Implementing EPA's Clean Power Plan:
Model State Plans

NACAA
national association of clean air agencies

May 2016

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Acknowledgments

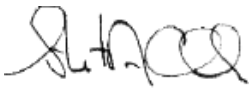
On behalf of the National Association of Clean Air Agencies (NACAA), we are very pleased to provide *Implementing EPA's Clean Power Plan: Model State Plans.* NACAA developed this comprehensive document to help states and localities comply with the Environmental Protection Agency's Clean Power Plan. We know that regulatory agencies across the country, as well as stakeholders who are involved in developing greenhouse gas compliance strategies, will find this document extremely valuable. NACAA's Model provides an excellent summary of state plan requirements and strategic planning decisions, analyzes primary plan types and example plan provisions and develops a complete model state plan, as well as a model initial submittal.

NACAA is especially thankful for the excellent contractual assistance provided by Bliss M. Higgins, a Principal at Ramboll Environ. The association is also very appreciative of the financial assistance provided by the Energy Foundation.

We are grateful to the many members of the association who participated in the development of this document, especially Stu Clark (Washington) and Larry Greene (Sacramento, California), Co-Chairs of NACAA's Global Warming Committee, under whose guidance the document was prepared. We recognize the important efforts and substantial input provided by the NACAA 111(d) Steering Committee for this project, including directors and staff from state and/or local air pollution control agencies in the following states: Arizona, California, Colorado, Delaware, Kentucky, Massachusetts, Michigan, Minnesota, Nebraska, New Mexico, South Carolina, Tennessee, Washington and Wisconsin.

Additionally, we want to recognize the excellent and ongoing dialogue NACAA has maintained with the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO) throughout EPA's development of the Clean Power Plan and NACAA's development of the Model Plans. Our collaboration, known as the "3-N" process, has helped the members of all three organizations better understand the impacts and implementation challenges related to the Clean Power Plan. We are particularly pleased that many of the policies and provisions in the NACAA Model Plans were derived directly from these multi-stakeholder discussions.

Finally, we very much appreciate the NACAA staff who guided and oversaw this project from start to finish, including S. William Becker, Executive Director, and Senior Staff Associates Phil Assmus and Karen Mongoven.



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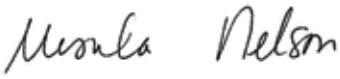

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Preface

This document, *Implementing EPA's Clean Power Plan: Model State Plans*, is intended to help states develop strategies to comply with EPA's Clean Power Plan. The Model should be viewed as a tool and a resource, not as an endorsement of any particular implementation plan pathway. We examine many options, evaluating each according to a range of criteria that reflect the widely varying policy preferences and constraints that exist among the states.

On February 9, 2016, as we were preparing to publish this document, the U.S. Supreme Court stayed implementation of the Clean Power Plan pending the final disposition of legal challenges to the rule. The Supreme Court's decision to grant the stay applications did not constitute a ruling on the rule's legal merits. That decision will be made, in the first instance, by the U.S. Court of Appeals for the District of Columbia Circuit, where petitions for judicial review of the rule have been filed. Parties to the court proceedings have submitted briefs laying out their legal claims, and the D.C. Circuit is scheduled to hear oral arguments on September 27, 2016, before the full court. After the court issues its opinion, which will probably not occur until the end of 2016 or early 2017, the decision will almost certainly be appealed to the U.S. Supreme Court. The judicial stay will remain in place until these legal proceedings play out and the Supreme Court either issues its own opinion or declines to review the D.C. Circuit's decision. The Clean Power Plan could be upheld in its entirety, or it could be struck down in whole or in part. The rule's ultimate fate will not be known until sometime in 2017 or later.

While the stay remains in effect, EPA will not take any actions to implement the Clean Power Plan and cannot enforce any of the rule's requirements. It will, however, continue to provide assistance to states that request it. Meanwhile, all of the rule's intervening implementation milestones, such as the September 6, 2016 deadline for states to make their initial submittals to EPA, will be postponed for an indeterminate amount of time. When (and if) the stay is lifted, it is unclear how the rule's implementation timeline will be affected. Some proponents of the stay have argued that all of the rule's deadlines should be tolled to account for the full length of the stay. EPA has stated that it will not decide how the rule's timeline should be adjusted until after the stay is lifted and the court's opinion is known. Adjustment of the implementation timeline will likely require additional rulemaking.

While the legal proceedings are ongoing, most states are, to varying degrees, continuing to plan for potential implementation of the Clean Power Plan. This is where NACAA's Model can be most helpful.

Though the Model draws heavily from the final Emission Guidelines and numerous technical support and guidance documents issued by EPA, the language has not been reviewed by the agency and cannot be considered presumptively approvable. The example regulatory language and supporting materials provided herein do not constitute EPA pre-approved plans. As states identify their final plan pathways, the example plan materials included in this document should be closely reviewed and adapted as necessary. Throughout this process, states should seek additional guidance from their EPA regional offices. In addition, future EPA guidance and rules may also influence state dialogue surrounding Clean Power Plan implementation. Important pieces of the rule's regulatory framework—in particular, the federal model trading rules, Clean Energy Incentive Program, and evaluation, measurement and verification guidance—remain unfinished. Details of these program elements, which could not be firmly addressed in this document, may also affect a state's preferred implementation pathway.

Regardless of the ultimate fate of the Clean Power Plan, many states will continue to advance efforts to reduce greenhouse gas emissions. We hope and expect that the NACAA Model will remain a useful tool to assist in this important challenge.

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Acronyms

AB 32 – (California) Assembly Bill 32, the Global Warming Solutions Act of 2006
BAU – Business as Usual
BSER – Best System of Emission Reduction
BTU – British Thermal Unit
CAA – Clean Air Act
CCS – Carbon Capture and Sequestration
CDX – (EPA's) Central Data Exchange
CEIP – Clean Energy Incentive Program
CEMS – Continuous Emissions Monitoring System
CF – Capacity Factor
CHP – Combined Heat and Power
CO_2 – Carbon Dioxide
CO_2e – Carbon Dioxide Equivalent
CPP – Clean Power Plan
CSAPR – Cross-State Air Pollution Rule
CSP – Concentrating Solar Power
DOE – (U.S.) Department of Energy
ECMPS – (EPA's) Emissions Collection and Monitoring Plan System
EE – Energy Efficiency
EERS – Energy Efficiency Resource Standard
eGRID – Emissions & Generation Resource Integrated Database
EGU – Electric Generating Unit
EIA – (U.S.) Energy Information Administration
EM&V – Evaluation, Measurement and Verification
EPA – (U.S.) Environmental Protection Agency
EPC – Energy Performance Contract
ERC – Emission Rate Credit
ERCOT – Electric Reliability Council of Texas
ETCS – ERC Tracking and Compliance System
FERC – Federal Energy Regulatory Commission
G&T – Generation and Transmission
GDP – Gross Domestic Product
GHG – Greenhouse Gas
GS-ERC – Gas Shift Emission Reduction Credit
HAP – Hazardous Air Pollutant
HHV – Higher Heating Value
IGCC – Integrated Gasification Combined Cycle
IOU – Investor-Owned Utility
IPM – Integrated Planning Model
IPP – Independent Power Producer
IRP – Integrated Resource Plan
ISO – Independent System Operator
ISO/RTO – Integrated Dispatch and Transmission System Operators
kWh – Kilowatt-hour
LDC – Local Distribution Company
LSE – Load-Serving Entity
M&V – Monitoring and Verification
MATS – Mercury and Air Toxics Standards
MISO – Midcontinent Independent System Operator
MMBTU – Million British Thermal Units
MWh – Megawatt-hour
MUSH – Municipal, University, State and Hospital
NAAQS – National Ambient Air Quality Standard(s)
NACAA – National Association of Clean Air Agencies
NARUC – National Association of Regulatory Utility Commissioners
NASEO – National Association of State Energy Officials
NERC – North American Electric Reliability Corporation
NESHAP – National Emission Standards for Hazardous Air Pollutants
NGCC – Natural Gas Combined Cycle
NGO – Non-governmental Organization
NNSR – Nonattainment New Source Review
NO_X – Nitrogen Oxide
NRC – Nuclear Regulatory Commission
NRECA – National Rural Electric Cooperative Association
NREL – National Renewable Energy Laboratory
NSPS – New Source Performance Standard
NUG – Non-Utility Generator
PM – Particulate Matter
PMA – Power Marketing Agency
PPA – Power Purchase Agreement
PSC – (State) Public Service Commission
PSD – Prevention of Significant Deterioration
PUC – Public Utility Commission
PUD – Public Utility District
PURPA – Public Utility Regulatory Policy Act of 1978
PV – Photovoltaic
RE – Renewable Energy
REC – Renewable Energy Credit
RGGI – Regional Greenhouse Gas Initiative
RIA – Regulatory Impact Analysis
RPS – Renewable Portfolio Standard
RTO – Regional Transmission Organization
SEO – State Energy Office
SEP – State Energy Program
SO_2 – Sulfur Dioxide
SPeCS – (EPA's) State Plan Electronic Collection System
SPP – Southwest Power Pool
TSD – (EPA) Technical Support Document
TVA – Tennessee Valley Authority
tWh – Terawatt-hour
WHP – Waste Heat Power

SECTION I:

An Overview of State Plan Requirements and Strategic Planning Decisions

1. Introduction

1.1 Introduction

On June 25, 2013, President Obama announced his Climate Action Plan, a multipronged approach to address global warming by reducing U.S. greenhouse gas (GHG) emissions, adapting to the effects of global warming, and participating in international efforts to address global warming.[1] A key element of the plan was a commitment to develop federal standards to reduce carbon pollution from new and existing power plants. In a Presidential Memorandum[2] released alongside the Climate Action Plan, the President directed the U.S. Environmental Protection Agency to do so, using its authority under sections 111(b) and (d) of the federal Clean Air Act (CAA). The memorandum also instructed EPA to launch this effort "through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants."

In accordance with the President's directive, on August 23, 2015, EPA issued a new federal regulation under CAA section 111(d) to reduce GHG emissions from existing power plants. Known as the "Clean Power Plan" (or "CPP"), the rule was officially published on October 23, 2015 in the Federal Register and is codified at 40 C.F.R. Part 60, Subpart UUUU.[3] The CPP is projected to achieve carbon dioxide (CO_2) emission reductions of approximately 32% nationwide from the power sector from 2005 levels by 2030, while leaving considerable flexibility to the states in selecting the specific structure and components of their plans to meet its requirements.[4]

Subpart UUUU establishes federal CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs) reflecting application of the Best System of Emission Reduction (BSER) for CO_2 that has been adequately demonstrated for the power sector. The rule relies largely on already emerging trends in clean energy deployment across the country, including renewable energy and other lower CO_2-emitting power generation. Each state with one or more affected EGUs must develop and implement a single-state or multi-state plan that sets emission standards for its affected EGUs to achieve the emission guidelines of Subpart UUUU.[5] In the final rule, EPA promulgated subcategory-specific emission performance rates, expressed in pounds of CO_2 emitted per net megawatt hour of energy produced from affected EGUs (lb CO_2/MWh-net) as the BSER emission guidelines, as well as specific statewide equivalent rate-based and mass-based emission goals derived using the subcategory performance rates and the states' mix of affected EGUs. In addition to adopting several forms of the BSER emission performance guidelines from which states may choose, the final rule allows states to adopt either an "emission standards" plan or a plan that relies wholly or partially on "state measures," which may be composed of reduction strategies that are neither emission standards nor federally enforceable, such as state Renewable Portfolio Standards (RPS).

While each state is responsible for developing and implementing an enforceable state plan or multi-state plan to achieve the CO_2 emission reductions from affected fossil fuel-fired EGUs as required by the emission guidelines, states have broad discretion in developing their plans, as described further in Section 1.3. Among the critical

1 The President's Climate Action Plan is available at http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

2 The Presidential Memorandum is available at https://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

3 80 Fed. Reg. 64,662 (Oct. 23, 2015). Throughout this document, the terms "CPP" or "Subpart UUUU" are used interchangeably in referring to the Clean Power Plan federal regulation and emission guidelines.

4 80 Fed. Reg. at 64,665.

5 The emission guidelines as finalized apply only to the 48 contiguous states and certain Indian tribes; EPA did not finalize emission performance goals for Alaska or Hawaii, or for the two U.S. territories with affected EGUs (Guam and Puerto Rico), so those areas are not required to submit state plans on the schedule established by the final rule. Also, Vermont and Washington, D.C. do not have any affected EGUs and therefore are not required to submit state plans.

strategic planning decisions each state must make are:

- Selecting the overall plan type (emission standards vs. state measures);
- Deciding whether and how to provide for interstate trading among affected EGUs;
- Deciding between a rate-based and mass-based approach;
- Determining what CO_2 reduction strategies to rely upon, including whether and how to incorporate renewable energy and energy efficiency strategies in the plan; and,
- Deciding whether to submit a single-state or multi-state plan, or a hybrid plan approach.

In addition to the EGU performance standards and statewide emission goals, Subpart UUUU establishes state plan submittal, review and approval requirements; affected EGU applicability criteria; compliance timelines; required plan components; required monitoring, recordkeeping and reporting for affected EGUs; required state reporting requirements; Emission Rate Credit (ERC) requirements for rate-based trading programs, including evaluation, measurement and verification (EM&V) requirements; and mass allocation requirements for mass-based trading programs.

Under the final rule as adopted, each state must submit either an "initial submittal" or a final plan to EPA for review and approval by September 6, 2016.[6] In an initial submittal, a state may request up to two additional years for final plan submittal.[7] Initial submittals requesting plan submittal extensions must describe the plan types under consideration and the progress made to date, explain why additional time is required, and provide a description of opportunities for public involvement on the initial submittal and plans for public engagement for the final plan development. EPA intends to issue and implement a federal plan in any state that fails to submit the required state plan in a timely manner.[8]

1.2 Model State Plans – Document Format and Content

This document, *Implementing EPA's Clean Power Plan: Model State Plans,* provides practical assistance to states in developing state plans to comply with the Clean Power Plan. The document is composed of three main sections, briefly described below.

Section I, An Overview of State Plan Requirements and Strategic Planning Decisions, includes this *Chapter 1, Introduction,* and four additional chapters. To set the stage for planning with a review of the context in which the power sector and fossil fuel-fired EGUs will be regulated under state plans, *Chapter 2, The U.S. Power Sector* provides an overview of the U.S. power sector, including the physical infrastructure, the business structure, and the way in which administrative authorities currently interact with and regulate affected EGUs. *Chapter 3, The Clean Power Plan* provides a summary of Subpart UUUU, including its applicability to states and affected EGUs, BSER, performance standards and emission goals, plan pathways and plan components, and compliance timelines. *Chapter 4, The State Planning Framework,* discusses the overall planning process each state will undertake, including timelines and milestones; stakeholder and vulnerable community involvement; considerations for regional planning partners and grid reliability; affected entities for important CO_2 reduction strategies; and options for state administrative authorities to implement and enforce the state plan. *Chapter 5, State Plan Types and Required Plan Components,* includes a summary of the basic plan types, implementation pathways and required plan components; the four "streamlined" plan pathways provided by EPA; the specific integrity assurance plan components required for each plan type; and the universal plan components required for all plan types. *Chapter 6, Key Decisions for State Planning,* discusses key considerations and decisions each state will face in creating the framework for the state plan. While a state's CPP design decisions will necessarily be formulated as part of an integrated and multifaceted whole, for purposes of discussion Chapter 6 presents separate sections on Trading Programs Considerations and Decisions, Rate-based vs. Mass-based Plans Considerations and Decisions, and Single-state vs. Multi-state Plans Considerations and Decisions.

Section II, The Primary Plan Types and Example Plan Provisions takes a deeper dive into each of the primary plan types in three chapters: *Chapter 7, Rate-based Emission Stan-*

6 As noted in the Preface to this document, the September 2016 deadline will be pushed back to a date uncertain due to the Supreme Court's decision to stay the rule's implementation pending judicial review.

7 The deadline specified in the final rule is September 6, 2018; the extent to which this deadline may be delayed due to the judicial stay is unknown.

8 On August 3, 2015, alongside the Clean Power Plan, EPA issued a proposed federal plan and model rules for state plans implementing rate-based and mass-based trading programs, the final versions of which will be codified at 40 C.F.R. Part 62, Subparts MMM and NNN. The proposal was published in the *Federal Register* on October 23, 2015 (80 Fed. Reg. 64,966).

dards Plans; Chapter 8, Mass-based Emission Standards Plans; and *Chapter 9, State Measures Plans.* Each of these chapters includes descriptions of multiple available options for emission standards or other CO_2 reduction strategies for each plan type, and discussions of special considerations for each plan type. For each plan type and CO_2 reduction option addressed, practical and policy considerations and implementation challenges are discussed, as well as illustrative examples identifying the administrative authority that would implement and enforce the emission reduction strategy, and examples of the specific compliance assurance and enforcement measures states may employ. Example rule language is included for multiple implementation options, reflecting the wide range of choices that may be considered by states in developing their plans.

Chapter 9, State Measures Plans includes sections on several non-emission standards reductions strategies, with several examples of rule language. This chapter serves a dual purpose, because each of these state measures could be relied upon by a state as a component of a state measures plan, or could be adopted as a complementary state measure that resides outside of the state emission standards plan. Sections are included on heat rate improvement standards, generation shift, renewable and low carbon energy, combined heat and power, building energy codes, above-code building certifications, energy savings performance contracting, and industrial energy efficiency programs. Each section in Chapter 9 provides options and examples for:

- Selecting the administrative authority that would be responsible for implementing and enforcing the CO_2 reduction strategy;
- Identifying the affected sources or other entities that would be subject to the requirements or that would undertake the voluntary measures;
- Establishing the specific standards or requirements that would apply and the form of the standard or program;
- Flexible compliance measures affected sources and entities could utilize to demonstrate compliance, where applicable; and
- Enforcement measures, including monitoring, recordkeeping and reporting requirements that would be required to assure the reductions achieved by the strategy can be accounted for in achieving the state's CO_2 emission performance targets under Subpart UUUU.

Finally, *Section III, Comprehensive Model Plan Submittals* includes two illustrative state plan submittals. First, a model of an initial submittal, as required for any state requesting an extension for final plan submittal, is provided. This model includes each of the three required initial submittal components: 1) an identification of the plan approach(es) under consideration and a description of progress on plan development; 2) an explanation of why additional time is needed to prepare the final plan; and 3) a description of the opportunities provided, and to be provided, for stakeholder engagement. The second model plan submittal assembles all of the required plan elements for a complete state plan. This model state plan is a mass-based emission standards plan, built upon an interstate trading platform that incorporates EPA-specified mass emission goals as the mass budget for each compliance period. The plan relies upon "new source complements" which are incorporated in the EPA-specified emission goals to address leakage to new sources, while also including provisions that encourage the advancement of energy efficiency as well the use of renewable energy and other low-emitting energy generation sources. In addition, the model plan presents an allowance allocation scheme with a number of components that can be readily adapted by states to meet their particular preferences.

2. The U.S. Power Sector

2.1 U.S. Power Sector Structure and Regulation

The CPP takes a broad approach to determining BSER for reducing CO_2 emissions from existing fossil fuel-fired EGUs as well as to structuring the emission guidelines under CAA section 111(d) for state plans. This broad-based section 111(d) regulatory framework was selected by EPA to reflect and accommodate the existing broad and interwoven system of power production and distribution, in which the affected EGUs play a crucial and integral role. The physical system of power plants, transmission stations and distribution grids bringing electricity to industrial, commercial, governmental and residential users is intricately connected from each point of generation to each consumer, with consumer demand dictating real-time response from the power industry. Indeed, American consumers expect a safe and reliable supply of energy on-demand, every minute of every day, at a cost affordable to all sectors of the population. The complex physical structure of the utility system is accompanied by a complex business structure, including private and public entities, which in turn is governed and regulated by a number of administrative bodies.

Regulations and administrative bodies currently engaged in oversight roles for the power sector operate at federal, regional, state and municipal levels, with varying purposes, procedures and levels of authority. In developing a state plan to comply with the Subpart UUUU requirements, three key questions each state must answer are:

1) What emission standards or other reduction strategies will the state rely upon to achieve the required CO_2 reductions?
2) Who will be the regulated, affected entities that will have obligations under the state plan or through complementary measures?
3) Who will be the administrative authority that implements and/or enforces each of the emission standards or state measures?

To resolve these questions, states will need to consider the existing framework of the power sector and the existing regulatory authorities governing the power sector in their state. This chapter provides a brief overview of power sector structure and regulation in the U.S., followed by an overview of options states may consider in defining affected entities and regulatory authorities for the state plan.[9]

2.1.1 Power Generation and Marketers' Business Structures

Administrative oversight and regulation of electric power companies varies depending on the business structure of the power company. In the U.S. today, those business structures reflect a myriad of forms, including various combinations of public and private entities, for-profit and not-for-profit corporations, and utility and non-utility entities. Companies also vary in the range of services they provide. Some energy companies are vertically integrated, including electric generation, transmission and distribution under the same parent entity. Some have generation assets only; others are generation and transmission companies; still others are distribution-only. In some cases a single parent or holding company umbrellas electricity generation under one or more subsidiaries, with transmission and distribution under one or more different subsidiaries. Power companies are also highly interactive, buying and selling generation, transmission and distribution services amongst themselves.

Given this myriad of business structures, business interactions and contractual obligations, a complete and comprehensive catalogue of power sector business structures is well beyond the scope of this document. This section presents a general overview of the main types of power sector business structures, as a reference for states in considering how to define affected entities and administrative authorities within the context of the state plan.

Electric power production and delivery to customers can be generally divided into five main categories: inves-

9 For a more detailed discussion of the structure and regulation of the power industry, *see* Regulatory Assistance Project, *Electricity Regulation in the US: A Guide,* March 2011, available at http://www.raponline.org/document/download/id/645.

Table 2.1. **Power Sector Business Structures, Number and Percent of Customers**[10]

Business Structure	Number	Approximate Number Served	Customer Density (#/mile of line)	Percent U.S. Customer Base
Investor-owned	192 *(70 parent companies)*	220 Million	34	68.5%
Public Power	2,009	48 Million	48	14.4%
Electric Cooperatives	871	42 Million	7.4	13%
Federal Power Agencies	9	39 Thousand	--	< 1%
Independent Marketers	211	6 Million	--	4%

tor-owned utilities; public power utilities (including municipal and public utility districts); electric cooperatives (usually rural); federal power agencies; and independent marketers. Table 2.1 provides a breakdown of the approximate number of each type of power company and the approximate percentage of U.S. customers served.

2.1.1.1 Investor-Owned Utilities

Utility companies owned by private shareholders are typically referred to as investor-owned utilities (IOUs). IOUs are profit driven, with shareholders expecting a return on investment. IOUs generally have a large asset base, composed of multiple power plants, and may be invested in both natural gas and electricity production. Many IOUs include multiple subsidiaries or divisions organized under a parent company or holding corporation. Many operate across a multi-state region. A few IOUs are transmission-only utilities; these include American Transmission Company (Wisconsin, Michigan, Minnesota and Illinois); Cross Texas Transmission (Texas); ITC Holdings Corporation (Michigan, Iowa, Minnesota, Illinois, Missouri and Kansas); and Vermont Electric Power Company (Vermont).

IOUs operate in all 50 states and the District of Columbia, and provide electric power for 220 million Americans, nearly 70% of the customer base.[11] Examples of IOUs include American Electric Power (AEP), Entergy, FirstEnergy Corporation, Hawaiian Electric Industries (HEI) and Southern Companies. 70 IOU parent companies are currently operating in the United States, with nearly 200 utility company subsidiaries. All U.S. IOUs belong to a single trade association, Edison Electric Institute (EEI).

2.1.1.2 Public Power Utilities

The term "public power" refers to not-for-profit utility entities that are owned and operated by the communities which they serve. Most public power utilities are municipal utilities, often referred to as "munis," which may be governed by the city council or overseen by local elected or appointed officials. In some cases, public power utilities serve a county or a designated public utility district (PUD), which may comprise multiple communities or portions of one or more counties. More than 2,000 community-owned electric utilities operate in 49 states (all but Hawaii) and are currently serving more than 48 million people, representing approximately 14 percent of U.S. electricity consumers. Some large cities are powered by municipal utilities, including Los Angeles, San Antonio, Seattle and Orlando. The Los Angeles Department of Water and Power, the nation's largest public power utility, serves approximately 1.5 million customers. However, many public power utilities are very small, with a customer base of less than 3,000. In fact, more than two-thirds serve a customer base of less than 10,000.[12]

Some public power entities are distribution-only, purchasing all of the power they distribute from IOUs, independent producers and marketers, or federal power marketers. Others own electric generating units and produce some or all of the power they distribute. Public power utilities are collectively represented by their trade group, the American Public Power Association (APPA). The Large Public Power Council (LPPC) represents 26 of the largest public power entities.

10 Data on number of utilities and percent customer base from American Public Power Association, http://www.publicpower.org/files/PDFs/PPFactSheet.pdf, accessed 5/23/2015. Data on customer density from National Rural Electric Cooperative Association (NRECA), *Annual Meeting Fact Sheet,* March 2014, www.nreca.coop/wp-content/uploads/2014/12/AnnualMeetingFactSheet.pdf. Data on number of customers served from *U.S. Electric Industry Statistics,* American Public Power Association, *2014-15 Annual Directory and Statistical Report,* data sourced from Energy Information Administration, available at www.publicpower.org.

11 Edison Electric Institute (EEI), www.eei.org.

12 American Public Power Association (APPA), www.publicpower.org.

2.1.1.3 Electric Cooperative Utilities

Electric cooperatives (co-ops) are privately owned, non-profit electric utilities. Co-ops are owned by the cooperative members, who are also the customers. Electric co-ops are incorporated business entities with the purpose of providing "at-cost" electricity to members. They are typically governed by a membership-elected board of directors, who oversee the co-op's management. Electric cooperatives are usually either generation and transmission (G&T) cooperatives, composed of the power generating plants and transmission stations delivering power to the grid, or distribution cooperatives, which distribute the power received from the transmission substations through the power grid network to member customers. Electric cooperatives tend to operate in rural areas, bringing power to a low-density population. The National Rural Electric Cooperative Association (NRECA) is the trade group representing electric cooperatives. According to NRECA, as of 2014 there were 903 electric co-ops, including 65 generation and transmission and 838 distribution co-ops, serving approximately 42 million people, operating in 47 states and in 2,500 of 3,141 U.S. counties.[13]

2.1.1.4 Federal Power Marketing Agencies and TVA

Another type of public entity electricity sector business type is a federal power marketing agency (PMA). These are federal agencies, housed within the U.S. Department of Energy (DOE), created for the purpose of marketing power from federal dams and water resource projects. PMAs operate these federal hydropower generation resources as well as transmission assets that deliver the power to the wholesale market. PMAs are wholesale sellers of power to IOUs, public power or co-op buyers. There are four federal regional-based PMAs, marketing power in 34 states: Bonneville Power Administration (Northwestern region); Southeastern Power Administration; Southwestern Power Administration; and Western Area Power Administration.

Another federally-owned public power entity, which is not a PMA, is the Tennessee Valley Authority (TVA). TVA is a not-for-profit corporation, owned by the U.S. government, and is fully self-financed, receiving no taxpayer money. In addition to providing electricity to parts of seven states, TVA provides flood control, navigation and land management for the Tennessee River system. TVA is the nation's largest public power provider. Its electric power service territory includes most of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina and Virginia, with a customer base of more than 9 million people. TVA sells electricity to 155 power distributor customers and 56 directly served industries and federal facilities. Operations are funded primarily through electricity sales and power system financings.[14]

2.1.1.5 Independent Power Producers and Marketers

Independent power producers (IPPs) are non-utility generator (NUG) private entities that own electric generating units and produce electricity for sale to utilities. Electricity generated by IPPs is either sold to utilities under long-term contracts or sold directly onto the wholesale market.

The IPP sector, initiated in 1978 under the federal Public Utilities Regulatory Policy Act (PURPA), saw strong growth with the adoption of the Energy Policy Act of 1992 (EPAct). Since 1992, the IPP sector has grown considerably and has invested significantly in both natural gas combined cycle (NGCC) turbines and wind energy. Developers of independent power take on the full financial risk of permitting and constructing new power plants, and unlike utilities, cannot recover losses from rate-paying customers if the project fails and investments are lost.[15]

Some IPPs are industrial plants that operate combined heat and power (CHP) facilities, supplying steam and power for their own operations and selling excess power to the grid. Some IPPs are merchant suppliers, selling power on a "spot market" or capacity market basis. Many IPPs enter into long-term contracts with utilities that establish fixed-formula pricing; therefore, if construction and operating costs exceed the contractual sales price the IPP suffers a loss. Contracts are also generally of a pay-for-goods nature; the IPP is paid based on electricity generated and provided to the buyer, and not based on capacity available. In lieu of selling power to utilities, IPPs may sell to independent power marketers, which buy and sell electricity as an investment commodity.

The NUG contribution to electricity generation and existing EGU CO_2 emissions is significant. NUGs account for about 42% of the U.S. electric generating capacity, and

13 National Rural Electric Cooperative Association (NRECA), *Annual Meeting Fact Sheet,* March 2014, www.nreca.coop/wp-content/uploads/2014/12/AnnualMeetingFactSheet.pdf.

14 *See* www.tva.com.

15 Northwest and Intermountain Power Producers Coalition (NIPPC), *Introduction to Independent Power Producers,* www.nippc.org/commitments/index.tpl?cntid=10547527139422.

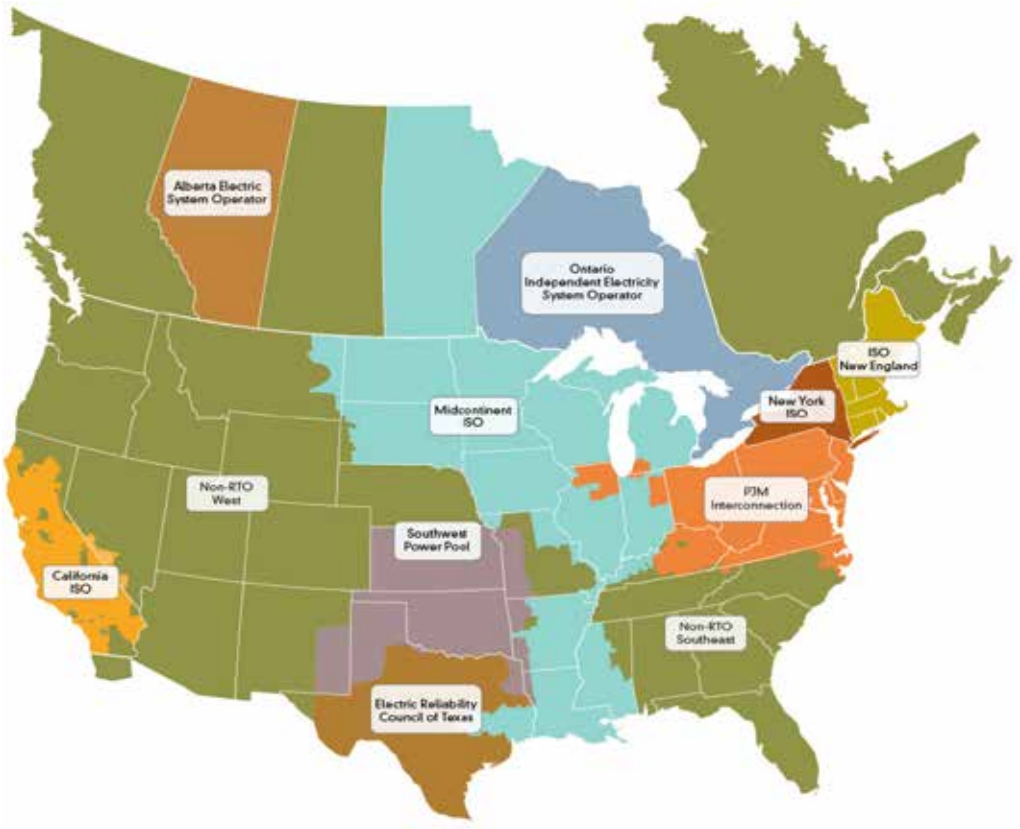
about 41% of U.S. electricity generated. About 74% of NUG generating capacity is from coal, oil and gas.[16]

2.1.2 Regional Transmission Operators and Independent System Operators

Another type of business organization in the power sector has grown out of the restructuring of the industry to provide for competition in the generation market through equal access to the transmission grid.[17] This organization type is the independent system operator (ISO) or regional transmission operator (RTO). In most of the northeast and central United States, as well as California, electricity is provided through highly organized wholesale markets, where energy resources are bid and dispatched in hourly and daily auctions, creating real-time competition in the generation market. In addition, the Federal Energy Regulatory Commission (FERC) requires non-discriminatory access to transmission lines at regulated rates under a tariff system. In these areas of the country, RTOs and ISOs operate (but generally do not own) the interstate electricity grid over a large region, and manage the dispatch of power generation through an auction-based energy market. RTOs and ISOs are independent, not-for-profit organizations that have been approved by FERC as meeting certain qualifying criteria. A key characteristic of both ISOs and RTOs is that, in contrast with grid operators in vertically-integrated utility operated systems, ISOs and RTOs are not affiliated with (i.e. cannot own an interest in) any of their member market participants, thus eliminating any conflict of interest or inherent bias in providing access to the transmission grid.[18]

RTOs are distinguished from ISOs in that RTOs service a broader geographic region, whereas ISOs that are not qualified by FERC as RTOs service a single state (e.g., California ISO and New York ISO). The Electric Reliability Council of Texas (ERCOT) functions as an ISO, but is not FERC-regulated. There are currently ten RTOs and ISOs operating in the U.S. and Canada, with seven operating in the U.S. In 2009, U.S. RTOs/ISOs managed 60% of the power supplied to customers.[19] For a map of RTO and ISO service areas, see Figure 6.1.

Figure 2.1. **Map of U.S. and Canada ISO and RTO Operating Regions**[20]



16 U.S. Electric Industry Statistics and U.S. Electric Generating Capacity by Utility Type and Fuel Type, 2012, American Public Power Association, both from the 2014-15 Annual Directory and Statistical Report, data sourced from Energy Information Administration, available at www.publicpower.org, accessed May 24, 2015.

17 ISOs were introduced in FERC Orders Nos. 888/889 as a way satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada) and delineated twelve characteristics and functions that an entity must satisfy in order to become a Regional Transmission Organization. http://ferc.gov/industries/electric/indus-act/rto.asp; also see the 2014 RTO map at http://ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf.

18 Electricity Market FAQ, Compete Coalition, http://competecoalition.com/press_kit/faq, retrieved May 24, 2015.

19 http://www.eia.gov/todayinenergy/detail.cfm?id=790.

20 http://sustainableferc.org/iso-rto-operating-regions/, retrieved May 3, 2015.

2.2 U.S. Power Sector Regulation and Oversight

This section provides a general summary of the typical federal, state and local regulatory and administrative oversight framework for the U.S. electric utility sector, as a reference for states in considering avenues for compliance with the CPP. As with business structures, the exact oversight roles and framework vary from state to state, and within a given state, from one locale to another.

2.2.1 Federal Regulation – FERC, NERC, NRC and EPA

The Federal Energy Regulatory Commission (FERC) is a federal government agency that regulates the transmission and wholesale sales of electricity in interstate commerce. In addition, FERC reviews certain mergers, acquisitions, and corporate transactions by electricity companies; reviews siting applications for electric transmission projects in certain areas designated as having insufficient transmission facilities; establishes mandatory reliability standards for high voltage interstate transmission systems; monitors and investigates wholesale energy markets; and licenses private, municipal and state hydroelectric projects. RTOs and ISOs must meet FERC criteria, must obtain FERC approval of their tariff system, and are subject to monitoring by and reporting to FERC. FERC is a regulatory body with the enforcement authority to impose civil penalties.

There are many power sector operations and types of electric business structures that do not come under FERC authority. [21] For example, FERC does not regulate municipal utilities, public utility districts, most rural electric cooperatives, federal PMAs, or the TVA. FERC does not regulate nuclear energy facilities, which are regulated at the federal level by the Nuclear Regulatory Commission (NRC). FERC is not responsible for the regulation of retail sales of electricity. Also, FERC does not mandate or approve the construction of new power generating facilities.

Operating under FERC oversight, the North American Electric Reliability Corporation (NERC) is a not-for-profit corporation with international regulatory authority. NERC develops and enforces Reliability Standards that meet FERC requirements. NERC delegates its authority to monitor and enforce compliance to regional entities. Transmission in the continental U.S. is managed under eight regional reliability planning areas, each represented by a U.S. Electric Reliability Council that carries out the duties of NERC.[22]

The Nuclear Regulatory Commission (NRC) is a federal government agency that licenses and regulates the civilian use of radioactive materials to protect public health and safety, promote the common defense and security, and protect the environment. The NRC regulates commercial nuclear power plants and has enforcement authority, but does not own or operate nuclear power plants.[23]

Most existing federal environmental regulation that applies to the power sector comes under the jurisdiction of U.S. EPA. Implementation and enforcement of most federal Clean Air Act regulations are delegated to state and local clean air agencies. In addition to being subject to multi-sector regulations such as the New Source Review and Title V operating permit programs, several significant sector-specific air quality regulations have been adopted by EPA, including the Acid Rain Program, the Mercury and Air Toxics Standards (MATS), and the Cross-State Air Pollution Rule (CSAPR). Utilities are currently subject to EPA GHG monitoring and reporting regulations. Existing New Source Performance Standards (NSPS) regulate criteria pollutants from electric generating units. Other applicable National Emissions Standards for Hazardous Air Pollutants (NESHAPs) include rules for stationary internal combustion engines and stationary combustion turbines. EPA non-air regulations with applicability to power plants include regulations for managing combustion waste from fossil fuels and rules governing water intake structures as well as water discharges.

2.2.2 State and Local Regulation and Oversight

At the state level, the primary agencies with jurisdiction over electric utility services are the State Public Service Commissioners (PSC), also frequently named the Public Utility Commissioner (PUC). The role of the PSC is to oversee the operations and management of utilities to assure reliable service at fair and reasonable rates. Every state has a PSC. In most states, the PSC regulates capital expenditures and rate schedules of IOUs, but does not have a direct role with regard to regulation of air emissions or environmental impacts. Also, most PSCs do not have authority over public power or cooperative utilities. Most

21 *What FERC Does,* http://www.ferc.gov/about/ferc-does.asp, accessed May 24, 2015.

22 *About NERC and Key Players,* http://www.nerc.com/About-NERC/Pages/default.aspx, accessed May 24, 2015.

