (12) of this section.

(1) An EM&V plan must provide a detailed description of the EE projects or EE measures that the EM&V plan addresses.

(2) An EM&V plan must specify the period of time for which the EM&V plan applies, which may not exceed the effective useful life (EUL) of the EE projects or EE measures addressed in the EM&V plan, as specified in paragraph (e)(9) of this section.

(3) An EM&V plan must specify that all electricity savings from EE projects or EE measures addressed in the EM&V plan will

be quantified after the electricity savings have occurred, or at the same time that the electricity savings are occurring.

(4) An EM&V plan must specify how electricity savings will be quantified and verified in accordance with the requirements in paragraphs (f)(4)(i) through (x) of this section for each type of EE project and/or EE measure that the EM&V plan addresses, as applicable. A single EM&V plan must separately address and specify these requirements for each distinct type of EE project and/or EE measure that comprise the EE resource.

(i) An EM&V plan must specify that all electricity savings will be quantified pursuant to the EM&V plan must be quantified as equal to the difference between the electricity usage with the EE project and/or EE measure in place and the applied common practice baseline (CPB) for each EE project and/or EE measure, which must meet the requirements of paragraph (f)(5) of this section.

(ii) An EM&V plan must include EM&V method(s) used to quantify electricity savings that adhere to one or more best-practice protocols or guidelines, which must meet the requirements of paragraphs (f)(6) and (f)(7) of this section.

(iii) The EM&V methods included in an EM&V plan must specify how the interactive effects among EE projects or EE measures will be addressed, and such specifications must meet the requirements of paragraph (f)(8) of this section.

(iv) The EM&V methods included in an EM&V plan must include a methodology for adjusting electricity usage values to account for the effects of independent variables, which must meet the requirements of paragraphs (f)(6) and (f)(8)(ii) of this section.

(v) An EM&V plan must indicate whether a pre-specified EUL or an annually verified EUL will be applied for each EE project and EE measure addressed in the EM&V plan, and include a demonstration of why that EUL appraoch is appropriate for the specific EE project or EE measure addressed in the EM&V plan. A pre-specified EUL must meet the requirements of paragraph (f)(9)(i) of this section and an annually verified EUL must meet the requirements of paragraph (f)(9)(ii) of this section.

(vi) An EM&V plan must include the method for verifying the installation and operation of each EE project or EE measure addressed in that EM&V plan, which must meet the requirements of paragraph (f)(10) of this section.

(vii) An EM&V plan must include the method for assessment of the accuracy of quantified electricity savings from the EE project(s) or EE measure(s) addressed in an EM&V plan, which must meet the requirements of paragraphs (f)(6) and (f)(11) of this section.

(vii) An EM&V plan must include the method for adjustment to the quantified electricity savings to account for transmission and distribution losses, as applicable, which must meet the requirements of paragraph (f)(12) of this section.

(ix) An EM&V plan must include any additional information necessary to demonstrate that electricity savings from an EE project or EE measure addressed in an EM&V plan will be appropriately quantified and verified, which must meet the requirements of paragraph (f)(13) of this section.

(x) Any other requirements necessary to quantify and verify electricity savings, as specified by the State.

(5) An EM&V plan must document the basis for selection of each CPB applied in the EM&V plan and must:

(i) Demonstrate the appropriateness of that CPB for the specific EE project or EE measure to which it is applied, which must be based on each of the following:

(A) Characteristics of the EE project(s) and/or EE measure(s) (e.g., installation of high-efficiency equipment or facility operational change);

(B) For high-efficiency equipment, the installation strategy (e.g. replacement upon equipment failure, early replacement, or new construction);

(C) Local consumer and market characteristics (e.g., prevailing market shares of equipment of particular energy efficiency levels among different consumer segments);

(D) Applicable building energy codes and standards (e.g. state-adopted building energy codes related to building envelope, equipment efficiency, or overall performance rating); and

(E) Applicable appliance and equipment standards (e.g. federal or state standards for minimum energy efficiency levels for particular lighting or HVAC technology).

(ii) Specify the process by which the applied value of a CPB will be reviewed at least every 3 years and updated as necessary. An updated value of a CPB must be applied to all EE projects or EE measures addressed in an EM&V plan that are installed or that begin operating after such an update occurs. The review and update process specified in the EM&V plan must ensure that applied values of a CPB will reflect changes, if any, in the electricity use that would occur, in the absence of the EE project or EE measure, at the more energy-efficient of:

(A) The highest level of energy efficiency required by the applicable federal, state, or local building energy code or product or equipment standard, if any; or

(B) The expected technology, operating conditions, or practices that would have existed at the time of implementation or the likely subsequent replacement within the timeframe of the EUL of the EE project and/or EE measure, in the absence of the EE project or EE measure.

(6) An EM&V plan must document the basis for selection of the best-practice EM&V protocols or guidelines applied in the EM&V plan, specify how the best-practice EM&V protocols or guidelines will be applied, and demonstrate the appropriateness of those best-practice EM&V protocols or guidelines for the EE projects and/or EE measures to which they are applied. A protocol or guideline is considered to be “best practice” if it:

(i) Is identified as a best-practice protocol or guideline in the EE EM&V guidance issued by the EPA; or

(ii) Has gone through a rigorous and credible development and vetting process that includes review by EM&V experts and other stakeholders representing multiple affected organizations and interests, and has been approved by the State as meeting the requirements of paragraph (f)(6).

(7) An EM&V plan must document the basis for selection of the one or more EM&V method(s) identified in the EM&V plan, specify how the EM&V method(s) will be applied, and demonstrate the appropriateness of that the EM&V method(s) for the EE project(s) and/or EE measure(s) to which it is applied. Each EM&V method must be applied according to the following requirements:

(i) Each EM&V method must fall within one of the following categories: Direct measurement and verification EM&V methods; deemed savings EM&V methods; or comparison group EM&V methods.

(ii) If the EM&V method is the deemed savings EM&V method, the following requirements must be met:

(A) The EM&V plan must document why the use of the specific deemed savings electricity savings value or formula is appropriate for the specific EE project(s) and/or EE measure(s) addressed in the EM&V plan.

(B) The deemed savings electricity savings value or formula must be documented in a freely available database or spreadsheet, which may be known as a technical reference manual (TRM), that is accessible on a public Web site, specifies the conditions for which each deemed savings electricity savings value or formula may be applied (e.g., climate zone, building type, and implementation strategy, such as retrofit, replacement on failure, or new construction), and specifies the source of each deemed savings value or formula.

(C) A deemed savings electricity savings value or formula must quantify electricity savings as the difference between the electricity used by the EE project or EE measure and the CPB for each EE project or EE measure, as described above in paragraph (f)(5) of this section. A deemed savings electricity savings value or formula for an EE project must also account for the interactions between individual EE measures that comprise the EE project.

(D) An EM&V plan must specify the process by which each deemed savings electricity savings value or formula will be reviewed at least every 3 years in accordance with paragraph (f)(7)(ii) of this section, and updated as necessary, to reflect applicable research studies and analysis. The EM&V plan must also specify the process by which an updated deemed savings electricity savings value or formula will be applied to all EE projects and/or EE measures addressed in an EM&V plan that are installed or begin operating after such an update occurs.

(8) An EM&V plan must describe how interactive effects and independent variables are addressed in the EM&V methods for

quantification of electricity savings in the EM&V plan, in accordance with the following requirements:

(i) An EM&V plan must at a minimum address the following three types of interactive effects:

(A) Other-system effects;

(B) Multi-measure effects; and

(C) EE program overlap.