23 *About NRC,* http://www.nrc.gov/about-nrc.html, accessed May 24, 2015.

state commissioners are appointed to their positions by their governor or the state legislature, while commissioners in fourteen states are elected to their positions.[24] One way that many PSCs assure reliable service at reasonable rates is through the Integrated Resource Planning (IRP) process. IRP procedures vary considerably from state to state, but can involve considerations for improving energy efficiency of existing EGUs, planning for retirement of existing units and construction of new EGUs, and consideration of available generation resources owned by others. PSCs have a regulatory role and often establish requirements for IRP, including PSC approval of the plan, as a prerequisite for approval of a rate increase or for other required approvals. While PSC approval is required for rate adjustments to recoup capital investments, in many cases the PSC does not have enforcement authority and the IRP does not become an enforceable vehicle. The IRP itself is usually a living document that is periodically revised. However, in some cases the PSC is directly involved in setting mandatory energy efficiency (EE) or renewable energy (RE) requirements and has the authority to enforce compliance with those requirements. For example, in some states a mandatory Renewable Portfolio Standard is established, administered and enforced by the PSC, with utilities being subject to penalties for failure to meet the RPS.[25] The National Association of Regulatory Utility Commissioners (NARUC) is the national coalition that represents PSCs. NARUC's members include all fifty states, the District of Columbia, Puerto Rico, and the Virgin Islands.

The state and/or local environmental agency also has existing authority to regulate the power sector, with jurisdiction over environmental protection. In most cases, the state or local air quality office has been delegated the authority to implement and enforce nearly all of the federal environmental regulations adopted by EPA. In addition, many state and local air quality agencies have state or local level environmental requirements that apply to the power sector. Most state and local air pollution control agencies belong to the National Association of Clean Air Agencies (NACAA).

Municipal utilities are regulated at the local level, either by the city council or by a separate council that is appointed by the mayor or city council, or elected by the municipality. Rural electric co-ops are usually governed by a membership-elected board of directors. These governing bodies may not have a role in regulating environmental impacts directly, but generally would have the authority to make decisions on expenditures for efficiency improvements, investment in new electric generation resources, and purchase of power from other generators or power marketers, within the limits of authority provided under the bylaws or other governing principles of the co-op.

2.2.3 Federal Department of Energy and State Energy Offices

The U.S. Department of Energy (DOE or Energy Department) also plays a significant role with regard to the power sector. The stated mission of the Energy Department is "to ensure America's security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions."[26] In particular, DOE implements a loan guarantee program for innovative energy efficiency, renewable energy, and advanced transmission and distribution projects and for qualifying commercial technologies. Also, the U.S. State Energy Program (SEP) administered by DOE is a cost-shared program that provides funding directly to the states for allocation by the State Energy Offices (SEOs) for use in efficiency, renewable, and alternative energy demonstration activities. The Energy Department's National Electricity Delivery Division (NEDD) is responsible for providing technical assistance to states to facilitate the development of reliable and affordable electricity infrastructure. DOE also develops projects for "next generation" electricity delivery technologies, and supports activities to accelerate introduction to the marketplace of "next generation" and Smart Grid technologies. While the Energy Department is not generally viewed as a regulatory body, NEDD also authorizes the export of electricity, issues permits for the construction of cross-border international transmission lines, and supports the coordination of Federal transmission permitting on Federal lands.

At the state level, the SEO serves as a corollary to the U.S. Energy Department. Every state has an SEO, which generally functions in a non-regulatory role to develop state energy policies, to support research, demonstration and deployment of new energy technologies, and to support emergency response and mitigation related to energy infrastructure. The SEO usually partners with

24 http://www.naruc.org/about.cfm.

25 For example, in Hawaii the state legislature has adopted a Renewable Portfolio Standard. The Hawaii PUC has the authority to prescribe what portion of the renewable portfolio standards shall be met by specific types of renewable electrical energy resources for a given utility, and to assess penalties if a utility company fails to meet the standard. http://energy.gov/savings/renewable-portfolio-standard, accessed May 24, 2015.

26 http://energy.gov/mission, accessed May 24, 2015.

the private sector in research efforts and to support the deployment of energy efficiency programs and other energy resources. SEOs receive and allocate funding from DOE under the SEP to develop energy efficiency and renewable energy projects. SEOs are represented by the National Association of State Energy Officials (NASEO), a non-profit association.[27]

27 http://www.naseo.org.

3. The Clean Power Plan

On June 25, 2013, President Obama announced his Presidential Climate Action Plan.[28] As part of the announcement, the President issued a memorandum[29] to the EPA Administrator, directing EPA to take several actions to address carbon pollution from the U.S. power sector. For existing power plants, the President directed EPA to use its authority under CAA section 111(d) to issue proposed carbon pollution emission guidelines in 2014, to finalize the emission guidelines in 2015, and to include in the guidelines requirements that states submit the state plans required under section 111(d) in 2016. The memorandum also directed EPA to develop this effort "through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants," and to engage in extensive outreach to states, tribes, the power sector, labor leaders, non-governmental organizations (NGOs), technical experts, the public and other stakeholders. In response, EPA held eleven public listening sessions across the country and met with numerous state and tribal officials, industry representatives, labor unions and NGOs. After considering all of the information received, EPA developed the proposed CPP. The proposed rule was published in the *Federal Register* on June 18, 2014.[30] EPA estimated that the agency received more than 2 million comments on the proposal during the 165-day comment period.[31]

The final rule was issued on August 3, 2015, published in the Federal Register on October 23, 2015, and codified at 40 C.F.R. Part 60, Subpart UUUU.[32] EPA has also made available an online "Clean Power Plan Toolbox" containing documents and resources to support the development of state plans.[33] Among the documents and information included on the Clean Power Plan Toolbox website are several Technical Support Documents associated with the final rule; a draft Evaluation, Measurement and Verification Guidance; background documents about the energy sector, existing state programs, and utility incentive programs; and many other clean-power related resources.

On the same day that the final CPP was released, EPA co-proposed two federal plans for CPP implementation – a rate-based trading plan and a mass-based trading plan – together with two proposed model state trading rules.[34] Federal plans will be finalized only for any state with affected EGUs that EPA determines has failed to timely submit an approvable state plan under Subpart UUUU. When EPA finalizes rate-based and/or mass-based model state trading rules, those models (as finalized) would be presumptively approvable for use by a state as a component of its state plan submittal.

This chapter provides a summary of the final CPP, focusing on those elements of the rule that have the most bearing on state plan development and state compliance. A summary of the proposed federal plans and model state trading rules is also provided.

3.1 Statutory and Regulatory Framework

Section 111 of the CAA requires EPA to develop and publish a list of source categories which "cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health and welfare." CAA section 111(b) requires EPA to establish "standards of performance" for emissions from new, modified and reconstructed sources in the listed source categories, referred to as New Source Performance Standards (NSPS). Under section 111(d), EPA is required to publish guidelines for states to submit plans to control emissions from existing

28 http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

29 https://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

30 79 Fed. Reg. 34,830 (proposed June 18, 2014).

31 FACT SHEET: Clean Power Plan & Carbon Pollution Standards Key Dates, EPA, http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-carbon-pollution-standards-key-dates.

32 80 Fed. Reg. 64,662 (Oct. 23, 2015).

33 http://www2.epa.gov/cleanpowerplantoolbox.

34 80 Fed. Reg. 64,966 (proposed Oct. 23, 2015).

sources in each source category for which EPA establishes an NSPS and for which the regulated pollutant is not either regulated through a National Ambient Air Quality Standard (NAAQS), or as a federal Hazardous Air Pollutant (HAP) under section 112 of the CAA.

The CAA designates the level of control that must be applied under section 111 as the "best system of emission reduction" (BSER). Several criteria must be considered in determining BSER, as established under the CAA and as interpreted by the courts. First, section 111 defines the term "standard of performance" to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Thus, EPA must determine BSER based on reduction strategies that are adequately demonstrated, considering cost, non-air quality and energy impacts. Also, the courts have interpreted BSER to be a system of emission reduction that promotes the development and implementation of new technology.

EPA adopted regulations to implement CAA section 111(d) at 40 C.F.R. Part 60, Subpart B. Those regulations specify that EPA will publish emission guidelines that reflect the application of the best system of emission reduction, considering cost, that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. After opportunity for public comment and consideration of comment received, EPA is to adopt in Subpart C of 40 C.F.R. Part 60, upon or after adoption of the NSPS for the source category for the designated pollutant, the emission guidelines for state plans for existing sources.

Under CAA section 111 and 40 C.F.R. Part 60, Subpart B, when EPA finalizes existing source emission guidelines, each state must develop and submit to EPA for approval a state plan for reducing emissions from existing affected sources. Each state plan must include "standards of performance" or "emission standards"[35] that are at least as stringent as the emission guidelines adopted by EPA, unless a showing is made in accordance with the rules that the compliance timeline and level of stringency established in the guidelines would be physically impossible or would impose unreasonable cost due to the plant age, location, or basic process design, or that other factors specific to the facility (or class of facilities) make application of a less stringent standard or final compliance time significantly more reasonable.

3.2 Scope of the Emission Guidelines

The final CPP emission guidelines include not only the BSER performance rates that state plans must achieve for their affected EGUs, but also state plan content, plan adoption, submittal and approval criteria, and other related provisions for implementation of the performance standards adopted by states. Subpart UUUU includes the following provisions:

- Applicability provisions defining the states that must submit a state plan or a negative declaration;
- Applicability provisions defining affected EGUs that must be addressed in the state plans, and EGUs that are excluded from being affected EGUs;
- The BSER CO_2 emission performance rates for affected EGUs and equivalent statewide emission goals as determined by EPA;
- Required state plan components, submittal procedures and timelines, the EPA review and approval process, and plan revision procedures;
- State recordkeeping and reporting requirements;
- Minimum required monitoring, recordkeeping and reporting for affected EGUs;
- Emission Rate Credits (ERCs) qualifying resources, and minimum procedures for the issuance and tracking of ERCs;
- Evaluation, measurement and verification minimum requirements; and
- Mass allowance allocation requirements for plans relying on mass-based trading.

3.3 Applicability to States and EGUs

The Subpart UUUU emission guidelines apply directly to the governors of states, who are obligated to adopt and implement a plan for affected EGUs in their state. Although Subpart UUUU does not apply directly to EGUs, the rule specifies applicability criteria for EGUs that must be subject

35 40 C.F.R. § 60.21(f) defines "emission standard" as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions." Design, equipment, work practice or operational standards are not considered standards of performance or emission standards for purposes of a state plan under Subpart UUUU, although these types of requirements can be used to provide for implementation of the standards of performance. *See* 80 Fed. Reg. at 64,854.

to the state plan, as well as exclusions denoting EGUs that are not subject to state plan requirements.

3.3.1 Applicability to States

Subpart UUUU applies to the governor of each state in the contiguous United States. For each state in the contiguous United States with one or more affected EGUs that commenced construction on or before January 8, 2014, the governor must submit a state plan or a multi-state plan to EPA to implement the emission guidelines. For each state in the contiguous United States with no affected EGUs that commenced construction on or before January 8, 2014, the governor must submit a negative declaration letter to EPA.

3.3.2 Affected EGUs Subject to State Plans

The EGUs that must be addressed in the state plan are any affected EGU that commenced construction on or before January 8, 2014. An affected EGU is a fossil fuel-fired steam generating unit, integrated gasification combined cycle (IGCC) unit, or stationary combustion turbine that meets the following criteria, as applicable, unless specifically excluded.

1) The EGU serves a generator or generators connected to a utility power distribution system with a name-plate capacity greater than 25 MW-net (i.e., capable of selling greater than 25 MW of electricity);
2) The EGU has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and
3) For stationary combustion turbines, the EGU meets the definition of either a combined cycle or combined heat and power combustion turbine.

It is important to note that simple cycle stationary combustion turbines are not affected EGUs under Subpart UUUU. In addition, the following EGUs are excluded from being affected EGUs:

a) EGUs that are subject to 40 C.F.R. Part 60, Subpart TTTT (standards of performance for new, modified or reconstructed EGUs[36]) as a result of commencing construction after the Subpart TTTT applicability date;
b) Steam generating units and IGCCs that are, and always have been, subject to a federally enforceable permit limiting annual net-electric sales to one- third or less of its potential electric output, or 219,000 MWh or less;
c) Non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;
d) Stationary combustion turbines not capable of combusting natural gas (e.g., not connected to a natural gas pipeline);
e) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit limiting, annual net-electric sales to a utility distribution system to no more than the greater of either 219,000 MWh or the product of the design efficiency and the potential electric output;
f) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;
g) EGUs that are a municipal waste combustor unit that is subject to 40 C.F.R. Part 60, Subpart Eb; and
h) EGUs that are a commercial or industrial solid waste incineration unit that is subject to 40 C.F.R. Part 60, Subpart CCCC.

3.4 Best System of Emission Reduction (BSER)

As noted above, each state must design its plan to require that its affected EGUs meet the CO_2 emission performance standards that reflect the application of the best system of emission reduction (BSER), as determined by EPA. EPA adopted emission guidelines that take into account the wide range of CO_2 reduction measures already being implemented in states around the country, including both "inside the fenceline" measures that directly reduce the amount of CO_2 emitted by the operation of fossil-fuel fired EGUs, and measures that occur "outside the fence-line," such as generating electricity from renewable energy sources, thereby reducing the operation of fossil-fuel fired

36 Alongside the CPP, EPA finalized New Source Performance Standards regulating GHG emissions from new, modified and reconstructed power plants under CAA section 111(b). 80 Fed. Reg. 64,510 (Oct. 23, 2015). These standards are codified at 40 C.F.R. Part 60, Subpart TTTT.

EGUs. Specifically, EPA established BSER as a combination of three distinct measures, or building blocks:

Building Block 1 – Heat Rate Improvements at affected coal-fired steam EGUs;

Building Block 2 – Shifting generation from higher-emitting (i.e., coal and oil) affected steam EGUs to existing NGCC EGUs up to a utilization of 75% of the net summer capacity; and,

Building Block 3 – Shifting generation from existing affected fossil-fueled EGUs to new zero-emitting Renewable Energy (RE) generating capacity.

To develop the performance level reflecting CO_2 emissions that could be achieved from affected EGUs by applying BSER, EPA grouped the affected EGUs into two subcategories: 1) steam generating units and IGCCs; and 2) stationary combustion turbines. In general, the first subcategory includes coal- and oil-fired steam units, while the second subcategory includes NGCCs.[37] EPA determined the level of reductions that could be achieved by applying each of the three building blocks to the fleet of affected EGUs within each of three regional electric power interconnects: the Western interconnection; the Eastern interconnection; and the Electricity Reliability Council of Texas interconnection. EPA then selected the least stringent resulting emission rate among the three interconnects for each subcategory for each year from 2022 to 2030. For each source subcategory, the least stringent annual rates were averaged for years 2022 through 2029 to set the interim performance rate for that subcategory nationally. The final (i.e., applicable for 2030 and after) national performance rate for each subcategory is the least stringent estimated 2030 performance rate among the three regions.

In addition, although EPA established subcategory emission performance rate standards in the form of lb/MWh-net, EPA also established interim and final emission goals for each state in both rate-based and mass-based form, in Table 2 and Table 3 of Subpart UUUU, respectively. The statewide emission goals are presumptively considered equivalent to the Table 1 subcategory performance rates for each state. The final emission guidelines allow each state to demonstrate compliance with either the Table 1 subcategory performance rates, the Table 2 statewide rate based emission goals, or the Table 3 statewide mass-based emission goals.[38]

Under the guidelines, state plans are not required to rely on the specific building blocks that EPA established as BSER. Rather, each state can design the state plan using any method(s) of CO_2 emission reduction it chooses, so long as the plan is projected to achieve the performance rates established in Subpart UUUU. Nonetheless, in designing a plan to achieve the performance rates required under Subpart UUUU, it is helpful to understand how the emission performance rates and statewide emission goals were derived. The following sections provide an explanation and illustrative examples for the derivation of the Subpart UUUU emission standards and goals.

3.4.1 Building Block 1 – Heat Rate Improvements

The first measure that EPA determined to be part of BSER is the "inside the fenceline" category of actions that reduce the carbon intensity of power generation at individual coal-fired steam EGUs by improving heat rate. Heat rate is the amount of energy input from fuel required to produce 1 kilowatt hour (kWh) of electricity. In the CPP, EPA expresses heat rate on a higher heating value (HHV) basis for fuel input and on a net electric output basis (i.e., electricity sent to the grid for distribution) in terms of Btu(HHV)/kWh-net. Heat rate can also be expressed on a gross electric output basis. The difference between gross and net electric output is the amount of electricity used at the power plant for auxiliary equipment, such as operating control systems, pollution control systems, coal cleaning, pumps, and other equipment. Heat rate improvement reduces CO_2 emissions by reducing the amount of fossil fuel burned by the EGU to produce a given amount of electricity.

Many different specific measures can result in heat rate improvements at coal-fired steam EGUs, including various equipment upgrades as well as work practice measures.[39] EPA groups all of these measures collectively and non-specifically as part of BSER under Building Block 1. A few specific examples include:[40]

- Replacement of drive motors for coal-handling;
- Installation of neural network and digital control systems;

37 Note that simple cycle turbines, which are typically used as peaking units, are not affected EGUs under Subpart UUUU.

38 40 C.F.R Part 60, Subpart UUUU, Table 2 and Table 3. Table 4 of Subpart UUUU presents an additional set of statewide emission goals, which include a "new source complement" to the mass-based goals in Table 3. For a discussion of new source complements and Table 4 of Subpart UUUU, *see Chapter 5, State Plan Types and Required Plan Components.*

39 *See* NACAA, *Implementing EPA's Clean Power Plan: A Menu of Options,* May 2015, *Chapter 1: Optimize Plant Operations,* available at http://www.4cleanair.org/NACAA_Menu_of_Options.

40 Sargent and Lundy, LLC, *Coal Fired Power Plant Heat Rate Reductions,* January 22, 2009, available at http://www.epa.gov/airmarkt/resource/docs/coalfired.pdf.

- Installation of intelligent soot blower systems;
- Upgrades to air pre-heater seal systems to reduce leakage;
- Turbine upgrades;
- Steam condenser tube cleaning;
- Rebuild of boiler feed pump;
- Flue gas system forced draft and induced draft fan upgrade or replacement;
- Installation of variable frequency drives for fan motors;
- Improvements to efficiency of air pollution control equipment (e.g., flue-gas desulfurization, electrostatic precipitation and selective catalytic reduction technologies);
- Improvements to water cooling and water treatment systems.

While the heat rate improvement examples listed above primarily address equipment upgrades, EPA also concluded, through review of historical data, that adoption of best practices for operating and maintenance can significantly improve heat rate without equipment changes. EPA estimated the level of emission reductions that could be achieved by affected EGU coal steam units collectively, including both equipment upgrades and best practices such as improved staff training, boiler chemical cleaning, and software upgrades. Estimates of achievable heat rate improvements for each of the three regional interconnects were made on a percent improvement basis, which was assumed to result in an equivalent percent reduction in the baseline lb/MWh-net emission rate for coal steam EGUs in the region.

The achievable emission rate improvements for coal-fired steam EGUs as determined by EPA for Building Block 1 are shown in Table 3.1.[41]

In determining BSER, EPA found that the collection of measures affected EGUs can undertake to improve heat rate are adequately demonstrated, technically feasible and can be achieved at a reasonable cost. EPA also noted that other BSER factors, such as non-air health and environmental benefits and the advancement of technical innovation, favor heat rate improvements as an element of BSER. For example, minimizing the fossil fuel used to generate electricity from a coal-fired steam EGU would also minimize solid waste resulting from coal combustion waste products. Also, heat rate improvements through equipment upgrades would advance the use of state-of-the art technology for the upgraded equipment components.

One concern EPA noted in relation to heat rate improvements is the "rebound effect." This concept considers that coal-fired steam EGUs are the most carbon intensive of all types of fossil-fired EGUs, therefore shifting utilization from other types of EGUs to this EGU group would have the effect of increasing CO_2 emissions. Investments in heat rate improvements to make coal-fired steam EGUs more efficient could, without consideration of other policies or measures, result in increasing the utilization of these units, thereby offsetting the CO_2 reduction gains that would otherwise have been achieved. This concern is addressed by the inclusion of the other components of BSER, i.e., generation shifting to existing NGCC EGUs and to zero-emitting RE EGUs.

Table 3.1 **Heat Rate Improvements Achievable by Coal-fired Steam EGUs Under Building Block 1**

Regional Interconnect	Heat Rate Improvement (Percent)
Eastern Interconnect	4.3
Western Interconnect	2.1
Electricity Reliability Council of Texas (ERCOT) Interconnect	2.3

3.4.2 Building Block 2 – Shifting Generation to Existing NGCC EGUs

Building Block 2 of BSER involves increasing the use of existing affected EGUs with a lower carbon intensity (NGCC EGUs) by shifting generation away from the higher carbon intensity affected EGUs (coal and oil steam EGUs). Because an NGCC EGU typically emits less than half the CO_2 per MWh of electricity produced than a typical coal-fired steam EGU, this reduction strategy can achieve significant CO_2 reductions.

EPA defined Building Block 2 as the gradual shifting of generation from affected coal and oil steam EGUs to affected NGCC EGUs within each of the three interconnect regions up to a maximum utilization rate of 75% of the net summer capacity, with the shift rate taking into account the historical load growth rate for each region. A shift from coal to NGCC has been occurring within the power industry since at least 2000. For example, NGCC power generation increased by more than four times from

41 80 Fed. Reg. at 64,727. For a more detailed presentation of EPA's analysis, see the *GHG Mitigation Measures Technical Support Document for the CPP Final Rule,* available at http://www2.epa.gov/cleanpowerplantoolbox.

Table 3.2 **Generation Increases Achievable by NGCC EGUs Under Building Block 2 (TWh)**

Regional Interconnect	2012	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total Increase
Eastern	735	896	941	988	988	988	988	988	988	988	253
Western	198	242	254	267	280	294	306	306	306	306	108
(ERCOT)	137	167	176	185	194	203	204	204	204	204	67

2000 to 2012, while generation from coal and oil/gas steam units decreased by approximately one third.[42]

In developing the emission guidelines, EPA determined that there remains additional available capacity from existing NGCC EGUs, and that the power sector has the mechanisms in place to achieve the level of generation shift reflected in Building Block 2.[43] For example, EPA noted that in 2012 about 10 percent of existing NGCC units operated at annual utilization rates greater than or equal to 80% on a net summer basis. In addition, in 2012 roughly 15% of existing NGCC units sustained an annual utilization rate of 75% or greater on a net summer basis, effectively serving as baseload units. On a seasonal basis, about 30% of NGCC plants operated at a utilization rate ≥ 75% net summer basis for the three month 2012 summer season.[44]

EPA also noted that the ability of EGU owners and grid operators to respond to emissions criteria and carbon allowance costs by favoring lower emitting EGUs in the dispatch algorithm has been adequately demonstrated. For example, the transmission grid system has successfully responded to the relative costs of allowances for NO_X and SO_2 for EGUs subject to market based programs under the CAA, as well as to the cost of CO_2 allowances for EGUs subject to the Regional Greenhouse Gas Initiative (RGGI) program, by factoring those costs directly into the variable costs of electricity production for the subject EGUs.[45]

EPA also examined the ability of the electricity delivery system to receive and transmit the increased generation from the locations of the affected NGCC units. EPA observed that the existing infrastructure already allows these levels to be achieved and sustained for extended periods. Further, significant expansions to the natural gas pipeline system have occurred in recent years, with additional expansions currently in progress. Similarly, substantial expansion of the electricity distribution system is currently underway.[46] To further address concerns related to the potential need for infrastructure improvements to accommodate generation shift to NGCC units, EPA quantified the level of CO_2 reductions from Building Block 2 based on a gradual shift along a glide path for each region.

Under Building Block 2, generation shift from coal and oil steam units to existing NGCC units is projected to occur gradually, with the shift in each region projected based on two parameters. First, EPA estimated a 22% increase from 2012 levels for each region to occur by 2022. Then, a 5% shift was projected to occur each year until the full Building Block 2 utilization level was achieved. Using the method described, EPA estimated that a total increase in generating capacity of 428 TWh[47] from existing NGCC facilities is feasible through Building Block 2.

Table 3.2 depicts the Building Block 2 projected glide path and power generation from NGCC units estimated by EPA for each region.

3.4.3 Building Block 3 – Increased Generation from New RE Generating Capacity

The third building block adopted as a component of BSER involves reducing generation from affected EGUs by increasing generation from renewable fuel through the deployment of new renewable energy (RE) capacity. The specific technologies considered in the analysis include utility-scale solar photovoltaics (PV), concentrating solar power (CSP), onshore wind, geothermal, and hydropower.[48]

EPA noted that generation of electricity from renewable energy sources is well demonstrated by the fact that most states have renewable portfolio standards (RPS),

42 80 Fed. Reg. at 64,795.

43 80 Fed. Reg. at 64,795-97.

44 80 Fed. Reg. at 64,799.

45 79 Fed. Reg. at 34,862; 80 Fed. Reg. at 64,796-97.

46 79 Fed. Reg. at 34,864.

47 One terawatt (TW) is equal to 1 trillion (1012) watts, 1 billion (109) kilowatts, or 1 million (106) megawatts.

48 80 Fed. Reg. at 64,808.

Table 3.3 **Generation Increases Achievable by New RE Capacity Under Building Block 3 (TWh)**

Regional Interconnect	2022	2023	2024	2025	2026	2027	2028	2029	2030
Eastern	166	182	218	256	292	328	365	401	438
Western	57	61	75	90	104	118	132	147	161
(ERCOT)	19	28	39	51	62	73	84	95	107

and by noting that in 2012 and 2013, RE accounted for twelve percent of the total U.S. generation, up from nine percent in 2009 and eight percent in 2005.[49] EPA also noted that owners of Subpart UUUU affected EGUs are already heavily invested in RE capacity, with 178 of the 404 affected owners representing 82% of affected EGU capacity also owning RE generating capacity equal to 25% of their collective total affected EGU capacity.[50] EPA used a seven-step process to quantify the amounts of incremental RE generation that could reasonably be attributed to Building Block 3.[51] The process included:

1) calculating five-year average and maximum annual capacity increases for each RE technology, based on historic data;
2) determining a capacity factor for each technology representative of expected future performance from 2022 to 2030;
3) calculating a maximum and average projected annual increase in generation for each RE technology using the capacity factor times the maximum and average five-year capacity change, respectively;
4) calculating generation from increased RE capacity for years 2013 to 2021;
5) applying the 2013 to 2021 RE increase and the average five-year generation growth to the first two years of the interim performance period (2022-2023);
6) applying the maximum annual increase from the five-year historic data to each subsequent year from 2024 to 2030; and
7) apportioning the national RE generating capacity growth across the three regional interconnects, based on Integrated Planning Model (IPM) analysis.

Table 3.3 depicts the levels of generation from new RE deployment estimated by EPA for each of the three regional interconnects, using the method described above.[52]

3.5 Affected EGU Emission Performance Rates and Statewide Emission Goals

Based on the determination of BSER, EPA developed affected EGU subcategory-specific emission performance rates and three additional sets of statewide emission goals that states may adopt as the compliance metric for their state plan. The performance rates and statewide emission goals are listed in Subpart UUUU tables as follows:

Table 1 – Subcategory CO_2 Emission Performance Rates (lbs. CO_2/MWh-net)

Table 2 – Statewide Rate-based CO_2 Emission Goals (lbs. CO_2/MWh-net)

Table 3 – Statewide Mass-based CO_2 Emission Goals (tons CO_2)

Table 4 – Statewide Mass-based CO_2 Emission Goals plus New Source Emissions Complement (tons CO_2)

The state-specific emission goals are not compliance requirements, but rather provide alternatives that states may elect to adopt as BSER-equivalent emission standards for their affected EGUs.

3.5.1 Table 1 Subcategory Emission Performance Rates

By applying the BSER building blocks to the two subcategories of affected EGUs on a regional basis, and selecting the least stringent performance rate from among the three regions for each year, EPA developed subcategory emission performance rates for affected EGUs, as shown in Table 3.4 below. These performance rates are codified at 40 C.F.R. Part 60, Subpart UUUU, Table 1, and are referred to simply as the "Table 1 performance rates" throughout this document.

EPA set the subcategory emission performance rates for two performance periods: 1) an eight-year interim performance period of January 1, 2022 through December

49 79 Fed. Reg. at 34,866; 80 Fed. Reg. at 64,803.

50 80 Fed. Reg. at 64,805.

51 80 Fed. Reg. at 64,807-09.

52 80 Fed Reg. at 64,809. Values are converted to TWh and rounded to the nearest whole digit for consistency with Table 3.2.

Table 3.4 **CO_2 Emission Performance Rates for Affected EGUs that Commenced Construction on or Before January 8, 2014 (Subpart UUUU Table 1)**

Affected EGU Subcategory	Interim Performance Rate (8-year average, 1/1/2022 to 12/31/2029) (lbs, CO_2/MWh-net)	Final Performance Rate (2-year blocks, beginning 1/1/2030 – 12/31/2031) (lbs, CO_2/MWh-net)
Steam Generating Unit or IGCC	1,534	1,305
Stationary Combustion Turbine	832	771

31, 2029; and, 2) a final performance period, beginning January 1, 2030. The interim performance rate applies as an eight-year block average performance rate over the interim period. The final performance rate applies as a two-year block average, beginning with 2030-2031. In addition, Subpart UUUU establishes three interim step periods within the interim period:

Interim Step 1 – three years (2022–2024);
Interim Step 2 – three years (2025–2027); and,
Interim Step 3 – two years (2028–2029).

A state plan that adopts the Table 1 performance rates as the applicable affected EGU emission standards must also establish emission performance rates for each subcategory of affected EGUs for each of the three interim step periods.[53]

States may adopt a plan that applies the Table 1 performance rates to the affected EGUs in their state through a number of different approaches, including a single-state plan with intrastate or interstate trading or through a multi-state plan.

Compliance by affected EGUs with the Subpart UUUU Table 1 performance rates is demonstrated by adjusting the affected EGU's actual performance rate through the use of Emission Rate Credits (ERCs) representing one MWh of generation from zero-emitting RE sources or other qualifying ERC resources, as provided in the EPA-approved state plan. State plans that apply rate-based emission standards to their affected EGUs must adopt the following equation for affected EGUs to demonstrate compliance with their applicable performance rate standard:[54]

$$\textbf{CO}_2\textbf{ emission rate} = \frac{\Sigma\ \textbf{MCO}_2}{\Sigma\ \textbf{MWh}_{\textbf{op}} + \Sigma\ \textbf{MWh}_{\textbf{ERC}}}$$

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.

MCO_2 = Measured CO_2 mass in lbs summed over the compliance period for an affected EGU.

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

MWh_{ERC} = ERC replacement generation for an affected EGU in MWh.

3.5.2 Table 2 and Table 3 Statewide Emission Goals

To provide greater flexibility to states in designing their plans, EPA also developed statewide rate-based and mass-based emission goals as equivalent representations of the Table 1 performance rates. The statewide emission goals are codified at 40 C.F.R. Part 60, Subpart UUUU, Table 2, Statewide Rate-based CO_2 Emission Goals, and Table 3, Statewide Mass-based CO_2 Emission Goals. Subpart UUUU Table 2 and Table 3 are reproduced at the end of this chapter for reference.

The Table 2 rate-based emission goals were derived by applying the Table 1 subcategory emission rates to the statewide baseline generation (MWh-net) for each subcategory, summing the emissions to determine the fleet-wide projected emissions, and dividing by the total generation to obtain the blended statewide performance rate goal. To derive the statewide interim emission goal, EPA performed this calculation using the subcategory interim performance rates from Table 1; to derive the 2030 final performance rate, EPA performed the calculation using the Table 1 subcategory final performance rates. In addition, EPA developed calculations for each year from 2022 to 2029, and averaged together the results in increments matching the Subpart UUUU interim steps of 3 years (2022–2024), 3 years (2025–2027), and 2 years (2028–2029).

A state plan that adopts the Table 2 statewide interim and final emission goals as the compliance metric for the state plan must also establish emission limits for affected

53 40 C.F.R. § 60.5855(a).

54 40 C.F.R. § 60.5790(c)(1).

55 40 C.F.R. § 60.5770(c); 80 Fed. Reg. at 64,821; 80 Fed. Reg. at 64,828; 80 Fed. Reg. at 64,864.

EGUs for each of the three interim step periods.[55] The interim step emission goals contained in Table 12 of the preamble to the final CPP can serve as interim step emission standards and as interim step goals against which state plan performance can be evaluated.[56] Alternatively, the state may submit a plan that incorporates different interim step emission performance rates from those provided by EPA.[57] For further discussion of interim steps and plan performance demonstrations, see *Section 3.7, Compliance Timelines and Performance Periods.*

States may design a plan that requires the affected EGUs in their state to meet the Table 2 statewide emission goals, collectively on a statewide average for each performance period, in lieu of relying on the Table 1 subcategory rates. The Table 2 statewide goals can be used in a single-state plan with intrastate trading. Or, states may join their Table 2 goals to form a combined goal on a weighted average basis for a multi-state plan. However, a state cannot use the Table 2 individual statewide goals in a single-state plan with interstate trading.

In addition to the Table 1 and Table 2 rate-based performance metrics adopted by EPA in Subpart UUUU, EPA developed statewide mass-based emission goals to afford states greater flexibility in designing their plans, and to provide presumptively approvable mass-based metrics for states that prefer to implement a mass-based plan. Like the Table 2 rate-based emission goals, the Table 3 statewide mass-based statewide emission goals are derived as an equivalent representation of the Table 1 subcategory performance rates, as applied to the baseline affected EGU inventory for each state.

The Table 3 statewide mass-based emission goals are the sum of two components. The first component is the amount of emissions directly represented by the statewide rate-based emission goal. That is, the statewide emissions for this component are equal to the sum of the steam EGU Table 1 performance rate times the steam unit baseline generation, plus the NGCC EGU Table 1 performance rate times the NGCC baseline generation. The second component represents the emissions-associated load growth over the baseline generation levels that could be met by affected EGUs. This component was added so that the mass-based emission goals would be effectively equivalent to a rate-based goal or standard. Under the rate-based approach, affected EGUs are able to expand their output provided sufficient qualifying ERCs are available. In the application of Building Block 3 (replacement of fossil-fuel generation with incremental RE), EPA selected the least stringent level of RE deployment from among the three regions, and therefore there is remaining "beyond compliance" cost-effective RE available as determined in the analysis. The amount of emissions added to the mass-based emission goal for each state represents the apportioned amount of emissions that would result if this "beyond compliance" RE were deployed.[58] In other words, the Table 3 mass-based statewide emission goals include a component of emissions to allow for load growth to be met through operation of the existing affected EGU fleet.

As with the statewide rate-based emission goals, EPA developed calculations for mass-based goals for the interim and final performance periods, as well as for each year from 2022 to 2029. The interim year emissions results were averaged together in increments of 3 years (2022–2024), 3 years (2025–2027), and 2 years (2028–2029). A state plan that adopts the Table 3 statewide interim and final performance rates as the compliance metric for the state plan must also establish emission limits for affected EGUs for each of the three interim step periods.[59] The mass-based interim step goals, contained in Table 13 of the preamble to the final CPP, are average annual emission goals for each interim step, which can serve as interim step emission limits or goals against which state plan performance can be evaluated.[60] Alternatively, the state may submit a plan that incorporates different interim step emission performance rates from those provided by EPA.[61] For further discussion of interim steps and plan performance demonstrations, see Section 3.7, Compliance Timelines and Performance Periods.

States may design a plan that applies the Table 3 statewide emission goals collectively to their affected EGUs for each performance period, in lieu of relying on the Table 1 subcategory rates. The Table 3 statewide goals can be used as a cap (mass budget) in a single-state plan with intrastate or interstate trading, or can be combined (as an aggregated sum) with other states for a multi-state plan. Subpart UUUU Table 3 is reproduced at the end of this chapter for reference.

56 80 Fed. Reg. at 64,821-24.

57 80 Fed. Reg. at 64,828.

58 *See* EPA, *Clean Power Plan Goal Calculation Viewer* and EPA, *CO_2 Emission Performance Rate and Goal Computation Technical Support Document,* http://www2.epa.gov/cleanpowerplantoolbox.

59 40 C.F.R. § 60.5770(c); 80 Fed. Reg. at 64,821; 80 Fed. Reg. at 64,828; 80 Fed. Reg. at 64,864.

60 80 Fed. Reg. at 64,822-25.

61 80 Fed. Reg. at 64,828.

3.5.3 Table 4 Statewide Mass-based Emission Goals

EPA also adopted Table 4 of Subpart UUUU, Statewide Mass-based CO_2 Goals Plus New Source CO_2 Emission Complement. Subpart UUUU Table 4 is reproduced at the end of this chapter for reference.

The Table 4 statewide mass-based emission goals are an option that states may elect to adopt in their state plan to address the potential for leakage to new EGUs under a mass-based plan. Specifically, the Table 4 emission goals incorporate additional mass emissions representing a "new source complement" for states that elect to regulate new sources under state law, in order to assure that implementation of a mass-based plan is equivalent to implementation of the Table 1 subcategory performance standards. Because a mass-based emission standard could create an incentive for generation to be shifted to new fossil-fueled sources such as new NGCC, which are not affected EGUs, any state adopting a mass-based plan must provide a demonstration that the plan is designed in such a way as to minimize the potential for such leakage to occur. One way that states may make this demonstration is to regulate new sources under a combined emissions cap with existing sources (e.g., under a cap-and-trade program).[62] To facilitate plan development and plan approval, as well as to facilitate interstate trading through the adoption of "trading-ready" state plans, EPA has developed presumptively approvable new source mass emissions complements for each performance period for each state. The statewide emission goals in Table 4 are a sum of the Table 3 goals plus the respective new source complement, and serve as one option states may elect to address leakage to new sources under a mass-based plan. It should be noted that regulation of new sources under an emissions cap is not the only method by which a state can address the potential for leakage to new sources, and regulation of new sources will not be a federally enforceable state plan component.

Like the Table 3 emission goals, Table 4 statewide emission goals plus new source complements can be used as a cap (mass budget) in a single-state plan with intrastate or interstate trading, or can be combined (as an aggregated sum) with other states for a multi-state plan. If the state plan relies on the EPA-provided Table 4 mass budgets for existing sources plus new source complement, plan performance will be based on whether existing and new sources, together, meet the total mass budgets in Table 4.[63]

3.5.4 State Adjustments to Emission Performance Goals

Subpart UUUU provides broad flexibility to states in designing their plan, including the flexibility to adopt adjusted statewide emission performance goals in some situations. Specifically, there are certain circumstances under which a state is allowed to make revisions to the statewide emission goals provided in Table 2, Table 3 and Table 4 of Subpart UUUU. First, a state may submit a revision to the interim and final emission goals provided in Tables 2 and 3 as a result of changes to the affected EGU inventory. Additionally, a state may propose a statewide emission goal that incorporates a new source complement that is different from the one developed by EPA.[64] However, if the state plan uses an EPA-approved new source complement that the state proposed, plan performance will be evaluated based on whether existing affected EGUs meet the state's mass goal for affected EGUs.[65] Revisions to state performance goals can be submitted either as part of the initial plan or as a plan revision.[66]

Also, as noted above, a state that is implementing a plan based on statewide emission goals may adopt different interim step goals than those published by EPA in Tables 12 and 13 of the preamble to the final rule. EPA notes that the interim step emission goals provided in the final rule preamble tables "provide one illustrative pathway for states to consider in meeting their interim goals."[67] A state may choose to define different interim step emission levels for achieving the 8-year average interim emission goal, provided the interim steps demonstrate that the state is making steady progress toward the interim and final goals.[68]

62 For a more detailed discussion of plan components to address leakage under mass-based plans, see *Chapter 5, State Plan Types and Required Plan Components,* section 5.4.1, Leakage to New Fossil Fuel EGUs.

63 80 Fed. Reg. at 64,888.

64 40 C.F.R. § 60.5855(d). *See also* 80 Fed. Reg. at 64,824-25.

65 80 Fed. Reg. at 64,889.

66 80 Fed. Reg. at 64,824 ("EPA is allowing the flexibility for this type of adjustment…when submitting or revising its state plan.").

67 80 Fed. Reg. at 64,821.

68 80 Fed. Reg. at 64,865 and 80 Fed. Reg. at 64,828.

69 This could be an adjusted Table 3 goal, or a goal that incorporates an EPA-approved new source complement.

3.6 State Plan Types

This section provides a brief overview of available plan types. For a more detailed discussion of available plan pathways and the required components for different plan options, see *Chapter 5, State Plan Types and Required Plan Components.*

3.6.1 Emission Standards Plans and State Measures Plan Types

States may choose between two plan types to comply with Subpart UUUU: an "emission standards" plan type, and a "state measures" plan type. Both plan types can be designed as either single-state or multi-state plans. Both plan types can incorporate interstate trading.

Emission standards plans may be either rate-based or mass-based. The emission standards plan type is EGU-focused, in that it imposes federally enforceable emission standards directly on affected EGUs as the means of achieving compliance with the Subpart UUUU performance rates or statewide emission goals. The emission standards to which affected EGUs are subject may incorporate interstate trading provisions for ERCs under a rate-based plan, or may be comprised of an allowance holding and "true up" requirement (e.g., a cap-and-trade program) with interstate trading under a mass-based plan. Alternatively, a mass-based emission standards plan could impose mass-based emission limits directly on affected EGUs in the more traditional "command and control" regulatory framework.

The state measures plan type must be mass-based, demonstrating compliance against the Table 3 statewide mass emission goal or alternative EPA-approved mass emission goal. A state measures plan relies either wholly or in part on reduction strategies that are not emission standards and that are not federally enforceable. State measures such as Renewable Portfolio Standards (RPS), Energy Efficiency Resource Standards (EERS), and many other reduction strategies may be incorporated as part of the state plan and relied upon to achieve compliance with the mass-based emission goals. State measures that are not emission standards will not become federally enforceable, although they may create enforceable requirements under state law. However, if the state measures plan incorporates emission standards applicable to affected EGUs (e.g., a requirement to hold and retire allowances equal to actual emissions under a cap-and-trade program), such emission standards must be included as federally enforceable components of the state plan. Furthermore, a state measures plan must include a federally enforceable backstop that will assure compliance with the Table 3 state emission goals in the event the state measures fail to perform adequately during plan implementation.

3.6.2 Trading-Ready and Streamlined Plan Types

Within the primary plan types (emission standards and state measures), EPA has adopted two additional plan designations: "trading-ready" and "streamlined." First, certain plan designs are designated as "trading-ready," meaning that these plans, once approved by EPA, can participate with other EPA-approved trading-ready plans for interstate trading of ERCs or allowances on an EPA-administered or EPA-approved trading platform. To be trading-ready, the state plan must recognize ERCs (for rate-based plans) or allowances (for mass-based plans) issued by other states that also rely on an EPA-approved or EPA-administered trading platform; however, the state plan does not need to specifically identify trading partners. No formal agreement with other states that are also trading-ready is required. Rate-based plans must use the Table 1 subcategory performance rates as the applicable affected EGU emission standards in order to be trading-ready.

A streamlined state plan is one that imposes emission standards on all affected EGUs that, assuming full compliance by all affected EGUs, mathematically assures compliance with the applicable subcategory performance rates or statewide emission goal. Similarly, a state plan that also regulates new sources as a matter of state law, and that imposes emission standards on all affected EGUs and on new sources that, assuming compliance by all affected EGUs and new sources, mathematically assures compliance with the statewide emission goal plus new source complement, is also considered streamlined. For example, a state plan that directly imposes the Table 1 subcategory performance rates on each affected EGU as an enforceable emission standard would mathematically assure compliance, assuming all affected EGUs comply. As another example, a state plan that incorporates a mass-based cap-and-trade program and uses the applicable statewide mass goal for each interim step period and final performance period as the emissions cap would mathematically assure compliance with the state goal, assuming all affected EGUs comply. A state measures plan cannot be a streamlined plan. In addition, a rate-based plan that imposes varied performance rates on existing units is not a streamlined plan. Any plan that is a streamlined plan is not required to incorporate additional plan performance demonstrations (i.e.,

using modeling and other data to demonstrate the plan will achieve the required level of reductions), and is not required to incorporate corrective measure triggers.

3.7 Compliance Timelines and Performance Periods

A summary of compliance milestones for states and affected EGUs is provided in this section. ★*It is important to note that, as discussed in the Preface to this document, all dates listed in this section are potentially subject to change due to the Supreme Court-ordered stay on the rule's implementation pending judicial review. No submittals will be required while the stay remains in effect.*★

3.7.1 State Plan Submittals and EPA Approval Timeline

States have until September 6, 2016, or September 6, 2018 if a two-year extension is obtained, to submit their state plan to EPA for review approval. The first performance period for demonstrating reductions begins in 2022. Required state submittals leading up to the initial plan performance period, together with EPA review and approval timelines, are listed in Table 3.5.

3.7.2 The Clean Energy Incentive Program and Timeline

Subpart UUUU establishes the Clean Energy Incentive Program (CEIP), a program to incentivize projects for early action to reduce CO_2 emissions from affected EGUs. Qualifying projects include projects that generate metered MWh from wind or solar resources, or demand-side EE projects implemented in low-income communities. Additionally, projects must be located in or benefit a state that is participating in the program and has submitted a state plan including CEIP provisions.

Under the CEIP, participating states will issue ERCs or allowances to qualifying projects and EPA will award matching ERCs or allowances, up to a match limit equivalent to 300 million tons of CO_2 emissions. For every two MWh generated by qualifying RE wind or solar projects, the state will issue one ERC or allowance and EPA will provide one matching ERC or allowance. For every two MWh of avoided generation from qualifying EE projects, the state will issue two ERCs or allowances and EPA will award two matching ERCs or allowances.

The CEIP is a voluntary program in which states may participate by including provisions to issue early action ERCs or allowances to parties that implement qualifying projects. States that intend to participate in the CEIP must include a non-binding statement of intent in their initial submittal, if an initial submittal is made. Qualifying projects must commence construction (for RE) or commence operation (for EE) after the state submits the final state plan to EPA, or after September 6, 2018 if the state does not submit a plan by that date. Creditable MWh must be generated or avoided during years 2020 and/or 2021.

Table 3.6 provides a timeline for CEIP program milestones.

Table 3.5 **Timeline for Required State Submittals to EPA Leading up to Initial Plan Performance Periods**[70]

Submittal	Dates
State Initial Submittal requesting Extension ***or*** State Plan	September 6, 2016
State Letter of Negative Declaration, if no affected EGUs	September 6, 2016
EPA Letter stating the initial submittal does not qualify State for extension, if applicable (Extension deemed granted if no action taken by EPA to deny extension)	December 5, 2016
Progress Update, for states with extensions	September 6, 2017
Final State Plan, for states with extensions	September 6, 2018
EPA approval or disapproval of state plan	September 6, 2019
Milestone Status Report	July 1, 2021

70 All dates are listed as they appear in the final rule. The 2016 dates in the timeline will be postponed while the rule remains stayed, and all dates are potentially subject to change. For additional discussion of the judicial stay, see the Preface to this document.

Table 3.6 **Timeline for Required State Submittals and Project Implementation for the Clean Energy Incentive Program**

CEIP Milestone	Dates[71]
State Initial Submittal stating intent to participate OR State Plan incorporating CEIP program provisions	September 6, 2016
State submittal of final plan incorporating CEIP program provisions, if extension granted	September 6, 2018
Qualifying RE projects commence construction, or qualifying EE projects commence operation	September 7, 2018 (or after state plan submitted, if earlier)
Qualifying MWh generated by RE or avoided by EE	January 1, 2020 – December 31, 2021

3.7.3 Affected EGU Performance Periods and State Plan Reporting Periods

Affected EGU emission standard compliance periods and state plan performance periods are aligned with the timelines for the interim step periods, interim period and final period.[72] For the interim period, the EGU emission standards must have compliance periods that are no longer than each interim step period. For the final performance period, compliance periods for affected EGUs can be no longer than two years. States can set shorter compliance periods within each interim step period and for the final period, but the compliance periods must collectively cover the entire interim period and final period, and must end on the same schedule as each interim step and final reporting period.[73] The same compliance periods apply under a state measures plan, for any emission standards applicable to affected EGUs and for measures adopted under state law.[74]

State plan reporting to EPA and state plan performance demonstrations must be made consistent with the same timelines. For emission standards plans, states must report on July 1 following the end of each interim step period and the end of each final performance period. For state

Table 3.7 **State Plan Performance Periods and State Reporting Schedule**

Report	Performance Period Dates	State Report Due[75]
State Measures Annual Report	---	July 1, 2022
State Measures Annual Report	January 1 to December 31, 2022	July 1, 2023
State Measures Annual Report	January 1 to December 31, 2023	July 1, 2024
Interim Step Period 1 Report – All State Plans	January 1, 2022 – December 31, 2024	July 1, 2025
State Measures Annual Report	January 1 to December 31, 2025	July 1, 2026
State Measures Annual Report	January 1 to December 31, 2026	July 1, 2027
Interim Step Period 2 Report – All State Plans	January 1, 2025 – December 31, 2027	July 1, 2028
State Measures Annual Report	January 1 to December 31, 2028	July 1, 2029
Interim Step Period 3 – All State Plans	January 1, 2028 – December 31, 2029	July 1, 2030
Interim Performance Period – All State Plans	January 1, 2022 – December 31, 2029	July 1, 2030
Final Performance Periods – All State Plans	January 1, 2030 – December 31, 2031	July 1, 2032
All State Plans	Ongoing 2 year periods	July 1 every 2nd year

71 *See supra* note 70.

72 40 C.F.R. §§ 60.5770 and 60.5870.

73 40 C.F.R. § 60.5770; 80 Fed. Reg. at 64,864.

74 40 C.F.R. § 60.5770(d).

75 All dates are potentially subject to change. See Preface and note 70.

measures plan, additional reports must be submitted so that reporting occurs on an annual basis during the interim period. A schedule of state plan performance periods and reporting requirements is provided in Table 3.7.

3.8 Subpart UUUU Tables 1, 2, 3 and 4 and EPA Interim Step Goal Tables

The emission performance rates and statewide emission goals adopted by EPA in Subpart UUUU are provided on the following pages for ease of reference. In addition, Table 12 and Table 13 from the preamble to the final rule, which provide EPA-derived interim step goals, are provided.

Table 3.8 **40 C.F.R. Part 60, Subpart UUUU, Table 1**

Affected EGU Subcategory	Interim Performance Rate (8-year average, 1/1/2022 to 12/31/2029)	Final Performance Rate (2-year blocks, beginning 1/1/2030 – 12/31/2031)
Steam Generating Unit or IGCC	1,534	1,305
Stationary Combustion Turbine	832	771

Table 3.9 **40 C.F.R. Part 60, Subpart UUUU, Table 2**

Table 2 to Subpart UUUU of Part 60
Statewide Rate-based CO_2 Emission Goals (Pounds of CO_2 per Net MWh)

State	Interim Emission Goal	Final Emission Goal	State	Interim Emission Goal	Final Emission Goal
Alabama	1,157	1,018	Missouri	1,490	1,272
Arizona	1,173	1,031	Montana	1,534	1,305
Arkansas	1,304	1,130	Nebraska	1,522	1,296
California	907	828	Nevada	942	855
Colorado	1,362	1,174	New Hampshire	947	858
Connecticut	852	786	New Jersey	885	812
Delaware	1,023	916	New Mexico	1,325	1,146
Florida	1,026	919	New York	1,025	918
Georgia	1,198	1,049	North Carolina	1,311	1,136
Idaho	832	771	North Dakota	1,534	1,305
Illinois	1,456	1,245	Ohio	1,383	1,190
Indiana	1,451	1,242	Oklahoma	1,223	1,068
Iowa	1,505	1,283	Oregon	964	871
Kansas	1,519	1,293	Pennsylvania	1,258	1,095
Kentucky	1,509	1,286	Rhode Island	832	771
Lands of the Fort Mojave Tribe	832	771	South Carolina	1,338	1,156
Lands of the Navajo Nation	1,534	1,305	South Dakota	1,352	1,167
Lands of the Uintah and Ouray Reservation	1,534	1,305	Tennessee	1,411	1,211
Louisiana	1,293	1,121	Texas	1,188	1,042
Maine	842	779	Utah	1,368	1,179
Maryland	1,510	1,287	Virginia	1,047	934
Massachusetts	902	824	Washington	1,111	983
Michigan	1,355	1,169	West Virginia	1,534	1,305
Minnesota	1,414	1,213	Wisconsin	1,364	1,176
Mississippi	1,061	945	Wyoming	1,526	1,299

Table 3.10 **40 C.F.R. Part 60, Subpart UUUU, Table 3**

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240
Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962

Table 3.10 **40 C.F.R. Part 60, Subpart UUUU, Table 3,** *continued*

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684
Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

Table 3.11 **40 C.F.R. Part 60, Subpart UUUU, Table 4**

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346
Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626

Table 3.11 **40 C.F.R. Part 60, Subpart UUUU, Table 4,** *continued*

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850
New York	272,940,440	63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	361,531,056	82,001,704
Oregon	72,774,608	17,644,106
Pennsylvania	804,705,296	181,863,274
Rhode Island	29,819,360	7,168,032
South Carolina	234,516,064	52,606,510
South Dakota	31,963,696	7,161,036
Tennessee	257,149,584	57,329,988
Texas	1,707,356,792	396,210,498
Utah	220,386,616	50,601,386
Virginia	240,240,880	55,660,348
Washington	97,691,736	23,127,324
West Virginia	469,488,232	103,714,614
Wisconsin	252,985,576	56,617,764
Wyoming	295,724,848	66,945,204

Table 3.12 **Preamble to Final CPP, Table 12**

Table 12. Statewide Rate-based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh from All Affected Fossil Fuel-fired EGUs)

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	1,244	1,133	1,060	1,157	1,018
Arizona*	1,263	1,149	1,074	1,173	1,031
Arkansas	1,411	1,276	1,185	1,304	1,130
California	961	890	848	907	828
Colorado	1,476	1,332	1,233	1,362	1,174
Connecticut	899	836	801	852	786
Delaware	1,093	1,003	946	1,023	916
Florida	1,097	1,006	949	1,026	919
Georgia	1,290	1,173	1,094	1,198	1,049
Idaho	877	817	784	832	771
Illinois	1,582	1,423	1,313	1,456	1,245
Indiana	1,578	1,419	1,309	1,451	1,242
Iowa	1,638	1,472	1,355	1,505	1,283
Kansas	1,654	1,485	1,366	1,519	1,293
Kentucky	1,643	1,476	1,358	1,509	1,286
Lands of the Fort Mojave Tribe	877	817	784	832	771
Lands of the Navajo Nation	1,671	1,500	1,380	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,671	1,500	1,380	1,534	1,305
Louisiana	1,398	1,265	1,175	1,293	1,121
Maine	888	827	793	842	779
Maryland	1,644	1,476	1,359	1,510	1,287
Massachusetts	956	885	844	902	824
Michigan	1,468	1,325	1,228	1,355	1,169
Minnesota	1,535	1,383	1,277	1,414	1,213
Mississippi	1,136	1,040	978	1,061	945
Missouri	1,621	1,457	1,342	1,490	1,272
Montana	1,671	1,500	1,380	1,534	1,305
Nebraska	1,658	1,488	1,369	1,522	1,296
Nevada	1,001	924	877	942	855
New Hampshire	1,006	929	881	947	858
New Jersey	937	869	829	885	812
New Mexico*	1,435	1,297	1,203	1,325	1,146
New York	1,095	1,005	948	1,025	918
North Carolina	1,419	1,283	1,191	1,311	1,136
North Dakota	1,671	1,500	1,380	1,534	1,305
Ohio	1,501	1,353	1,252	1,383	1,190
Oklahoma	1,319	1,197	1,116	1,223	1,068
Oregon	1,026	945	896	964	871
Pennsylvania	1,359	1,232	1,146	1,258	1,095
Rhode Island	877	817	784	832	771
South Carolina	1,449	1,309	1,213	1,338	1,156
South Dakota	1,465	1,323	1,225	1,352	1,167

Table 3.12 **Preamble to Final CPP, Table 12,** *continued*

Table 12. Statewide Rate-based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-fired EGUs)

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Tennessee	1,531	1,380	1,275	1,411	1,211
Texas	1,279	1,163	1,086	1,188	1,042
Utah*	1,483	1,339	1,239	1,368	1,179
Virginia	1,120	1,026	966	1,047	934
Washington	1,192	1,088	1,021	1,111	983
West Virginia	1,671	1,500	1,380	1,534	1,305
Wisconsin	1,479	1,335	1,236	1,364	1,176
Wyoming	1,662	1,492	1,373	1,526	1,299

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

Table 3.13 **Preamble to Final CPP, Table 13**

Table 13. Statewide Mass-based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Tons of CO_2 from All Affected Fossil Fuel-fired EGUs)

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	66,164,470	60,918,973	58,215,989	62,210,288	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	33,061,997	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	33,683,258	30,322,632
California	53,500,107	50,080,840	48,736,877	51,027,075	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	33,387,883	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	7,237,865	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	5,062,869	4,711,825
Florida	119,380,477	110,754,683	106,736,177	112,984,729	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	50,926,084	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,550,142	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	74,800,876	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	28,254,411	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	24,859,333	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	71,312,802	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	611,103	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	24,557,793	21,700,587
Lands of the Ute Tribe of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,561,445	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	39,310,314	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,158,184	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	16,209,396	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,747,677	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	53,057,150	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	25,433,592	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	27,338,313	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	62,569,433	55,462,884
Montana	13,776,601	12,500,563	11,749,574	12,791,330	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	20,661,516	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	14,344,092	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	4,243,492	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	17,426,381	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	13,815,561	12,412,602
New York	35,493,488	32,932,763	31,741,940	33,595,329	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	56,986,025	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	23,632,821	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	44,610,332	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,643,164	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	99,330,827	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,657,385	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	28,969,623	25,998,968

Table 3.13 **Preamble to Final CPP, Table 13,** *continued*

Table 13. Statewide Mass-based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Tons of CO_2 from All Affected Fossil Fuel-fired EGUs)

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
South Dakota	4,231,184	3,862,401	3,655,422	3,948,950	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	31,784,860	28,348,396
Texas	221,613,296	203,728,060	194,351,330	208,090,841	189,588,842
Utah*	28,479,805	25,981,970	24,572,858	26,566,380	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
Washington	12,395,697	11,441,137	10,963,576	11,679,707	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	31,258,356	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	35,780,052	31,634,412

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

4. The State Planning Framework

The development of the state plan under Subpart UUUU bears resemblance to other familiar state air quality planning processes in many ways, including the development of prior 111(d) plans for existing sources in regulated source categories and SIPs for attainment and maintenance of the NAAQS. For example, Subpart UUUU supports the creation of trading programs similar to those that have been successfully used to reduce nitrogen oxide (NO_X) emissions, providing incentives to reduce emission rates and EGUs, shift power generation toward low- and zero-emitting generation sources, and improve demand-side energy efficiency. Yet, many aspects of power generation and distribution, such as approval to recover costs for newly constructed EGUs, are regulated by other authorities, such as the Public Service Commission. Thus, the development of the state plan under Subpart UUUU necessitates an examination of state and local authorities and invites the creation of interagency programs to achieve the CPP goals in ways that have not occurred to the same extent for other CAA plans. Also, EPA's approach in establishing the BSER emission guidelines in multiple forms, as subcategory performance standards with adjustments for emission reductions driven by other programs and entities, as well as in the form of statewide CO_2 rate-based and mass-based emission goals covering all fossil fired EGUs, affords states a much broader range of possible compliance strategies than has been seen for prior 111(d) plans.

The first step in creating the state plan is establishing planning framework – the planning team, planning timeline, and work processes that will be used to formulate the plan approach, provide input on key decisions about CO_2 reduction strategies, share the work load and offer feedback throughout the plan development phase.

4.1 Stakeholder Participation and the State CPP Taskforce

While the state air agency will likely be the primary responsible party for plan development in most cases, a number of stakeholders can play important supporting roles. Most states agree that planning for success in achieving compliance with the state goals for CO_2 emission reductions requires a collaborative effort among a range of stakeholders. In fact, state air quality authorities are accustomed to developing programs, policies and regulations through inter-agency efforts and stakeholder work groups including representatives from regulated entities, citizen groups, and other interested parties.

Drawing on a pool of interested stakeholders to form a State CPP Taskforce would support the planning effort. Relying on a broad-based taskforce to develop the state plan achieves two primary objectives. First, stakeholder participation in the planning process integrates input across all perspectives and allows the concerns of implementing agencies, regulated entities, service providers, consumers and citizen advocates to be taken into account during the planning stage. An open process and ongoing stakeholder feedback on potential conceptual designs for the plan approach, reduction strategies, projections of plan performance, and other plan elements can help to avoid conflicts and substantive changes during the formal public notice period.

In addition, the taskforce can provide a wealth of knowledge, expertise, skills and resources that may not otherwise be available to the state air agency. Sharing the workload of data collection, organization and evaluation, as well as assisting with outreach to the stakeholders' constituencies, can save time and result in a better end product. Particularly given that a number of parallel work efforts must occur during a compressed timeframe in order to meet the CPP plan development requirements and timelines, the creation of subcommittees or small workgroups with interest and expertise in particular planning elements can be a valuable planning approach.

4.1.1 Identify Taskforce Members

In planning for and development of the state plan, several categories of stakeholders will have valuable information and ideas as well as important environmental, economic, policy and business concerns to bring to the table. The following interests should be considered for

representation on the planning taskforce.

- Local Air Quality Agencies;
- State Energy Office (SEO) or equivalent;
- Governor's office;
- State legislative liaison;
- Public Utility Commission or equivalent;
- EPA Regional Office;
- Investor-owned utilities;
- Municipal utilities;
- Cooperative utilities;
- Independent generators;
- Integrated dispatch and transmission system operators (ISO/RTO);
- Coal and natural gas suppliers and distributors;
- Renewable energy (RE) developers;
- Energy efficiency program administrators and contractors;
- Labor unions;
- Ratepayer advocates, including groups focused on low-income consumers;
- Community representatives, including vulnerable communities and potentially impacted communities; and
- Environmental advocacy groups, including groups focused on environmental justice.

This list may not be all-inclusive for a particular state, and may include stakeholders that are not applicable for a particular state. Potential stakeholders and partners for effectively considering the pros and cons of a multi-state plan approach are addressed separately. In the early stages of planning, it may be best to err on the side of being overly inclusive to assure representation of all key stakeholders, since the form and requirements of the plan cannot be predicted with certainty at the outset. When soliciting members for the CPP planning taskforce, keep in mind that the process will extend over a one- to three-year period, so a long-term commitment is needed to maintain a cohesive group.

4.1.2 Identify and Engage Vulnerable Communities

In convening stakeholder meetings and creating the CPP taskforce, a critical constituency whose interests should be represented is the group of vulnerable communities, which must be identified by the state with input or concurrence from EPA.

Subpart UUUU explicitly requires documentation of the state's engagement with vulnerable communities as part of the initial plan submittal for any state requesting an extension for submittal of the final plan. Furthermore, EPA indicates in the preamble to the final rule that engagement with "vulnerable" and "overburdened" communities that may be affected by the state plan will be considered a required element of compliance with the public participation requirements of 40 C.F.R. § 60.23. The terms "vulnerable" and "overburdened" refer to low-income communities, communities of color, and indigenous populations that are most affected by, and least resilient to, the impacts of climate change, and are central to environmental justice considerations. Vulnerable communities could also include those whose jobs may be impacted by a shift from coal to renewable energy generation.

EPA refers states to *EPA's Guidance on Considering Environmental Justice During the Development of Regulatory Actions* to consider how best to identify and engage vulnerable communities in the plan development process, and also encourages states to use the proximity analysis EPA developed for the CPP rulemaking to identify vulnerable communities in their state.[76] EPA's proximity analysis identifies low-income communities and communities of color living within a three-mile radius of affected power plants, and is available as part of the *EJ Screening Report for the Clean Power Plan*. In addition, EPA has created an interactive mapping tool that includes affected power plants and provides maps of potentially vulnerable communities on a state level.[77] These methods serve as guidelines that could be used in identifying vulnerable communities; however, states should consult with their EPA Regional Office to gain concurrence with methods used to identify vulnerable communities in the state.

Once potentially vulnerable communities are identified, it is important for the state to reach out and seek engagement of community leaders in the planning process. In many cases, states may already be well aware of the vulnerable communities within their state, and have well-established and long-term relationships with the community leaders. Nonetheless, because EPA has explicitly included "meaningful engagement" with vulnerable communities as an initial submittal and plan approval criteria, it would be prudent to seek EPA Regional Office input and concurrence early in the planning process.

76 80 Fed. Reg. at 64,858 (preamble to final CPP, section VIII.E).

77 80 Fed. Reg. at 64,914-19 (preamble to final CPP, section IX); http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/.

4.1.3 Establish a Common Knowledge Base

When the taskforce is convened, it may be prudent to establish a common knowledge base before diving into the planning process. Having taskforce members share executive-level overviews about their areas of expertise is also a good way for the individuals on the team to get to know one another and the interests they represent. One or two brief presentations at the outset of each of the early meetings may be desirable, to cover such topics as: the power supply structure and ownership in the state; the power generator inventory baseline profile and trends; the existing regulatory framework for generation, dispatch and transmission; and, existing policies and programs for RE and EE. A shared space for making these presentations and additional reference materials available in electronic formats should be provided for the taskforce as well as for public access.

4.1.4 Identify Key Policy Goals and Priority Planning Factors

To facilitate data gathering and decision-making, it will be helpful to develop a concise set of key policy goals and priorities for consideration along the way. For example, all stakeholders will probably agree that the following factors must be taken into account in the planning process:

- Cost of the reduction strategy;
- Cost of the program implementation;
- Technical feasibility of the reduction strategy; and
- Impact on cost and reliability of electric service to customers.

However, state policies and goals, and stakeholders' views, may differ in other areas, such as the following:

- Balancing CO_2 reductions with collateral environmental impacts or benefits;
- Increasing reliance on natural gas versus non-emitting generation;
- Incentivizing improvement versus retirement of existing coal plants;
- Preferences for particular generation sources over others, such as nuclear, hydro, wind, solar or biomass generation;
- Supporting energy sector job retention and growth; and
- State participation in, and administration and oversight of, a market-based trading program.

Developing a short list of agreed-upon policy goals or priorities can help the taskforce refocus and return to common ground during discussions of various issues throughout the planning process. Stakeholders will have differing views on many of these issues, and many of these factors cannot be mutually optimized. The state plan will need to strike a balance among sometimes-conflicting priorities. Accordingly, any underlying priority policy goals, resource constraints or legal concerns should be considered as early in the process as feasible.

4.1.5 Form Taskforce Workgroups

The State CPP Taskforce can provide valuable "volunteer" time, knowledge and skills to assist state staff in planning work. Many planning tasks are suited to small group efforts, and states may want to consider drawing from the larger taskforce to establish smaller stakeholder workgroups for the primary planning areas. Some topics that may be suited to smaller workgroup development, for presentation to the larger taskforce, are listed below.

- Baseline development and characterization;
- Performance periods and interim step goals;
- Inside the fenceline reduction strategies and potential for reductions;
- Generation shifting potential and methods;
- RE strategies, reduction potential and options for implementation;
- Treatment of existing nuclear power plants and large hydroelectric generators;
- Energy efficiency strategies, reduction potential and options for implementation;
- Emerging technologies and other possible strategies;
- Trading program elements – ERCs, allowances, allocations, qualifying resources, tracking system, trading partners; and
- Methods for modeling to project plan performance and to select compliance strategies.

4.2 Potential Regional Partners and Grid Reliability

A special consideration in the planning process is the question of whether the state should pursue a single-state plan or combine goals and efforts with one or more other states to develop a multi-state plan. Closely related is the question of whether the state will participate in an interstate trading program, and if so, whether the state will prepare a single-state plan with interstate trading, or a multi-state plan that implements a joint emission goal. A detailed discussion of these important topics is provided in *Chapter 6, Key Decisions for State Planning.* One aspect of these considerations is the identification of potential partners.

Another important factor in designing the state plan that provides a strong impetus for regional coordination is the need to consider grid reliability. Appropriately, EPA has placed a strong emphasis on protecting and maintaining grid reliability in developing the emission guidelines, and Subpart UUUU requires each state plan submittal to demonstrate that the reliability of the electrical grid has been considered in the development of the state plan.[78]

This section provides a discussion of consideration of grid reliability and a brief summary of additional factors for identifying potential state partners, for purposes of bringing together one or more states to explore the possible benefits of collaboration and to begin the planning and decision-making process.

In considering issues related to interstate coordination discussed in this section, it is important to note that these factors need not be decisive. In fact, there are many cases in which divergent policies exist within a single grid region, and there are many programs that span non-contiguous states in different grid regions. Examples include allowance trading programs such as CSAPR and RGGI, and many state RE standards that accept renewable energy credits that are generated in other states.

4.2.1 Planning for Grid Reliability

EPA's purpose in explicitly requiring that states consider and document their consideration of grid reliability as part of the state plan development is to ensure that the plan provides enough flexibility for affected EGUs to avoid potential conflict between maintaining reliable electric service and complying with applicable plan provisions and emission standards.[79] While the rule does not provide any specific requirements detailing how a state must "consider" grid reliability, EPA suggests in the preamble to the final rule that one particularly effective way of doing so is by consulting with the ISO/RTO or other planning authorities for the region in which the affected EGUs operate, as part of the planning process, and documenting this consultation in the state plan submittal. To meet this Subpart UUUU requirement, states will want to assure the regional ISO or RTO is represented on the planning team (if the state is in an ISO/RTO operating region), as well as other planning or administrative authorities with a role in power reliability planning. EPA further recommends that the state ask the planning authority to review the plan during the plan development stage and provide an assessment of any reliability implications of the plan. Accordingly, these representatives should be specifically tasked with providing input on potential impacts to grid reliability of various state plan options, and with assisting in providing potential resolutions to grid reliability issues.

While the state is not required to follow the recommendations of the ISO/RTO or other planning authority, EPA recommends that the state document its response to those recommendations in the final plan submittal to EPA. Consultation with grid reliability planning authorities and experts is intended to assure that the state plan will achieve the emission guidelines in a manner that maintains grid reliability. Of course, input from this consultation process cannot be used to relax the emission performance rates or emission goals for a state or to exempt any affected EGU from compliance with the state plan. It should be noted that Subpart UUUU provides additional specific provisions to address grid reliability. One such provision is the grid reliability "safety valve," which allows an affected EGU to operate outside the performance requirements of the state plan on a temporary basis in the event of an unforeseen emergency situation that creates an imminent threat to grid reliability. In addition, Subpart UUUU requires the state to submit a modification to the state plan to address grid reliability concerns if such a condition persists for more than 90 days. For a more detailed discussion of grid reliability plan components and Subpart UUUU requirements, see *Section 5.5, Universal Plan Components.*

Consideration of grid reliability is an ongoing, integrated aspect of the planning process, and should not be viewed as an isolated task. While there are many possible designs for state plans that could achieve the CPP emission guidelines, different approaches may have different levels of flexibility and therefore may differ in their potential to impact grid reliability. ISOs/RTOs or other planning authority experts could be engaged to support state planning efforts specifically by evaluating and modeling various possible plan options to consider their effectiveness at reducing CO_2 emissions, EGU compliance flexibility, and cost, in the context of grid reliability concerns. For example, the evaluations might consider different allocation schemes for allowances under a mass-based trading program. Or, an evaluation might be performed to assess the implications of EGU-specific versus facility-wide compliance requirements, to model the implications of trading programs with participation by different groups or numbers of states, or to understand the value of extending ERC eligibility to different types of resources.

78 40 C.F.R. § 60.5745(a)(7).

79 80 Fed. Reg. at 64,874-81 (preamble to final CPP, section VIII.G.2.c).

4.2.2 Commonality of Utility Companies

Where one or more utility companies owns or operates generation units in multiple states, a commonality of CO_2 reduction strategies, regulatory requirements, emissions limits, performance standards, evaluation, measurement and verification (EM&V) programs, trading programs and other plan aspects can lead to cost savings and increased operational and compliance flexibility. Thus, in identifying potential state partners, consideration should be given to the service areas of the utilities that operate within the state. Table 4-1 provides a list of some of the larger utility companies and their service area states. Figure 4.1 is a map of U.S. service areas for investor-owned utilities.

Table 4.1 **Major Utility Companies Service Areas by State**

Parent Utility Company	Region				
	West	Northwest	Central	Northeast	Southeast
AES Corporation				Indiana, Ohio	
Algonquin Power & Utilities Corporation				New Hampshire	
ALLETE			Minnesota, Wisconsin		
Alliant Energy Corporation			Iowa, Minnesota, Wisconsin		
Ameren Corporation			Illinois, Missouri		
American Electric Power			Arkansas, Louisiana, Oklahoma, Texas	Indiana, Michigan, Ohio, Virginia	Kentucky, Tennessee, Virginia,
West Virginia,					
American Transmission Company (Transmission-Only Utilities)			Illinois, Minnesota, Wisconsin	Michigan	
Avista Corporation			Alaska, Idaho, Washington		
Berkshire Hathaway Energy	California, Nevada, Utah	Idaho, Oregon, South Dakota, Washington, Wyoming	Illinois, Iowa		
Black Hills Corporation	Colorado	South Dakota, Wyoming	Minnesota		
CenterPoint Energy			Texas		
Chesapeake Utilities Corporation					Florida
Cleco Corporation			Louisiana		
CMS Energy Corporation			Michigan		
Consolidated Edison				New Jersey, New York, Pennsylvania	
Dominion					North Carolina, Virginia
DTE Energy Company				Michigan	

Table 4.1 **Major Utility Companies Service Areas by State,** *continued*

Parent Utility Company	Region				
	West	Northwest	Central	Northeast	Southeast
Duke Energy					North Carolina, South Carolina
Duquesne Light Holdings				Pennsylvania	
Edison International	California				
El Paso Electric Company			Texas, New Mexico		
Emera				Maine	
Empire District Electric Company			Montana, Kansas, Oklahoma		
Energy Future Holdings			Texas		
Entergy Corporation			Arkansas, Louisiana, Mississippi, Texas		
Eversource Energy				Vermont, New Hampshire, Massachusetts, Connecticut	
Exelon Corporation			Illinois	Maryland, Pennsylvania	
First Energy Corporation				Ohio, New Jersey, Pennsylvania, Ohio, Pennsylvania, Maryland,	West Virginia, Virginia
Fortis	Arizona			New York	
Gaz Métro				Vermont, New York, New Hampshire	
Great Planes Energy			Kansas, Missouri		
Hawaii Electric Industries	Hawaii				
Iberdrola USA				Maine, New York	
IDACORP		Idaho, Oregon			
Integrys Energy Group			Wisconsin		
ITC Holdings Corporation *(Transmission-only Utilities)*			Iowa, Minnesota, Illinois, Missouri, Kansas	Michigan	
LS Power *(Transmission-only Utilities)*					
			Texas		

Table 4.1 **Major Utility Companies Service Areas by State,** *continued*

Parent Utility Company	Region				
	West	Northwest	Central	Northeast	Southeast
MDU Resources Group		North Dakota, South Dakota, Minnesota, Wyoming			
MGE Energy			Wisconsin		
Mt. Carmel Public Utility Company			Illinois		
National Grid				New York, Massachusetts, Rhode Island	
NextEra Energy					Florida
NiSource				Indiana	
NorthWestern Energy		Montana, Wyoming			
OGE Energy Corporation			Oklahoma		
Ohio Valley Electric Corporation	No service territory				
Otter Tail Corporation		North Dakota, South Dakota	Minnesota		
Pepco Holdings				New Jersey, Delaware, Maryland	Virginia
PG&E Corporation	California				
Pinnacle West Capital Corporation	Arizona				
PNM Resources	New Mexico		Texas		
Portland General Electric		Oregon			
PPL Corporation				Pennsylvania	Kentucky, Virginia
Public Service Enterprise Group				New York, New Jersey	
Puget Energy		Washington			
SCANA Corporation					South Carolina
Sharyland Utilities			Texas		
Southern Company					Alabama, Georgia, Mississippi
TECO Energy					Florida
UGI Corporation				Pennsylvania	
UIL Holdings Corp.				Connecticut	
Unitil				New Hampshire	
Upper Peninsula Power Company			Wisconsin		
Vectren Corp.				Indiana	

Table 4.1 **Major Utility Companies Service Areas by State,** *continued*

Parent Utility Company	Region				
	West	Northwest	Central	Northeast	Southeast
Vermont Electric Power Company (*Transmission-Only*)				Vermont	
Westar Energy			Kansas		
Wisconsin Energy Corporation			Wisconsin		
Xcel Energy	New Mexico		Texas		

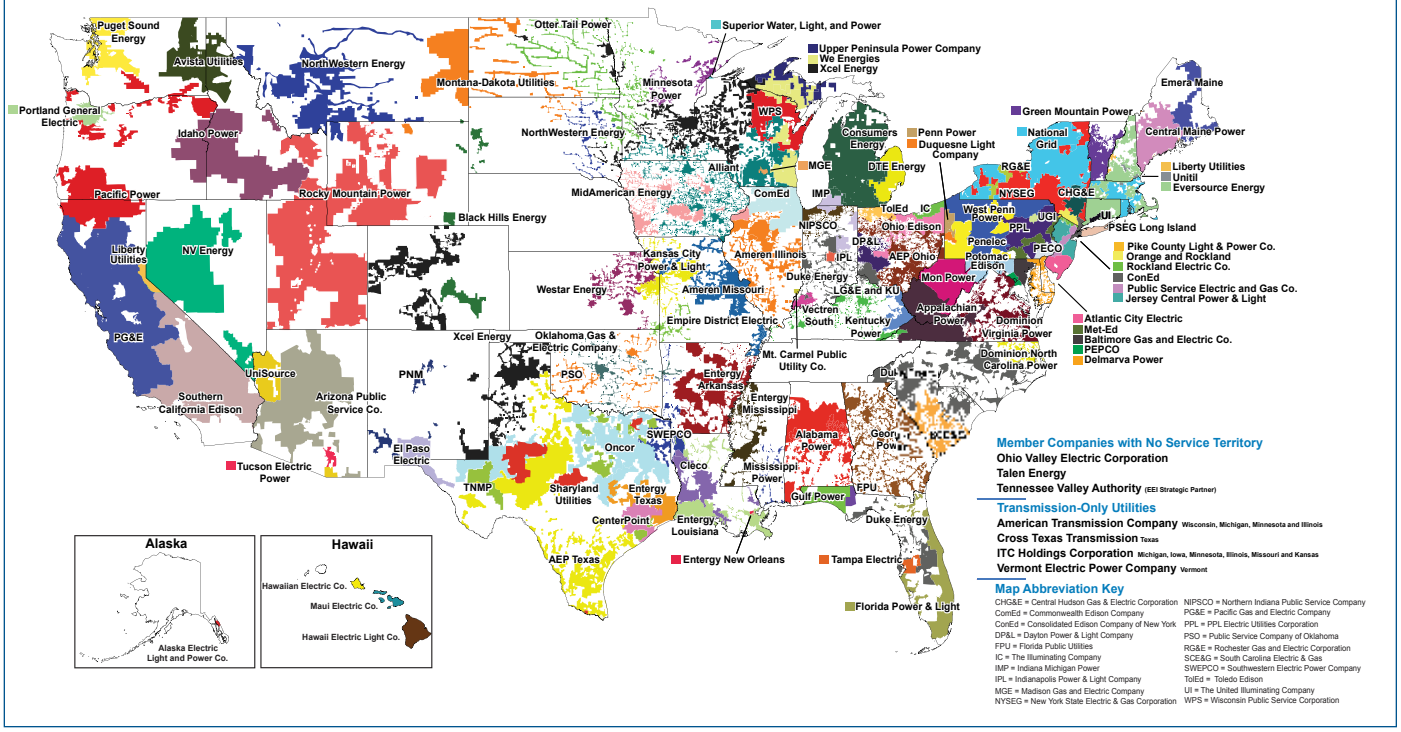
4.2.3 Commonality of Transmission and Distribution Grids

As noted above, states that share an interconnected power supply will need to coordinate planning so as to consider grid reliability across the region as their respective (or joint) plans are implemented. Similarly, where a common transmission and distribution system operator serves multiple states, those states are potential trading partners. Many aspects of the state plan will rely upon or impact the transmission and distribution system. Generation shifting from carbon-intensive EGUs such as coal-fired boilers to lower- or zero-carbon fuel-based generation, such as natural gas or renewables, will require changes in the dispatching algorithms and coordination of resource planning across the grid. As with the electricity generators, common requirements and goals across state lines for integrated grid systems will tend to optimize operational and compliance flexibility while minimizing cost and increasing reliability. Figure 2.1 provides a map of Independent System Operator service areas. A map of investor-owned utilities' service territories is provided in Figure 4.1.