(ii) An EM&V plan must identify any independent variables that affect electricity use, and specify how the quantified value of electricity savings will be adjusted to account for the effects of such independent variables. The EM&V plan must indicate that electricity savings will be be quantified for the average conditions of the independent variables over the EUL of the EE project or EE measure in the EM&V plan.

(9) An EM&V plan must indicate whether a pre-specified EUL or an annually verified EUL will be applied for each EE project and EE measure addressed in the EM&V plan, and include a demonstration of why that EUL appraoch is appropriate for the EE project(s) and/or EE measure(s) to which it is applied. EULs for an EE project must account for differences in EUL values among the EE measures that comprise the EE project, as applicable. An EUL must meet the following requirements:

(i) Pre-specified EUL. A pre-specified EUL must be based on the criteria in paragraph (f)(9)(i)(A); and only if the criteria in paragraph (f)(9)(i)(A) are unavailable, then by the criteria in paragraph (f)(9)(i)(B); and only if the criteria in paragraph (f)(9)(i)(B) are unavailable, then by the criteria in paragraph (f)(9)(i)(C).

(A) An EE project or EE measure persistence study conducted according to the requirements of a best practice protocol for determining EUL values, and with the 80 percent confidence limits for the EUL no more than +/-20 percent different from the EUL estimate.

(B) A deemed EUL that is documented in a database or spreadsheet, which may be known as a TRM, and that meets the requirements for documentation of deemed savings values and forumulas described in paragraph (f)(7)(ii) of this section.

(C) An independent third-party laboratory lifeftime testing protocol.

(i) Annually verified EUL. An annually verified EUL must verify on an annual basis that the EE measures addressed in an EM&V plan, including EE measures that comprise an EE project, are delivering electricity savings and meet the requirements in paragraph (f)(10) of this section.

(10) An EM&V plan must document the best-practice approaches that will be used to verify electricity savings from EE projects or EE measures adressed in the EM&V plan, in accordance with the following requirements:

(i) To verify that EE projects or EE measures are installed and operating, the following requirements must be met, as applicable:

(A) For an EE program consisting of the installation of multiple EE projects or EE measures at different locations, the EM&V plan must specify the process that will be used to verify the quantity of each type of EE project or EE measure that is installed and operating during the period of time for which the EM&V plan applies.

(B) For EE projects or EE measures intended to influence consumer behavior, the EM&V plan must specify the process that will be used to verify that the project(s) or measure(s) continue to have the intended effect on consumer behavior during the period of time for which the EM&V plan applies.

(C) For an EE project that may be partially operational, the EM&V plan must specify the process that will be used to verify what portions of the EE project are installed and operational during the period of time for which the EM&V plan applies.

(ii) To verify the quantified value of electricity savings, each EM&V plan must specify the processes and approaches that will be applied for quality assurance and quality control of all values, formulas, and calculations used to quantify electricity savings.

(11) Each EM&V plan must specify how the accuracy of electricity savings will be assessed for the EE projects or EE measures adressed in the EM&V plan. This must include an assessment of how the types of measurement error that are inherent to EM&V will be controlled, as well as how random error will be quantified. The quantifiable statistical errors that must be considered include both sampling error and modeling or estimation error. For each reporting period, the total quantified electricity savings values must have a 90 percent confidence interval with end points that differ from the quantified value by no more than +/-10 percent of that value. This requirement for statistical accuracy applies to the combined effect of all measurable sources of statistical uncertainty across the EE projects or EE measures addressed in an EM&V plan. It is not necessary to calculate an explicit 90

percent confidence interval for the total quantified electricity savings, as long as it can be shown using valid statistical methods that the confidence interval is not more than 10 percent from the estimate.

(12) An EM&V plan may include a method for quantifying avoided electricity transmission and distribution losses for the EE projects and/or EE measures adressed in the EM&V plan, provided that requirements of paragraph (g) of this section are met.

(g) Transmission and distribution electricity losses. If avoided transmission and distribution electricity losses will be included in the quantification of eligible electricity generation from RE and non-affected CHP resources that are sited and interconnected on the retail-consumer side of the utility meter; or electricity savings from a demand-side EE measure, program, or project, the applicable EM&V plan must specify the method used to determine the associated transmission and distribution loss factor, as well as the numerical value of such loss factor. Avoided transmission and distribution electricity losses are quantified by multiplying the eligible MWh generation from RE and non-affected CHP resources that are sited and interconneted on the retail-consumer side of the utility meter, or MWh savings from demand-side EE by the appropriate loss factor. The appropriate loss factor must be determined in accordance with paragraphs (g)(i) through (g)(ii) of this section, as applicable.

(i) The appropriate loss factor is the annual average loss factor of the electric utility serving the physical address where the eligible resource is located. The loss factor is determined using the most recent publicly available data for the utility reported in Form 861 (EIA-861) to the U.S. Energy Information Agency using the following equation:

$$T\&D\ utility\ loss\ factor = \frac{Total\ electricity\ losses}{Total\ retail\ electricity\ sales + Total\ electricity\ losses}$$

Where:

T&D utility loss factor	=	A factor derived using EIAs 861 Operational Dataset for an individual utility for a specific year.
Total electricity losses	=	A value found in EIAs 861 Operational Dataset “total energy losses” column of the disposition data for the individual utility. Losses are electricity not consumed by the utility customer load, such as electricity consumed directly by the individual utility (MWh).
Total retail	=	A value derived from EIAs 861 Operational

electricity sales		Dataset from the "retail sales" column of the disposition data for the individual utility (MWh).

(ii) Where the data necessary for calculating a utility-specific average transmission and distribution loss factor(s) under subparagraph (i) above is unavailable, incomplete, or not reported in EIA-861, or where an eliglble resource or program is implemented across multiple utility service territories, the appropriate loss factor is the average loss rate for all utilities in the state where the eligible resource is located. The loss factor is determined using the most recent publicly available data reported in EIA-861 and the following equation:

$$T\&D\ State\ loss\ factor = \frac{\sum Total\ electricity\ losses_{state}}{\sum Total\ retail\ electricity\ sales_{state} + \sum Total\ electricity\ losses_{state}}$$

Where:

T&D State loss factor	=	A factor derived using EIAs 861 Operational Dataset at the State level.
Total electricity $losses_{state}$	=	A value derived from EIAs 861 Operational Dataset by summing the values from the "total energy losses" column of the disposition data for each utility in the State (MWh).
Total retail electricity $sales_{state}$	=	A value derived from EIAs 861 Operational Dataset by summing the values of the "retail sales" column from the disposition

data for each utility in the State (MWh).

§ 62.16460 What are the requirements for monitoring and verification reports for eligible resources?

Affected EGUs may use for compliance ERCs issued to eligible resources only if those ERCs have been issued to eligible resources in accordance with the requirements for monitoring and verification reports set forth in paragraphs (a) through (c) of this section and meet other applicable requirements.

(a) M&V report requirements. Any M&V report that is submitted, in support of the issuance of ERCs to a eligible resource that can be used for compliance by an affected EGU in accordance with § 62.16420, must meet the requirements of this section.

(b) M&V report contents. Each M&V report must include the information in paragraphs (b)(1) and (2) of this section.

(1) For the first M&V report submitted for an eligible resource, demonstration that the electric generating unit(s) that comprise(s) an eligible electric generating resource or the energy efficiency project(s) and/or measures that comprise(s) an eligible energy efficiency resource are installed or implemented

consistent with the description in the approved eligibility application required in § 62.16445(a).

(2) For each M&V report submitted for an eligible resource it must include the following:

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

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

(iii) Documentation (including data) of the electricity generation or electricity savings by the eligible resource , quantified and verified in MWh for the period covered by the M&V report (on an ex-post basis), in accordance with the EM&V plan for the eligible resource;

(iv) All relevant data and supporting documentation that support quantified and verified MWh of electricity generation or electricity savings for the eligible resource, including all activity data, as provided in accordance with the EM&V plan for the eligible resource; and

(v) Documentation of any change in ownership interest of the qualifying eligible resource, including the date of the change.

(c) Any M&V report submitted pursuant to this subpart must include the following certification from the authorized account representative for the eligible resource:

(1) "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) [Reserved]

§ 62.16465 What are the requirements for verification reports?

Affected EGUs may use for compliance ERCs issued to eligible resources only if those ERCs have been issued in accordance with the requirements for verification reports set forth in subsections (a) through (c) of this section, and meet other applicable requirements of this subpart.

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of subsection (b) of this section (for a verification report included as part of an eligibility application) or subsection (c) of this section (for a verification report included as part of an M&V report), and must include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable requirements of this subpart. The verification statement must clearly identify how levels of verification assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: "I certify under penalty of law that I

have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and provide the accredited independent verifier's assessment including the information required in paragraphs (b)(1) through (6) of this section.

(1) The eligibility of the eligible resource to be issued ERCs, in accordance with § 62.16435 and **§** 62.16445(a), including an analysis of the adequacy and validity of the information included in the eligibility application to demonstrate that the eligible resource meets each applicable requirement of § 62.16435 and **§** 62.16445(a).

(2) The eligible resource is not duplicative of an eligible resource used to meet emission standards or a state measure in another approved State plan.

(3) The eligible resource exists or has been and/or will be implemented in the manner specified in the eligibility application.

(4) The EM&V plan for the eligible resource meets the requirements of § 62.16455.

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (e.g., reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system).

(6) Any other information required by the State or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied in the eligibility application.

(c) A verification report included as part of a M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and provide the accredited independent verifier’s assessment of each of the following:

(1) The adequacy and validity of the information and data included in the M&V report to quantify the MWh of electricity

generation or electricity savings during the period covered by the M&V report, as well as all supporting information and data identified in the EM&V plan and included in the M&V report. The analysis by the accredited independent verifier must include a quality assurance and quality control check of the data included in the M&V report, as well as all relevant data that supports the data included in the M&V report, and an evaluation of whether quantified electricity generation or electricity savings in the M&V report are within a technically feasible range for the eligible resource.

(2) The electricity generation or electricity savings in the M&V report were quantified and verified in accordance with the EM&V plan for the qualified eligible resource, and the M&V report meets all other applicable requirements of this subpart.

(3) Any other information required by the State or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data included in the M&V report.

§ 62.16470 What is the accreditation procedure for independent verifiers?

Affected EGUs may use for compliance ERCs from eligible resources only if those ERCs have been verified by independent verifiers accreditated through the procedures set forth in this section, and meet other applicable requirements.

(a) Only State-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the State which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet and maintain each of the requirements in paragraphs (c)(1) through (7) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, and resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the GHG Rate-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; performance of site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification statement, list of findings, and verification report; and internal review of the verification findings and report.

(2) Identification of the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and documentation that

they meet the requirements of section § 62.16470(d)(1). Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Independent verifiers must meet the requirements of **§** 62.16475 and maintain documentation that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in

31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either Standard & Poor’s or Moody’s, specifically, AAA, AA, A or BBB for Standard & Poor’s, and Aaa, Aa, A, or Baa for Moody’s. Any entity covered by this paragraph must disclose the level of professional liability insurance it possesses when entering into contracts to provide verification services pursuant to this regulation.

(7) Accredited independent verifiers must meet the requirements of § 62.16475 when providing verification services for an an eligible resource.

§ 62.16475 What are the procedures accredited independent verifiers must follow to avoid conflicts of interest?

Affected EGUs may use for compliance ERCs from eligible resources only if those ERCs have been verified by accredited independent verifiers that follow the procedures to avoid conflict of interest set forth in this section, and meet other applicable requirements.

(a) An accredited independent verifier must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) An accredited independent verifier must not have, or have had, any direct or indirect financial interest in, or other financial affiliation with (e.g., parent or subsidiary corporate relationship, general or limited partnership, etc.), an eligible resource, or prospective eligible resource, for which it seeks to provide verification services;

(2) An accredited independent verifier must not have, or have had, any direct or indirect organizational or personal relationships with an eligible resource, that would impact its impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report for the eligible resource;

(3) An accredited independent verifier must not have, or have had, any role in the development and implementation of an eligible resource for which it provides verification services, with the exception of the provision of verification services;

(4) An accredited independent verifier must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, ERC issuance, or the number of ERCs issued);

(5) An accredited independent verifier must not own, buy, sell, or hold ERCs, or other financial derivatives related to ERCs, or have a financial affiliation (e.g., ownership interest, parent or subsidiary corporate relationship, general or limited partnership, etc.) with other parties that own, buy, sell, or hold ERCs or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to comment on or otherwise influence the contents of any draft or final verification report before its submittal to the State. If an accredited verifier shares any drafts of a verification report with the subject of the report, the accredited independent verifier must also share any such drafts of the verification report with the State at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the State any potential COI, including any potential appearance of a COI, related to the eligible resource that is the subject of the verification report.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must submit to the State documentation regarding any potential COI as specified in paragraph (a) of this section related to the eligible resource.

(1) Such submittal must include all information necessary for the State to evaluate any potential COI, including any potential appearance of a COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(2) If a COI, or the appearance of a COI, is identified for any person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier must also propose to the State in such submittal the steps that will be taken to eliminate the COI, which include prohibiting the person or persons with the conflict from any involvement in the matter subject of the conflict, including verification services, access to information

related to the verification services, access to any draft or final verification reports, or any communications with the person(s) conducting the verification services.

(3) In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the State.

(e) Accredited verifiers have an ongoing obligation to disclose to the State any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(f) The State may reject a verification report from an accredited independent verifier, if the State determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the State rejects an accredited independent verification report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and ERCs must not be issued pursuant to it.

§ 62.16480 What is the process for the revocation of accreditation status for an independent verifier?

(a) The State may revoke the accreditation of an independent verifier at any time for cause, including for the following reasons:

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16475(d) through (f).

(2) Lack of continued qualification to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16465, 62.16470, and 62.16475.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

Designated Representatives

§ 62.16485 How are designated representatives and alternate designated representatives authorized and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16495, each affected EGU, and each eligible resource shall have one designated representative, with regard to all matters under the GHG Rate-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the affected

EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the tracking system operator of a complete certificate of representation under § 62.16500:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the affected EGU in all matters pertaining to the GHG Rate-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the designated representative by the State or the tracking system operator regarding the affected EGU.

(b) Except as provided under § 62.16495, each affected EGU may have one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of

the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the tracking system operator of a complete certificate of representation under § 62.16500,

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the alternate designated representative by the State or the tracking system operator regarding any such affected EGU.

(c) Except in this section, §§ 62.16490 through 62.16510, and § 62.16570, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16490 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16510 concerning delegation of authority to make submissions, each submission under the GHG Rate-based Trading Program must be made, signed, and certified by the designated representative or alternate designated representative for each affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the affected EGU for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(b) The tracking system operator will accept or act on a submission made for an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16510.

§ 62.16495 What are the processes for changing the designated representative, the alternate designated representative, the list of owners or operators, and the list of affected EGUs?

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the tracking system operator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the tracking system operator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the affected EGU.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the tracking system operator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the tracking system operator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the affected EGU.

(c) Changes in list of owners or operators. (1) In the event an owner or operator of an affected EGU is not included in the list of owners and operators in the certificate of representation under § 62.16500, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the affected EGU, and the decisions and orders of the State or tracking system operator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners or operators of an affected EGU, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16500 amending the list of owners or operators to reflect the change.