4.2.4 Commonality of Natural Gas Supplies

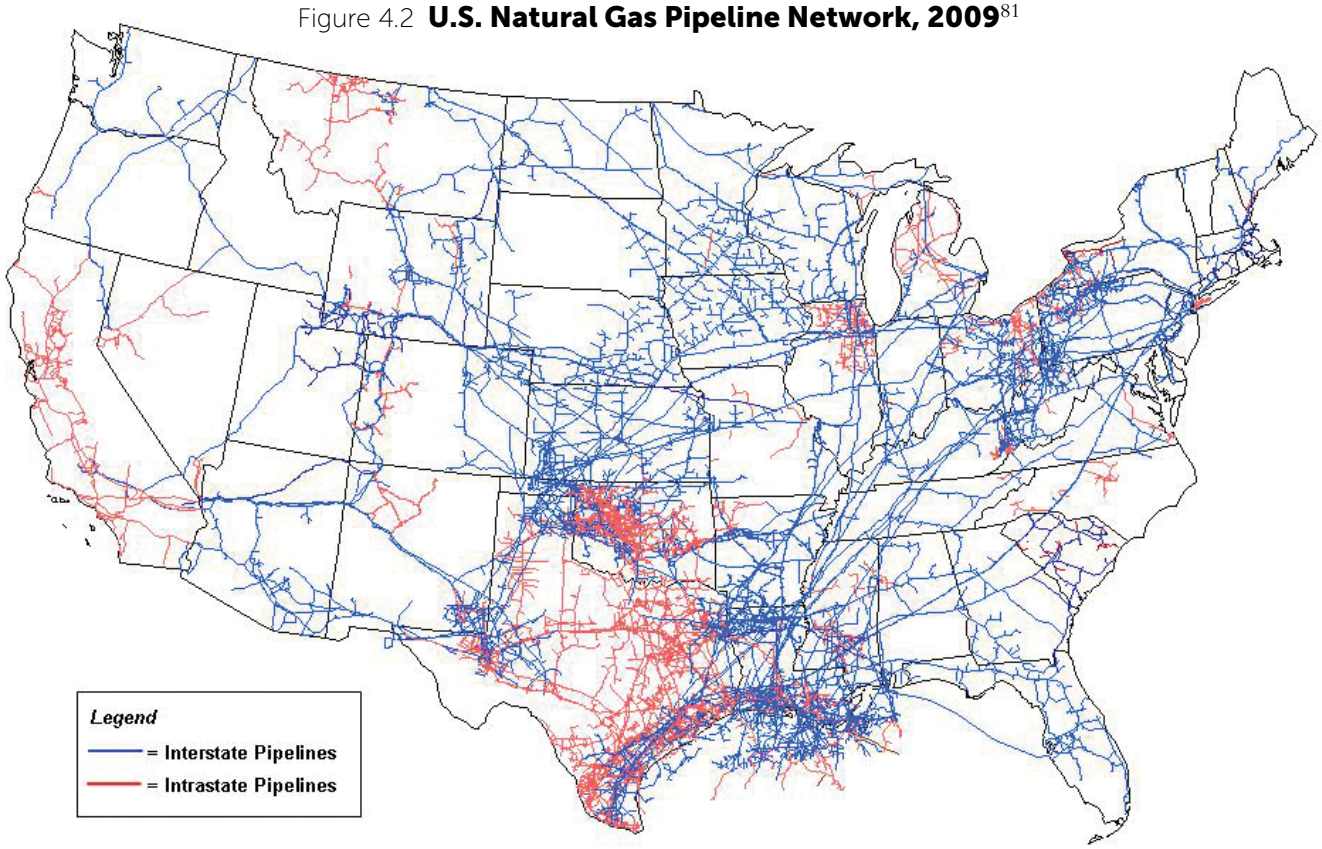
Another consideration for potential benefits in an interstate trading group or a multi-state plan is the commonality of natural gas supply lines among neighbouring states. For example, the capacity of the

Figure 4.1 **Map of U.S. Investor-Owned Utilities Service Areas**[80]



80 http://www.eei.org/about/members/uselectriccompanies/documents/eeimemcoterrmap.pdf, retrieved March 31, 2016.

Figure 4.2 **U.S. Natural Gas Pipeline Network, 2009**[81]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

existing infrastructure in a given state or location could affect the extent to which generation shifting to natural gas can be relied upon to reduce emissions from coal-fired EGUs. The cost and reliability of power production can be similarly impacted. Therefore, common requirements across the supply region for a particular pipeline system could be of benefit in achieving cost-effective and reliable generation shifts. A map of natural gas pipelines is provided in Figure 4.2.

4.2.5 Regional Economic, Social and Environmental Factors

States may also want to consider common regional economic and social influences in identifying potential state partnerships for interstate trading or multi-state plans. For example, states with large metropolitan areas that cross state lines may find it beneficial to implement a common plan in order to avoid or minimize differences in electricity costs and energy efficiency policies and programs among a shared commuter base. State economies that share common primary industry and trade sectors may also find partnering benefits. Finally, states with shared environmental concerns, such as nonattainment areas for the same NAAQS, may find a number of benefits in implementing a common and consistent plan, especially where cross-state pollution and/or fossil fuel-fired power plant emissions are a significant factor in the attainment and maintenance plan.

4.3 Identify Planning Milestones and Schedule

One of the first tasks of the planning team will be to develop a planning schedule that outlines primary tasks required, with a focus on early identification of tasks requiring a long lead-time and tasks that must be accomplished within an independently prescribed schedule, such as seeking legislative changes. As discussed above, many of the key decisions are interrelated and will therefore require a process of examining multiple lines of inquiry in parallel. Therefore, a planning schedule that sets forth multiple tasks in parallel, with milestones for related decision points, will be needed.

For example, a decision to pursue a multi-state plan will influence the selection of whether to utilize a mass-based or rate-based approach, and what type of trading

81 http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html, retrieved May 3, 2015.

program to implement. The decision of whether to join with other states, and identifying which other states would make desirable partners, may be influenced by the level of integration of the state's transmission and distribution system and the extent to which the subject utility companies have fleets operating across state lines. However, if the state's policy goals and legal authorities are incompatible with those of potential state partners, those concerns may ultimately override possible benefits of the partnership. Other key factors in deciding what type of plan to pursue will be cost and energy reliability. Thus, the state will need to develop information about multiple plan options in parallel in order to select the best compliance pathways for the state.

Of course, the planning calendar must take into account the Subpart UUUU plan submittal schedule and the required plan components. Table 4.2 provides a skeleton of planning milestones for reference as a starting point in developing the more detailed state planning project schedule. For a detailed discussion of required plan components, see *Chapter 5, Plan Types and Required Plan Components.*

If the state plans to request a two-year extension for final plan submittal, all required elements of the initial submittal must be complete in advance of September 6, 2016. Assuming the two-year extension is provided, an interim update to the planning process must be submitted to EPA by September 6, 2017,[82] and the final plan must be submitted no later than September 6, 2018. The planning calendar must be built around these three key

Table 4.2 **State Planning Milestones and Schedule**[83]

Milestone	Target Date	Comments
Stakeholder Meeting(s)		A series of meetings will likely be held throughout the planning process
Identify Vulnerable Community Representatives		
Identify Taskforce Members		
Convene State CPP Taskforce		
* Identify plan approaches that will be considered		
* Provide opportunity for public engagement and comment, including vulnerable communities and other stakeholders		
* Document progress and identify plans for public engagement in final plan development		
Initial Plan Submittal to EPA	***September 6, 2016***	Items with asterisk (*) listed above are required components of Initial Submittal. Due date for EPA Submittal; must be made electronically and signed by Governor or Designee
* Final Selection of Plan Approach		
* Draft required legislation and regulations		
* Prepare/update comprehensive schedule for completing plan development		
2017 Interim Planning Update Submittal	***September 6, 2017***	Items with asterisk (*) listed above are required components of 2017 Update Submittal.
Complete all required plan components		
Final Plan Submittal	***September 6, 2018***	Due date for EPA Submittal; must be made electronically and signed by Governor or Designee

82 See Section III for a Model Initial State Plan Submittal.

83 All dates are potentially subject to change due to the judicial stay on the CPP's implementation. For additional discussion of the judicial stay, see the Preface to this document.

submittal dates, with time incorporated for any required state legislation, compliance with the state administrative rulemaking process, and public notice and comment.

4.4 Determining the Level of CO_2 Reductions Needed

At the outset, it is important to evaluate the affected EGU inventory and power sector structure in relation to the final CPP emission guidelines so that planning decisions can be made in the context of the state's particular circumstances. One of the early tasks critical to successful planning is to evaluate the current level of affected EGU CO_2 emissions and the level of emission reductions that will be needed to meet the Subpart UUUU emission guidelines. The number and type of affected EGUs, business structure of the power sector, current fuel mix, level of CO_2 reductions required, state investment in coal and natural gas development, and other factors may impact decisions regarding plan type and reduction strategies. This section provides an example of an initial planning exercise the state may choose to undertake to develop the context for considering key planning decision points.

4.4.1 Affected EGUs Baseline and Current CO_2 Emissions

To document the state's 2012 baseline inventory of affected EGUs, the best starting place is EPA's inventory as updated with corrections for the final CPP. This inventory is readily available in the EPA Clean Power Plan State Goal Visualizer.[84] This inventory provides affected EGU information including the Generator ID, plant name, fuel type, prime mover type, nameplate capacity (MW), summer capacity (MW), heat input capacity (lb/MMBtu), 2012 electricity generation (MWh) and 2012 CO_2 emissions. Information on planned or announced retirement dates is also included, as well as reasons for excluding listed EGUs that are not affected EGUs under Subpart UUUU.

Starting with the 2012 baseline inventory, an update of the inventory should be developed to include unit-specific 2015 emissions, as reported under 40 C.F.R. Part 75. Any other updates to affected EGU data should also be included, such as information about affected EGUs that have started operation since 2012, and documentation of any retirements, fuel changes, or changes triggering applicability of 40 C.F.R. Part 60, Subpart TTTT. The performance rate of each affected EGU, expressed in lb/MWh-net, should also be computed.

4.4.2 Evaluation of Current Inventory in Comparison to Subpart UUUU Goals

To gain a clear understanding of the level of emission reductions needed for compliance, comparisons of the current affected EGU emissions inventory to Subpart UUUU performance standards, interim step goals, interim emission goals and final emission goals should be prepared. This evaluation will support the state planning efforts in assessing and establishing interim step milestones, identifying the level of ERCs that will be needed for compliance with a rate-based plan, estimating the level of RE and EE deployment that may occur, and assessing potential compliance strategies, including entry into a market-based trading program.

It will be helpful to compare and evaluate the 2012 and 2015 affected EGU inventory against each of the Subpart UUUU standards and goals. For states considering a rate-based plan, plotting the individual affected EGU performance (lb/MWh) will provide a visual indicator of the range of performance within the fleet and identification of outliers that would be most challenged in obtaining sufficient ERCs to demonstrate compliance on a unit-by-unit basis. A comparison of 2012 to 2015 performance to identify significant shifts or emissions trends will also be helpful. In addition, an estimate of the approximate level of ERCs that would be required on a statewide basis to meet the Table 1 subcategory performance standards can be derived using the 2015 performance levels and a projection of generation for future performance periods, taking into consideration any planned retirements. It will also be helpful to project generation shift from coal to NGCC affected EGUs where appropriate.

Similar comparisons can be made on a statewide level in comparison to the Subpart UUUU Table 2 rate-based interim and final emission goals. For consideration of interim step goals that would be used to assess plan performance during implementation, Table 12 of the preamble to the final rule provides a good starting point.[85]

Comparisons should also be made of the 2012 baseline and 2015 current inventories to the mass-based interim and final emission goals set forth in Subpart UUUU Table 3. Note that the Table 3 interim and final emission goals represent cumulative emissions for eight-year and two-year blocks, respectively, therefore these goals need

84 EPA, Clean Power Plan State Goal Visualizer, Appendix 1 – All Units (2012), available at https://www.epa.gov/sites/production/files/2015-08/clean-power-plan-state-goal-visualizer_0.xlsm.

85 80 Fed. Reg. at 64,822-24.

to be adjusted for comparison to a single-year inventory. Table 13 of the preamble to the final rule provides state-specific mass-based interim step goals, which represent yearly average total emission rates for all affected EGUs in increments of 3 years (2022–2024), 3 years (2025–2027) and 2 years (2028–2029) for Interim Steps 1, 2 and 3, respectively.[86] The Table 13 interim goals and final goals also represent total annual emissions for all affected EGUs, with the interim goal representing an average across the eight-year interim compliance period.

For some states, the results of this early planning exercise will show that significant CO_2 reductions are needed to comply with Subpart UUUU, while other states may find that the mass emissions from their affected EGU fleet are already at or below the interim or final mass emission goals. Comparison of 2012 and 2015 data will also help to identify trends that may affect projections. An understanding of the level of reductions needed for compliance and historical trends, as well as the total estimate level of RE and/or EE deployment needed to balance emissions and generation from affected EGUs within the state, will provide useful information in the state planning process.

4.5 Affected EGUs and Other Affected Entities Under the State Plan

One important aspect of the planning framework is to develop an understanding of what facilities and other entities will be regulated by the state plan, either by the imposition of substantive requirements, or through administrative requirements such as applying for approval as an ERC resource provider. Affected EGUs are the primary affected entities under the state plan, and under some plan structures they may be the only affected entities. However, in addition to the owners and operators of affected EGUs, states may elect to regulate other entities, or may find it necessary to regulate other entities, in order to accomplish all of the strategies necessary for achieving the required CO_2 emission reductions. Even under plans where entities other than the affected EGUs are not directly regulated, virtually all state plans will in some way require or result in actions by other parties. This is because some reduction strategies cannot be wholly accomplished at the affected EGU or are not wholly within the control of the EGU owner/operator.

4.5.1 Affected EGUs

Subpart UUUU applies directly to the governor of each state in the contiguous United States, not to the owners or operators of EGUs. The governor of each contiguous state with one or more affected EGUs that commenced construction on or before January 8, 2014 must submit a plan that implements emission standards and/or other state measures for affected EGUs to meet the Subpart UUUU emission guidelines.

Under Subpart UUUU, unless specifically excluded, an affected EGU is a steam generating unit, integrated gasification combine cycle (IGCC) unit, or stationary combustion turbine that:

1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity); and
2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

For purposes of Subpart UUUU, a stationary combustion turbine must meet the definition of either a combined cycle or combined heat and power combustion turbine to be an affected EGU. Importantly, simple cycle natural gas stationary combustion turbines do not meet these definitions and are not affected EGUs. Any EGU that is a "new" or "reconstructed" source regulated under 40 C.F.R. Part 60, Subpart TTTT is excluded from the requirement to be regulated under state plans implementing Subpart UUUU. Several other exclusions are incorporated at 40 C.F.R. § 60.5850.

Each state plan must identify the inventory of affected EGUs that are subject to the plan. In addition, each state plan must set forth standards of performance for emissions from affected EGUs that reflect the emissions limitation achievable from BSER. For state plans that are emission standards plans, the standards of performance are directly imposed on affected EGUs in the form of mass emission limits, performance rate standards coupled with ERC compliance demonstration provisions, or mass-based allowance holding and "true-up" provisions. Two important variations are available to states that adopt mass-based plans. First, under a state measures plan, federally enforceable standards of performance may be imposed on affected EGUs in conjunction with other state-enforceable requirements applicable to affected EGUs or other affected entities. Alternatively, a state measures plan may be designed to rely only upon state-enforceable measures

86 80 Fed. Reg. at 64,825.

that are not performance standards for affected EGUs, with performance standards for EGUs incorporated as the federally enforceable backstop.[87] Second, mass-based plans may regulate Subpart TTTT sources under the same regulatory structure as Subpart UUUU sources and be approved as emission standards plans.

4.5.2 Other Affected Entities

Three general types of CO_2 reduction strategies may require action by entities other than the owners and operators of affected EGUs:

1) Strategies involving increased dispatch of lower carbon fossil fuel EGUs (i.e., generation shifting to NGCC units);
2) Strategies involving an increase in generation from non-emitting units, including renewable generators, nuclear power plants, and hydroelectric plants that do not qualify as renewable under state regulations; and
3) Strategies involving the deployment of energy efficiency measures.

Because most, if not all, state plans will need to rely on one or more of these measures to achieve the required CPP reductions, entities other than affected EGUs will have some role to play in the success of the plan. For example, a mass-based emission standards plan that imposes direct emission limits on affected EGUs which are sufficiently stringent to achieve the statewide mass-based emission goal would not need to regulate other affected entities under the state plan. However, such a plan may still leverage strategies such as generation shifting to lower carbon emissions, as well as renewable energy sources and deployment of energy efficiency measures, in order for the affected EGUs to meet the mass emission standards while still assuring the region can meet consumer power demand. Thus, the parties that control generation and dispatch operations, implement energy efficiency programs, and plan, build and deploy renewable energy resources all have a role in achieving compliance, even though they may not all be directly regulated under the state plan.

Under a rate-based plan, the emission standards that apply to affected EGUs are in the form of performance rates that account for zero-emitting generation and/or avoided generation in the form of ERCs. Thus, the entities responsible for generating ERC resources clearly have a role in plan implementation and compliance. And, although the owner/operator of the affected EGUs relying on the ERCs for compliance will ultimately be accountable for assuring applied ERCs meet all qualifying criteria, either a state administrative body or others acting on their behalf will be responsible for receiving and reviewing ERC applications and issuing ERC certificates. In addition, states that adopt emission standards plans may implement measures such as Renewable Portfolio Standards (RPS), Energy Efficiency Resource Standards (EERS), demand-side energy efficiency (EE) programs, or other mechanisms to complement their plans. These same types of strategies may be the primary strategies implemented under a state

Table 4.3 **Potential or Likely Affected Entities *in Addition to* Affected EGUs**

State Plan Type	Generation Shifting	RE Measures	EE Measures
Mass-based Emission Standards	None, except that Subpart TTTT EGUs may be included to address leakage	None	None
Rate-base Emission Standards	ERC Providers, which may include: Vertically integrated utility; or, distribution utility or RTO/ISO	ERC Providers, which may include: Generator utilities, distribution utilities, IPPs, 3rd-party administrators, state agency	ERC Providers, which may include: Generator utilities, distribution utilities, IPPs, municipalities
State Measures	Utilities; Distribution utility; RTO/ISO	Generator utilities, distribution utilities, IPPs, 3rd-party administrators, state agency	Generator utilities, distribution utilities, IPPs, municipalities, counties, universities, schools, hospitals, state agency

87 For a more detailed discussion of performance standards, emission standards plans and state measures plans, see *Chapter 5, State Plan Types and Required Plan Components.*

measures plan, either with or without corresponding emission standards.

In essence, even though affected EGUs may be the only parties directly regulated or subject to enforcement action under some state plans, many states will likely choose to provide for some mechanism to motivate action by other parties to ensure successful implementation.

Table 4.3 provides an illustrative matrix of potential or likely affected entities included in a state plan, based on plan type and reduction strategy. The table is not an exhaustive list of potential plan designs, nor does it indicate a required approach for any particular case. The following sections discuss the non-EGU entities involved in the main categories of CO_2 reduction strategies, as they relate to the power sector structure and operation, and potential mechanisms for regulating, engaging or incentivizing their action.

4.5.3 Trading as a Mechanism to Engage Non-EGU Entities

As an initial consideration in relation to the need to address non-EGU entities as affected parties under that state plan, it is helpful to note that Subpart UUUU encourages and provides for the adoption of market-based trading programs to achieve CO_2 reductions from affected EGUs. As discussed in detail in Chapter 6, Key Decisions for State Planning, a market-based trading program offers many advantages, including increased compliance flexibility for affected EGUs. Emission standards that incorporate emissions trading have the effect of setting source-level, source category-wide standards across a region, which individual sources can meet through a variety of technologies and measures.

Under a mass-based trading program, the emission performance standard applicable to affected EGUs is the requirement, at the end of each performance period, to hold and retire allowances equal to the unit's actual emissions. Under a rate-based trading program, the emission performance standard applicable to affected EGUs is a uniform subcategory-specific emission rate, for which compliance is demonstrated through assessment of actual EGU emission rates and the holding and retirement of ERCs in sufficient quantities to bring the actual emission rate in line with the performance standard. In either case, a trading program creates and incentivizes a market platform through which numerous parties other than affected EGUs can participate in a variety of reduction strategies that drive the state plan to success. Importantly, a trading program places the full responsibility for compliance directly on affected EGUs, without the need for a state administrative authority to impose direct requirements for reduction measures on any other party. Instead, the market creates indirect economic incentives for other parties to engage, through the value of allowances or ERCs, by investing in renewable energy deployment, energy efficiency, or other clean energy resources, for a profit.

In effect, the purchase of an ERC or allowance by the owner/operator of an affected EGU represents an investment in emission reductions via whatever strategy made the ERC or allowance available, even though the activity generating the ERC or making the allowance available for sale may have been taken at another source or by a third-party entity. Put simply, when a state establishes emission standards that incorporate trading as a compliance mechanism, the tradable ERCs serve as a medium through which non-EGUs can be engaged in the state plan, without the need for enforceable requirements.[88] To a lesser extent, the same is true of allowance-holding requirements, or any plan structure that requires reductions in aggregate EGU emissions.

Thus, for state plans that adopt trading-based emission standards, there is no need to identify other parties as affected entities that are subject to emission standards or operating limits, or that are required to achieve certain levels of emission reductions. Nonetheless, states may want to consider what other entities will be involved in undertaking the activities and investments that will be required for affected EGUs to comply. This awareness will allow the state to ensure there are adequate mechanisms to properly incentivize and enable these parties, and to assure there are no undue constraints that would impede the success of the state plan.

For state measures plans and for state emission standards plans that do not provide for market-based trading, the state may choose to regulate or incentivize other affected entities through state-enforceable requirements or through voluntary programs, depending on the specific strategies elected to compose the state plan. The following sections discuss non-EGU entities that may be involved in achieving reductions relied upon by the state plan.

88 Of course, ERC resource providers will need to demonstrate that ERCs meet all qualifying criteria and that all evaluation, measurement and verification procedures are met, as defined by the state plan. Nonetheless, participation as an ERC provider is voluntary, not mandatory. Furthermore, in the event an ERC application is disapproved, there are no enforcement consequences for the applicant. If an ERC is determined to be invalid after use by an affected EGU, the EGU owner/operator bears the consequences of noncompliance.

4.5.4 Affected Entities for EGU Dispatch and Generation Shifts

In a state plan that relies in part on emission reductions from affected EGUs by shifting power generation from coal-fired steam boilers to existing NGCC units, as in Building Block 2 of BSER, all actions under the strategy directly involve affected EGUs. However, in some cases the owner/operator of the affected EGU does not have full control over dispatch. In many states, the real-time decisions regarding dispatch of EGUs is controlled by a distribution utility or by an independent RTO or ISO. It must be recognized, however, that even in RTO- and ISO-operated regions, EGU owners/operators still have significant control over which of their units are dispatched and how units are prioritized in the dispatch algorithms, because the owner/operator elects which units to enter into the dispatch market and sets the bids. As with other environmental standards, compliance with emission standards under the state plan will effectively represent a variable cost of operation that will figure into the dispatch bid.

If the state has vertically integrated utilities, where the same entities that own and operate affected EGUs also directly control the dispatch of those affected EGUs, no other entity would need to be subject to enforceable requirements to achieve the generation-shift strategy for those EGUs, regardless of the type of plan the state adopts. In theory, assuming all dispatch is controlled by utility companies that also own and operate affected EGUs, then those investor-owned utilities (IOUs), public power utilities, and electric cooperatives could all be required to meet provisions for prioritizing dispatch of the affected EGUs so as to reduce CO_2 emissions.[89] One special consideration for generation dispatch shifting in a state with vertically integrated utilities is the effect of and impact to independent non-utility power generators and independent power marketers. For NUG-owned affected EGUs, the owner/operator does not have direct or full control over dispatch. Rather, the independent power generator or independent marketer sells power to the utilities. Therefore, the state plan may need to include provisions to assure that the utilities prioritize dispatch of NGCC over purchase of power generated by higher-emitting affected EGUs. Even in this case, however, the universe of affected entities is composed of the owners and operators of affected EGUs, which includes those who control the dispatch of power sources to the grid.

In a state where the distribution of electricity is controlled by a distribution utility or an independent RTO or ISO, the entity controlling dispatch may need to be subject to enforceable requirements in order to assure successful implementation of the EGU dispatch-shifting strategy. The determination of whether any additional affected entity must be included under the state plan will depend at least in part on the type of plan the state implements, as discussed in the following paragraphs.

For an emissions standard plan that is mass-based, even if trading is not incorporated, specific requirements for generation dispatch shifting do not need to be included as enforceable measures in the state plan. This is because the direct monitoring and reporting of mass emissions from affected EGUs, together with direct enforcement of the applicable emission limits, will serve to assure compliance. That is, the enforceable mass-based emission limits for affected EGUs will be set in a manner that effectively incorporates or "presumes" the projected generation shifting, such that compliance with the emission limits will achieve the emission reductions attributed to the generation dispatch shifting strategy. For an emission standard plan that is rate-based, the rate based emission limits for affected EGUs (either the Table 1 subcategory performance rate limits or the statewide Table 2 equivalent performance rate goals) reflect anticipated ERC adjustments for avoided generation from RE or EE measures. Because a system for creating, tracking and using ERCs (which will include or reflect generation shifting) is provided in the plan, the distribution utility or system operator would not need to be included as an affected entity in the plan.[90]

The owners and operators of the affected EGUs could assure compliance with an emission standards plan, including one that does not involve interstate trading, through direct transactions with the dispatch utility or RTO/ISO, without the need for state regulatory action (as described above). That is, the owner/operator could restrict availability of the EGU or incorporate the variable cost representative of the state plan requirement in setting the bid for unit dispatch in such a way to provide a reasonable assurance of compliance. Advance planning will be necessary to ensure that any restrictions on EGU operation are addressed in a manner consistent with RTO/ISO dispatch planning and dispatch procedures.

89 CO_2 emissions would be only one factor considered in prioritizing dispatch of EGUs. For model rule language to implement this strategy, see Chapter 9, Section 9.5, Generation Shift to Existing NGCC EGUs.

90 For model rule language to implement this strategy, see Chapter 6, Rate-based Emission Standards Plans.

However, the state may choose to establish complementary state-enforceable measures or state-implemented policies to assure that generation shifting occurs in sufficient amounts to achieve the state emission performance goal. State provisions applicable to the dispatch utility or RTO/ISO may be desired, but are not necessary, to make compliance with the direct emissions limits achievable for the affected EGUs. Similarly, for a state measures plan that relies on generation shift from coal to existing NGCC units, compliance obligations are shared among the affected EGUs and other affected entities and/or the state. In this case, to achieve generation shifting from coal-fired to NGCC affected EGUs, the distribution utility or independent system operator could become an affected entity with state-enforceable requirements under the state plan.

4.5.5 Affected Entities for Renewable Energy Measures

As discussed in more detail in Section 2.4, EPA's BSER determination is based on a range of measures that fall into three main categories (the Building Blocks), including improved operations at EGUs, increasing the dispatch of lower-emitting affected EGUs, and increasing generation from zero-emitting energy sources. Although avoided generation through the deployment of demand-side energy efficiency measures was not included as an element of BSER, EPA recognized that EE and many other strategies could be employed by states in designing their state plans. As a practical matter, in order to achieve the proposed emission performance goals, states will almost certainly need to rely on strategies "beyond the fenceline" of the affected EGUs, including avoidance of CO_2 emissions through the utilization of zero-emitting generation sources and/or implementation of EE measures.[91]

In determining affected entities or non-EGU parties involved in carrying out the state plan for purposes of RE measures, the pertinent questions are:

- Who will be responsible for the development and deployment of RE resources?;
- Who will be responsible for tracking, monitoring, and reporting on RE generation?; and
- Are federally enforceable requirements needed in the state plan to assure compliance?

The development of RE projects is encouraged in a number of ways. For instance, many states have adopted Renewable Portfolio Standards (RPS) as a matter of state law. The RPS applies directly to distribution utilities in the state (either the power generating utility, the distribution utility, or both, as appropriate for that state), and sets a prescribed minimum percentage of the annual retail electricity supply that the utility must obtain from RE sources. Other approaches are often incentive-based programs for development of RE generation resources, such as tax credits, loan guarantees, or shared cost of development. These approaches encourage the development of RE projects by IPPs and/or utilities, but do not mandate RE growth to occur.

As discussed previously, for state plans that are mass-based emission standards plans, the affected EGUs are ultimately responsible for assuring that all necessary CO_2 reduction strategies are achieved. In this case, no additional affected entities and no specific enforceable RE measures can be included in the state plan. Also, if the plan incorporates market-based trading, the allowance market itself may be sufficient to incentivize RE development and deployment. The state may desire, nonetheless, to retain or adopt RPS requirements and/or RE incentive programs at the state level as complementary measures to the state plan.

For a rate-based emission standards plan, some RE requirements will likely need to be incorporated into the state plan, in the form of resources eligible for ERC issuance. A specific performance standard for RE, such as an RPS, could be used but would likely not be needed in the state plan, because RE deployment is already accounted for in the rate-based EGU emission limit. However, the mechanism for adjusting the affected EGU's actual emission rate to account for avoided generation through ERCs will need to be made federally enforceable. To the extent the generation and application of ERCs involve other entities, those entities will be affected entities under the state plan. For example, the owner/operator of the RE generation source may be subject to registration, monitoring and reporting requirements. Also, ERC registry and tracking systems implemented for managing credits will impose some level of regulation or contract obligation on the registry operator, who will be responsible for meeting certain registration, quality assurance, auditing, and reporting requirements. Under a rate-based emission standards plan, neither the owner/operator of the RE generation source nor the operator of the registry system

91 In fact, EPA acknowledged in the proposed CPP rule that a BSER based on only the first two building blocks would achieve fewer CO_2 reductions than those reflected in the proposed state emission performance goals. 79 Fed. Reg. at 34,836. Other reductions measures, such as carbon capture, could potentially be implemented, however, to achieve reductions without RE and EE reliance.

would need to be required to achieve a particular level of RE power generation or RE credits. Requirements for these affected entities would be administrative only and participation in the program would be voluntary, not mandated.

For a state measures plan in a state with vertically integrated utilities, each utility could potentially be an affected entity subject to state-enforceable RPS requirements or responsible for achieving other RE measures under the state plan. For a state measures plan in a state with a restructured power sector, the responsibility for achieving RE generation growth may be assigned to the distribution utility, or may be shared among multiple affected entities and the state. For example, a requirement to provide RE generation capacity available for dispatch could be applied to the generation utilities, while a requirement to preferentially dispatch RE generation (subject to other considerations, such as reliability) could be applied to the distribution utility or system operator. Administrative requirements for tracking, monitoring and reporting RE generation and/or RE credits would also need to be included in the state plan, as with the rate-based emission standards plan. Again, the state may also choose to implement incentive programs as complementary measures that remain outside of the federally enforceable state plan, but that nonetheless help to support the growth of RE deployment.

4.5.6 Affected Entities for Energy Efficiency Measures

For implementing EE measures, the same three questions would apply as for RE measures:

- Who will be responsible for the development and deployment of EE programs?;
- Who will be responsible for tracking, monitoring, and reporting on EE programs?; and
- Are federally enforceable requirements needed in the state plan to assure compliance?

Numerous types of EE programs can be implemented for purposes of achieving compliance with Subpart UUUU, and the specific affected entities involved can vary based upon the EE program. Because EE programs are highly variable and are administered in many ways by a number of different entities, defining the affected entities and administrative authority responsibilities for EE measures is one of the most challenging aspects of state plan development. As with other CO_2 reduction measures, the possible scenarios regarding affected entities that will either be subject to state-enforceable requirements, participate in voluntary incentive programs, or enter into market-based trading under the state plan depends upon the type of plan adopted by the state, as well as how the state decides to assign compliance responsibilities under the plan.

For mass-based emission standards plans, no additional affected entity is necessary other than the affected EGUs and no enforceable measures other than the mass emission limits are required to assure compliance with the CPP performance goals. With mass-based emission limits, EE measures that avoid EGU CO_2 emissions can be part of a state's overall strategy for reducing affected EGU CO_2 emissions, but may be retained at the state level as complementary to the state plan. CO_2 emissions performance would be assured through compliance with the mass emission limits applicable to affected EGUs.

Other plan types will require some incorporation of EE measures into the state plan, to the extent avoided generation through demand-side EE is relied upon as a qualified ERC resource under a rate-based plan, or as a reduction strategy under a state measures plan. However, in many cases the state may choose either to place responsibility for the successful deployment of EE programs on the owners and operators of affected EGUs, or to accept responsibility for implementation of EE programs through a state agency.

For rate-based emission standards plans, the full responsibility for compliance with the emission performance standard remains with the owners and operators of affected EGUs. Nonetheless, EGUs will rely on development and deployment of EE programs for avoided CO_2 emissions, in order to adjust their emission rates through ERCs and demonstrate compliance. Toward that end, at least some level of EE program administrative requirements must be incorporated in the state plan. EE measures can be credited in the compliance demonstration for the applicable rate-based emission limit either by adjusting an affected EGU's actual CO_2 emission rate through an administrative action by the state, or through the use of an ERC credit system or market-based trading approach. These mechanisms would be included in a state plan to ensure that the actions are properly quantified, monitored, verified and reported.[92] However, there would be no need for Energy Efficiency Resource Standards (EERS) that establish a required level for EE avoided MWh, because compliance with the subcategory performance standards, or with the statewide or multi-state emission performance rate, would be

92 40 C.F.R. §§ 60.5795, 60.5800 & 60.5810.

demonstrated by compliance with the applicable emission standards.

Requirements for EM&V, recordkeeping and reporting would also need to be specified in the state plan.[93] Parties subject to those requirements would be affected entities subject to administrative requirements, but participation by affected entities would be voluntary. For example, the state plan may specify qualification requirements for third party energy performance service companies, or standards that energy audits must meet. Or, the state plan would specify EM&V procedures or certain administrative or auditing procedures that must be followed by third party administrators of EE programs. Also, the affected EGUs ultimately would bear the consequences of non-compliance with their applicable emission standard in the event of any non-compliance with ERC issuance requirements.

For state measures plans that rely on EE measures in part to achieve compliance with the state mass-based emission goals, the specific EE measures must be incorporated into the state plan but would be state-enforceable measures.[94] In addition to EM&V measures and other administrative requirements related to EE programs, the state could elect to establish a state-enforceable level of EE deployment (i.e., an EERS) capable of providing avoided MWhs sufficient to meet the projections relied upon in the state plan. The affected entities subject to the EERS could be one or more of the following: a vertically integrated utility company (in states with a traditional power sector structure); the generator utilities and/or the distribution utility (in states with a restructured power sector); non-utility power producers that own or operate affected EGUs; a municipality, county or other subdivision of government; or a defined sector such as universities, schools and hospitals. Another option is for the state to take on all or part of the responsibility for achieving an EERS, either under a state measures plan or as a complementary measure to supplement an emission standards state plan.

4.6 Administrative Authorities to Implement the State Plan

Equally as important as understanding what entities will be regulated under the state plan is understanding what state agencies will serve as the regulatory authority or administrative authority for various aspects of the state plan. Many states may prefer to rely upon existing authorities to implement and enforce the state plan, augmenting those authorities where appropriate with interagency or intergovernmental agreements. In some cases, however, new or expanded legislative authorities may be required, depending on the particular circumstances in the state as well as the plan type and reduction strategies desired.