(d) Changes in affected EGUs at the source. Within 30 days of any change in which affected EGUs are located at a source (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16500 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation must identify, in a format prescribed by the tracking system operator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the source.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the tracking system operator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the

affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the source.

§ 62.16500 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the elements in paragraphs (a)(1) through (5) of this section in a format prescribed by the tracking system operator.

(1) Identification of the affected EGU for which the certificate of representation is submitted, including name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by the affected EGU, net-summer capacity, actual or projected date of commencement of commercial operation, and a statement of whether the affected EGU is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected EGU.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected EGU”;

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the GHG Rate-based Trading Program on behalf of the owners and operators of the affected EGU and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the State or tracking system operator regarding the affected EGU”; and

(iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the affected EGU; and ERCs and proceeds of transactions involving GHG Rate-based Trading Program ERCs will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of ERCs by contract, ERCs and proceeds of transactions involving GHG Rate-based Trading Program ERCs will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the tracking system operator, documents of agreement referred to in the certificate of representation shall not be submitted to the Tracking system operator. The Tracking system operator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

<u>§ 62.16505 What is the tracking system operator’s role in objections concerning designated representatives and alternate designated representatives?</u>

(a) Once the tracking system operator receives a complete certificate of representation under § 62.16500, he or she will rely on the certificate of representation unless and until he or she receives a superseding complete certificate of representation under § 62.16500.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the tracking system operator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the State or tracking system operator under the GHG Rate-based Trading Program.

(c) The tracking system operator will not address or attempt to resolve any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of ERC transfers.

<u>§ 62.16510 What process must designated representatives and alternate designated representatives follow to delegate their authority?</u>

(a) A designated representative or alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the tracking system operator provided for or required under this subpart.

(b) In order to delegate authority to a natural person to make an electronic submission to the tracking system operator in accordance with paragraph (a) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the tracking system operator a notice of delegation, in a format prescribed by the tracking system operator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(3) For each agent, a list of the type or types of electronic submissions under paragraph (a) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Tracking system operator that is made by an agent identified in this notice of delegation and of a type listed for delegation to such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16510(c), if any, shall be deemed to be an electronic submission by me"; and

(ii) "Until this notice of delegation is superseded by another notice of delegation under § 62.16510(c), if any, I agree to maintain an e-mail account and to notify the Tracking system operator immediately of any change in my e-mail address unless all delegation of authority by me under § 62.16510 is terminated."

(c) A notice of delegation submitted under paragraph (b) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Tracking system operator and until receipt by the Tracking system operator of a superseding notice of delegation, if any, submitted by such designated representative or alternate designated representative, as appropriate. Such superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(d) Any electronic submission covered by the certification in paragraph (b)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (c) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping, Reporting

§ 62.16515 How are compliance accounts, retirement accounts, and general accounts established and used, and how is ERC issuance documentation accessed?

(a) Compliance accounts. (1) Upon receipt of a complete certificate of representation under § 62.16500, the tracking system operator will establish a compliance account for the affected EGU for which the certificate of representation was submitted, unless the affected EGU already has a compliance account. The designated representative and any alternate designated representative of an affected EGU shall be the authorized account representative and the alternate authorized account representative, respectively, of the compliance account.

(2) The compliance account will hold ERCs intended for surrender by a designated representative when demonstrating the affected EGU’s compliance with a CO_2 emission standard as applicable in § 62.16420. A compliance account may be established for each affected EGU within the facility.

(b) Retirement accounts. The tracking system operator will establish a retirement account, into which ERCs held in a compliance account for an affected EGU are transferred for surrender by the designated representative of an affected EGU, in order to demonstrate compliance with the applicable emission standards. The retirement account may held by only the tracking system operator. Except for actions by the tracking system operator as provided for in § 62.16550 and § 62.16565, once an

ERC is retired, the ERC shall no longer be transferable to another account in that ERC-TCS or any other ERC tracking system.

(c) General accounts—(1) Application for a general account. (i) The designated representative of an affected EGU, the authorized account representative of an eligible resource, and any other person on behalf of any other entity may apply to open a general account, for the purpose of holding and transferring ERCs, by submitting to the tracking system operator a complete application for a general account. Such application must designate one authorized account representative and may designate one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and any alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to ERCs held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the tracking system operator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons, and associated identifying information, subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the ERCs held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: “I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to ERCs held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the GHG Rate-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the State or the tracking system operator regarding the general account”; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the tracking system operator, documents of agreement referred to in the application for a general account shall not be submitted to the tracking system operator. The tracking system operator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the tracking system operator of a complete application for a general account under paragraph (c)(1) of this section, the tracking system operator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the tracking system operator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to ERCs held in the general account in all matters pertaining to the GHG Rate-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to ERCs held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the State or the tracking system operator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account must be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to ERCs held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the ERCs held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) Except in this section, whenever the term “authorized account representative” is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) <u>Changing authorized account representative and alternate authorized account representative; changes in persons</u>

with ownership interest. (i) The authorized account representative or alternate authorized account representative of a general account may be changed at any time upon receipt by the tracking system operator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative or alternative authorized account representative, before the time and date when the tracking system operator receives the superseding application for a general account shall be binding on the new authorized account representative or alternative authorized account representative, as the case may be, and the persons with an ownership interest with respect to the ERCs in the general account.

(ii)(A) In the event a person having an ownership interest with respect to ERCs in the general account is not included in the list of such persons under section (c)(1)(ii)(C) of this section in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the State or the tracking system operator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to ERCs in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the ERCs in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the tracking system operator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the tracking system operator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the tracking system operator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the State or the tracking system operator under the GHG Rate-based Trading Program.

(iii) The tracking system operator will not address or attempt to resolve any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of ERC transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative or alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the tracking system operator provided for or required under this subpart.

(ii) In order to delegate authority to a natural person to make an electronic submission to the tracking system operator in accordance with paragraph (c)(5)(i) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the tracking system operator a notice of delegation, in a format prescribed by the tracking system operator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such agent, a list of the type or types of electronic submissions under paragraph (c)(5)(i) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the tracking system operator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under **§** 62.16515(c)(5)(iii), if any, shall be deemed to be an electronic submission by me”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under **§** 62.16515(c)(5)(iii), if any, I agree to maintain an e-mail account and to notify the Tracking system operator immediately of any change in my e-mail address unless all delegation of authority by me under **§** 62.16515(c)(5) is terminated.”

(iii) A notice of delegation submitted under paragraph (c)(5)(ii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the tracking system operator and until receipt by the tracking system operator of a superseding notice of delegation, if any, submitted by such authorized account representative or alternate authorized account representative, as appropriate. Such superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(iv) Any electronic submission covered by the certification in paragraph (c)(5)(ii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iii) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the tracking system operator a request to close the account. Such request must include a correctly submitted ERC transfer under § 62.16525 for any ERCs in the account to one or more other ERC-TCS accounts.

(ii) If a general account has no ERC transfers to or from the account for a 12-month period or longer and does not contain any ERCs, then the tracking system operator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the tracking system operator receives a correctly submitted ERC transfer under § 62.16525 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the tracking system operator good cause as to why the account should not be closed.

(d) Account identification. The tracking system operator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the tracking system operator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of ERCs in the account, only if the submission has been made, signed, and certified in accordance with § 62.16490(a) and § 62.16510 or paragraphs (c)(2)(ii) and (c)(5) of this section.

(f) ERC identification information. Any ERC issued in the ERC-TCS will be assigned a unique serial identifier that includes at a minimum the two digit postal abbreviation of the

State in which it was issued and includes the year it was issued, and the eligible resource category that generated it. The format of the unique serial identifier may only be changed by the Administrator.

(g) Records supporting ERC issuance. The tracking system operator will maintain in the ERC-TCS and make publicly available records of, for each ERC, all of the following:

(1) Account holder name and identifying information;

(2) Authorized account representative name and identifying information;

(3) Qualifying eligible resource identification number, name, State, and contact information including street address, mailing address, phone number, and email address;

(4) Category of qualifying eligible resource, according to the categories specified in § 62.16435(a)(4);

(5) Date the qualifying eligible resource commenced generation or saving of energy;

(6) Identifying information for each ERC, including the unique serial identifier that meets the requirements of paragraph (f) of this section;

(7) Records of ERC transfers among accounts, including the date of transfer and the accounts involved in the transfer;

(8) Date an ERC was surrendered for a compliance demonstration;

(9) Date an ERC was retired by the regulatory body; and

(10) Each eligibility application, EM&V plan, M&V report, and verification report associated with the issuance of each ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the tracking system operator.

(h) Access to records supporting ERC issuance. The tracking system operator will provide access and functionality to allow each ERC to be traceable by the public to the records in the ERC-TCS listed in paragraph (g) of this section. The tracking system operator will provide internet-based electronic access to this information in the ERC-TCS searchable by, at a minimum, each eligible resource, affected EGU, eligible resource category, and ERC.

(i) Report Generation in the ERC-TCS. The tracking system operator will provide internet-based electronic access to data in the ERC-TCS to enable the generation of at least the following reports at the start of the first compliance period and for as long as this regulation is effective.

(1) Account activity reports. Each account holder can generate account activity reports based on records of their account activity, including the information listed in paragraph (g) of this section.

(2) Public reports. The public can generate reports that include all of the information listed in paragraph (g) of this section; a list of all registered account holders in the ERC-TCS, including compliance accounts and general accounts; a list of all eligible resources (including access to all documentation for such eligible resources); a list of all accredited independent verifiers; and aggregate ERC activity statistics on at least an annual basis, for at least the following: issuance of ERCs, transfers among accounts, transfers in or out of the ERC-TCS to/from another approved ERC tracking system (if relevant), and ERC retirements.

(3) EPA reports. The EPA or State regulators can generate reports including the information listed in paragraph (g) of this section and any other information regarding ERC issuance, transfer, surrender, and retirement for purpose of compliance with this regulation.

(j) Interactions with other ERC tracking systems. If approved in connection with a State plan, then the ERC-TCS will provide for transfers of ERCs to/from another ERC tracking system approved in connection with a State plan by the EPA.

§ 62.16525 How must transfers of ERCs be submitted?

(a) An authorized account representative seeking recordation of an ERC transfer must submit the transfer to the tracking system operator.

(b) An ERC transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the tracking system operator:

(i) The account numbers established by the Tracking system operator for both the transferor and transferee accounts;

(ii) The serial number of each ERC that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date the transfer is signed; and

(2) When the tracking system operator attempts to record the transfer, the transferor account includes each ERC identified by serial number in the transfer.

§ 62.16530 When will ERC transfers be recorded?

(a) Except as provided in paragraph (b) of this section, within five business days of receiving an ERC transfer that is correctly submitted under § 62.16525, the tracking system operator will record an ERC transfer by moving each ERC from the transferor account to the transferee account as specified in the transfer.

(b) An ERC transfer to or from a compliance account that is submitted for recordation after the ERC transfer deadline for a compliance period and that includes any ERCs allocated for any compliance period before such ERC transfer deadline will not be recorded until after the tracking system operator completes the deductions from such compliance account under § 62.16535 for the compliance period to which the ERC transfer deadline applies.

(c) Where an ERC transfer is not correctly submitted under § 62.16525, the Tracking system operator will not record such transfer.

(d) Within five business days of recordation of an ERC transfer under paragraphs (a) and (b) of the section, the tracking system operator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of an ERC transfer that is not correctly submitted under § 62.16525, the tracking system operator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16535 How will deductions for compliance with a CO_2 emission standard occur?

For affected EGUs subject to the emission standards listed in Table 1 of this subpart, the owner or operator of an affected EGU must demonstrate compliance with its CO_2 emission standard in accordance with § 62.16420(c) and incorporate ERCs as listed in paragraphs (a) through (f) of this section.

(a) Availability for deduction for compliance. ERCs are available to be deducted from a compliance account and used for compliance with an affected EGU’s CO_2 emissions standard for a compliance period only if the ERCs:

(1) Were issued for a year in such compliance period or a prior compliance period; and

(2) Are held in the affected EGU's compliance account as of the ERC transfer deadline for such compliance period.

(b) Deductions for compliance. After the recordation, in accordance with § 62.16530, of ERC transfers submitted by the ERC transfer deadline for a compliance period, the tracking system operator will deduct from each affected EGU's compliance account ERCs available under paragraph (a) of this section in order to determine whether the affected EGU meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of ERCs deducted and subsequently added to the total MWh generated by the affected EGU adjusts the affected EGU’s CO_2 emission rate to equal the CO_2 emission standard for such compliance period; or

(2) If there are insufficient ERCs to complete the deductions in paragraph (b)(1) of this section, until no more ERCs available under paragraph (a) of this section remain in the compliance account.

(c) Identification of ERCs by serial number. The designated representative for an affected EGU's compliance account may request that specific ERCs, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (e) of this section. Such request must be submitted to the tracking system operator by the ERC transfer deadline for such compliance period and, in order to be complete, must include, in a format prescribed by the tracking system operator, the identification of the affected EGU and the appropriate ERC serial numbers.

(d) First-in, first-out. The tracking system operator will deduct ERCs under paragraph (b) or (e) of this section from the affected EGU's compliance account in accordance with a complete request under paragraph (c) of this section or, in the absence of such request or in the case of identification of an insufficient amount of ERCs in such request, on a first-in, first-out accounting basis in the order of recordation.

(e) Deductions for exceeding the emission standard. After making the deductions for compliance under paragraph (b) of this section for a compliance period in which the affected EGU has exceeded its CO_2 emission standard, the tracking system operator must deduct from the affected EGU's compliance account an amount of ERCs equal to two times the number of ERCs the EGU failed to hold in the compliance account as of the ERC transfer deadline in order to meet its emission standard. The ERCs deducted must be of a vintage year that corresponds to years that fall within the compliance period for which excess emissions occurred, a prior compliance period, or the compliance period immediately subsequent to the compliance period for which excess emissions occurred.

(f) Recordation of deductions. The tracking system operator will record all deductions under paragraphs (b) and (e) of this section in the appropriate compliance account.

§ 62.16540 What are the monitoring requirements for an affected

EGU?

(a) The owner or operator of an affected EGU must comply with the requirements in the section to monitor CO_2 emissions and net energy output at the EGU.

(1) The owner or operator must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) Each compliance period shall include only “valid operating hours” in the compliance period, i.e., operating hours for which:

(i) “Valid data” (as defined in § 62.16570) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

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

(3) The owner or operator must measure and report the hourly CO_2 mass emissions (lbs) from each affected EGU using the

procedures in paragraphs (a)(3)(i) through (vii) of this section, except as provided in paragraph (a)(4) of this section.

(i) The owner or operator must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, the owner or operator may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then the owner or operator must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

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

(iii) Next, multiply each hourly CO_2 mass emission rate by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb. In the case of units that share a common emission stack and have emissions that are not individually monitored pursuant to part 75 of this chapter, the measured CO_2 mass at the stack will be apportioned to each affected EGU based on net load. For any hour where one or more EGUs are not producing load the apportionment will be based on operating time.

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

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(3)(ii) of this section over the entire quarter or compliance period, as applicable.