As discussed in Section 2.1, there are a number of different types of utility and non-utility power generators that may be subject to emission limits for affected EGUs under state plan requirements in any given state, and these affected EGUs may be governed by different regulatory authorities. Also, the state may elect to develop a plan that incorporates a number of different CO_2 reduction strategies, implemented in a variety of ways under different administrative authorities. Some of those reduction strategies may already be in place to varying degrees at the state level, administered under either the PSC or the SEO. As discussed in Section 2.3, implementation of a rate-based emission standards plan will require administrative mechanisms and authorities to issue and track ERC resources. For a state measures plan, administrative authority to adopt and enforce strategies such as generation dispatch shifting, RE deployment and EE program deployment will be necessary.

As discussed throughout in Chapter 2, The U.S. Power Sector, the types of electric power producers, distributors and system operators vary from state to state, as do specific regulatory authorities. For example, municipal power, public utility districts, IPPs, federal PMAs, the TVA, and electric cooperatives have varied structures and often are not regulated by the PSC. Identifying existing authority and the appropriate state or local agent to serve as the administrative authority for certain areas is an important early step in the state planning process. Also, early steps should be taken to identify existing gaps in legal authorities that would limit or eliminate desired flexibilities and options for CPP compliance. Certain areas may require special consideration and could significantly influence the design of the state plan, the affected entities' assigned obligations under the state plan, and the reduction strategies selected. Some of these issues are examined briefly below. The following sections discuss the administrative authorities a state is most likely to consider for implementing and enforcing the state plan, as well as some possible arrangements for interagency or intergovernmental collaboration.

93 40 C.F.R. §§ 60.5830 & 60.5835.

94 "'State measures' refer to measures that are adopted, implemented, and enforced as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable state plan." 80 Fed. Reg. at 64,832 n.782.

4.6.1 Existing Administrative Authorities

As discussed in Section 2.2, both the PSC and the state air quality agency already have some level of regulatory authority over all or some of the affected EGUs in the state. The SEO also plays a role in RE and EE program administration, particularly with regard to deployment of incentive programs and programs for state facilities. In addition, municipal governments are in the regulator seat for municipal utilities. Each of these existing administrative authorities may have a role to play in implementing the state plan for existing power plants.

4.6.2 Administrative Authority for Implementing Trading-based State Plans

One significant advantage in adopting a trading-based emission standards plan is that this approach simplifies the role of the administrative authority. Because under a market-based trading program the affected EGUs are directly and solely responsible for compliance with the performance standards adopted to implement the Subpart UUUU emission guidelines, the traditional role of the environmental or state air quality agency as the enforcement authority is a natural fit. The administrative functions for operation and maintenance of the allowance tracking system and for holding auctions, or for operation and maintenance of the ERC tracking system, as well as reviewing applications and issuing ERCs, could all be carried out by third parties under contract to the state, or distributed among state agencies as desired.

The authority to create a new trading program or to join an existing regional program, such as RGGI, would likely require state legislation if statutory authority supporting such activity is not already in place. Therefore, evaluation and consideration of this approach should be undertaken early in the state planning process.[95]

4.6.3 Administrative Authority for EGU Emission Limits and "Inside the Fenceline" Requirements

The state air quality agency is the state level authority that traditionally adopts, implements and enforces CAA requirements, including those for developing state plans under CAA Section 111(d). Specifically with regard to the adoption, implementation and enforcement of emission limits that apply directly to the affected EGUs at existing power plants, the state air quality agency will likely have the authority and administrative infrastructure needed.[96] In some cases, the state delegates this authority to local or district air quality agencies; this arrangement will likely also be extended to state plan implementation to comply with Subpart UUUU. The same approach will apply for other "inside the fenceline" requirements to reduce CO_2 emissions, such as heat rate standards, and also to EGU emission limits that are expressed as allowance holding requirements. These emission limits and operational standards can be readily adopted into the state air quality administrative code, and can be implemented and enforced directly through the state regulation as well as through the Title V operating permit program.

4.6.4 Administrative Authority for EGU Dispatch and Generation Shifts

The state air quality agency may not have the requisite authority to directly regulate the dispatch of particular EGU fuel types, such as requiring increased utilization of NGCC turbines. Furthermore, the state air quality agency is likely not staffed with the resources or the expertise to oversee dispatch decisions. In today's highly integrated electric power delivery system, dispatch decisions are made through a combination of capacity market contracts (usually committing generation resources three years in advance) as well as in real time, based on customer load demand. Dispatch decisions must consider reliability and safety, in addition to competitive cost. The distribution utility and/or the RTO/ISO are the entities directly responsible for managing dispatch of available EGUs to meet demand in a reliable and cost-effective manner. PSCs regulate investor-owned utilities, including investor-owned distribution utilities. PSCs also have a role in determining what EGUs will be available for dispatch, through the rate approval and IRP process for PSC regulated utilities. However, PSCs generally do not regulate public power utilities, electricity cooperatives or IPPs. RTOs and ISOs operate in accordance with FERC requirements, but are not subject to PSC oversight. Therefore, PSCs have limited regulatory authority to achieve the goal of shifting generation from high-carbon to low-carbon fossil-fuel EGUs. As discussed in Section 4.1, it must also be recognized, however, that even in RTO- and ISO-operated regions, EGU owners/operators still have significant control over which of their units are dispatched and how units are prioritized in the

95 For further discussion of trading programs, see *Chapter 6, Section 6.1, Trading Program Considerations and Decisions.*

96 Some states may need new explicit legislative authority to implement a new federal regulation, such as the CPP. Other states already have broad authority to implement any New Source Performance Standard adopted by EPA.

dispatch algorithms, because the owner/operator elects which units to enter into the dispatch market and sets the bids. As with other environmental standards, compliance with emission standards under the state plan will effectively represent a variable cost of operation that will figure into the dispatch bid. To the extent the state air quality agency has authority to implement and enforce those emission standards, the agency can indirectly influence EGU dispatch and utilization.

Given these gaps in authority to directly interject an environmental factor into the dispatch algorithms currently in use by distribution utilities and RTO/ISOs, a state that chooses to directly mandate shifts in generation dispatch among affected EGUs may need to acquire new authorities. This may be desirable either as a complementary measure to support an emission standards plan or as a state-enforceable strategy under a state measures plan. An example of this approach would a fossil-fuel portfolio standard for existing EGUs.[97] Alternatively, the state could rely on the existing administrative authority of the air quality agency to indirectly require or encourage generation shifts through the establishment of emission limits or operating limits on individual EGUs or on groups of EGUs.

Another approach to encourage utilization shifting to lower-emitting affected EGUs is a market-based program. In the preamble to the proposed Subpart UUUU, EPA noted,

> *Under both RGGI and California's Global Warming Solutions Act, shifting generation from more carbon-intensive EGUs to less carbon-intensive EGUs is a way to facilitate compliance with regulatory requirements. In both cases, the industry has demonstrated the ability to respond to the regulatory requirements of these state programs.*[98]

As noted above, state air quality agencies are well positioned to implement and enforce an emission standard that incorporates trading as a compliance mechanism.

4.6.5 Administrative Authority for RE Measures and EE Measures

One of the recurring themes in state CPP planning is the question of state RE and EE programs, particularly those that are not directly applicable to utilities. These programs offer significant opportunity to contribute CO_2 reductions towards compliance with the state performance goals. At the same time, participation by consumers is generally voluntary and is driven by incentive-based marketing. States will need to assess whether or to what extent reliance on these programs is necessary or desired to achieve compliance with the EGU performance standards or state performance goals. Further, states will need to carefully consider how to design the state plan to balance federal enforceability of affected EGU emission standards with the state-enforceability or voluntary nature of these energy efficiency and RE programs.

RPS and EERS directly applicable to utilities are typically under the domain of the PSC. In states with existing RPS or EERS, particularly those with future compliance dates, the existing requirements could be relied upon to achieve compliance with the CPP emission guidelines. For emission standards plans that rely on RPS or EERS applicable to utilities as complementary measures entirely outside of the federally enforceable requirements of the state plan, little change would be needed to the existing regulatory framework for the substantive requirements of these measures. Similarly, for state measures plans that rely in part upon compliance with utility-driven RPS or EERS to achieve the Subpart UUUU mass emission goals, these standards would be included as part of the state plan but would remain supporting, state-enforceable mechanisms and would not be incorporated as part of the federally enforceable plan. In this case, the existing statutory or regulatory vehicle could be submitted as a plan element, with the PSC as the administrative authority for these measures. Or, the state air quality administrative code could be revised to reference the existing statutory or PSC regulatory requirements. Incorporation of existing standards into the state plan could be augmented by an interagency memorandum of understanding between the state air quality office and the PSC, delineating how the two agencies would share responsibilities for implementing, enforcing, tracking, monitoring and reporting.

For rate-based emission standards plans, EM&V, recordkeeping and reporting requirements would need to be included in the state plan for ERC-eligible measures, as would any mechanisms for trading or for adjusting actual EGU emission rates to account for the RPS generation and for EE-avoided MWh. The state may want to consider some sharing of responsibility between the PSC and the state air quality agency for administering the EM&V, recordkeeping and reporting requirements. For example, if the PSC has established protocols for EM&V and requirements for utilities to keep records of RPS and

97 For further discussion and example rule language, see *Chapter 9, State Measures Plans.*

98 79 Fed. Reg. at 34,858. For further discussion of market-based programs, see *Chapter 6, Key Decisions for State Planning.*

EERS information and report to the PSC, these existing protocols and reporting requirements could be augmented as necessary to comply with Subpart UUUU and incorporated into the state plan to meet the compliance demonstration requirements for RPS and EERS under a rate-based approach. The PSC could provide data to the state air quality agency for purposes of tracking progress and for state reporting to EPA. This information-sharing arrangement could be established through a memorandum of agreement between the two agencies.

Beyond the regulatory role of the PSC in implementing RE and EE program requirements for utilities, the SEO has existing duties and authority related to RE and EE deployment. Incentive programs for increased deployment of RE and EE, as well as deployment of EE programs for state facilities and agencies, are already administered by the SEO in most states. If the existing programs are to be retained and relied upon for Subpart UUUU compliance, or if similar types of programs not applicable to utilities are to be implemented or enhanced for purposes of Subpart UUUU compliance, it would be logical to rely on the SEO as the administrative authority for those programs. As with other reduction strategies, if the state is adopting a rate-based plan and these RE and EE measures will qualify for ERCs representing avoided MWh for purposes of adjusting the actual EGU emission rates to demonstrate compliance, then the mechanisms for creating, quantifying, and tracking the RE- and EE-achieved reductions must be included as part of the state plan. A similar approach can be taken as described for the utility-driven RPS and EERS standards administered by the PSC, except that here the primary administrative authority would be the SEO.

If the state is adopting a state measures plan and the state's projections for achieving the state mass-based emission goals rely in part upon a projected level of RE power generation or EE-avoided power generation, then the projected level of reductions from RE and EE programs must be included in the state plan. This may be accomplished by documenting the responsible state agency (e.g., the state air quality administrator or the SEO) and the state-enforceable or state's legal obligations to maintain the specified RE and EE programs. The legal instrument for obligating the state agency to maintain the programs would likely be a state statute or executive order. For example, a statute that establishes the SEO's authority for implementing consumer-based EE incentive programs, coupled with a demonstration of authorized funding, could serve to demonstrate that the SEO is obligated to execute the program as projected in the state plan performance demonstrations. Or, a state executive order that directs all state agencies to enter into an energy performance contract (EPC) before expending capital for state buildings, naming the SEO as the administrator for the implementation, could serve to demonstrate that the SEO is legally obligated to execute the EPC program as projected.

Similar analysis will be necessary for states in which new or expanded nuclear generation is counted toward compliance. To the extent that such generation is financed through PSC-authorized cost-recovery from ratepayers, the PSC will likely issue ERCs and make them available to affected EGUs in the state. Should a state include nuclear generation in an RPS-like crediting program, considerations discussed above for RE will apply. For other non-emitting generators that are not eligible for existing state RE programs, such as certain hydroelectric generators, special consideration will likely be needed in the context of the various regulatory structures discussed above.

5. State Plan Types and Required Plan Components

The CPP affords states many avenues of discretion in selecting a pathway to achieve the required CO_2 reductions from existing fossil fuel-fired EGUs. First, each state has the discretion to select among four forms of the emission performance rates or statewide emission goals affected EGUs must meet, which are set forth in Tables 1, 2, 3 and 4 of Subpart UUUU. The options include:

- Table 1, the subcategory performance rate standards;
- Table 2, the statewide rate-based emission goals;
- Table 3, the statewide mass-based emission goals; or
- Table 4, the statewide mass-based emission goals for affected EGUs plus new source complements.[99]

Each state also has the discretion to identify the reduction strategies that will be relied upon to achieve compliance. In addition to emission standards applicable to affected EGUs, states may also implement strategies that do not impose emission standards directly on affected EGUs. If necessary to demonstrate the CPP goals will be achieved, the state would submit these strategies as state measures that are not federally enforceable. If compliance can be demonstrated through the affected EGU emission standards alone, the state may choose to keep such measures completely outside of the state plan. In addition, each state can elect whether to develop and implement a single-state plan with full reliance on intrastate compliance measures, a single-state plan that allows interstate trading among affected EGUs and other entities, or a multi-state plan that demonstrates compliance with combined multi-state performance standards or emission goals. Notably, a state may elect to divide the state's affected EGU fleet for coverage under two different plans, which may provide for interstate trading or multi-state plan participation in two different ISO or RTO areas.[100] Within each of these potential plan pathways, states have significant discretion to define the administrative measures that will be used to assure the reduction strategies are achieved.

State discretion is not without limits, however. The CPP incorporates a number of plan integrity assurances, including trading constraints, plan corrective measures requirements and backstop requirements, which apply depending on the particular state plan pathway adopted. These requirements and constraints are designed to contain the considerable flexibility offered states and affected EGUs within boundaries that assure the integrity of the emission goals are maintained and that BSER emission reductions are not double-counted or foregone. Understanding the levels of freedom allowed, the various constraints imposed on state planning and the conditions under which certain state plan requirements apply is critical in selecting the most appropriate path for a state plan.

5.1 Basic Plan Types and Implementation Options

The CPP describes two basic types of state plans, depicted in Figure 5.1. The first is the "emission standards" plan type, which relies on federally enforceable CO_2 emission standards directly applicable to affected EGUs. An emission standards plan can be implemented through either mass- or rate-based emission limits, or through imposition of an allowance system under a cap-and-trade program. An emission standards plan may be designed to achieve either the subcategory-specific performance rates, the statewide average rate-based emission goals for affected EGUs, the statewide cumulative mass-based emission goals for affected EGUs, or the statewide cumulative mass-based emission goals for affected EGUs plus new source complements.

The second basic plan type is the "state measures" plan, which relies wholly or partially on state-only enforceable measures. A state measures plan must be mass-based; it must demonstrate compliance with either the statewide

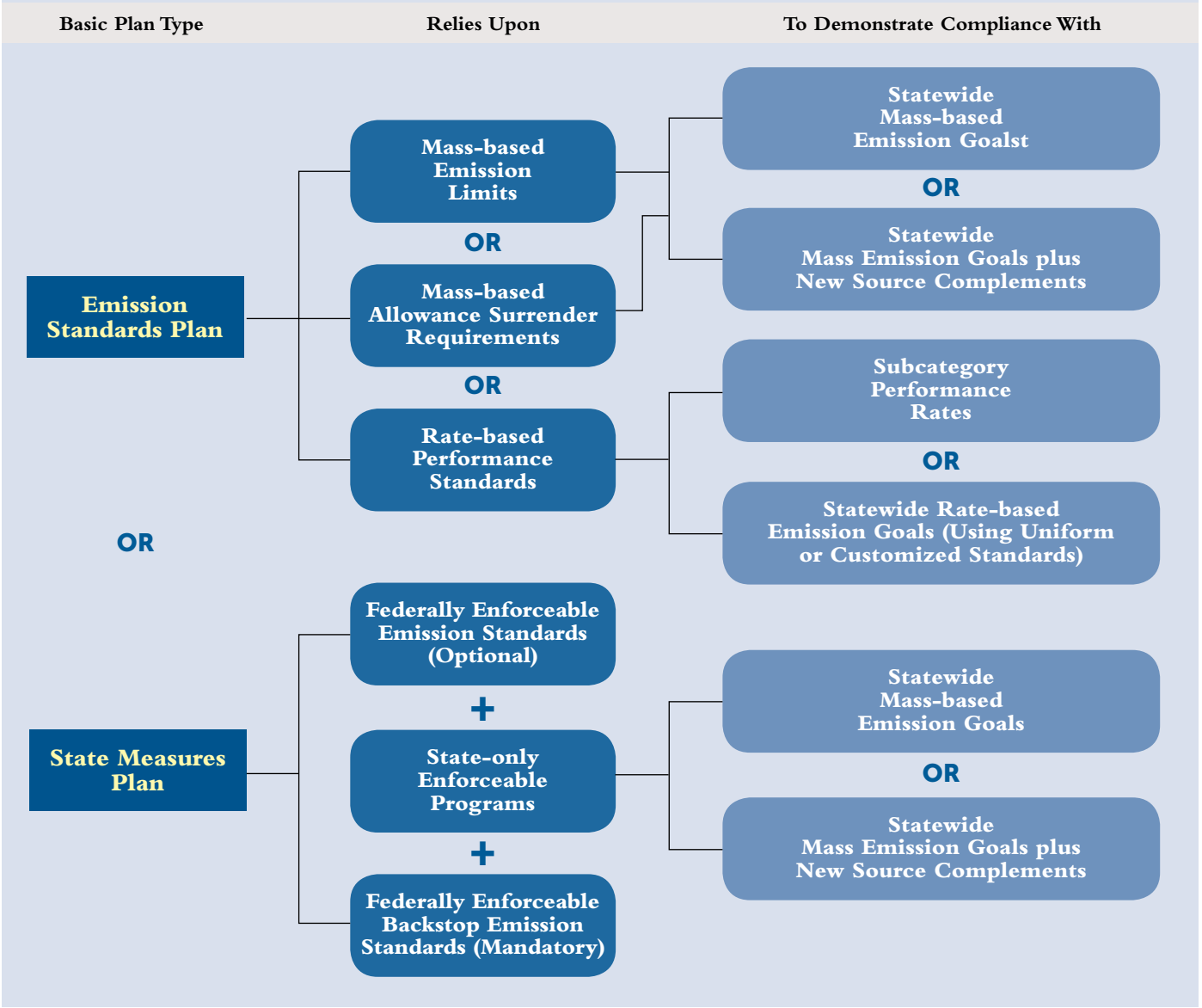
99 40 C.F.R. Part 60, Subpart UUUU, Tables 1, 2, 3 and 4 (frequently referred to in this document simply as Table 1, Table 2, Table 3 and Table 4).

100 40 C.F.R. § 60.5750(c); 80 Fed. Reg. at 64,840.

(or multi-state) mass emission goal for affected EGUs under Table 3 or the mass emission goal plus new source complement under Table 4 of Subpart UUUU. The state is not required to adopt emission standards applicable to affected EGUs under a state measures plan; however, any emission standards the state does adopt that are applicable to affected EGUs under a state measures plan must be federally enforceable.[101] All other CO_2 reduction strategies may be retained outside the federally enforceable elements of the state measures plan. State measures may be implemented through state-enforceable mechanisms, policies, or voluntary, incentive-based programs. In addition, a state measures plan must include a backstop composed of federally enforceable emission standards applicable to affected EGUs. Implementation of the backstop would be triggered in the event the state measures plan misses the Interim Step 1 or Interim Step 2 goals by 10% or more, or fails to achieve the applicable mass-based interim or final CPP performance goals during any performance period.

To provide compliance flexibility to affected EGUs, reduce compliance costs and minimize concerns regarding reliability of electric service, all types of plans can utilize trading of allowances or emission rate credits, subject to constraints depending on the plan type and pathway selected.

Figure 5.1 **Basic State Plan Types and Implementation Options**



101 80 Fed. Reg. at 64,836-39 (preamble to final CPP, section VIII.C.3.a). Note that 40 C.F.R. § 60.21(f) defines "emission standard" to include "establishing an allowance system" and EPA has clarified that allowance systems are emission standards under the CPP.

5.2 Required Plan Components

EPA has identified four "streamlined" plan pathways that require fewer plan elements and demonstrations. States may elect one of the streamlined plans or may design a more customized approach. Whether a streamlined or customized path is selected, many components will need to be assembled to make up the totality of the state plan. These include legal authorities, regulations, administrative programs and procedures for trading, affected source inventories, baselines and projections, and interim goals and compliance schedules, to name just a few. Subpart UUUU lists required plan submittal components in two groups: those components that must be included as federally enforceable plan provisions, and those that must be submitted as part of the plan but will not become federally enforceable plan provisions.[102]

5.2.1 Federally Enforceable Plan Components

40 C.F.R. § 60.5740 lists those required components that will be codified as federally enforceable elements of the state (or multi-state) plan. They are summarized in Table 5.1 below.

5.2.2 Additional Required Plan Components

In addition to the five required plan elements that must be codified as federally enforceable requirements, several other supporting plan elements must be included with the plan submittal, as provided in 40 C.F.R. § 60.5745. Those supporting plan elements are presented in Table 5.2, below.

5.3 Streamlined Plan Pathways

EPA has denoted certain emission-standards plan designs as streamlined plan pathways, subject to inclusion of fewer plan components and fewer plan demonstrations upon submittal.[103] No state measures plan, regardless of design, is considered a streamlined plan.

Any state plans meeting the streamlined plan criteria of 40 C.F.R. § 60.5740(a)(2)(i), as described below, by the nature of the form and level of the emission standards imposed, will mathematically assure compliance with the CPP emission goals. This mathematical demonstration is considered sufficient demonstration of the plan's projected performance and no further detailed projection of performance demonstrating that the plan will assure compliance with CPP interim step goals, interim period goal or final

Table 5.1 **Required Federally Enforceable State or Multi-state Plan Components** (40 C.F.R. § 60.5740)

No.	Required Plan Component	Description
1	**Identification of affected EGUs**	Identify each affected EGU and CO_2 emissions inventory from the most recent calendar year available.
2	**Emission standards**	If emission standards are included, identify each emission standard for each affected EGU as specified in § 60.5775, compliance periods according to § 60.5770, and a demonstration that the emission standards collectively will achieve the applicable state performance rates or goals. Include all required triggers for corrective action, if applicable, as specified in § 60.5740.
3	**State measures backstop**	If a state measures plan is submitted, include required backstop emission standards for affected EGUs.
4	**Monitoring, recordkeeping and reporting requirements**	Include all required monitoring, recordkeeping and reporting requirements for affected EGUs, consistent with or not less stringent than the requirements of § 60.5860.
5	**State reporting**	Describe the process, contents and schedule for state reporting to EPA as required under § 60.5870.

102 The preamble to the proposed CPP set forth four general criteria for a state plan to be approvable, which EPA proposed to review in combination with a determination of whether a plan submittal included all required plan components to assess whether a state plan is satisfactory. In the final CPP, EPA has decided against use of specified approvability criteria separate from the list of required plan components, noting that any plan that satisfactorily meets the required plan components would also meet the proposed approvability criteria.

103 40 C.F.R. § 60.5740(a)(2)(i); 80 Fed. Reg. at 64,832-33 (preamble to final CPP, section VIII.C.1).

Table 5.2 **Required Final Plan Submittal Information (Not Federally Enforceable)**
(40 C.F.R. § 60.5745)

No.	Required Plan Component	Description
1	**Plan description**	Describe the plan type and pathway, including whether the plan is single- or multi-state and the geographic boundaries of the plan.
2	**CO_2 performance rates or statewide CO_2 emission goals**	Identify which performance rates or goals the plan is designed to achieve (Subpart UUUU Table 1, 2, 3 or 4). Include calculations for multi-state goals, if applicable. Include interim step, interim period, and final period performance rates or goals.
3	**Demonstration projecting affected EGUs' compliance**	The plan must include a demonstration that the affected EGUs are projected to achieve the selected CO_2 performance rates or emission goals. The level of demonstration is dependent on plan type.
4	**Demonstration for each emission standard**	Demonstrate each standard is quantifiable, non-duplicative, permanent, verifiable and enforceable. Specific criteria are provided at § 60.5775.
5	**Emission standards plan information**	For rate-based or mass-based plans that apply emission standards that mathematically assure compliance with the Table 1, 2, 3 or 4 emission rates, no additional demonstration is needed. For all other emission standards plans, a detailed demonstration that the plan will assure compliance is required, as specified at § 60.5745.
6	**State measures plan information**	Required information includes, but is not limited to, a description of state measures' projected impacts, applicable state laws and regulations, identification of implementing entities, schedules and milestones for implementation, EM&V measures, and plan performance projections.
7	**Electrical grid reliability consideration**	Each state must document consultation with ISOs, RTOs, and/or the state energy officer, or other means of assessing and considering the plan's potential impact on grid reliability.
8	**Milestone schedule leading to January 1, 2022**	A plan implementation timeline from submittal to January 1, 2022 is required for all plans.
9	**Demonstration of adequate legal authority and funding**	Documentation of adequate legal authority and funding to implement and enforce the plan must be included.
10	**Demonstration of projected compliance with interim step goals**	Include a demonstration that interim step goals will be met and the methodology used to make the projection.
11	**Certification and documentation of public hearing on state plan**	Documentation must include a list of witnesses and their affiliations, and a summary of comments received.
12	**Documentation of community outreach and involvement**	Document community outreach conducted during plan development, including outreach to vulnerable communities.
13	**Supporting materials**	Any other supporting materials needed to evaluate the plan.

goal is required. In addition, the plan is not required to include provisions for corrective measures to be implemented upon a triggering event. Specifically, the streamlined plan is not subject to the triggering of a corrective measure based on an exceedance of an Interim Step 1 and/or Interim Step 2 performance rate or goal by 10 percent or greater, or for a failure to meet an interim period (2022 to 2029) goal, or for failure to meet any final reporting period performance rate or emission goal.[104]

While streamlined plans are exempt from detailed plan performance projection demonstrations and from the inclusion of triggers for corrective measures, other plan integrity assurance provisions will still apply. For example, a mass-based streamlined plan must still include provisions to address leakage to new fossil fuel-fired EGUs.

5.3.1 Mass-based Streamlined Plan Designs

A mass-based emission standards plan is considered a streamlined plan if it meets one of the two following designs:

1) The plan is designed to demonstrate compliance using Table 3 (affected EGUs only), and the plan imposes emission standards on all affected EGUs that mathematically assure compliance with the Table 3 statewide mass emission goals, assuming full compliance by all affected EGUs;[105] or
2) The plan is designed to demonstrate compliance using Table 4 (affected EGUs plus new source complement), and the plan imposes federally enforceable emission standards on all affected EGUs plus state-enforceable emission standards on all new sources subject to Subpart TTTT, which, taken together, mathematically assure compliance with the Table 4 statewide mass emission goals plus new source complement, assuming full compliance by all affected EGUs and Subpart TTTT-affected new sources.[106]

Either of these types of mass-based emission standards plans can be implemented through a budget trading program (allowance system) that provides for interstate trading using either a single-state or multi-state plan design, and still be considered a streamlined plan. For a mass-based plan, a plan design mathematically assures compliance with the Table 3 or Table 4 goals if the sum of the mass emission limits applicable to each affected EGU equals the total statewide mass-based goal. If the mass-based plan relies on an allowance trading program, with affected EGUs required to hold allowances equal to their actual emissions at the end of each performance period, then the total allowance budget for the program (including any set-asides) must be equal to or less than the statewide (or combined multi-state) mass-based goal for that performance period in order for the plan design to mathematically demonstrate compliance.

5.3.2 Rate-based Streamlined Plan Designs

A rate-based emission standards plan is considered a streamlined plan if it meets one of the two following designs:

1) The plan applies the Table 1 subcategory performance rates (or more stringent performance rates) as the emission standards applicable to affected EGUs within each corresponding subcategory, such that the applicable emission standards will mathematically assure achievement of the Table 1 performance rates on a statewide or multi-state basis, assuming full compliance by all affected EGUs.[107] Such plans can provide for Emission Rate Credit (ERC)-based interstate trading using either a single-state or multi-state plan design, provided that all plans included in the trading program apply the same emission standards; or
2) The plan applies a single, uniform performance rate, equal to the Table 2 statewide rate-based goal (or weighted average multi-state goal) for each performance period, to every affected EGU, provided that interstate trading is only allowed among the states subject to the same multi-state plan.[108]

5.3.3 Streamlined Plan Mass-based Allocation Example

The following simplified example illustrates the establishment of mass allocations under a streamlined plan design, in a manner that mathematically demonstrates assurance of compliance with the statewide mass-based performance goal for the performance period 2030–2031. This example is based on Iowa state data,[109] but is not intended to represent the Iowa state plan. The example assumes that the state is implementing a single-state plan

104 40 C.F.R. §§ 60.5740(a)(2) & 60.5745(a)(5).

105 40 C.F.R. § 60.5740(a)(2)(i)(B).

106 40 C.F.R. § 60.5740(a)(2)(i)(C).

107 40 C.F.R. § 60.5740(a)(2)(i)(A).

108 40 C.F.R. § 60.5740(a)(2)(i)(B).

109 EPA, Clean Power Plan State Goal Visualizer, Appendix 1 – All Units (2012), available at https://www.epa.gov/sites/production/files/2015-08/clean-power-plan-state-goal-visualizer_0.xlsm.

Table 5.3 **Example Mass-based Allocation that Mathematically Assures Compliance with Table 3 Performance Goal**

Affected EGU	2012 Baseline Emissions (tons)	2030 – 2031 Allocation (tons)
COALST2	1,389,770	1,910,000
COALST3	690,518	1,520,000
COALST4	251,076	350,000
COALST5	677,427	1,040,000
COALST6	672,879	950,000
COALST9	5,284,146	5,060,000
COALST10	5,720,046	6,430,000
COALST12	1,332,873	2,430,000
COALST13	2,780,939	3,830,000
COALST14	1,464,970	1,480,000
COALST15	95,738	260,000
COALST16	378,847	500,000
COALST17	16,181	240,000
COALST18	87,271	520,000
COALST19	948,317	1,220,000
COALST21	6,513	230,000
COALST23	3,772,270	5,060,000
COALST24	5,446,776	5,660,000
COALST25	4,693,781	4,460,000
NGCC1	6,758	40,000
NGCC2	8,835	50,000
NGCC3	78,018	280,000
NGCC4	78,018	280,000
NGCC5	80,108	290,000
NGCC6	110,851	260,000
NGCC7	110,851	260,000
NGCC8	163,656	380,000
Total EGU Allocations		**44,990,000**
±10% EE Allocation Set-aside		**5,010,000**
Table 3 Performance Goal		**50,036,272**
Difference (Performance Goal – Allocations)		**36,272**

that participates in a mass-based interstate trading program. For the final performance period, the state's Table 3 mass-based two-year block performance goal is 50,036,272 tons CO_2. To assure and mathematically demonstrate that the plan will achieve compliance, the allocation budget for the performance period is set equal to the performance goal, at 50,036,272 tons. The state has 25 affected coal-steam EGUs, four affected oil-gas steam EGUs, and eight affected NGCC EGUs. In general, the allocations presented in Table 5.3 are set as follows. First, the state has set aside a 10% allocation of the total compliance budget for demand-side EE investment. All four oil-gas EGUs and six affected coal-steam EGUs are scheduled to retire prior to 2030, and are therefore not provided allocations for the 2030–2031 performance period.[110] Allocations for the remaining coal-fired steam EGUs represent a 33% reduction in emissions from the 2012 baseline, adjusted to account for the 10% set-aside and normalized for each affected EGU based on nameplate capacity. Allocations for the NGCC units represent a 50% increase in emissions from the 2012 baseline (to allow for and incentivize generation-shifting from coal-fired EGUs to existing NGCC units), adjusted to account for the set-aside, and normalized based on nameplate capacity. For a detailed, step-by-step explanation of the determination of EGU-specific allocations, see *Section 8.2, Mass-based Trading Programs.*

As seen in the table above, the total allocations distributed for the performance period are less than the Table 3 performance goal; therefore, the plan mathematically assures compliance, assuming all affected EGUs meet the requirement to hold allowances equal to actual emissions at the end of the performance period. A plan that takes this approach for all performance periods (i.e., sets an emission budget that is equal to or less than the state mass CO_2 performance goal for the performance period) is a streamlined plan not subject to the requirement for corrective measures. Furthermore, for a mass-based trading program that uses this approach, achievement of the state goal will be assessed based on compliance by affected EGUs with the allowance-holding requirement, and not based on reported actual CO_2 emissions derived from monitoring data. In addition, such a state plan may provide for banking of allowances for use in future performance periods, including the interim performance periods and all final performance period 2-year blocks.[111]

110 These ten EGUs may not be subject to an enforceable requirement to retire, and would still be subject to the requirement to surrender allowances equal to any actual emissions at the end of the performance period.

5.4 Integrity Assurance Plan Components

As previously noted, EPA has incorporated several required plan elements into the final CPP emission guidelines that are intended to balance the considerable flexibility granted to states and affected EGUs with assurances of plan integrity such that the intended emission reductions derived from the application of BSER will be fully achieved. While all plans require some degree of performance demonstrations, monitoring, recordkeeping and reporting, certain plan types require additional demonstrations and are subject to specific constraints and requirements. The type and extent of integrity assurance components required are dependent on the type of plan and specific plan pathway selected by the state. Accordingly, states will want to carefully consider the full range of requirements applicable to each plan pathway in order to make fully informed planning decisions. The four "streamlined" plan pathways identified above generally require the least degree of integrity assurance, although several plan integrity elements can still be required.

Integrity assurance measures are those required plan components intended to assure that a state plan as designed and implemented will achieve the intended CO_2 reductions, consistent with BSER, while minimizing the likelihood of creating unintended consequences such as market perversions or incentives leading to high or highly fluctuating cost of generating power and/or compromises to grid reliability. The particular integrity assurance measures are specific to the type of plan adopted. Some integrity assurance measures are composed of specific plan provisions for particular types of state plans or trading programs, while others require particular plan demonstrations in the initial plan submittal or provisions for corrective actions in the event the plan does not perform as expected. This section discusses the various integrity assurance measures required for state plans under the final CPP.

5.4.1 Leakage to New Fossil Fuel EGUs

In the context of this section, "leakage" refers to the potential for an alternative form of the BSER standard (specifically, the rate-based and mass-based performance goals in Tables 2 and 3) to create an incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs to a greater extent than would otherwise occur if BSER were implemented in the form of the subcategory performance rates.[112]

5.4.1.1 Leakage Provisions for Mass-based Plans

In the final CPP, EPA requires that any state adopting a mass-based state plan include requirements that address leakage, or provide adequate justification that leakage would not occur under the plan.

Building Block 2 of BSER projects reductions in CO_2 emissions from affected coal-steam EGUs specifically by shifting generation to affected NGCC EGUs up to a utilization equivalent to 75% of the NGCC units' summer capacity rates. This anticipated generation shift is accounted for in the development of the Table 1 subcategory rate-based performance standards. EPA converted the subcategory rate-based performance standards to alternative statewide rate-based and mass-based emission goals in order to increase the level of flexibility accessible to states and affected EGUs in the design and implementation of state plans. However, if a mass-based plan is elected, an incentive could be created to shift generation to new fossil fuel-fired EGUs that are not subject to a mass-based limit or allowance requirement under the state plan, in lieu of shifting generation to existing NGCC units that must comply with a mass-based emission standard.[113] To minimize or avoid this incentive, the final CPP includes an obligation for state plans with mass-based programs to address potential leakage of emission increases from new sources through one of three options. The final emission guidelines are unclear as to whether the requirement to address leakage will be applied to any mass-based plan, only to mass-based emission standards plans, or only to mass-based trading program plans.[114] Given this ambiguity

111 80 Fed. Reg. at 64,890.

112 80 Fed. Reg. at 64,822-23 (preamble to final CPP, section VII.D).

113 Although new NGCC units must meet the CAA section 111(b) performance standards of 40 C.F.R. Part 60, Subpart TTTT, these are rate-based standards and would not restrict the level of generation in the same way as would a mass-based standard applied under the state plan for Subpart UUUU. Thus, avoiding increased generation from existing NGCC units by shifting generation to new NGCC units effectively relaxes the existing-source mass-based limit (which presumed a high level of utilization) while not increasing the stringency of the new-source rate-based limit. According to EPA's analysis, this would result in foregone emission reductions under the state section 111(d) plan.

114 The rule language at 40 C.F.R. § 60.5790(b)(5) requiring that leakage be addressed applies only to "a plan that sets a mass-based emission trading program." However, the preamble discussion in section VII.D, "Addressing Potential Leakage in Determining the Equivalence of Statewide CO_2 Emission Performance Goals," applies more broadly to "states adopting a mass-based state plan." 80 Fed. Reg. at 64,823. Section VIII.J, "Additional Considerations and Requirements for Mass-Based State Plans," states the "leakage must be addressed in a state plan with mass-based emission standards." However, this statement is included under the subsection titled "Use of Emission Budget Trading Programs." 80 Fed. Reg. at 64,887.

surrounding EPA review and approval, a state adopting any type of mass-based plan would likely want to consider the potential for leakage and include a leakage demonstration with the plan submittal.

Under the first option, the state can elect to regulate new non-affected EGUs through state-only enforceable requirements, under the mass-based program. If new fossil fuel-fired EGUs are subject to mass-based limits or allowance provisions in the same manner as existing EGUs, the incentive for leakage is minimized or avoided. To facilitate this approach, EPA has adopted, in Table 4 of Subpart UUUU, statewide mass-based emission goals that include a new source complement of mass emissions. If adopted by the state, the Table 4 statewide emission goals are a presumptively approvable option to address potential leakage to new sources. Although the Table 4 emission goals have been adopted by EPA under Subpart UUUU, EPA stresses that any requirements applicable to new sources must be incorporated into the state plan as state-only enforceable measures and will not be adopted by EPA as federally enforceable measures. EPA does not have authority to regulate new sources under CAA section 111(d), therefore new source requirements cannot be codified as federally enforceable requirements of the state plan. New-source applicable requirements that would be adopted by the state include the new source complement emissions budget and any corresponding requirements, such as allowance holding requirements, as well as monitoring, recordkeeping and reporting requirements relied upon by a state to address leakage.