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

(vii) The owner or operator must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected EGU; the owner or operator must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

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

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly affected EGU heat input rates (mmBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each valid operating hour (as defined in paragraph (a)(2) of this section, determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

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

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(iii) of this section over the entire quarter or compliance period, as applicable.

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

(5) The owner or operator must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standard No. C12.20. Further, the owner or operator that is a combined heat and power affected EGU must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(5)(i) of this section.

(i) For each valid operating hour of a compliance period that was used in paragraph (a)(3) or (4) of this section to calculate the total CO_2 mass emissions, the owner or operator must determine the corresponding hourly net energy output(P_{net})

according to the procedures in paragraphs (a)(5)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, then the owner or operator must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, the owner or operator must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(A) Calculate P_{net} for the affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

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

Where:

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

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

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

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

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

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in § 62.16570, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable as defined in § 62.16570) from any integrated equipment that is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

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

(B) If applicable to the affected EGU (for example, for combined heat and power), then the owner or operator must calculate $(Pt)_{PS}$ using the following equation:

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

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

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

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in

§ 62.16570 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

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

(C) Sum all of the values of P_{net} over the entire compliance period. Then, divide the total CO_2 mass emissions from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values to determine the CO_2 emission rate (lb/net MWh) for the compliance period.

(ii) [Reserved]

(6) In accordance with § 60.13(g) of this chapter, if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emission standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each affected EGU separately. If an owner or operator chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output for all affected EGUs that are served by the common stack and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g) of this chapter, if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3)(i) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and the owner or operator elect to monitor in the ducts), then the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator must determine compliance with an applicable emission standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

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

(b) [Reserved]

§ 62.16545 May ERCs be banked for future use or transfer?

(a) An ERC may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any ERC that is held in a compliance account or a general account will remain in such account unless and until the ERC is deducted or transferred under §§ 62.16530, 62.16535, 62.16550, or 62.16565.

§ 62.16550 How does the tracking system operator process account errors?

The tracking system operator may, at his or her sole discretion and on his or her own motion, correct any error in any ERC-TCS account. Within 10 business days of making such correction, the racking system operator will notify the authorized account representative or designated representative for the account.

§ 62.16555 What are the reporting, notification and submission requirements for a designated representative of an affected EGU?

The designated representative must prepare and submit reports for the affected EGU according to paragraphs (a) through (g) of this section, as applicable.

(a)(1) The designated representative must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and must include the following information, as applicable, in the quarterly reports:

(i) The percentage of valid operating hours in each quarter described § 62.16540(a)(2) (i.e., the total number of valid operating hours in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

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

(iii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the reporting quarter;

(iv) The calculated CO_2 mass emissions (lb) for each valid operating hour in the reporting quarter;

(v) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the reporting quarter; and

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

(2) At the end of each compliance period, June 5th of the year following the end of the compliance period, the designated representative of an affected EGU must submit a report to the ERC-TCS that includes the following:

(i) the information in paragraphs (a)(1)(i) through (vi) as applicable to the complete compliance period;

(ii) ERC replacement generation (if any), properly justified (see paragraph (a)(2)(iii) of this section);

(iii) The CO_2 emission standard (as identified in Table 1 of this subpart) with which the affected EGU must comply, the affected EGU’s CO_2 emission rate calculated according to § 62.16420(c), and if the affected EGU is complying with an emission standard by using ERCs, a list of all unique ERC serial numbers retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrates that it meets the requirements of § 62.16435 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(b) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (a) of this section, then the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in § 62.16540(a)), and shall not be used in the compliance determinations.

(c) The designated representative of each affected EGU at any facility must make all submissions required under the GHG Rate-based Trading Program, except as provided in § 62.16510. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(d) The designated representative must submit all electronic reports required under paragraph (a)(1) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets

Division in the Office of Atmospheric Programs of EPA; and must submit all electronic reports required under paragraph (a)(2) of this section using the ERC-TCS provided by the Tracking system operator.

(e) For affected EGUs under this subpart that are not in the Acid Rain Program, the designated representative must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(f) If an affected EGU captures CO_2 to meet the applicable emission standard, then the designated representative must report in accordance with the requirements of part 98, subpart PP, of this chapter and either:

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

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

(g) The designated representative must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to the affected EGUs.

§ 62.16560 What are the recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraph (b) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(b) Unless otherwise provided, the owner or operator of an affected EGU must maintain the following records on site at the affected EGU for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s). This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(1) The certificate of representation under § 62.16500 for the designated representative for each affected EGU and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents must be retained on site at the affected EGU beyond such 5-year period until such certificate of representation and

documents are superseded because of the submission of a new certificate of representation under § 62.16500 changing the designated representative.

(2) All emissions monitoring information, in accordance with this subpart.

(3) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU’s emission standard under § 62.16420 and any other requirements of the GHG Rate-based Trading Program.

(4) Data that are required to be recorded by part 75, subpart F, of this chapter.

(5) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the following information:

(i) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the tracking system operator.

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

§ 62.16565 What actions may the tracking system operator take on submissions?

(a) The tracking system operator may review and conduct independent audits concerning any submission under the GHG Rate-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The tracking system operator may deduct ERCs from or transfer ERCs to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16570 What definitions apply to this subpart?

As used in this subpart all terms not defined herin will have the meaning given them in the Clean Air Act and in subparts A, B, TTTT, and UUUU of part 60 of this chapter.

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate.

Affected electric generating unit or Affected EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Alternate designated representative means the natural person who is authorized by the owners or operators of the affected EGU to act on behalf of the designated representative in matters pertaining to the GHG Rate-based Trading Program. If the affected EGU is also subject to any or all of the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative for the affected EGU under those programs.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of ERCs held in the general account and means, for a compliance account of an affected EGU, the designated representative.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Business day means a day that does not fall on a weekend or a federal holiday.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Common practice baseline (CPB) means the level of energy performance that would occur, in the absence of the EE project or EE measure, at the more energy efficient of either (1) the highest level of energy efficiency required by the applicable federal, state, or local building energy code or product or equipment standard, if any (i.e., the code or standard that corresponds to the lowest electricity consumption of the buildings or equipment it applies to, all else equal); or (2) the expected technology, operating conditions, or practices that would have existed at the time of implementation or the likely subsequent replacement within the EUL of the EE project or EE measure, in the absence of the EE project or EE measure.

Common stack means a single flue through which emissions from two or more units are exhausted.

Comparison group EM&V method means an electricity savings quantification approach that is based on the differences in electricity consumption patterns between a population of premises with EE projects or EE measures in place and a comparison group of premises without the EE projects or EE measures. Examples of comparison group methods include randomized control trials (RCTs) and quasi-experimental methods.

Compliance account means an account, established by the tracking system operator for an affected EGU under this subpart, in which any ERCs issued to the affected EGU are recorded and in which any ERCs held are available for use for a compliance period in a given year in complying with the affected EGU's CO_2 emission standard in accordance with §§ 62.16420 and 62.16535.

Compliance period means any of the following multi-year periods starting January 1 of the first calendar year of the period and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024;

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027; and

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

(4) Final compliance period, as defined in this section.

Conservation voltage reduction or CVR means an EE measure that produces electricity savings by reducing voltage at the electrical feeder level.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16540(a)(3). The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

CSAPR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(a) of this chapter and in accordance with subpart AAAAA of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.38(a)(3), (4), or (5) of this chapter.

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(b) of this chapter and in accordance with subpart BBBBB of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.38(b)(3), (4), or (5) of this chapter.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.38(b) of this chapter and in accordance with subpart EEEEE of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.38(b)(6), (7), (8), or (9) of this chapter.

CSAPR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.39 of this chapter and in accordance with subpart CCCCC of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.39(d), (e), or (f) of this chapter.

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established under section 110 of the Clean Air Act and § 52.39 of this chapter and in accordance with subpart DDDDD of part 97 of this chapter, including such a program that is revised or established in a state implementation plan revision approved in accordance with § 52.39(g), (h), or (i) of this chapter.

Deduct ERCs means permanently withdraw ERCs from a compliance account (e.g., by the tracking system operator in order to account for compliance with the applicable CO_2 emission standard).

Deemed savings EM&V method means an electricity savings quantification approach that applies estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values.

Demand-side energy efficiency or demand-side EE means an installed piece of equipment or system, a modification of existing equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in the electricity use (in MWh) required to provide the same or greater level of service at an end-use facility, premises, or equipment connected to the delivery side of the electricity grid. Demand-side EE is implemented through EE programs, projects, or measures.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit’s capacity for planning purposes.

Designated representative means the natural person who is authorized by the owners or operators of the affected EGU to represent and legally bind each owner or operator in matters pertaining to the GHG Rate-based Trading Program. If the affected EGU is also subject to any or all of the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative for the affected EGU under those programs.

Direct measurement and verification EM&V method means an electricity savings quantification approach that uses onsite observations, engineering calculations, statistical analyses, and/or computer simulation modeling using measurements to determine savings from an individual EE project or EE measure.

EE program overlap means the circumstance in which the decision to install or implement a particular EE project or EE measure at a customer facility or end-use is influenced by more than one EE program. The electricity savings associated with that EE project or EE measure might improperly be counted partly or wholly by more than one EE program if the program overlap is not addressed.

Effective useful life (EUL) means the duration of time an EE project or EE measure is anticipated to remain in place and operable with the potential to save electricity.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of a demand-side EE project or EE measure.

Eligible resource means a resource that meets the requirements of § 62.16435, has an eligibility application that has been approved by the State according to § 62.16445, and that has been registered with the ERC Document Management and Approval System and the ERC-TCS (or an ERC tracking system approved in a State plan by the EPA). An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16455.

Emissions means air pollutants exhausted from an affected EGU or facility into the atmosphere, as measured, recorded, and reported to the Tracking system operator by the designated representative, and as modified by the State or the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission rate credit or ERC means a tradable compliance instrument with an assigned vintage year that meets the requirements of § 60.5790(c)(2) of this chapter and that is issued by the State, or by another state that has adopted regulations that are included in a state plan designated by the state as ready-for-interstate-trading with the GHG Rate-based Trading Program and approved by the Administrator as such.Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once installed or operational, that results in a reduction in the electricity use (in MWh) required to provide the same or greater level of service at an end-use facility, premises, or equipment connected to the delivery side of electricity grid; EE measures may be implemented as part of an EE program or an EE project.

Energy efficiency program or EE program means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE projects or EE measures that, once installed or operational, result in a reduction in the electricity use (in MWh) required to provide the same or greater level of service for the purpose of reducing electricity usage across multiple end-uses, facilities, or premises.

Energy efficiency project or EE project means a combination of measures, technologies, energy-use practices or behaviors that, once installed or operational, results in a reduction in the electricity use (in MWh) required to provide the same or greater level of service; EE projects may be implemented as part of an EE program.

Energy efficiency resource means one or more energy efficiency projects or measures, as specified in an eligibility application in accordance with § 62.16445.

ERC Document Management and Approval System means the system specifed in the approved State plan that documents and maintains all information that supports State issuance of ERCs pursuant to subpart UUUU of part 60 of this chapter and provides the ERC-TCS electronic, internet-based access to all information that supports the eligibility of eligible resources and issuance of ERCs, including, for each ERC, an eligibility application, M&V reports, and independent verifier verification reports.

ERC Tracking and Compliance System (ERC-TCS) means the system administered by the EPA by which the tracking system operator records issuance, deductions, and transfers of ERCs under the GHG Rate-based Trading Program, and that provides public access to all information supporting the State issuance of ERCs through a link to the State ERC Document Management and Approval System specified in the approved State plan.

ERC transfer deadline means, for a compliance period, midnight of June 1 (if it is a business day), or midnight of the first business day thereafter (if June 1 is not a business day), immediately after such compliance period and is the deadline by which an ERC transfer must be submitted for recordation in an affected EGU's compliance account in order to be available for use in complying with the affected EGU's CO_2 emission standard for such compliance period in accordance with §§ 62.16420 and 62.16535.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating resource for generating ERCs pursuant to this regulation, including the type of resource.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final compliance period means a compliance period within the final period. Each final compliance period is 2 calendar years, with the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter for as long as this regulation is in effect. The final period is comprised of final compliance periods, each of which is 2 calendar years.

Gas-shift Emission Rate Credit or GS-ERC means an ERC that can only be generated by an affected EGU meeting the applicability definition of a stationary combustion turbine and that is generated through the proceedures in §62.16434.

General account means an ERC-TCS account established under this subpart that is not a compliance account or a retirement account.

Generator means a device that produces electricity.

GHG Rate-based Trading Program means a State CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter).

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

Heat input means, for an affected EGU for a specified period of time, either heat input rate multiplied by the operating time or the gross calorific value of the fuel (in mmBtu/lb of fuel) fed into the affected EGU multiplied by the average fuel feed rate for the operating time (in lb of fuel/time) multiplied by the operating time, as measured, recorded, and reported to the Administrator (eg. Part 75) by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Hold ERCs means treat ERCs as included in an ERC-TCS account as of a specified point in time when they:

(1) Have been recorded by the tracking system operator in the account or transferred into the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart.

Indian country has the same meaning as in 18 U.S.C. 1151.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

M&V report means a monitoring and verification report that meets the requirements of § 62.16460.

M&V reporting period means the reporting period that the M&V report covers which is not to exceed the bounds of a compliance period.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Multi-measure effects means the combined effects on electricity savings of more than one EE measure installed in the same facility at the same time, affecting the same system or systems. Multi-measure effects may be different (usually less) than the sum of electricity savings from each EE measure by itself (e.g., joint installation of building shell improvements and cooling system upgrades).

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) at the time of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) at the time of such completion as specified by the person conducting the physical change.

Net summer capacity means 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.

Non-affected CHP unit means a CHP unit that does not meet the applicability criteria of § 62.16410.

Operator means, for an affected EGU, any person who operates, controls, or supervises the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such affected EGU.

Other system effects means the effect of an EE measure designed to reduce the electricity use of one system also affects the electricity use of another system (e.g., a lighting measure that also reduces cooling loads and increases heating loads).

Owner means, for an affected EGU, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU;

(2) Any holder of a leasehold interest in an affected EGU, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from an affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners or operators have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16415; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Primary fuel means, for the purposes of a non-affected CHP unit, the fuel that is used to produce the highest percentage of heat input for all fossil fuels used at a CHP unit during the applicable calendar year.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or receipt of means, when referring to the tracking system operator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to ERCs, the moving of ERCs by the tracking system operator into, out of, or between ERC-TCS accounts, for purposes of issuance, transfer, or deduction.

Renewable energy resource means the renewable electric generating technologies listed in § 60.5800(a)(4)(i) of this chapter.

State measures means measures that the State adopts and implements 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.

Submit means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Supplemental fuel means for non-affected CHP units fuel where the heat from combustion is used solely for electricity generation or the production of useful thermal output (e.g., use of duct burners in the heat recovery steam generator of a combustion turbine).

Tracking system operator means, the State or an entity acting on behalf of the State, including the Administrator of the United States Environmental Protection Agency.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity losses on the system.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means for non-affected CHP units the same definition in subpart UUUU with respect to affected EGUs.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report submitted by the independent verifier that meets the requirements of § 62.16465.