The second option avoids the imposition of any requirements directly on new fossil fuel-fired EGUs. Under this approach, the state can include an allocation scheme that avoids or minimizes incentives for leakage to new sources. In the proposed federal plan for CPP implementation, EPA included two allocation schemes that could potentially be used to accomplish this effect. The first scheme involves the state establishing a set-aside of a certain portion of allowances to target RE deployment. This would have the effect of incentivizing increased generation shift to new RE units, thereby reducing or balancing the incentive for generation shift to new fossil fuel-fired EGUs. Alternatively, the state could directly reward increased utilization of existing NGCC units, consistent with the application of BSER, by allocating a portion of allowances based on the level of generation. This would create an incentive for existing NGCC units to increase output and maintain a high level of utilization (or, at least, this approach would reduce the incentive for existing NGCC units to decrease output in order to reduce mass emissions for compliance with a mass-based limit). The ability for existing NGCC units to receive a greater allowance allocation with increased utilization could offset the incentive to shift to new fossil fuel-fired EGUs that are subject to rate-based standards under Subpart TTTT.[115]

The third alternative is a state-determined customized approach, by which the state could develop its own new source complement budget or an approvable equivalent method for addressing new sources under the state program. The state-designed approach would be included in the plan, with supporting documentation, and reviewed by EPA. This option could include providing a demonstration and justification that leakage to new fossil fuel-fired EGUs is not anticipated under the state plan. If the state adopts the Table 4 statewide emissions budget, plan performance will be evaluated by EPA by comparing existing plus new source emissions to the Table 4 emission goals. If the state develops and adopts its own new source emissions budget, the state plan performance will be evaluated by EPA by comparing existing source emissions to the Table 3 emission goals.[116]

5.4.1.2 Leakage Provisions for Rate-based Plans

EPA's regulatory analysis concluded that the same concern regarding leakage to new fossil fuel-fired EGUs does not occur within a state under a rate-based program as under a mass-based program.[117] Accordingly, a rate-based plan is not required to include specific requirements to address potential emission increases from new sources in the same manner as a mass-based plan. Rather, leakage to new-source EGUs under rate-based trading programs is constrained as an initial design matter. Specifically, an EGU subject to the CAA section 111(b) standards of 40 C.F.R. Part 60, Subpart TTTT is not an allowable source of ERCs under a rate-based plan.[118]

In certain cases where affected EGUs complying with a rate-based plan may interact across state boundaries with affected EGUs under a mass-based plan, however, certain leakage concerns still arise. To address these concerns, EPA

115 80 Fed. Reg. at 64,887-90 (preamble to final CPP, section VIII.J.2.b).

116 80 Fed. Reg. at 64,887-90 (preamble to final CPP, section VIII.J.2.b).

117 80 Fed. Reg. at 64,822-23 (preamble to final CPP, section VII.D).

118 40 C.F.R. § 60.5800(c)(1); 80 Fed. Reg. at 64,903 (preamble to final CPP, Section VIII.K.1.b).

adopted a number of additional constraints on the issuance of ERCs, which are discussed under Interstate Effects.

5.4.2 Interstate Leakage and Market Effects

Another plan integrity concern arising from the broad range of state discretion in plan development is the potential for interstate effects due to differing program characteristics across states operating on the same interconnected power distribution grid. If EGUs and other entities are subject to differing performance standards or trading programs, incentives could also differ across state boundaries for dispatch of new and existing fossil fuel-fired EGUs, deployment of RE and demand-side EE, and employment of reduction measures at existing EGUs. Also, reduction measures implemented by or in one state, such as deployment of new RE generation, can affect the generation at affected EGUs in a neighboring, interconnected state. The owners and operators of affected EGUs will have a market-driven incentive to implement the least-cost available compliance option in every state and across states. In fact, it is important to retain a sufficient level of compliance flexibility across the power sector in order to minimize potential impacts on the cost of electricity and on grid reliability. At the same time, however, advantages and incentives resulting solely from differences among programs from state to state could lead to double-counting of emission reductions or to the failure to achieve emission reductions at a level consistent with the application of BSER. Also, the market value of allowances and ERCs could be perversely affected by the imposition of different performance standards across state boundaries where trading systems would allow the sale of the same credit asset. Such market perversions could ultimately lead to the very effects compliance flexibility aims to avoid—impacts on grid reliability and increases in customer costs.

The final CPP incorporates certain aspects and provides for certain state plan approaches that are designed to eliminate or reduce adverse interstate effects. For example, the BSER subcategory performance rates were developed using a regional approach, and the final statewide emission goals differ to a much lesser degree than the proposed goals, reducing the level of potential disparity in credit values and minimizing incentives for generation-shifting across state lines to achieve lower compliance costs. Also, the final CPP provides for multi-state plans, which would eliminate differences in performance standards, trading systems requirements, and other plan requirements across the multi-state region. In addition, the CPP allows for the implementation of shared interstate trading systems, even in cases where each state retains its own statewide performance standards or emission goals. All of these measures will serve to reduce concerns about interstate effects as state plans are implemented.

Beyond these final CPP elements to avoid or minimize interstate leakage and market perversions, EPA has incorporated additional integrity assurance requirements for state plans. These integrity assurance measures place specific constraints on interstate trading approaches and on trading across state boundaries, as discussed below.

5.4.2.1 Interstate Leakage Provisions for Mass-based Plans

Mass-based plans are required to incorporate specific provisions to address potential leakage to new sources, as described above, and these plan provisions can help to guard against leakage to new source EGUs across state lines as well as within the state. In addition, mass-based plans must include provisions that prohibit double-counting of allowances, by requiring that allowances are non-duplicative and by assuring that each allowance is surrendered and retired upon being relied-upon for compliance purposes.[119]

Beyond these required plan provisions, concerns regarding double-counting of emission reductions or distortion of credit values among affected EGUs are inherently addressed to a large degree by the design of a mass-based program. This is because all trades among mass-based programs are denominated through a uniform allowance measurement (ton), which is the same single and direct measure for determining compliance (monitored and reported emissions, in tons). There is no need to adjust the reported emission rate to reflect strategies such as generation from RE or avoided generation through EE measures, as there is under a rate-based program, because the effect these measures have on mass emissions is directly accounted for at the stack monitor.

As noted above, however, there are interstate-effect concerns that can arise within a state implementing a mass-based plan, to the extent actions that occur within the mass-based state may affect emissions or generate emission reduction credits in a neighboring rate-based state. EPA has addressed these concerns through plan requirements for the rate-based state, which are summarized below.

119 40 C.F.R. §§ 60.5775 & 60.5780.

5.4.2.2 Interstate Leakage Provisions for Rate-based Plans

To demonstrate compliance with the subcategory performance rate standards or the statewide rate-based emission goals under a rate-based program, affected EGUs must be able to account for creditable measures that indirectly reduce CO_2 emissions from affected EGUs. These measures may include generation at eligible RE EGUs, generation-shifting from existing fossil-steam EGUs to existing NGCC units, avoided generation through EE measures, or other measures incorporated in the state plan as eligible for ERC issuance. To assure the integrity of the BSER emission guidelines in relation to potential interstate effects, EPA has imposed several design requirements and geographical restrictions on rate-based plans, particularly with regard to the eligibility of ERC resources.[120] Integrity assurance measures to guard against leakage under rate-based trading programs are enumerated below.

Two fundamental criteria apply to all rate-based trading programs:

1) First, the final CPP provides that all ERCs must be denominated in units of MWh. The MWh general accounting method addresses interstate effects to a large extent by providing a credit currency that is indifferent to the specific rate-based emission goals or standards that may apply across a region.[121]
2) Second, state plans participating in rate-based trading programs must include specific provisions to require that all ERCs issued or relied upon are non-duplicative, and must require all ERC resources to meet all applicable EM&V and trading program requirements.

Additionally, ERC trading across state boundaries can only occur when the participating states are implementing the same performance standards for affected EGUs or are demonstrating compliance with the same combined multi-state rate-based goal. This requirement affects both single-state "trading-ready" plans as well as multi-state plans:

1) Each single-state rate-based plan must adopt the Table 1 subcategory performance rates as the applicable emission standard for affected EGUs in order to be eligible for participation in an interstate rate-based trading program.[122]
2) For states implementing a multi-state plan with a rate-based trading program, the plan must either impose the subcategory performance rate standards of Table 1, or demonstrate compliance with weighted average multi-state rate-based emission goals equivalent to the Table 2 statewide rate-based emission goals.[123]

Furthermore, issuance of ERCs for trade under a rate-based program is restricted for measures taken in states that are implementing a mass-based plan.

1) Generation and trading of ERCs from resources located in mass-based states, beyond the qualified use of RE generation noted below, is generally prohibited. Specifically, an affected EGU subject to a rate-based plan cannot claim ERCs for any emission reduction measures located in a mass-based state other than RE-generation ERCs that meet specific eligibility requirements.[124] For example, demand-side EE measures implemented in a state with a mass-based plan cannot be issued ERCs for use in a state with a rate-based plan, even if the EE measures were funded by a utility in the rate-based state, and regardless of whether the EE measures arguably reduced generation from an EGU in a rate-based state. In addition, affected NGCC located in a mass-based state cannot be issued ERCs reflecting generation shift from steam EGUs, regardless of where the shifted generation is distributed for use and regardless of whether the shift arguably came from an EGU subject to a rate-based plan.
2) Notwithstanding the general prohibition described above, MWh generated by an RE facility located in a mass-based state can be considered eligible for ERCs to be traded under a rate-based program, provided the RE-generated power was intended to meet electricity load in a state with a rate-based plan and was treated as serving the regional load that includes a rate-based state.[125]

To meet the requirement that dispatch of RE units located in a mass-based state are intended to provide generation in a rate-based state, the entity applying for the ERC issuance must provide evidence, which may include a power delivery contract that specifies power will be generated for a rate-based state or a power purchase contract

120 40 C.F.R. §§ 60.5795 & 60.5800; 80 Fed. Reg. at 64,896 (preamble to final CPP, section VIII.K.1.a(2)).

121 80 Fed. Reg. at 64,895 (preamble to final CPP, section VIII.K.1.a(1)).

122 40 C.F.R. § 60.5750(d).

123 40 C.F.R. § 60.5750(a).

124 80 Fed. Reg. at 64,911-14 (preamble to final CPP, section VIII.L).

125 40 C.F.R. § 60.5800(a)(3)(ii); 80 Fed. Reg. at 64,911-14 (preamble to final CPP, section VIII.L).

involving a rate-based state. A state plan that intends to allow the issuance of ERCs to RE resources located in a mass-based state must specify what demonstrations would be acceptable in the state plan.[126]

Taken together, these integrity measures minimize the potential for interstate leakage by avoiding market distortions due to differences in the stringency of rates across the trading area, minimizing the potential for double-counting, and minimizing the likelihood of foregone reductions.

5.4.3 Mass-based Trading Programs with Broad Applicability and Flexibility

Another potential state plan integrity concern relates to the potential loss of emission reductions from affected EGUs under trading programs with broad applicability extending beyond the power sector and/or with broad flexibility provisions that would expand the emissions budget for EGUs. To be approvable, each state plan must demonstrate that the emission standards or state measures comprising the plan collectively will result in affected EGUs achieving the CO_2 emission performance rates or CO_2 emission goals established in Subpart UUUU. The CPP allows a state to rely upon an existing trading program, such as the California AB 32 or RGGI programs, or to design and implement a program that has an expanded applicability beyond Subpart UUUU-affected EGUs, or that includes provisions which could functionally expand the corresponding emissions budget under the program. This type of expanded mass-based trading program can be utilized, provided the plan also addresses all affected EGUs and assures compliance with the CPP emission goals for the affected EGUs.

5.4.3.1 Provisions that Expand Applicability

If the mass-based trading program establishes requirements for sources that are not affected EGUs under Subpart UUUU, those requirements cannot be made federally enforceable requirements of the state plan. EPA does not have the legal authority to regulate any sources other than existing EGUs under a state plan for implementing Subpart UUUU; therefore, requirements for other types of sources cannot be adopted as federally enforceable measures. A trading program with broad source applicability, such as the California AB 32 or RGGI program, can be submitted and implemented as part of a state measures plan, wherein the full trading program is described and provided as supporting documentation in the state's submittal but is not made federally enforceable. In this way, the state can satisfy the requirement to regulate affected EGUs under the state plan for implementing Subpart UUUU, while still implementing a mass-based trading program with broader applicability. However, the flexibility of being able to rely upon a trading program that applies to a broader set of affected sources must be balanced by certain integrity measures.

5.4.3.2 Provisions that Functionally Expand the Emissions Budget

Mass-based trading programs may include a number of design elements intended to provide compliance flexibility to guard against potential negative impacts to grid reliability or to incentivize and accommodate cost-effective CO_2 emission reductions from a wide range of sources. Such provisions may include automatic increases in the overall emissions budget (i.e., a release of reserve allowances) in the event of allowance prices reaching a threshold cost due to demand outpacing availability. Another example of a budget-expanding provision is the recognition of offset allowances generated from sources outside the program scope. Provisions that would result in an actual or effective increase in the allowable emissions budget for affected EGUs could be part of a mass-based trading program relied upon to meet the state CPP emission goals. However, as with trading programs that encompass a broader universe of affected sources, such plans must be submitted as state measures plans and would not be considered streamlined plans under the CPP.

5.4.3.3 Required Integrity Measures for Expanded Trading Programs

A plan incorporating a mass-based trading program with broader source coverage and other flexibility that does not mathematically assure achievement by affected EGUs (or affected EGUs plus new fossil fuel-fired EGUs) with the state emission goal (or mass-based emission goal plus new source complement) must be submitted as a state measures plan.[127] Several integrity measures are required for a plan design involving a mass-based trading program with broad source applicability and/or budget-expanding provisions to be approvable under Subpart UUUU. Those integrity assurance measures include:

- Inclusion of any emission standards applicable to affected EGUs as federally enforceable measures under the state plan;

126 80 Fed. Reg. at 64,911-14 (preamble to final CPP, section VIII.L).

127 80 Fed. Reg. at 64,891.

- A detailed demonstration of how the plan will achieve compliance by affected EGUs with the state interim and final performance goals of Table 3 or Table 4 of Subpart UUUU;
- An accounting of net allowance imports and exports among affected EGUs across state boundaries, with state administrative adjustments to affected EGU-reported CO_2 mass emissions to reflect the net transfer of allowances; and
- A federally enforceable backstop that includes federally enforceable emission standards for affected EGUs, to be implemented in the event the plan fails to meet performance goals.

First, any emission standards under the state-enforceable trading program that apply specifically to affected EGUs under Subpart UUUU must be codified through a federally enforceable mechanism, such as regulatory provisions adopted by the state for that purpose or CAA Title V operating permit conditions, and must be included as federally enforceable elements of the state plan.[128] The federally enforceable affected-EGU requirements must include both the emission standards (i.e., the requirement to hold allowances equal to actual emissions) and all associated monitoring, recordkeeping, reporting and "true-up" requirements.[129]

Second, because the trading program would not mathematically assure compliance with either the statewide mass emission goals of Table 3 or the mass emission goals plus new source complements of Table 4, the plan submittal must provide a detailed demonstration of how the program is projected to achieve the required CO_2 reductions from affected EGUs for each performance period.[130] For any mass-based plan to be approvable, the state submittal must demonstrate that affected EGUs will meet either the statewide mass emission goals of Table 3, or the mass emission goal plus new source complement of Table 4. Further discussion of the plan demonstration requirements is provided in Section 5.4.4 below.

Third, a mass-based plan with applicability to sources beyond affected EGUs (or beyond affected EGUs plus new EGUs if the plan uses Table 4 performance goals), if linked to other mass-based trading programs, must employ provisions to adjust affected-EGU mass emission rates to account for imports and exports of allowances across state boundaries.[131] Such mass-based plans must achieve, in practice, the statewide mass emission goals of Table 3 (or Table 4), as well as the associated interim step goals (±10%). To assure that the linked states are achieving these mass emission goals, EPA will review the linkages during the plan approval process. Once approved, reported CO_2 emissions from affected EGUs must be administratively adjusted by the state to account for net imports and exports of allowances among the linked states. For the state implementing the program with broad applicability, plan performance will be determined based on a comparison of the state's mass emission goal to the reported EGU emissions after adjustments for net imports or exports.[132] This integrity assurance mechanism is discussed in detail in Section 6.3.1.2.

Fourth, a plan based on a trading program applicable to a broad set of affected sources must include federally enforceable backstop measures, since the plan is a state measures plan.[133] Further discussion of federally enforceable backstop integrity provisions is provided in Section 5.4.6.

5.4.4 Projected Compliance Demonstration Requirements

Every state plan must include a demonstration that the affected EGUs are projected to achieve the CO_2 subcategory emission performance rates of Table 1, the statewide emission performance rate goals of Table 2, or the statewide mass emission performance goals of Table 3 or Table 4, as incorporated in the state plan.[134] For any plan with a streamlined design that mathematically assures compliance with the performance rate standards or goals, no further demonstration of projected compliance is required. Otherwise, a detailed demonstration of projected compliance is required. The information and analyses required to demonstrate a projection of compliance differ based on the type of plan.

For rate-based plans that neither impose the Table 1 subcategory-specific emission performance standards as an applicable emission standard for each affected EGU, nor impose the Table 2 statewide average performance goal (or weighted average multi-state performance goal for a multi-state plan), a detailed demonstration is required.

128 80 Fed. Reg. at 64,835-37 (preamble to final CPP, section VIII.C.3).

129 80 Fed. Reg. at 64,891-92 (preamble to final CPP, section VIII.J.2.d).

130 40 C.F.R. §§ 60.5745(a)(3) & 60.5745(a)(5)(iv)-(v); 80 Fed. Reg. at 64,835-37 (preamble to final CPP, section VIII.C.3).

131 40 C.F.R. § 60.5740; 80 Fed. Reg. at 64,893-94 (preamble to final CPP, section VIII.J.3.a(2)).

132 80 Fed. Reg. at 64,893.

133 40 C.F.R. §§ 5740(a)(3) & 5745(a)(6).

134 40 C.F.R. § 5740(a)(3).

Table 5.4 **Required Plan Demonstration Elements for Rate-based Plans that Do Not Apply the Table 1 or Table 2 Performance Rates to Affected EGUs**
40 C.F.R. § 60.5745(a)(5)(ii)

No.	Plan Demonstration Component	Description
(5)(ii)	**Projection of compliance for interim and final performance periods, including each of the following:**	Demonstrate that the adjusted weighted average CO_2 emission rate of affected EGUs, when weighted by projected generation, will be equal to or less than the Table 1 or Table 2 performance rates.
A	**An analysis of the projected change in generation of affected EGUs**	Project how generation will shift based on compliance costs and incentives under applicable emission rates.
B	**A projection of generation shifts**	Project generation shifts between affected EGUs and across affected and non-affected EGUs over time.
C	**Analysis of availability of ERCs**	Document assumptions regarding availability and use of MWhs generated or avoided by ERC-eligible resources.
D	**Projections of calculations adjusting affected EGU reported CO_2 emissions**	Document specific calculations or assumptions of how affected EGUs will adjust reported CO_2 emission rates using ERCs to demonstrate compliance with applicable emission-rate standards.
E	**Documentation for eligible RE in mass-based states**	Document consideration in the plan projection that RE generation in mass-based states eligible for ERCs, if any, will meet the geographic eligibility criteria.
F	**Any other assumptions relied upon in the compliance projection**	Such assumptions may include anticipated EGU retirements, impacts on load demand due to measures not eligible for ERCs, etc.
(5)(v)	**Include all items listed in § 60.5745(a)(5)(v)**	Both rate- and mass-based plans subject to the requirement for a detailed performance demonstration must include items A through L of 40 C.F.R. § 60.5745(a)(5)(v).

Specifically, a projection is required to demonstrate that the variable performance rates imposed on affected EGUs as the applicable emission standards will achieve the Table 1 or Table 2 performance rates when future projected generation for the individual EGUs is considered. Table 5.4 lists the plan demonstration elements that are required specifically for rate-based plans. In addition, both rate-based and mass-based plans required to submit detailed compliance projections must include the elements in Table 5.6.

For mass-based plans that do not mathematically demonstrate that the Table 3 or Table 4 statewide mass emission performance goals will be achieved, the plan demonstration must show that the state plan design would achieve the applicable goals for each performance period, assuming compliance by the affected EGUs (or affected EGUs plus new sources). For such plans, the demonstration must include emission budgets for affected EGUs during the interim and final performance periods that are equal to or lower than the applicable Table 3 emission goals (see Table 5.5).

Table 5.5 **Required Plan Demonstration Elements for Mass-based Plans with Standards for Affected EGUs that Cumulatively Exceed the Table 3 or Table 4 Performance Goal**
40 C.F.R. § 60.5745(a)(5)(iv)

No.	Plan Demonstration Component	Description
(5)(v)	**Include all items listed in § 60.5745(a)(5)(v)**	Both rate- and mass-based plans subject to the requirement for a detailed performance demonstration must include items A through L of § 60.5745(a)(5)(v).

Table 5.6 **Required Plan Demonstration Elements Applicable for Both Rate-based Plans and Mass-based Plans that Do Not Meet Streamlined Plan Design Criteria**
40 C.F.R. § 60.5745(a)(5)(v)

No.	Plan Demonstration Component	Description
A	**A summary of each affected EGU's projected future operation**	Must include annual generation, CO_2 emissions, fuel use, fuel prices, fuel carbon content, fixed and variable operations and maintenance costs, heat rates, and electric generation capacity and capacity factors
B	**Identification of any anticipated new generating capacity**	Include RE, new NGCC and any other.
C	**Analysis of the potential for building unplanned new generating capacity**	In addition to planned, anticipated generation capacity increases, what is the potential for new capacity?
D	**A timeline for implementation of EGU actions, if applicable**	This may include heat rate improvements, fuel switching, retirement, implementation of controls or shifts in utilization, etc.
E	**Wholesale electricity prices**	A projection of anticipated prices
F	**A geographic representation capturing impacts to or changes in the electric system**	
G	**Time period of the demonstration analysis**	The projections must extend at least through 2030.
H	**Anticipated load forecast at the state or regional level**	Include the source and basis, justification and documentation of underlying assumptions.
I	**Demonstration that each emission standard is quantifiable, verifiable, non-duplicative, permanent and enforceable**	See criteria at 40 C.F.R. § 60.5775.
J	**Projected prices for ERCs or allowances**	
K	**Identification of planning reserve margins**	
L	**Any other applicable assumptions used in the projection**	

In addition, both rate-based and mass-based plans required to submit detailed compliance projections must include the elements in Table 5.6.

In addition to those plan demonstration requirements listed in Tables 5.5 and 5.6, which apply to all mass-based plans, a state measures plan (which must be a mass-based plan) is subject to additional plan demonstrations as delineated at 40 C.F.R. § 60.5745(a)(6). Those additional plan demonstration elements are summarized in Table 5.7, below.

5.4.5 Corrective Measures and Corrective Measure Triggers

As previously discussed, one type of integrity measure included under the final CPP applies to any state plan that is an emission standards plan and that does not meet the streamlined plan criteria. Specifically, any state or multi-state emission standards plan that is not designed to mathematically assure compliance with emission rate performance standards or statewide goals set forth in Tables 1, 2, 3 or 4 of Subpart UUUU, as selected and adopted by the state, must include triggers for corrective actions to be executed in the event a required performance metric is not achieved. However, state measures plans must include

Table 5.7 **Additional Required Plan Demonstration Elements for State Measures Plans**
40 C.F.R. § 60.5745(a)(6)

No.	Plan Demonstration Component	Description
1	**A description of all state measures relied upon to achieve the mass-based emission performance goals**	Include projected impacts of each measure over time, applicable state laws and regulations, and identification of implementing entities.
2	**A schedule of milestones for implementation of state measures**	Include demonstration of how EM&V requirements will be met.
3	**Projection that state measures in combination with any EGU emission standards will meet the performance goals**	Project performance for all performance periods, including interim steps, interim and final performance periods.
4	**A CO_2 performance projection for affected EGUs**	Document baseline demand and supply forecasts, impacts on demand and supply from the plan, and documentation/ explanation of how projections were made.
5	**Demonstrate that each state measure meets the requirements of §§ 60.5775 and 60.5780**	State-enforceable emission standards for sources that are not affected EGUs must be quantifiable, verifiable, non-duplicative, permanent and enforceable per § 60.5775. Section 60.5780 delineates the types of state measures that may be relied upon in a state measures plan.

a federally enforceable backstop provision in lieu of the corrective measures triggers. As described in Section 5.3, and set forth at 40 C.F.R. § 60.5740(2)(i), state plans that do not require triggers for corrective measures are those that impose emission standards on all affected EGUs that mathematically assure compliance with:

- the subcategory performance rates of Table 1; or
- the statewide rate-based performance goals of Table 2; or
- the statewide mass-based performance goals of Table 3; or
- the statewide mass-based performance goals of Table 4, in conjunction with state-enforceable emission standards for new sources.

5.4.5.1 Plan Designs that Require Corrective Measure Triggers

Examples of state plan designs that do not meet the streamlined design criteria listed above and that do require triggers for corrective measures include any plan that imposes "case-by-case" performance rates or emission standards for individual affected EGUs, based on such factors as heat rate and projected heat rate improvement plans, nameplate capacity, intended mode of operation, or fuel type/subtype designed in a fashion that would not mathematically average or sum to the respective emission goals. Such a plan does not impose emission standards on all affected EGUs that would demonstrate compliance with the performance standards or statewide goals of Subpart UUUU through a simple mathematical demonstration. Rather, these plan designs rely at least in part upon other factors or actions in addition to affected-EGU compliance and/or the accuracy of other predictions and assumptions, such as projected utilization rates of affected EGUs, in order to achieve compliance.

The final CPP, while affording states the flexibility to design their plan in a way that does not directly impose the emission standards established as BSER, balances that flexibility with additional integrity assurance requirements, in the form of corrective measure triggers, for plans that cannot make a straightforward mathematical demonstration of compliance.

5.4.5.2 Corrective Measure Triggers

Notably, the state is not required to identify and adopt the corrective measures as part of the initial state plan. Rather, for state plans that are subject to the corrective measures integrity assurance requirements, the state plan need only include specific triggers that would require adequate corrective measures to be adopted and implemented according to the specified timelines. The plan must include a corrective action trigger for each of the events listed in Table 5.8, based on plan type.

Table 5.8 **Required Triggers for Corrective Measures, by Plan Type**
40 C.F.R. § 60.5745(a)(5)(v)

No.	Corrective Action Triggers	Description
	RATE-BASED PLAN REQUIRED TRIGGERS	
1	**Interim Step 1 Performance Goal (2022–2024), ≥10% exceedance**	For rate-based plans, the average EGU performance rate achieved by affected EGUs is compared to each interim step goal.
2	**Interim Step 2 Performance Goal (2025–2027), ≥10% exceedance**	For rate-based plans, the average EGU performance rate achieved by affected EGUs is compared to each interim step goal.
3	**Interim Period Performance Goal (2022–2029), any level of exceedance**	There is no separate Interim Step 3 trigger required. Any level exceedance of the eight-year average Interim Performance Goal triggers corrective measures.
4	**Final Period Performance Goal (2030–2031; 2032–2033; etc.), any level of exceedance for any performance period**	Corrective measures are triggered for any level of exceedance for any two-year block performance period.
	MASS-BASED PLAN REQUIRED TRIGGERS	
No.	Corrective Action Triggers	Description
1	**Interim Step 1 Performance Goal (2022–2024), ≥10% exceedance**	For mass-based plans, the cumulative sum of mass emissions from all affected EGUs, or all affected EGUs plus new fossil fuel-fired EGUs if applicable, is compared to each interim step goal.
2	**Interim Step 2 Performance Goal (2025–2027), ≥10% exceedance**	For mass-based plans, the cumulative sum of mass emissions from all affected EGUs, or all affected EGUs plus new fossil fuel-fired EGUs if applicable, is compared to each interim step goal.
3	**Interim Period Performance Goal (2022–2029), any level of exceedance**	There is no separate Interim Step 3 trigger required. Any-level exceedance of the eight-year cumulative Interim Performance Goal triggers corrective measures.
4	**Final Period Performance Goal (2030–2031; 2032–2033; etc.), any level of exceedance for any performance period**	Corrective measures are triggered for any level of exceedance for any two-year block performance period.

5.4.5.3 Corrective Measures Minimum Requirements and Timelines

Corrective measures adopted and implemented by the state in response to a corrective measures trigger must be sufficient to ensure achievement with future CO_2 performance goals or performance standards, and must also be designed to achieve sufficient reductions to offset any emissions reduction shortfalls that led to the corrective measures being triggered.

If any corrective measures-triggering event occurs, then the state must notify EPA in the next state report, on or before July 1 of the year following the end of the performance period.[135] If the needed corrective measures are not already incorporated in the approved state plan, the state must revise the plan to include the required corrective measures. Table 5.9 outlines the timeline that applies for the plan revision and implementation of corrective measures.[136] Assuming EPA approves the plan revision as submitted within twelve months of submittal, implementation of the corrective measures may occur up to five-and-a-half years after the end of the performance period for which the performance goal was not met.

5.4.6 Federally Enforceable Backstops for State Measures Plans

The federally enforceable backstop provision is an integrity assurance measure that is similar in nature to the corrective measures provisions, but applies specifically to a state measures plan. In the case of a state measures plan, the federally enforceable backstop is a corrective action that must be incorporated in the state plan at the time of plan

135 40 C.F.R. §§ 60.5870(b) & (d).

136 40 C.F.R. § 60.5785(c).

Table 5.9 **Schedule for Adoption and Implementation of Corrective Measures After a Triggering Event**
(40 C.F.R. § 60.5785)

Expected Milestone Deadline	Milestone
July 1, Year 1 *(calendar year following performance period that triggered corrective measures)*	State notifies EPA of triggering event in the next annual state report
July 1, Year 3	State submits revised plan to EPA, within 24 months of the annual report
July 1, Year 4	EPA acts on plan review and approval, within 12 months after submittal of plan
January 1, Year 6	State implements corrective measures, within 6 months of EPA approval

submittal. Under a state measures plan, the state cannot wait until a triggering event occurs to design and adopt the backstop measures.[137] State measures plans are required to include the federally enforceable backstop provisions (40 C.F.R. § 60.5740(a)(3)) in lieu of the corrective measures triggers.

A state measures plan is a plan that relies upon state-enforceable provisions, in addition to or in lieu of emission standards applicable to affected EGUs, to achieve the mass-based emission performance goals of Subpart UUUU Table 3 or Table 4. State measures plans may include, but are not limited to, the following:

- a plan that relies on work practice standards, operational limits, renewable or fossil-fuel portfolio standards or other "non-emission standards," rather than imposing emission standards on all affected EGUs, to meet the performance goals of Subpart UUUU; or
- a plan that relies on a combination of emission standards applicable to affected EGUs, such as unadjusted performance rate standards, in addition to other measures administered by the state or other entities, such as demand-side EE or RE programs, to collectively achieve the performance goals of Tables 2 or 3 of Subpart UUUU.

In addition, a plan that involves a mass-based trading program with broad applicability (beyond affected EGUs and new sources subject to Subpart TTTT) and/or broad flexibility provisions that could expand the budget beyond the state emission goal is a state measures plan. Any such plan must include a federally enforceable backstop as an integrity assurance component. The backstop serves dual purposes. First, the backstop serves to meet the state's requirement to adopt emission standards to implement the Subpart UUUU emission guidelines, as required by CAA Section 111(d) and implementing regulations. Also, the backstop serves to assure the Subpart UUUU performance standards and goals will be achieved in the event the state measures do not perform as intended.

The federally enforceable backstop must include emission standards applicable to all affected EGUs subject to the state plan. The emission standards submitted with the plan must be designed to achieve compliance with either the Table 1 subcategory performance rate standards, or the rate-based or mass-based performance goals of Tables 2, 3 or 4 during the interim and final performance periods. In addition, any shortfall in emission reductions that would have occurred during the interim and/or final performance periods must be made up by the backstop measures. Accordingly, the state may either submit a plan revision to address the reduction shortfalls after the backstop is triggered (i.e., when the reason for the shortfall and the extent of the shortfall have been identified), or the state may include in the final plan as submitted provisions requiring automatic adjustments to the federally enforceable emission standards sufficient to make up for any emissions reduction shortfall, such that no additional rulemaking and plan revision is required.[138]

5.4.6.1 Federally Enforceable Backstop Triggers

The federally enforceable backstop provisions of a state measures plan are triggered by the same events as corrective measures under a mass-based emission standards plan. That is, a failure to meet the Interim Step 1 or Interim Step 2 performance goals by ≥10%, a failure to meet the cumulative interim performance goal for the performance period 2022–2029, or a failure to meet the final performance goal for any two-year performance period would trigger the backstop measures. In addition to these triggers, the federally enforceable backstop is triggered if the state measures plan fails to meet any programmatic milestone for state measures relied upon under the plan. For example, if the

137 80 Fed. Reg. at 64,835-36, 64,844, and 64,864-69 (preamble to final CPP, sections VIII.C.3, VIII.D.2, and VIII.F).

138 40 C.F.R. § 60.5740(a)(3).

Table 5.10 **Required Triggers for Federally Enforceable Backstop Provisions Under a State Measures Plan**
40 C.F.R. § 60.5740(a)(3)

No.	Corrective Action Triggers	Description
1	**Any failure to meet a Programmatic Milestone**	The state measures plan must define programmatic milestones designed to achieve the mass-based performance goals for each performance period.
2	**Interim Step 1 Performance Goal (2022–2024), ≥10% exceedance**	The cumulative sum of mass emissions from all affected EGUs is compared to each interim step goal. Adjustments for net exports/imports must be made if the plan includes a trading program that covers non-EGU sources.
3	**Interim Step 2 Performance Goal (2025–2027), ≥10% exceedance**	The cumulative sum of mass emissions from all affected EGUs is compared to each interim step goal. Adjustments for net exports/imports must be made if the plan includes a trading program that covers non-EGU sources.
4	**Interim Period Performance Goal (2022–2029), any level of exceedance**	There is no separate Interim Step 3 trigger required. Any level exceedance of the eight-year cumulative Interim Performance Goal triggers corrective measures. Adjustments for net exports/imports must be made if applicable.
5	**Final Period Performance Goal (2030–2031; 2032–2033; etc.), any level of exceedance for any performance period**	The backstop is triggered for any level of exceedance for any two-year block performance period. Adjustments for net exports/imports must be made if applicable.

state is relying upon a particular level of demand-side EE deployment under a state program by a particular milestone date in order to reach the interim performance goal, and that milestone is not met, then the federally enforceable backstop measures would be triggered. Also, the federally enforceable backstop is already adopted and incorporated into the plan, therefore the triggering event triggers actual implementation of the enforceable provisions and associated compliance obligations, as opposed to triggering the beginning of a rulemaking and approval period.

Table 5.10 summarizes the triggering events for implementing the federally enforceable backstop emission standards under a state measures plan.

5.5 Universal Plan Components

As discussed in Section 5.4, integrity assurance plan components, which are intended to assure the functionality of the plan for purposes of achieving the CO_2 emission reductions corresponding to the BSER level of control, vary based on the plan type and the specific plan design. Many other required plan components are universal—that is, they must be included as part of the final state plan submittal regardless of the type of plan the state adopts. Universally required plan components are discussed in this section.

5.5.1 Initial Plan Submittal and Progress Report Components

Under the final CPP as adopted, every state is required to make at least an initial submittal by September 6, 2016.[139] If not requesting an extension for final plan submittal, then the final plan submittal with all required plan components is due by September 6, 2016. If the state is seeking a two-year extension for a final plan submittal, only limited information is required. None of the plan components required for final plan submittal is explicitly required in an initial plan submittal if the state is requesting an extension, with the exception of a demonstration of opportunity for public participation and engagement with stakeholders on plan development.

Initial plan submittals for those states seeking a two-year extension must be submitted by September 6, 2016 and must include three components:[140]

139 The September 6 deadline will shift due to the stay on the rule's implementation pending judicial review, and all other CPP dates and deadlines are potentially subject to change. For additional discussion of the judicial stay, see the Preface to this document.

140 40 C.F.R. § 60.5765(a). See Section III of this document for a Model Initial State Plan Submittal.

1) An identification of final plan approach(es) under consideration and a description of the progress made to date on the final plan components;
2) An appropriate explanation of why the state requires additional time to submit a final plan; and
3) A demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during preparation of the initial plan submittal, and plans for engagement during the development of the final plan.

Each state granted an extension for final plan submittal must also submit a progress report, due by September 6, 2017. The progress report must include three components:

1) A status summary for each component of the final plan, including an update from the initial submittal and a list of final plan components that are not complete;
2) A commitment to a plan approach (such as single- vs. multi-state and rate-based or mass-based emission performance level, rate-based or mass-based emission standards), including draft or proposed legislation and/or regulations; and
3) An updated comprehensive schedule and milestones for completing the final plan, including updates to community engagement undertaken and planned.

5.5.2 Affected EGU Inventory

Each state plan submittal must include an inventory of CO_2 emissions for the most recent calendar year for which data are available for each of the affected EGUs covered by the plan.[141] If the plan is a multi-state plan, the plan should identify all affected EGUs covered by the plan for each state. Assuming the state is making a final plan submittal in September 2018, the required inventory will likely be for 2016 or 2017 emissions.

Nationally available sources of reported CO_2 emissions from affected EGUs include EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* developed to comply with the United Nations Framework Convention on Climate Change (UNFCCC).[142] Also, the U.S. EPA Greenhouse Gas Reporting Program Dataset, which includes data reported under the 40 C.F.R. Part 98 Mandatory GHG Reporting Program, is publicly available online.[143] In addition, EPA maintains the Emissions and Generation Resource Integrated Database (eGRID), which houses air emissions data, net generation, resource mix and other data for the U.S. power sector.[144] These sources typically are approximately one-to-two calendar years behind the current year in making data available. For example, the 2014 *Inventory of U.S. Greenhouse Gas Emissions and Sinks* was released in February 2016. Similarly, the U.S. EPA Greenhouse Gas Reporting Program summary data for 2014 data became available in August 2015. The eGRID database has been released less frequently than annually, with the most recent release (Tenth edition) occurring in October 2015 and including data for calendar year 2012.

Though not required as a plan component or element of the EGU inventory, states will likely want to maintain and track CO_2 emissions inventories and trends for affected EGUs for each year commencing at least with the 2012 baseline year that EPA relied upon to establish BSER. In that case, the state may choose to include, as supporting documentation with the plan submittal, affected EGU emissions data for 2012 forward to the most current year available. The state may also choose to include other relevant data that are not explicitly required under the rule to the extent they are relevant and available, such as type of unit, fuel type, capacity, net generation, heat rate, or planned retirement date. For an illustrative example of an affected EGU inventory, see *Section III, Comprehensive Model Plan Submittals.*

5.5.3 Emission Standards

Each state plan will include emission standards for affected EGUs. For plans that are emission standards plans, the emission standards are the primary mechanism for implementing and enforcing the emission guidelines and collectively serve to demonstrate that the state's affected EGUs will achieve either the subcategory performance rates or statewide performance goal. For state measures plans, emission standards for affected EGUs may comprise a portion of the collective reductions, together with non-federally enforceable state measures, to achieve compliance. Under a state measures plan, any emission standards applicable to affected EGUs must be made federally enforceable. For state measures plans designed to rely solely upon reduction strategies that are not emission

141 40 C.F.R. § 60.5740(a)(1).

142 EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014,* Report No. EPA 430-R-16-002, February 22, 2016, available at http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.

143 EPA, Greenhouse Gas Reporting Program Data Sets, available at https://www.epa.gov/ghgreporting/ghg-reporting-program-data-sets.

144 EPA, Emissions & Generation Resource Integrated Database (eGRID), available at https://www.epa.gov/energy/egrid.

standards for affected EGUs to achieve compliance, the state plan nonetheless must include a federally enforceable backstop composed of emission standards for affected EGUs.

5.5.3.1 Definition of Emission Standards Under Subpart UUUU

In the final rule, EPA has clarified that only certain types of requirements that limit emissions are considered "emission standards" for purposes of implementing the Subpart UUUU emission guidelines. The term "emission standard" is defined under Subpart A of 40 C.F.R. Part 60 as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions."[145] In adopting the final Subpart UUUU regulation, EPA clarifies that the adoption of an allowance system providing for trading among affected EGUs, and requiring each affected EGU to hold allowances equal to actual emissions, does constitute the adoption of emission standards for purposes of Subpart UUUU.[146] Similarly, rate-based emission limits that allow for a demonstration of compliance through the use of ERCs are emission standards. Mass emission limits (e.g., a limit on the allowable tons per year of CO_2) and performance rate limits (e.g., a limit on the allowable tons of CO_2 per MWh of energy produced, or per MMBtu of heat input) also constitute emission standards under the definition. Furthermore, any requirement for affected EGUs that constitutes an emission standard and that is relied upon to achieve the Subpart UUUU performance standards or goals must be included in the state plan as a federally enforceable component.[147]

EPA further clarifies that certain other requirements that limit emissions do not meet the definition of emission standards. For example, operational limits that limit operating hours, heat input, or energy output are not emission standards, even though these requirements would have the effect of limiting CO_2 emissions.[148] Additional examples of requirements and standards that may be applied to affected EGUs or their owner/operators to limit emissions but are not emission standards include renewable or fossil-fuel portfolio standards, heat rate performance standards, and enforceable EGU retirement deadlines. Any of these types of standards may be relied upon by a state to achieve the Subpart UUUU emission guidelines for affected EGUs, but these strategies would constitute state measures and would not be adopted by EPA as federally enforceable state plan components.

If the state is relying solely on measures that do not constitute emission standards, then the state has two options to meet the requirement for the adoption and implementation of emission standards. The first option is to adopt emission standards for affected EGUs that result from and are derived from the non-emission standard requirements (e.g., to adopt a mass emission limit that reflects potential emissions under restricted operating hours) and to include these emission standards in the state plan. This option could severely restrict the compliance flexibility inherent under the state measure, so may be an undesirable approach. The second option is to submit a state measures plan with emission standards included only as a backstop, in which case the emission standards become effective only in the event the state measures fail to meet interim or final performance goals.

5.5.3.2 Quantifiable, Non-duplicative, Permanent, Verifiable and Enforceable

As explained above, each state plan must include emission standards, either as a primary plan component or as a state measures backstop. The state plan must include a demonstration that each emission standard is quantifiable, verifiable, non-duplicative, permanent, and enforceable.[149] This demonstration will generally be a straightforward documentation of, or reference to, other plan components. A description of each of these terms is included in the final rule at 40 C.F.R. § 60.5775.

An emission standard is *quantifiable* if it can be reliably measured in a manner that can be replicated. An emission standard is *verifiable* if adequate monitoring, recordkeeping and reporting requirements are in place to allow the regulatory authority to independently evaluate and determine compliance. These two characteristics are closely related and will generally be met through the minimum required monitoring, recordkeeping and reporting provisions for affected EGUs included in the final rule.

An emission standard is *non-duplicative* if it is not incorporated as an emission standard in another state plan, unless the state plan is a multi-state plan. This characteristic is intended to assure that the same CO_2 reductions

145 40 C.F.R. § 60.21(f).

146 80 Fed. Reg. at 64,832-33 (preamble to final CPP, section VIII.C.1).

147 80 Fed. Reg. at 64,836 (preamble to final CPP, section VIII.C.3.a).

148 80 Fed. Reg. at 64,834-35 (preamble to final CPP, section VIII.C.2.a.(1) & a.(3)).

149 40 C.F.R. § 60.5745.

are not "double-counted" under multiple state plans. Such a concern would generally only arise under a trading program, and the final rule includes many integrity assurance measures to guard against double-counting. In addition, state plans that incorporate ERC trading must include an explicit prohibition against double-counting of ERCs and must include adequate evaluation, measurement and verification (EM&V) systems. Also, both allowance and ERC trading programs must include robust accounting platforms to register and track individual trading units. These mechanisms all serve to demonstrate that the emission standards are non-duplicative.

An emission standard is *permanent* provided the standard must be met for the relevant compliance period, unless it is replaced or rescinded through an approved plan revision. This characteristic is readily demonstrated through the mechanism used to impose the emission standard (such as the state regulation or statute), including the relevant averaging period and/or compliance deadline.

Finally, an emission standard is *enforceable* if:

- the standard itself is clearly specified in a technically accurate form, with regard to the numeric limit, the units of measure and the associated averaging period or applicable time period;
- the compliance requirements are clearly defined;
- the parties responsible for compliance are clearly specified;
- the standard and compliance requirements are enforceable as a practical matter; and
- the state, EPA and third parties have the ability to enforce the standard and secure appropriate corrective measures.

The first four elements of the enforceability criteria will generally be demonstrated using the same basis as the demonstrations for the quantifiable, verifiable and permanent criteria. The final element, regarding the ability to enforce and secure corrective measures by EPA, the state and third parties, will generally be demonstrated through the state regulatory and statutory authority and as a matter of federal law, under sections 113 and/or 304 of the Clean Air Act.

5.5.4 State Plan Description, Milestones and Demonstration

Each final state plan submittal must include a description of the plan, including the plan type and pathways and an identification of which performance standards or statewide goals the plan is designed to achieve. In addition, each plan must include a schedule of the interim step performance goals and milestones for implementation. The milestone schedule must address the time period from plan submittal to January 1, 2022, as well as each interim step period, the full interim performance period, and the final performance period(s).

Each state plan must include no more than three interim step performance periods and corresponding interim performance standards or performance goals that demonstrate progress toward the final compliance goals. The final rule defines three interim steps, Interim Step 1 (January 2, 2022 to December 31, 2024); Interim Step 2 (January 1, 2025 to December 31, 2027); and Interim Step 3 (January 1, 2028 to December 31, 2029).[150] In addition, EPA has established both rate-based and mass-based interim step performance goals for each state, which are not included in Subpart UUUU but instead are presented only in the preamble to the final rule.[151] States are provided the flexibility to adjust the interim steps and corresponding interim step performance goals, provided that the plan will still meet the interim performance rate or state emission goal for the 2022–2029 performance period on an eight-year average (rate-based) or cumulative (mass-based) basis, and the applicable final performance rate or emission goal is still achieved.[152]

Also, each state plan must include a projection demonstrating that affected EGUs will achieve each interim and final performance standard or requirement through compliance with the plan. While each plan must include such a demonstration, the level of detail and specific content of the demonstration requirements vary based on plan type. For further discussion of plan demonstration requirements, see Section 5.4.

5.5.5 State Reporting to EPA

One of the items that must be included as a federally enforceable component of each state plan is a description of the process, contents and schedule for state reporting to EPA regarding plan implementation and progress. Under the schedule adopted in the final CPP, an initial report must be submitted by July 1, 2021, that demonstrates the state has met or is on track to meet the applicable interim step performance goals.[153] Interim period reporting starts

150 40 C.F.R. § 60.5880.

151 80 Fed. Reg. at 64,824-25 (preamble to final CPP, section VII, Table 12 and Table 13). All dates are subject to change due to the judicial stay on CPP implementation. For further discussion of the stay, see the Preamble to this document.

152 40 C.F.R. § 60.5855; 80 Fed. Reg. at 64,828.

153 40 C.F.R. § 60.5740(a)(5).

with a report covering Interim Step 1, due no later than July 1, 2025. Subsequent reports from the state to EPA are due no later than July 1 of the year following the end of each performance period, including each interim step period and each two-year performance period subject to the final performance rates or goals, commencing with the 2030–2031 performance period. States implementing a state measures plan must submit annual reports during the interim period, in addition to the reports due at the end of each interim step period. The state report for each compliance period must include the information listed in Table 5.11.

Table 5.11 **Required Content for State Reporting to EPA**
40 C.F.R. § 60.5870

No.	State Reporting Requirement
1	Report the emission performance achieved by all affected EGUs, an identification of whether each affected EGU is in compliance with applicable emission standards, and whether the statewide collective EGUs are on schedule to meet the applicable performance rates or emission goals.
2	For interim step periods 1 and 2, provide a comparison of the applicable interim emission performance rate or goal to the actual emission performance achieved by all affected EGUs.
3	Report any other information that the state plan specified for reporting in the description of reporting contents.
4	Include a report of the program review conducted by the state assessing whether the program is being properly administered, including whether ERC resources are being properly quantified, verified and reported and including assessment of verifier eligibility, conduct and quality of verifier reviews.
5	For state measures plans, also report the status of implementation of any applicable federally enforceable emission standards and of state measures, including the status of periodic programmatic milestones as included in the state plan.
6	For state measures plans, include a notification that the backstop has been triggered, if applicable, detailing the step for implementation and steps taken to notify affected EGUs.
7	Include a notification that corrective measures were triggered, if applicable.
8	In the report for 2029, due by July 1, 2030, include a report for performance over the interim period (2022 through 2029).
9	In the event of triggering the grid reliability safety valve, submit an initial report within 48 hours, a second notification within 7 days from the initial report, and a final report no later than 7 days prior to the end of the 90-day safety valve period. (See more detailed discussion in Section 5.5.7).

Under the final CPP, states are required to submit the state plan, as well as all state reports and notifications, through EPA's State Plan Electronic Collection System (SPeCS), a web-based system accessed through EPA's Central Data Exchange (CDX). Reports must be submitted by the governor or the governor's delegated authority, and must be submitted in both non-editable and editable format. All records used to determine compliance must be retained for a minimum of 10 years, for the interim period, and 5 years, for the final period, from the date the record is used to determine compliance with an emission standard, plan requirement, performance rate or emission goal.

5.5.6 Affected EGU Monitoring, Recordkeeping and Reporting Requirements

State plan submittals must demonstrate that each emission standard is quantifiable and verifiable through monitoring, recordkeeping and reporting requirements for affected EGUs.[154] Both emission standards plans and state measures plans must include EGU monitoring requirements to track and report plan performance, including continuous monitoring[155] and quarterly reporting of actual hourly CO_2 emissions and net energy output from affected EGUs. The final rule specifies a comprehensive set of EGU monitoring, recordkeeping and reporting requirements that will provide a consistent approach across states, largely incorporated from 40 C.F.R. Part 75. In particular, each affected EGU must monitor in accordance with a Part 75 Monitoring Plan, and must report data to EPA's Emissions Collection and Monitoring Plan System (ECMPS) electronically using extensible-markup language (XML) format.[156] The CPP minimum requirements for affected

154 80 Fed. Reg. at 64,843-55 (preamble to final CPP, section VIII.D).

155 Affected EGUs that exclusively combust liquid fuel and/or gaseous fuel may monitor fuel flow rate and gross calorific value of the fuel in lieu of using CEMS.

156 80 Fed. Reg. at 64,864-65 (preamble to final CPP, section VIII.F.1); see also ECMPS Reporting Instructions Monitoring Plan and ECMPS Reporting Instructions Emissions, EPA, March 11, 2015, http://www.epa.gov/airmarkets/participants/monitoring/reporting-instructions.html.

EGU monitoring, recordkeeping and reporting differ depending on whether the EGU is subject to rate-based or mass-based emission standards, as set forth at 40 C.F.R. § 60.5860. The following tables provide a summary of the minimum required EGU monitoring, recordkeeping and reporting requirements. Table 5.12 summarizes common requirements that apply for both rate- and mass-based standards.

Table 5.13 summarizes the minimum monitoring, recordkeeping and reporting requirements for rate-based emission standards.

Table 5.12 **Required Affected EGU Monitoring, Recordkeeping and Reporting Requirements that Apply for Both Rate- and Mass-based Emission Standards**
40 C.F.R. § 60.5860

No.	Monitoring Requirements
1	Prepare a monitoring plan in accordance with 40 C.F.R. 75.53(g) and (h) unless such a plan is already in place. § 60.5860(a)(1)
2	Measure and record hourly CO_2 mass emissions: Install, certify, operate, maintain and calibrate a CO_2 CEMS according to 40 C.F.R. 75.10. Convert data to hourly mass emissions data. §§ 60.5860(a)(3), (a)(4) & 60.5860(b)
3	In lieu of CO_2 CEMS, may calculate CO_2 using data from a continuous O_2 monitor in accordance with 40 C.F.R. 75.10. Alternatively, If combust only liquid and/or gaseous fuel, may measure fuel flow rate and determine gross calorific value. § 60.5860(a)(4)
4	Install, calibrate, maintain and operate watt meters to continuously measure and record hourly net electric output. Must also monitor thermal and mechanical output, if applicable, for CHP units. §§ 60.5860(a)(5) & 60.5860(b)(3)
No.	**Recordkeeping Requirements**
1	If two or more EGUs serve a common electric generator, apportion net energy output to individual affected EGUs using fraction of total steam load; or, if the EGUs are identical, may use the fraction of the total heat input. § 60.5860(a)(8)
2	Maintain records for 5 years (onsite for at least 2 years) after end of each compliance period. §§ 60.5860(c) & (c)(1)
3	Keep all documents, data files, and calculations and methods used to demonstrate compliance with emission standards. § 60.5860(c)(2)
4	Keep copies of all reports submitted to state under the state plan. § 60.5860(c)(2)
5	Keep all data required to be recorded under Part 75 Subpart F. § 60.5860(c)(2)
No.	**Reporting Requirements**
1	Submit report to the state at the end of each compliance period. Reporting to the state is in addition to reporting to ECMPS as required under Part 75. § 60.5860(d)
2	Report all hourly CO_2 for each affected EGU, or group of EGUs sharing a common stack, in accordance with treatment of invalid data or substitute data as specified for rate- and mass-based limits. § 60.5860(d)(1)
3	Include in the report the applicable emissions standard and a demonstration that the affected EGU met the emission standard. § 60.5860(d)(4)
4	If the affected EGU captures CO_2 to meet the applicable emissions standard, report captured CO_2 in accordance with Part 98 Subpart PP. § 60.5860(f)
5	If the affected EGU captures CO_2 to meet the applicable emissions standard, report injected CO_2 under Subpart RR if injected onsite, or transfer to a facility that reports under Subpart RR is sent offsite for injection, or to a facility that has received an innovative technology waiver. §§ 60.5860(f) and (g)

Table 5.13 **Required Affected EGU Monitoring, Recordkeeping and Reporting Requirements that Apply Specifically for Rate-based Emission Standards**
40 C.F.R. § 60.5860

No.	Monitoring Requirements
1	Definition of compliance period and valid operating hours. Each compliance period shall include only valid operating hours, for which both emissions and net energy output data are valid. Substitute data are not considered valid. §§ 60.5860(a)(2) & 60.5850(a)(5)(v)
2	If two or more EGUs share a common exhaust gas stack and same emissions standard, may monitor at the stack and sum net electric output. If this option is chosen, then the hourly net electric output for the common stack is the sum of the hourly net output for the individual affected EGUs sharing the stack, and the operating time is the "stack operating hours." § 60.5860(a)(6)
3	If exhaust gases from an EGU are routed to two or more stacks, monitor CO_2 at each stack separately, sum emissions and divide by net energy output for affected EGU. Also, if emissions are routed through multiple ducts and the owner/operator elects to monitor each duct; then each duct must be monitored separately, emissions summed and divided by net energy output for the affected EGU. § 60.5860(a)(7)
4	Follow all additional applicable monitoring, recordkeeping and reporting requirements of § 60.5745(a). § 60.5080(e)
No.	**Recordkeeping Requirements**
1	Maintain all data with respect to any ERCs generated by the affected EGU or used by the affected EGU: include eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC. Also include all records and reports relating to the surrender and retirement of ERCs, including the date each ERC was surrendered or retired. § 60.5860(c)(2)
No.	**Reporting Requirements**
1	Report hourly CO_2 (tons/hr) for each valid operating hour as monitored and reported under part 75. § 60.5080(d)(2)
2	Report net electric output and net energy output for each valid operating hour. § 60.5060(d)(2)
3	Report hourly CO_2 mass emissions (lb) for each valid operating hour as calculated. § 60.5080(d)(2)
4	Report the sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values for all of the valid operating hours in the compliance period. § 60.5060(d)(2)
5	Report the ERC replacement generation with supporting documentation and justification, and the calculated CO_2 mass emission rate in lbs/net MWh. § 60.5080(d)(2)
6	Report a list of all unique ERC serial numbers retired, the date it was retired and the resource identification information. § 60.5080(d)(5)

The following Table 5.14 summarizes the minimum required monitoring, recordkeeping and reporting requirements that must be included in each state plan that includes mass-based emission standards.

5.5.7 Consideration of Grid Reliability

Each state plan submittal must include a demonstration that the reliability of the electrical grid has been considered in the development of the plan.[157] In addition to this demonstration, which is a universally required plan component for all state plans, the final rule also makes two other grid reliability considerations available to states. First, the final rule provides a reliability safety valve that can be triggered for one or more individual EGUs whose utilization becomes critical to grid reliability, at a level that was unanticipated in the plan development and such that the EGU cannot comply with applicable state plan requirements. Second, the final rule is clear that the state can (and must) revise the state plan to address the reliability issue in the event it continues beyond 90 days.

157 40 C.F.R. § 60.5745(a)(7).

Table 5.14 **Required Affected EGU Monitoring, Recordkeeping and Reporting Requirements that Apply Specifically for Mass-based Emission Standards**
40 C.F.R. § 60.5860

No.	Monitoring Requirements
1	Definition of compliance period. Each compliance period shall include a full dataset. CO_2 emissions must be reported for each operating hour; substitute data must be used for in-valid data hours. § 60.5860(b)
2	Calculate hourly CO_2 mass emissions for each valid hour. Sum all of the hourly CO_2 mass emissions values over the compliance period to determine CO_2 mass emissions for the compliance period. The cumulative sum of mass emissions from all affected EGUs is compared to each interim step goal. Adjustments for net exports/imports must be made if the plan includes a trading program that covers non-EGU sources. §§ 60.5860(b)(1) and (2)
No.	**Reporting Requirements**
1	Report hourly CO_2 (tons/hr) and unit (or stack) operating time, as monitored and reported under part 75. § 60.5860(d)(3)
2	Report the calculated CO_2 mass emissions for each unit or stack operating hours in the compliance period. § 60.5860(d)(3)
3	Report the sum of the CO_2 mass emissions for all of the unit or stack operating hours in the compliance period. § 60.5860(d)(3)
4	Report net electric output and net energy output, hourly and summed for the compliance period. § 60.5860(d)(3)
5	Reporting of cumulative data on a calendar year basis in lieu of the compliance period is acceptable for compliance periods comprised of a discrete number of calendar years. § 60.5860(d)(3)
6	If complying by use of allowances, report a list of all allowance serial numbers retired, with date surrendered/retired. Additional information is required if allowance was a set-aside. § 60.5860(d)(6)

5.5.7.1 Consideration of Reliability During Plan Development

The purpose of the consideration of grid reliability as part of the state plan development is to ensure that the plan provides enough flexibility for affected EGUs to avoid potential conflict between maintaining reliable electric service and complying with applicable plan provisions and emission standards.[158] While the rule does not provide any specific requirements detailing how a state must "consider" grid reliability, EPA suggests in the preamble to the final rule that one particularly effective way of doing so is by consulting with the ISO/RTO or other planning authorities for the region in which the affected EGUs operate, as part of the planning process, and documenting this consultation in the state plan submittal. EPA further recommends that the state ask the planning authority to review the plan during the plan development stage and provide an assessment of any reliability implications of the plan. While the state is not required to follow the recommendations of the ISO/RTO or other planning authority, EPA recommends that the state document its response to those recommendations in the final plan submittal to EPA.

Consultation with grid-reliability planning authorities and experts is intended to assure that the state plan will achieve the emission guidelines in a manner that maintains grid reliability. Input from this consultation process cannot be used to relax the emission performance rates or emission goals for a state or to exempt any affected EGU from compliance with the state plan.

While there are many possible designs for state plans that could achieve the CPP emission guidelines, different approaches may have different levels of flexibility and therefore may differ in their potential to impact grid reliability. ISOs/RTOs or other planning authority experts could be engaged to support state planning efforts by evaluating and modeling various possible plan options to consider effectiveness at reducing CO_2 emissions, EGU compliance flexibility, cost, and grid reliability concerns. For example, the evaluations might consider different allocation schemes for allowances under a mass-based trading program. Or, an evaluation might be performed to assess the implications of EGU-specific versus facility-wide compliance requirements, to model the implications of trading programs with participation by different groups or numbers of states, or to understand the value of extending ERC eligibility to different types of resources.

5.5.7.2 Grid Reliability Safety Valve

In the event of an unforeseen emergency situation that creates an imminent threat to grid reliability that requires one or more affected EGUs to operate outside of the limits in the approved state plan, the state may notify EPA of

158 80 Fed. Reg. at 64,876-77 (preamble to final CPP, section VIII.G.2.c).

the situation and establish temporary modified emission standards for the affected EGU(s).[159] Although not set forth in the final rule language, the preamble to the final rule lays out three criteria that must be met to trigger the safety valve. First, the reliability event must be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event. Second, the relief provided is restricted to EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face failure. Third, the EGUs in question are subject to state plan requirements that impose emissions constraints that will be violated by the EGUs' operation in response to the emergency.[160]

Even where a grid reliability emergency may occur, EPA expects that there would only be a need to trigger the safety valve in cases where the state plan is "relatively inflexible." Specifically, EPA notes that the agency does not anticipate that EGUs operating under a trading program would meet the criteria to authorize use of the safety valve.[161] Nonetheless, the availability of the reliability safety valve is not restricted to certain plan types under the rule; rather, it is included as a universally available component of the final emission guidelines that can be used on a case-by-case basis where warranted by emergency circumstances. Therefore, most states will likely want to include the safety valve provisions in any state-adopted regulation for implementation of the CPP.

To provide relief from otherwise applicable state plan requirements during a grid emergency, the state must make an initial notification to EPA within 48 hours of the emergency occurrence. The initial notification must include a description of the emergency situation, identify the affected EGUs that are required to operate outside the limits of the approved state plan to address the emergency, and specify modified temporary emission standards under which the affected EGUs will operate.

A second notification must be submitted within seven days of the initial notification. The second notification must provide a description of the emergency and explain why the emergency requires the affected EGUs to operate under modified emission standards. The second notification must also describe how the state is coordinating with relevant reliability authorities to alleviate the emergency, and indicate the maximum time that the need for the modified limits is anticipated. The second notice must also include written concurrence from the reliability authority and information on any analysis of the reliability concern they have conducted. If appropriate, the second notice may revise the modified emission standards from those provided in the initial notification.

The initial notification constitutes an approved short-term modification of the state plan, without the need to go through the full revision process, provided the state also submits the seven-day notification. However, EPA reserves the right to disallow the short-term modification if the notification is found to be "improper" upon EPA review.[162] The short-term modification of the state plan is effective for up to 90 days.

5.5.7.3 State Plan Revisions to Address Grid Reliability

One of the state reporting requirements included under the final rule is a requirement to report to EPA that the state plan will be revised to address grid reliability concerns that cannot be resolved within 90 days and that lead to a situation wherein one or more affected EGUs cannot meet load demand while still complying with applicable state plan requirements.[163] As noted above, once triggered, the reliability safety valve can provide temporary relief from the otherwise-applicable emission standards or other performance requirements for an affected EGU for up to 90 days. At least seven days prior to the end of this 90-day period after triggering the grid reliability safety valve, the state must notify EPA that either the reliability concern has been resolved and the affected EGU(s) will resume compliance with the approved state plan, or that the state will revise the plan to address the reliability concern in a manner such that compliance with the Subpart UUUU emission guidelines can still be achieved.[164] In this event, the state must provide in the notification to EPA a schedule for the submittal of the plan revision. The notification must also include documentation of the ongoing reliability emergency, with written concurrence from the relevant reliability coordinator or planning authority confirming that the affected EGU(s) in question must continue to operate beyond the requirements of the state plan in order to address the reliability emergency. However, excess emissions beyond the approved state plan that continue beyond

159 80 Fed. Reg. at 64,874-81 (preamble to final CPP, section VIII.G.2).

160 80 Fed. Reg. at 64,877-79 (preamble to final CPP, Section VIII.G.2.e).

161 80 Fed. Reg. at 64,877-79 (preamble to final CPP, section VIII.G.2.e).

162 40 C.F.R. §§ 60.5785(e) & 60.5870(g).

163 § 60.5870(g).

164 40 C.F.R. § 60.5870(g)(3).

the 90-day period allowed by the safety valve are counted in the compliance demonstration against the state's overall emission goal or affected EGU emission standards.[165]

5.5.8 Public Participation and Engagement

Another universally required component for all state plans is documentation of public participation and engagement in the plan development as required by 40 C.F.R. § 60.23. In addition, EPA specifies in the preamble to the final rule that, for purposes of Subpart UUUU, compliance with the public participation provisions of § 60.23 must include active engagement with vulnerable communities that may be affected by the state plan. Because specific documentation of meaningful engagement with vulnerable communities is a required element of an initial plan submittal, it is important for states to recognize and act to meet this requirement quickly.

5.5.8.1 Procedural Requirements

The state must conduct a public hearing on the final state plan prior to adoption and submittal to EPA. In the final plan submittal, the state must include certification that the plan was made available to the public and that reasonable notice and opportunity for public comment was provided, that a 30-day notice of the required hearing was provided, and that the required hearing was held. In addition, the state must provide documentation of the list of witnesses appearing at any public hearing on the plan, with a summary of comments.

5.5.8.2 Vulnerable Communities Engagement

The final rule explicitly requires documentation of the state's engagement with vulnerable communities as part of the initial plan submittal for any state requesting an extension for submittal of its final plan. Furthermore, as stated above, EPA indicates in the CPP preamble that engagement with vulnerable and "overburdened" communities that may be affected by the state plan will be considered a required element of compliance with 40 C.F.R. § 60.23. The terms "vulnerable" and "overburdened" refer to low-income communities, communities of color, and indigenous populations that are most affected by, and least resilient to, the impacts of climate change, and are central to environmental justice considerations.[166] EPA refers states to EPA's *Guidance on Considering Environmental Justice During the Development of Regulatory Actions* to consider how best to identify and engage vulnerable communities in the plan development process, and also encourages states to use the proximity analysis EPA developed for the CPP rulemaking to identify vulnerable communities in their state.[167] These methods serve as guidelines that could be used in identifying vulnerable communities; however, states should consult with their EPA Regional Office to gain concurrence with methods used to identify vulnerable communities in the state.

5.5.9 Legal Authority, Funding and Other Supporting Materials

Each state plan must include documentation that the state has adequate legal authority to implement and enforce all plan components. The final plan submittal must also document that adequate funding mechanisms are in place to allow the state to exercise these authorities. These demonstrations can be made by submitting copies of statutes, regulations, legal orders, state-adopted budgets, fee schedules, or other relevant documents.

Finally, the state must include with its state plan submittal any supporting materials necessary to support EPA's review and evaluation of the adequacy of the plan. This may include modeling, calculations, reference documents, or other materials relied upon by the state in the plan.[168]

5.6 Determining State Plan Submittal Requirements

The choices states make in designing their state plans will determine their state plan submittal requirements. This section synthesizes the preceding discussion to illustrate the various submittal requirements that apply under different implementation scenarios. Three particular design decisions will have the most significant impact on plan submittal requirements: (1) whether to adopt a rate-based or mass-based emission goal; (2) whether to rely on state measures; and (3) whether to adopt an approach that qualifies as one of EPA's "streamlined" plan types. Decisions as to (4) whether to request a deadline extension through an initial plan submittal and (5) whether to participate in the Clean Energy Incentive Program (CEIP) also impact submittal requirements, though less significantly.

The following subsections include tables organized to isolate the subsets of state plan submittal requirements

165 40 C.F.R. § 60.5870(g)(3).

166 80 Fed. Reg. at 64,848 (preamble to final CPP, Section VIII.D.2.a.(6)).

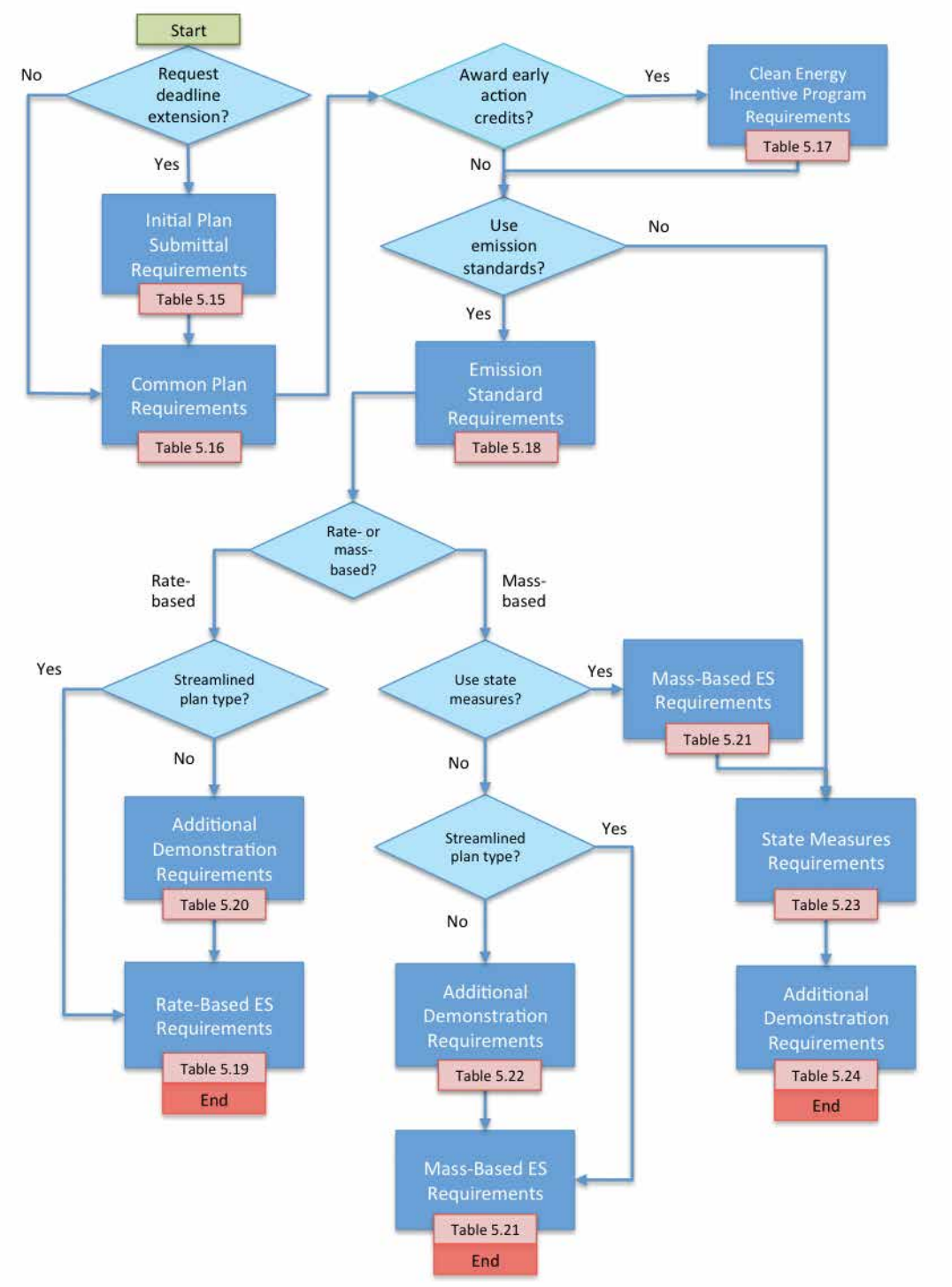
167 80 Fed. Reg. at 64,858.

168 40 C.F.R. § 60.5745; 80 Fed. Reg. at 64,848-49 (preamble to final CPP, section VIII.D.2.a(7)).

triggered by each of the above implementation decisions. Each table is introduced with a short applicability discussion identifying when that group of state plan requirements applies. Individual table entries list the required plan element and provide citations to the corresponding regulatory text, any related regulatory requirements, and discussions of the plan requirement in the final CPP's Federal Register preamble.

States may determine a full set of state plan submittal requirements by reviewing each subsection and adding any requirements made applicable by a particular implementation choice. Figure 5.2 further demonstrates how to build a complete list of plan submittal requirements with flowchart illustrating the relationships between individual implementation decisions and the applicability of the plan requirement tables.

Figure 5.2 **State Clean Power Plan Submittal Requirements Flowchart**



5.6.1 Initial Plan Submittal Requirements

Table 5.15 summarizes the plan requirements that apply if a state decides to make an initial submittal requesting a deadline extension to file a final state plan. Under the timeline adopted in the final CPP, states must submit their initial plan submittal no later than September 6, 2016.[169] States awarded extensions do not need to make their final plan submittals until September 6, 2018 but must instead provide the following information by the September 2016 deadline.[170]

Table 5.15 **Initial Plan Submittal Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Requirements (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Identification of a final plan approach or approaches under consideration and a description of progress made to date on final plan components	§ 60.5765(a)(1) [64,947]		64,857
Explanation of why the state requires additional time to submit a final plan by September 6, 2018	§ 60.5765(a)(2) [64,947]		64,857-78
Demonstration or description of opportunities for public comment and stakeholder engagement during and after the initial plan development	§ 60.5765(a)(3) [64,947]		64,858
Non-binding statement of intent to participate in the Clean Energy Incentive Program[171]	§ 60.5737(d) [64,943]		64,830 64,856
Progress report by September 6, 2017	§ 60.5765(c)(1)-(3) [64,947]		64,859

169 The September 2016 deadline will be pushed back, and all other CPP deadlines are potentially subject to change, due to the Supreme Court-ordered stay on the rule's implementation. See the Preface to this document for further discussion of the judicial stay.

170 *See* 80 Fed. Reg. at 64,856-60. EPA issued an October 22, 2015 memorandum entitled *Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act* to further clarify these requirements. The memorandum is available at http://www3.epa.gov/airquality/cpptoolbox/cpp-initial-subm-memo.pdf.

171 This requirement applies only if the state intends to award early action credits to qualifying renewable energy and energy efficiency projects under EPA's Clean Energy Incentive Program (CEIP). See Table 3 for additional CEIP requirements.

5.6.2 Common Plan Requirements

Table 5.16, below, describes the state plan submittal requirements that are common to all plan types.

Table 5.16 **Common Plan Submittal Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Requirements (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Description of the plan approach and geographic scope	§ 60.5745(a)(1) [64,944]		64,844
Identification of the applicable performance rate or state emission goal	§ 60.5745(a)(2) [64,944]	Single-state: § 60.5855 [64,953] Multi-state: § 60.5750 [64,946] Schedule and Compliance Periods: §60.5770 [64,947]	64,849 64,851
Identification of affected EGUs including an inventory of their CO_2 emissions	§ 60.5740(a)(1) [64,943]	Affected EGU criteria: § 60.5845 [64,953]	64,844
Demonstration that the performance rate or emission goal will be met	§ 60.5745(a)(3) [64,944]		64,844-46 64,865-56
Identification of monitoring, reporting, and recordkeeping requirements for each affected EGU	§ 60.5740(a)(4) [64,944]	General requirements: § 60.5860. [64,953]	64,847 64,865
Description of the state reporting process	§ 60.5740(a)(5) [64,944]	General requirements: § 60.5870 [64,948] Timing requirements: § 60.5770 [64,947] Section 111(d) implementing regulations: 40 C.F.R. Part 60, Subpart B, except for § 60.24	64,847-48 64,850-51 64,852
Demonstration that electrical grid reliability has been considered	§ 60.5745(a)(7) [64,946]		64,849 64,876-67
Timeline listing all programmatic steps and milestones	§ 60.5745(a)(8) [64,946]		64,849
Demonstration of adequate legal authority and funding to implement and enforce the state plan	§ 60.5745(a)(9) [64,946]		64,848-49
Demonstration that each interim step goal will be met	§ 5745(a)(10) [64,946]	Interim requirements: § 60.5855(c) [64,953]	64,844-46 64,865
Certification and documentation that a public hearing was held	§ 5745(a)(11) [64,946]	Section 111(d) implementing regulations: § 60.23	64,848
Documentation of any community outreach and community involvement	§ 5745(a)(12) [64,946]		64,848
Supporting materials	§ 5745(a)(13) [64,946]		64,848-49

5.6.3 Clean Energy Incentive Program Requirements

States may choose to award early action credits for eligible energy efficiency and renewable energy projects in 2020 and 2021 by participating in the Clean Energy Incentive Program (CEIP). Those that do are subject to the plan submittal requirements in Table 5.17.[172]

Table 5.17 **CEIP Submittal Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Requirements (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Statement of intent to participate in the program	§ 60.5737(d) [64,943]		64,830
Mechanism to issue early action ERCs or allowances	§ 60.5737(d) [64,943]		64,830 64,831-32
Evaluation, monitoring and verification requirements for ERCs or allowances[173]	§ 60.5737(e) [64,943]	ERC issuance: § 60.5805 [64,951] ERC tracking: § 60.5810 [64,951] Allowance allocations: § 60.5815 [64,951] Allowance tracking: § 60.5820 [64,952] Mass compliance demonstration: § 60.5825 [64,952] EM&V plans: § 60.5830 [64,952] M&V reports: § 60.5835 [64,952]	64,831-32

5.6.4 Emission Standard Requirements

Table 5.18 applies to state plans that rely on one or more emission standards to achieve their CPP emission goals. State plans that rely on a combination of emission standards and state measures must also fulfill these requirements, but they are considered "state measures plans." As such, they are subject to further requirements as well.[174] The additional requirements applicable to state measures plans appear in Tables 5.23 and 5.24.