Vintage year means the applicable calendar year identifier assigned to each ERC, which corresponds to the year in which the electricity generation or electricity savings that led to the issuance of a specific ERC occurred.

Waste heat to power unit (WHP unit) means a non-affected CHP unit in which (1) fuel is combusted to provide useful thermal output to an industrial, institutional, or commercial process, (2) all or some of the remaining heat (i.e., waste heat) from that process is used to generate electricity, and (3) no supplemental fuel is combusted to generate electricity. If supplemental fuel is combusted to generate electricity, the unit is not a waste heat to power unit. Stationary combustion turbines, steam generating units where the steam is expanded through a steam turbine prior to the energy being used for useful thermal output, and non-affected CHP units where fuel is combusted in the heat recovery steam generator are not waste heat to power units.

§ 62.16575 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit

CPP—clean power plan

CO_2—carbon dioxide

COI—conflict of interest

EE—energy efficiency

EGU-electric generating unit

EM&V-evaluation, measurement, and verification

ERC-emission rate credit

ERC-TCS-ERC Tracking and Compliance System

GCV-gross calorific value

GS-ERC-gas shift emission rate credit

H_2O—water

hr—hour

IGCC—integrated gasification combined cycle

kg—kilogram

kW—kilowatt electrical

lb—pound

M&V—Monitoring and verification

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt-hour

T&D—transmission and distribution

O_2—oxygen

PSD-prevention of significant deterioration

yr—year

Table 1 to Subpart NNN of Part 62—CO_2 Emission Standards (Pounds of CO_2 Per Net MWh)

Compliance Period	Affected steam generating unit or integrated gasification combined cycle (IGCC) unit emission standards	Affected stationary combustion turbine emission standard
Compliance Period 1 (2022-2024)	1,671	877
Compliance Period 2 (2025-2027)	1,500	817
Compliance Period 3 (2028-2029)	1,380	784
Final Compliance Periods	1,305	771

Table 2 to Subpart NNN of Part 62—Regional Combustion Turbine Capacity Factors (percent)

Regional Electricity Interconnection	Regional NGCC capacity factor (in percent)
Eastern	55.8
Western	48.5
Texas	50.5

Table 3 to Subpart NNN of Part 62 - Assumed Replacement Thermal Energy Unit Efficiency (TEU_E)

Fuel Type	Median Efficiency (in percent)
Coal	85%
Liquid	85%
Natural Gas	80%
Other Fuels	75%

*   *   *   *   *

PART 78 -- APPEAL PROCEDURES

4. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, and 7651, *et seq*.

5. Section 78.1 is amended by adding paragraphs (a)(1)(i)(G), (a)(1)(v) and (vi), and (b)(19) and (20) to read as follows:

§ 78.1 Purpose and scope.

(a) * * *

(1) * * *

(i) * * *

(G) State regulations approved under subparts B and UUUU of part 60 of this chapter that implement a mass-based or rate-based trading program, including State regulations incorporating the provisions of subpart MMM or NNN of part 62 of this chapter.

* * * * *

(v) All references in paragraph (b) of this section and in § 78.3 to subpart MMM of part 62 of this chapter shall be read to include the comparable provisions in State regulations approved under subparts B and UUUU of part 60 of this chapter that implement a mass-based trading program.

(vi) All references in paragraph (b) of this section and in § 78.3 to subpart NNN of part 62 of this chapter shall be read to include the comparable provisions in State regulations approved under subparts B and UUUU of part 60 of this chapter that implement a rate-based trading program.

* * * * *

(b) * * *

(19) Under subpart MMM of part 62 of this chapter,

(i) The decision on the allocation of CO_2 allowances under

§ 62.16240 of this chapter.

(ii) The decision on the transfer of CO_2 allowances under § 62.16330 of this chapter.

(iii) The decision on the deduction of CO_2 allowances under § 62.16340 of this chapter.

(iv) The correction of an error in an ATCS account under § 62.16355 of this chapter.

(v) The adjustment of information in a submission and the decision on the deduction and transfer of CO_2 allowances based on the information as adjusted under § 62.16370 of this chapter.

(vi) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

(20) Under subpart NNN of part 62 of this chapter,

(i) The decision on the qualification status of affected EGUs under § 62.16434 of this chapter.

(ii) The decision on the qualification status of eligible resources under § 62.16435 of this chapter.

(iii) The decision on the revocation of qualification status of an eligible resource under § 62.16440 of this chapter.

(iv) The decision on the issuance of emission rate credits under § 62.16445 of this chapter.

(v) The decision on adjustments for error or misstatement, and the suspension of ERC issuance under § 62.16450 of this chapter.

(vi) The decision on the accreditation of independent verifiers under § 62.16470 of this chapter.

(vii) The decision on the revocation of accreditation status under § 62.16480 of this chapter.

(viii) The decision on the transfer of emission rate credits under § 62.16530 of this chapter.

(ix) The decision on the deduction of emission rate credits under § 62.16535 of this chapter.

(x) The correction of an error in an ATCS account under § 62.16550 of this chapter.

(xi) The adjustment of information in a submission and the decision on the deduction and transfer of emission rate credits based on the information as adjusted under § 62.16565 of this chapter.

(xii) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

*   *   *   *   *

6. Section 78.3 is amended by:

a. Adding paragraphs (a)(12) and (13);

b. Revising paragraph (b)(3)(i)(A);

c. Adding paragraphs (b)(3)(i)(D) and (c)(7)(vi);

d. Revising paragraph (d)(2)(i); and

e. Adding paragraph (d)(9).

The additions and revisions read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(12) The following persons may petition for administrative review of a decision of the Administrator that is made under subpart MMM of part 62 of this chapter and that is appealable under § 78.1(a):

(i) The designated representative for a unit or source, or the authorized account representative for any ATCS account, covered by the decision; or

(ii) Any interested person with regard to the decision.

(13) The following persons may petition for administrative review of a decision of the Administrator that is made under subpart NNN of part 62 of this chapter and that is appealable under § 78.1(a):

(i) The designated representative for a unit or source, the owner or operator of an eligible resource, or the authorized account representative for any ATCS account, covered by the decision; or

(ii) Any interested person with regard to the decision.

(b) * * *

(3) * * *

(i) * * *

(A) The designated representative or authorized account representative, for a petition under paragraph (a)(1), (2), (10), (11), or (12) of this section.

* * * * *

(D) The designated representative, owner or operator, or authorized account representative, for a petition under paragraph (a)(13) of this section.

* * * * *

(c) * * *

(7) * * *

(vi) Subpart UUUU of part 60 of this chapter and subpart MMM or NNN of part 62 of this chapter.

(d) * * *

(2) * * *

(i) A certificate of representation submitted by a designated representative or an application for a general account submitted by an authorized account representative under the Acid Rain Program, subpart AAAAA, BBBBB, CCCCC, DDDDD, or EEEEE of part 97 of this chapter, or subpart MMM or NNN of part 62 of this chapter.

*   *   *   *   *

(9) Any provision or requirement of subpart B or UUUU of part 60 of this chapter or subpart MMM or NNN of part 62 of this chapter, including any emission standard and any emission monitoring, recordkeeping, or reporting requirements.

4. Section 78.4 is amended by adding paragraph (a)(1)(v) to read as follows:

§ 78.4 Filings.

(a) *   *   *

(1) *   *   *

(v) Any filings on behalf of owners and operators of a unit or source covered by subpart MMM or NNN of part 62 of this chapter shall be signed by the designated representative. Any filings on behalf of persons with an ownership interest with respect to CO_2 allowances or emission rate credits shall be signed by the authorized account representative.

*   *   *   *   *