Table 5.18 **State Measures Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Identification of all emission standards applicable to affected EGUs	§ 60.5740(a)(2) [64,943]	Schedules, performance and compliance periods: § 60.5770 [64,947] General requirements: § 60.5775 [64,947]	64,849-50 64,851 64,864-65
Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable	§ 60.5745(a)(4) [64,944]	General requirements: § 60.5775 [64,947]	64,850

172 *See* 40 C.F.R. § 60.5737.

173 The CEIP's evaluation, measurement and verification requirements apply to early action ERCs awarded under a rate-based state plan and early action allowances awarded under a mass-based state plan.

174 *See, e.g.*, 40 C.F.R. § 60.5740(a)(2)(iii).

5.6.5 Rate-based Emission Standard Requirements

The requirements of Table 5.19 apply to states that adopt a rate-based form of the CO_2 emission goal, including EPA's CO_2 emission performance rates (Subpart UUUU Table 1) or EPA's statewide rate-based CO_2 emission goals (Subpart UUUU Table 2).

Table 5.19 **Rate-based Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Requirement that each affected EGU use an adjusted emission CO2 emission rate to demonstrate compliance	§ 60.5790(c)(1) [64,949]		64,894-96
Requirements for ERC eligibility, tracking, surrender, revocation, banking and borrowing	§ 60.5790(c)(2)-(4) [64,949] § 60.5805 [64,951]	Resource eligibility: § 60.5800 [64,950] EGU eligibility: § 60.5795 [64,950] ERC tracking: § 60.5810 [64,951]	64,896-904 64,907
Process and requirements for ERC issuance	§ 60.5805 [64,951]	EGU eligibility: § 60.5795 [64,950] Resource eligibility: § 60.5800 [64,951] EM&V plan: § 60.5830 [64,952] ERC tracking: § 60.5810 [64,951] M&V reports: § 60.5835 [64,952]	64,904-06 64,906-08
Evaluation, measurement and verification (EM&V) plans for eligible resources	§ 60.5830 [64,592]	ERC issuance: § 60.5805 [64,951]	64,906-07 64,908-10
Monitoring and verification (M&V) reporting for eligible resources	§ 60.5835 [64,592]	ERC issuance: § 60.5805 [64,951]	64,906-07 64,908-10
Additional monitoring, reporting, and recordkeeping requirements for affected EGUs with rate-based emission standards	§ 60.5860 [64,953]	Monitoring: § 60.5860(a)(2) [64,953]; § 60.5860(a)(3) or (4) [64,954]; § 60.5860(a)(5)(iii) [64,955]; § 60.5860(a)(5)(vi) [64,955] Recordkeeping: § 60.5860(c)(2)(iv) [64,956] Reporting: § 60.5860(d)(2) [64,956] § 60.5860(d)(5) [64,956]	64,850-51

5.6.6 Additional Rate-based Demonstration Requirements

Rate-based emission standard plans that qualify as one of EPA's streamlined plan types can avoid additional plan requirements to demonstrate that the state's total inventory of affected sources will meet the aggregate emission limit. No elements beyond those listed in the tables above are required for a state plan that "applies separate rate-based CO_2 emission standards for affected EGUs (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates listed in Table 1… [to Subpart UUUU of Part 60] or uniform rate-based CO_2 emission standards equal to or lower than the rate-based CO_2 emission goals listed in Table 2 … [to Subpart UUUU of Part 60]."[175]

However, the additional plan requirements of Table 5.20 must be included if the state plan "applies rate-based emission standards to individual affected EGUs at

175 40 C.F.R § 60.5745(a)(5)(i).

a lbs CO_2/MWh rate that differs from the CO_2 emission performance rates in Table 1 … [to Subpart UUUU of Part 60] or the State's rate-based CO_2 emission goal in Table 2 … [to Subpart UUUU of Part 60]."[176]

Table 5.20 **Additional Rate-based Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Triggers for corrective measures[177]	§ 60.5740(a)(2)(ii) [64,943]	Corrective measures trigger requirements: § 60.5740(a)(ii)(A)-(G) [64,943-44] Plan revision requirements: § 60.5795(c) [64,950]	64,866-69

Additional Demonstration Requirements	
Demonstration Requirement	**Citation (40 C.F.R.)**
Projection that the adjusted weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the rate-based CO_2 emission goal	§ 60.5745(a)(5)(ii)
Address plan performance during the interim and final performance periods	§ 60.5745(a)(5)(ii)
An analysis of the change in generation of affected EGUs given the compliance costs and incentives under the application of different emission rate standards across affected EGUs in a State	§ 60.5745(a)(5)(ii)(A)
A projection showing how generation is expected to shift between affected EGUs and across affected EGUs and non-affected EGUs over time	§ 60.5745(a)(5)(ii)(B)
Assumptions regarding the availability and anticipated use of the MWh of electricity generation or electricity savings from eligible resources that can be issued ERCs	§ 60.5745(a)(5)(ii)(C)
The specific calculation (or assumption) of how eligible resource MWh of electricity generation or savings are being used in the projection to adjust the reported CO_2 emission rate of affected EGUs	§ 60.5745(a)(5)(ii)(D)
If a state plan provides for the ability of renewable energy resources located in states with mass-based plans to be issued ERCs, consideration in the projection that such resources must meet geographic eligibility requirements, consistent with 60.58000(a)	§ 60.5745(a)(5)(ii)(E)
Any other applicable assumptions used in the projection	§ 60.5745(a)(5)(ii)(F)
A summary of each affected EGU's anticipated future operational characteristics	§ 60.5745(a)(5)(v)(A)
Identification of any planned new electric generating capacity	§ 60.5745(a)(5)(v)(B)
Analytic treatment of the potential for building unplanned new electric generating capacity	§ 60.5745(a)(5)(v)(C)
A timeline for implementation of EGU-specific actions	§ 60.5745(a)(5)(v)(D)
All wholesale electricity prices	§ 60.5745(a)(5)(v)(E)
A geographic representation appropriate for capturing impacts and/or changes in the electric system	§ 60.5745(a)(5)(v)(F)
A time period of analysis, which must extend through at least 2031	§ 60.5745(a)(5)(v)(G)
An anticipated electricity demand forecast	§ 60.5745(a)(5)(v)(H)
A demonstration that each emission standard included in the plan meets the requirements of §60.5775	§ 60.5745(a)(5)(v)(I)
Any ERC prices	§ 60.5745(a)(5)(v)(J)
Identification of planning reserve margins	§ 60.5745(a)(5)(v)(K)
Any other applicable assumptions used in the projection	§ 60.5745(a)(5)(v)(L)

176 40 C.F.R. § 60.5745(a)(5)(ii); 80 Fed. Reg. at 64,844-46.

177 Required if the plan does not impose emission standards that "assuming full compliance by affected EGUs, mathematically assure achievement" of EPA's performance rates or statewide CO_2 emission goals. 40 C.F.R. §§ 60.5740(a)(2)(i)(A), (B) & (C).

5.6.7 Mass-based Emission Standard Requirements

States that adopt a mass-based emission trading program, e.g., EPA's statewide mass-based CO_2 emission goals (Subpart UUUU Table 3) or EPA's statewide mass-based CO_2 goals plus new source emission complement (Subpart UUUU Table 4) are subject to the requirements of Table 5.21.

Table 5.21 **Mass-based Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Identify additional CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs with mass-based emission standards	§ 60.5790(b)(1) [64,949] § 60.5860 [64,955]	General requirements: § 60.5860 [64,955] Monitoring: § 60.5860(a)(5)(vii) [64,955] § 60.5860(b) [64,955] Reporting: § 60.5860(d)(3) [64,9556] § 60.5860(d)(6) [64,956]	64,887
Requirements for State allocation of allowances.	§ 60.5790(b)(2) [64,949]	General requirements[178]: § 60.5815 [64,951]	64,892
Requirements for tracking of allowances	§ 60.5790(b)(3) [64,949]	General requirements: § 60.5820 [64,952]	64,887
Specify a "true-up" or compliance demonstration process for affected EGUs	§ 60.5790(b)(4) [64,949]	General requirements: § 60.5825 [64,952]	64,887
Address increased emissions from new sources (leakage)	§ 60.5790(b)(5) [64,949]		64,887-90

178 States may develop allowance set-asides as one of many approaches to allowance allocation. 40 C.F.R. § 60.5815(c). However, any set-aside allowances must meet the ERC resource qualification requirements of § 60.5800, the ERC issuance requirements of § 60.5805, the EM&V plan requirements of § 60.5830, and the M&V reporting requirements of § 60.5835.

5.6.8 Additional Mass-based Demonstration Requirements

Streamlined mass-based emission standard plans can avoid compliance projection requirements to show that the state's total inventory of affected sources will meet the aggregate emission limit. No additional demonstration is required if the mass-based emission standards for affected EGUs "do not exceed the State's EPA-specified mass CO_2 goal" in Table 3 or Table 4[179] to Subpart UUUU of Part 60.[180]

The Table 5.22 requirements must, however, be included in the state plan if the mass-based emission standards for affected EGUs "cumulatively exceed the state's EPA-specified mass CO_2 emission goal" (i.e., Table 3 goal).[181]

Table 5.22 **Additional Mass-based Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Triggers for corrective measures[182]	§ 60.5740(a)(2)(ii) [64,943]	Corrective measures trigger requirements: § 60.5740(a)(ii)(A)-(G) [64,943-44] Plan revision requirements: § 60.5795(c) [64,950]	64,866-69

Additional Demonstration Requirements	
Requirement	**Citation (40 C.F.R.)**
Demonstrate that the state program will achieve the State mass-based CO_2 emission goals.	§ 60.5745(a)(5)(iv)
A summary of each affected EGU's anticipated future operational characteristics	§ 60.5745(a)(5)(v)(A)
Identification of any planned new electric generating capacity	§ 60.5745(a)(5)(v)(B)
Analytic treatment of the potential for building unplanned new electric generating capacity	§ 60.5745(a)(5)(v)(C)
A timeline for implementation of EGU-specific actions	§ 60.5745(a)(5)(v)(D)
All wholesale electricity prices	§ 60.5745(a)(5)(v)(E)
A geographic representation appropriate for capturing impacts and/or changes in the electric system	§ 60.5745(a)(5)(v)(F)
A time period of analysis, which must extend through at least 2031	§ 60.5745(a)(5)(v)(G)
An anticipated electricity demand forecast	§ 60.5745(a)(5)(v)(H)
A demonstration that each emission standard included in the plan meets the requirements of § 60.5775	§ 60.5745(a)(5)(v)(I)
Any allowance prices	§ 60.5745(a)(5)(v)(J)
Identification of planning reserve margins	§ 60.5745(a)(5)(v)(K)
Any other applicable assumptions used in the projection	§ 60.5745(a)(5)(v)(L)

179 Table 4 goals are available as a streamlined plan option based on substitution language at 40 C.F.R. § 60.5790(b)(5)(i).

180 40 C.F.R. § 60.5745(a)(5)(iii).

181 40 C.F.R. § 60.5745(a)(5)(iv); 80 Fed. Reg. at 64,844-46.

183 Required if the plan does not impose emission standards that "assuming full compliance by affected EGUs, mathematically assure achievement" of EPA's performance rates or statewide CO_2 emission goals. 40 C.F.R. §§ 60.5740(a)(2)(i)(A), (B) & (C).

5.6.9 State Measures Requirements

State plans that rely on one or more state measures, regardless of whether they also rely on any emission standards, are considered state measures plans.[183] The requirements in Table 5.23 apply.

Table 5.23 **State Measures Plan Requirements**

State Plan Requirement	Citation (40 C.F.R.) [80 Fed. Reg.]	Related Citations (40 C.F.R.) [80 Fed. Reg.]	Preamble Discussion (80 Fed. Reg.)
Description of state measures, projected impacts of state measures, related state laws or regulations and identification of implementing parties	§ 60.5740(a)(2)(iii) [64,944] § 60.5745(a)(6)(i) [64,945]	General requirements: § 60.5780 [64,948]	64,852 64,852-53
Schedule and milestone for the implementation of state measures	§ 60.5745(a)(6)(ii) [64,945]		64,852
EM&V requirements as applicable[184]	§ 60.5745(a)(6)(ii) [64,945]	EGU ERC eligibility: § 60.5795 [64,950]	64,852
Demonstration that the state program will achieve the State mass-based CO_2 emission goals	§ 60.5740(a)(2)(iv) [64,944][185] § 60.5745(a)(6)(iii) [64,945]	Goal specification § 60.5855 [64,953]	64,846
Federally enforceable backstop	§ 60.5740(a)(3) [64,944]	Plan revision requirements: § 60.5785 [64,948] Trigger requirements: § 60.5740(a)(3)(i) [64,944] Implementation schedule: § 60.5740(a)(3)(iii) [64,944]	64,851-52
Performance projection	§ 60.5745(a)(6)(iv) [64,945]	See Performance Projection Requirement Table below	64,846 64,865-56

183 40 C.F.R. § 60.5740(a)(2)(iii).

184 EM&V requirements apply to state measures plans that include state measures "that do not have a direct effect on CO_2 emissions measured at an affected EGU's stack." 40 C.F.R. § 60.5745(a)(6)(ii).

185 The federally enforceable demonstration requirement of § 60.4740 applies only if a plan "requires state emission standards in addition to relying on State measures." 40 C.F.R. § 60.5740(a)(2)(iv). State measures plans that do not rely on a mixture of federally enforceable emission standards and state measures do not need to meet this requirement.

All state measures plans must also include a plan performance projection with the elements outlined in Table 5.24.[186]

Table 5.24 **Elements of Plan Performance Projections**

Performance Projection Requirement	Citation (40 C.F.R.)
A baseline demand and supply forecast as well as the underlying assumptions and data sources of each forecast	§ 60.5745(a)(6)(iv)(A)
The magnitude of energy and emission impacts from all measures included in the plan and applicable assumptions	§ 60.5745(a)(6)(iv)(B)
An identification of state-enforceable measures with electricity savings and RE generation, in MWh, expected for individual and collective measures and any assumptions related to the quantification of the MWh	§ 60.5745(a)(6)(iv)(C)
A summary of each affected EGU's anticipated future operational characteristics	§ 60.5745(a)(5)(v)(A)
Identification of any planned new electric generating capacity	§ 60.5745(a)(5)(v)(B)
Analytic treatment of the potential for building unplanned new electric generating capacity	§ 60.5745(a)(5)(v)(C)
A timeline for implementation of EGU-specific actions	§ 60.5745(a)(5)(v)(D)
All wholesale electricity prices	§ 60.5745(a)(5)(v)(E)
A geographic representation appropriate for capturing impacts and/or changes in the electric system	§ 60.5745(a)(5)(v)(F)
A time period of analysis, which must extend through at least 2031	§ 60.5745(a)(5)(v)(G)
An anticipated electricity demand forecast	§ 60.5745(a)(5)(v)(H)
A demonstration that each emission standard included in the plan meets the requirements of §60.5775	§ 60.5745(a)(5)(v)(I)
Any allowance prices	§ 60.5745(a)(5)(v)(J)
Identification of planning reserve margins	§ 60.5745(a)(5)(v)(K)
Any other applicable assumptions used in the projection	§ 60.5745(a)(5)(v)(L)

186 *See* 80 Fed. Reg. at 64,844-46.

6. Key Decisions for State Planning

EPA established multiple forms of the emission guidelines for affected EGUs in the final CPP, including subcategory-specific emission performance rates, statewide mass-based emission goals and statewide rate-based emission performance goals. States may select among four forms of the emission guidelines to demonstrate compliance, and they are afforded a high degree of flexibility in achieving their required emission reductions through a variety of plan types and reduction strategies. EPA incorporated this wide-ranging state discretion in recognition of several important factors. First, due to the variation in state and regional electricity systems, different types of plans may be better suited for different states or regions. Differing energy and environmental policy preferences across states and regions are another important consideration. Also, some states, such as the RGGI states and California,[187] have invested significant time and resources to develop mass-based trading programs, which they intend to retain and build upon to comply with the CPP.[188] EPA also recognized that compliance flexibility for affected EGUs is key to reducing CO_2 emissions while maintaining grid reliability and affordable power.[189]

Designing a plan type that best fits the state's current circumstances and supports its economic and energy goals—while at the same time assuring compliance with the CPP emission goals, protecting reliability of the energy grid, and minimizing cost to consumers—will require thoughtful planning and analysis by state agencies and stakeholders. Although specific state circumstances and policy goals may vary significantly, there are common key decisions that each state will need to make to develop a successful state plan. This chapter addresses several such key decision points. The chapter starts with considerations of implementing a trading program as the platform for CPP compliance, including CPP provisions that facilitate trading and the benefits of trading programs, as well as other considerations. Section 6.2 focuses on comparing rate-based with mass-based plan designs, examining differences in plan performance goals, plan components and demonstrations, EGU compliance demonstrations and compliance flexibility, and accommodation of load growth. Section 6.3 examines single-state vs. multi-state plans, including a detailed look at how states can interact using the different plan types.

6.1 Trading Program Considerations and Decisions

Trading program decisions, including whether to allow for trading, and if so, what type of trading program to adopt and how state trading partners will be selected, are among the fundamental decisions facing each state in complying with the final CPP. This section summarizes the trading-friendly provisions adopted by EPA in the final CPP, discusses the primary benefits of trading programs, and explores reasons why a state might elect to limit trading or not adopt a trading program. Special considerations specific to rate- and mass-based trading programs are discussed in Section 6.3.

A number of states have already implemented carbon trading programs to drive CO_2 reductions and to support the funding of RE and EE programs. While the use of a regional trading program as a plan approach was not explicitly proposed as a type of state plan under the proposed CPP, EPA did acknowledge existing programs, such as RGGI, and noted that states may elect to build upon those programs for CPP compliance. EPA received numerous

187 The Regional Greenhouse Gas Initiative (RGGI) is a market-based program to cap and reduce CO_2 emissions from the power sector. RGGI is a cooperative effort among nine member states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Similarly, under the California Global Warming Solutions Act of 2006, often referred to as "AB 32," California has established a cap-and-trade program applicable to sources responsible for 85% of the state's GHG emissions.

188 79 Fed. Reg. at 34,900.

189 80 Fed. Reg. at 64,665.

comments on the proposed CPP—including comments from power companies, states, public utility commissioners, energy agencies, and environmental advocates—expressing broad support for trading programs as a means to comply with the CPP emission guidelines and encouraging EPA to facilitate trading in the final rule.[190]

In the final CPP, EPA clarified that states may rely on trading programs to achieve compliance and adopted a number of provisions to facilitate interstate trading among states that elect to participate. EPA concluded that trading would be an appropriate compliance mechanism, and further, that states may incorporate emissions trading in their plans, due to a number of factors, including the:

1) global nature of CO_2 emissions and the resulting environmental impacts;
2) transactional nature of the industry; and
3) interconnected functioning and coordination of EGUs and the power grid.

EPA also notes that trading is considered an integral part of the BSER analysis because it is a reduction strategy that is available to states and has been adequately demonstrated to achieve emission reductions in the power industry.[191] Although the final CPP is designed to readily accommodate trading, and EPA evaluated BSER based on its conclusion that many, if not all, states would incorporate emission trading in their plans, states are not required to provide for trading in the state plan. Further, trading is not an "all or nothing" proposition. For example, the state plan could make provisions for interstate trading across multiple grid interconnects or could define a more limited trading region. Alternatively, the state plan could allow intrastate trading only.

6.1.1 CPP Provisions that Facilitate Trading

In the CPP, EPA took several steps to facilitate interstate trading as a compliance mechanism. Some specific aspects of the final rule that support trading include:

- The form of the emission guidelines;
- The methodology applied in developing the level of performance reflected in the emission guidelines;
- Minimum specified monitoring, recordkeeping and reporting for affected EGUs;
- Guidelines for qualifying ERC resources;
- Minimum requirements for evaluation, measurement and verification for ERCs;
- Provisions for mass allocation, allowance tracking and compliance true-up requirements;
- Requirements and guidelines for addressing interstate leakage;
- Provisions and minimum requirements for trading-ready state plans; and
- Provisions for an EPA-administered trading platform.

The final BSER emission guidelines set forth in Table 1 of Subpart UUUU are uniform subcategory performance rates that must be achieved by affected EGUs across all states. Application of the same performance rate to EGUs across state boundaries makes rate-based trading feasible. The performance rates are by definition *adjusted* CO_2 emission rates, determined by dividing the CO_2 emissions from the affected EGU by the sum of the unit's net energy output plus emission rate credits (ERCs) representing replacement generation from zero-emitting sources or avoided generation. Thus, the form of the emission guidelines contemplates most, if not all, affected EGUs will not meet the applicable performance rate without obtaining ERCs generated by another source.[192] The use of ERCs is in itself a form of averaging across generating units or other qualifying resources to attain compliance, and it would be natural for such a compliance strategy to involve the purchase of ERCs from entities that make the initial investment to generate the qualifying credits. To facilitate the trading of ERCs, the final rule establishes a standard denomination (MWh) and requires the compliance demonstration to use a standardized accounting methodology. The accounting method adds ERCs (MWh) to the denominator of the rate equation, without approximating or adjusting for the actual CO_2 emission reductions that result from the particular ERCs being applied. The adoption of a standardized set of performance rates for rate-based programs, together with a standardized methodology of accounting for ERCs, facilitates interstate trading by normalizing the value of each ERC and minimizing the likelihood of creating perverse incentives for development of ERC resources in states with higher-emitting EGUs.[193] Standardized, minimum requirements for qualifying ERC resources and for ERC evaluation, measurement and verification also serve to facilitate interstate trading by providing a level playing field across states and assuring integrity of the system.

190 80 Fed. Reg. at 64,733 n.380.

191 *Ibid.*

192 Affected EGUs that implement changes such as heat rate improvement or installation of CCS and reduce their performance rate below the applicable rate-based performance standard would be eligible to generate ERCs for use by other affected EGUs.

193 80 Fed. Reg. at 64,896.

The final emission guidelines similarly accommodate mass-based trading by providing the Table 3 and Table 4 BSER-equivalent mass-based statewide emission goals. The mass-based emission goals were derived using a consistent method for applying the subcategory performance rates to the state-specific affected EGU inventory, eliminating the likelihood of varying approaches reflected in the proposed CPP. Statewide mass emission goals reflecting a consistently applied methodology provide for a fully fungible commodity (tons) for trading emission allowances across states on a mass-based trading platform. Furthermore, EPA derived the subcategory performance rates by considering application of Building Blocks 2 and 3 across each of the three regional interconnections, rather than state-by-state. This approach minimized the range in the levels of the state-specific mass emission goals, thereby reducing the tendency for leakage or other perverse market effects in an interstate trading regime. States adopting a mass-based or emissions budget trading program[194] are also required to incorporate provisions to minimize leakage to new NGCC facilities that may otherwise occur at the expense of implementation of Building Block 2 of BSER (generation-shifting to underutilized existing NGCC units), further assuring the integrity of the emission guidelines if implemented through a market-based program. Also, the final CPP includes consistent provisions and minimum requirements for allocating allowances, as well as for tracking allowances and demonstrating compliance through allowance retirement, thereby assuring a standard infrastructure to support interstate trading.

EPA took additional steps to minimize the administrative burden to states in adopting and implementing interstate trading systems. First, the final rule explicitly authorizes interstate trading under state plans that meet specified minimum "trading-ready" criteria for mass- or rate-based programs.[195] This provision enables affected EGUs to trade across states without requiring the states to adopt an interstate MOU, to name the state trading partners in the state plan or regulations, or to develop and submit a multi-state plan. Also in the final CPP, EPA has committed to the development and deployment of an EPA-administered ERC and/or allowance tracking system. This option allows individual states to avoid the administrative burden and cost of developing a tracking system and should help to extend consistency of trading platforms from state to state.

All of these trading-friendly provisions are included as part of the final Subpart UUUU emission guidelines. In addition, the proposed federal plan and model state rules provide even greater support for interstate trading as a preferred CPP compliance method. Based on the proposal, EPA intends to establish and implement a multi-state trading program that could be utilized as the federally implemented plan for any state that fails to submit or implement an EPA-approved state plan. Finally, the proposed model state trading rules further encourage interstate trading as the vehicle for state plans, as the final adopted version of the model rules will provide states with presumptively approvable state rule language for trading programs.

6.1.2 Benefits of Trading Programs to Meet CPP Emission Guidelines

As cited by many commenting on the proposed CPP, the primary benefits associated with trading include enhancing compliance flexibility, minimizing cost, and protecting grid reliability.[196] Additional benefits can include incentivizing innovative compliance strategies, enhancing emission reductions as compared to more rigid compliance regimes, generating revenue for related or other programs and policy goals, and enhancing economic growth. This section discusses the many benefits of using a trading program as a CPP compliance platform.

6.1.2.1 Enhancing Compliance Flexibility

When a market-based trading program is used to achieve the emission performance goal across a large group of affected sources, the regulated entities have broad discretion to determine both how and where emission reductions will be made to achieve the goal. By adopting an emission performance standard, either as a mass emissions cap or as a subcategory-wide emission performance rate, without prescribing specific technologies, work practices, or other compliance strategies to meet the emissions standard, a trading program enables and encourages affected sources to continuously seek the most practical, technologically feasible and cost-effective means to comply. "Excess reductions" can be made at affected sources where the cost is lower, and these reductions can be sold to achieve compliance where the investment would otherwise be higher. In the context of reducing CO_2 emissions, this may not mean investment in emission control technology such as carbon capture and sequestration (CCS). Rather, investments in efficiency upgrades to improve heat rate performance can be made at

194 The terms "mass-based trading program," "emissions budget trading program," and "cap-and-trade program" are used interchangeably in this document.

195 40 C.F.R. § 60.5750(d); 80 Fed. Reg. at 64,946.

196 *See* 80 Fed. Reg. at 64,733 n.380.

EGUs where the return on investment is greatest. Similarly, utilization can be shifted to affected EGUs with the most cost-effective and least carbon-intensive performance, and qualifying low- or zero-emitting generation can be developed through investment in qualifying technologies and capacities that are most beneficial and cost-effective. A study comparing outcomes resulting from a flexible compliance regime to an inflexible standard suggests that the lack of compliance flexibility could potentially impose significant compliance risk on some sources, compromise the reliability and availability of electricity, or impact cost of electricity to consumers. Inflexible standards, such as those that require a particular technology to be adopted or a specific performance rate to be achieved at each affected source, have also been shown to result in a greater retirement rate of existing units.[197] These potential issues can be avoided or mitigated, however, by providing flexible compliance options within the regulatory framework.

A trading program also provides flexibility in deciding when investments to reduce emissions will be made, to the extent unused allowances or ERCs can be banked for use in future performance periods. This temporal flexibility can encourage affected parties to make cost-effective reductions early, thereby increasing the environmental benefits of the program. Finally, market-based trading programs expand compliance flexibility in terms of who can make the required investments to achieve compliance, and who can profit from those investments. The trading platform provides an avenue for affected EGUs, as well as third-party investors, to invest in energy efficiency and renewable energy through the purchase and sales of allowances or ERCs. Further, this can occur on a "speculative" basis, without the need for a particular utility or EGU owner to enter into a business agreement in advance of the investment. Thus, trading programs introduce expanded compliance flexibility on multiple levels, allowing the owners of affected EGUs, and effectively the trading market, to determine how, when, where and by whom emission reductions, or qualifying replacement or avoided generation, will be made.

6.1.2.2 Minimizing Compliance Costs

When trading programs are utilized to achieve emission reduction goals, a number of factors drive a reduction in the cost of achieving compliance as compared to more rigid approaches. First, as already described, trading allows for a substantial increase in compliance flexibility. This facilitates the use of the most cost-effective means to reduce emissions, regardless of the particular unit or location at which the reduction would occur. Accordingly, the investment cost of achieving emission reductions is reduced. In addition, because the market provides a real-time, cost-competitive platform for the sale of allowances or ERCs, traditional market factors (i.e., supply and demand) influence cost. As many studies have concluded, and empirical evidence supports, reliance on market-based trading to achieve emissions reductions goes hand-in-hand with minimizing the cost of compliance for affected EGUs, which in turn will minimize any impacts on the cost of electricity for consumers.[198] For example, RGGI has demonstrated success in achieving CO_2 reductions at a faster rate than the rate of reductions achieved by the rest of the U.S., while the cost of electricity for customers decreased.[199]

Analyses of existing market-based trading programs have found that emission reductions have been achieved at far lower costs than initially predicted. This has been demonstrated for both the U.S. Acid Rain Program and for RGGI.[200] For the Acid Rain Program, substantial emission reductions were achieved at lower than predicted cost even while power generation from fossil fuels increased by almost 40 percent, and the retail cost of electricity was reduced.

Investment in existing facilities may also be encouraged by adopting a program that allows for leveraging costs across individual units through trading or emissions averaging, as opposed to an inflexible standard that requires compliance with a uniform performance standard by each individual unit. Related research by Resources for the Future concludes that where the standard is flexible, substantially more investment to improve the operating efficiency of existing facilities occurs, whereas an inflexible standard leads to substantially greater retirement of existing facilities.[201]

Several analyses of the proposed CPP also concluded that

197 *Ibid.*

198 *See, e.g.,* Sam Napolitano et al., *The U.S. Acid Rain Program: Key Insights from the Design, Operation and Assessment of a Cap-and-Trade Program,* The Electricity Journal, Aug/Sept. 2007, Vol. 20, Issue 7, available at http://www2.epa.gov/sites/production/files/2015-06/documents/us_acid_rain_program_elec_journal_aug_2007.pdf.

199 Peter Shattuck et al., *The Regional Greenhouse Gas Initiative: Performance To-Date and the Path Ahead,* ENE, May 2014, http://www.env-ne.org/resources/detail/rggi-performance-to-date-and-path-ahead ("Fuel switching, improved energy efficiency, and growing renewable energy output have caused emissions to drop by 18% since RGGI launched, while electricity prices are lower than they were before RGGI took effect.").

200 Napolitano et al., *supra* note 198; Shattuck et al., *supra* note 199.

costs are minimized when a regionally based plan is utilized, and further, that the broader the geographic bounds of the region the greater the savings projected.[202] For example, MISO found that regional compliance produced $4 billion to $11 billion in cost savings over twenty years compared to state-by-state compliance, while sub-regional compliance resulted in savings of $2.5 billion to $11.5 billion.[203] Similarly, SPP estimated that the cost of state-by-state compliance is approximately $0.9 billion/year more than the cost of regional compliance, or nearly 40% more.[204]

6.1.2.3 Supporting Grid Reliability

Trading programs provide flexibility in terms of selecting how, when, and where compliance will be achieved, who will make the required monetary investments and who will receive the corresponding economic gains. Another form of flexibility achieved with this compliance strategy is found in the agility of the compliance market to respond to short-term shifts and longer-term economic trends, thereby helping to ensure the ongoing reliability of the power supply to meet consumer demand.

Many comments submitted to EPA on the proposed rule noted that the flexibility associated with trading or regionally coordinated programs supports electric reliability. EPA also asserts that the opportunities for trading within and between states will support electric system reliability. In particular, EPA stresses that the final CPP gives states "broad latitude to design plans that take into account any resource adequacy or reliability constraints they may face," and notes "an important example of this latitude is that states are encouraged to implement mass-based or rate-based plans that allow EGUs to take advantage of trading both within each state and across states."[205] The use of flexible, market-based trading or other regional approaches to achieve the emission performance levels required under the CPP is one of the key planks in the CPP's platform to assure resource adequacy and grid reliability.[206] Trading programs support reliability by allowing EGUs that are critical for meeting demand to be operated as needed and to comply through the use of purchased allowances or ERCs made readily available through a fluid market.

ISOs and RTOs concur that regional trading programs make grid operation far less complex than state-by-state compliance regimes. In its analysis of the proposed CPP within the Southwest Power Pool (SPP) service area, the SPP stated, *"While market design enhancements may be necessary to facilitate a regional compliance approach, it is expected that market design changes needed to support a state-by-state compliance approach would be more extensive and complex in order to accommodate the potential diversity of choices states might make with regard to their own compliance plans."*[207] When the same emissions-related dispatch rules can be applied across a system, such that the variable cost associated with CO_2 emissions is reflected based on a common market, integrated dispatching is less complicated and grid reliability is easier to maintain.

6.1.2.4 Incentivizing Innovation and Enhancing Emission Reductions

In addition to the primary benefits of enhancing compliance flexibility, minimizing cost, and protecting generation resource availability and grid reliability, trading programs offer significant additional benefits. Those can include incentivizing innovative compliance strategies and enhancing emission reductions. Rate-based trading programs can support investment in advanced and developing technologies by qualifying resources as eligible for ERC issuance and by creating set-asides of ERCs for targeted investments. Under a cap-and-trade program, because specific technologies and reduction strategies are not dictated, investors have the freedom to develop and introduce advanced technologies, such as energy storage, that will reduce CO_2 emissions. In addition, by attaching a monetary value to excess emission reductions, the program creates an incentive for entities to achieve cost-effective reductions where available, even if those reductions represent an excess beyond what would be required to meet their minimum performance level. This is particularly true

201 Dallas Burtraw et al., "Retail Electricity Price Savings from Compliance Flexibility in GHG Standards for Stationary Sources," *Energy Policy,* 42:67-77, 2012.

202 It is important to note that these studies provide qualitative examples only, as they were based on the proposed CPP and involved numerous assumptions about the strategies that would be adopted by states.

203 Midcontinent Independent System Operator, *MISO's Phase III Analysis of the Draft CPP, Final Report,* MISO Policy and Economic Studies Department, August 2015.

204 Southwest Power Pool, *SPP Clean Power Plan Compliance Assessment – State-by-State,* SPP Engineering, July 27, 2015.

205 EPA, *Technical Support Document: Resource Adequacy and Reliability Analysis,* August 2015, https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-adequacy-reliability.pdf.

206 80 Fed. Reg. at 64,874-81.

207 *SPP Clean Power Plan Compliance Assessment, supra* note 204.

where banking of allowances or ERCs is allowed, such that reductions achieved in one performance period can be used for compliance in the future.

The Acid Rain Program, RGGI, and California's AB 32 cap-and-trade programs have all demonstrated enhanced emission reductions in excess of the caps established for affected sources. In 1995, the first year of implementing EPA's Acid Rain Program, SO_2 emissions declined by 24% from 1990 levels, almost 4 million tons. By 2004, SO_2 emissions had dropped 34% from 1990 levels, to 10.3 million tons, well below the total available allowances of 17.1 million tons, despite a 20% increase in heat input (utilization) from 1990 levels.[208]

During the first phase of RGGI implementation, CO_2 emissions from the power sector declined across the nation due to a number of factors, including a decrease in the price of natural gas. Reflecting this national trend, CO_2 emissions under RGGI were significantly below projections and well below the emissions cap (Figure 6.1). Notably, a comparison of emission reductions in the RGGI states to the trend for the rest of the nation shows that RGGI states achieved a significantly sharper drop (Figure 6.2). Thus, RGGI demonstrated decreases to levels both far below the cap and at a greater rate of decline than non-RGGI states.[209]

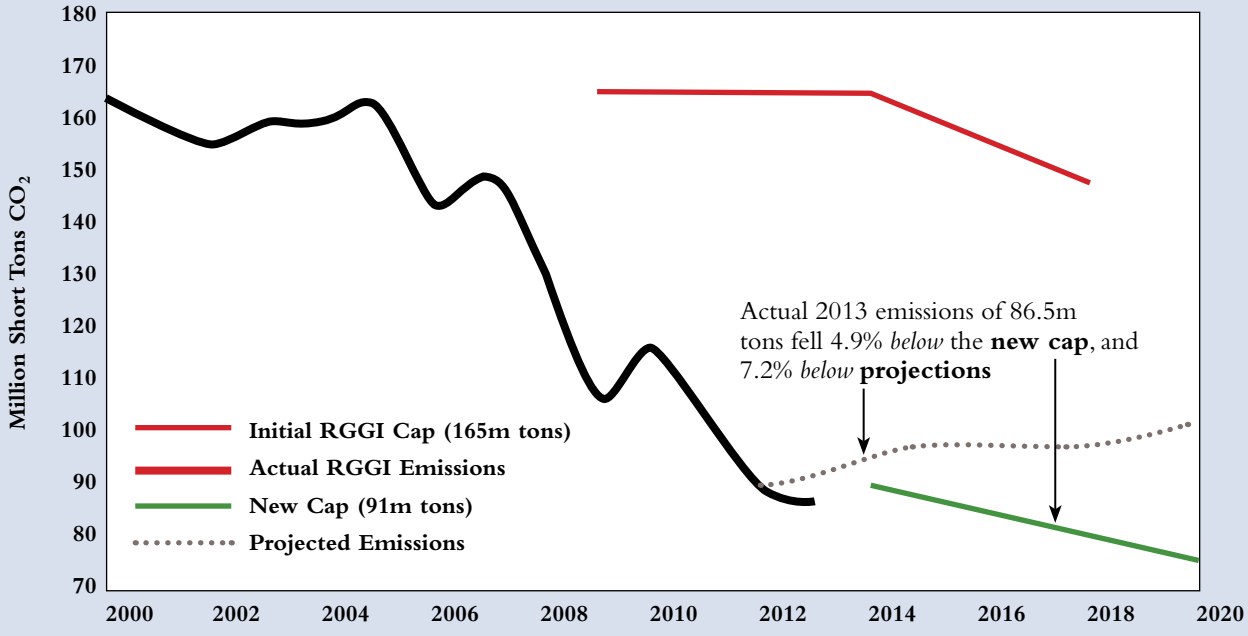
RGGI 2013 and 2014 emission levels continued to drop below adjusted projections and a significantly reduced cap, with levels at 4.9% and 5.2% below the cap for 2013 and 2014, respectively.[210]

Similarly, in California, the AB 32 cap-and-trade program has recently completed its first performance period, for calendar years 2013 and 2014. According to CARB's Mandatory GHG Reporting inventory, total GHG emissions across the compliance period decreased to approximately 146 million metric tons of CO_2e, 9% below the 2014 cap of 159.7 million metric tons.[212]

6.1.2.5 Generating Revenues and Enhancing Economic Benefits

Besides encouraging innovation and enhancing emission reductions as compared to command-and-control approaches, trading programs can generate revenues for related or other programs and policy goals, and have been correlated with enhanced economic growth and decoupling economic growth from emissions increases. For

Figure 6.1 **RGGI States Actual Emissions Compared to Cap and Projections**[211]



Sources: RGGI, Inc. and EPA

208 U.S. EPA, *Acid Rain Program 2004 Progress Report,* EPA 430-R-05-012, October 2005, available at http://www2.epa.gov/airmarkets/acid-rain-program-historical-reports.

209 Peter Shattuck & Jordan Stutt, *The Regional Greenhouse Gas Initiative: A Model Program for the Power Sector,* Acadia Center, July 2015, http://www.ourenergypolicy.org/wp-content/uploads/2015/07/RGGI-Emissions-Trends-Report_Final.pdf.

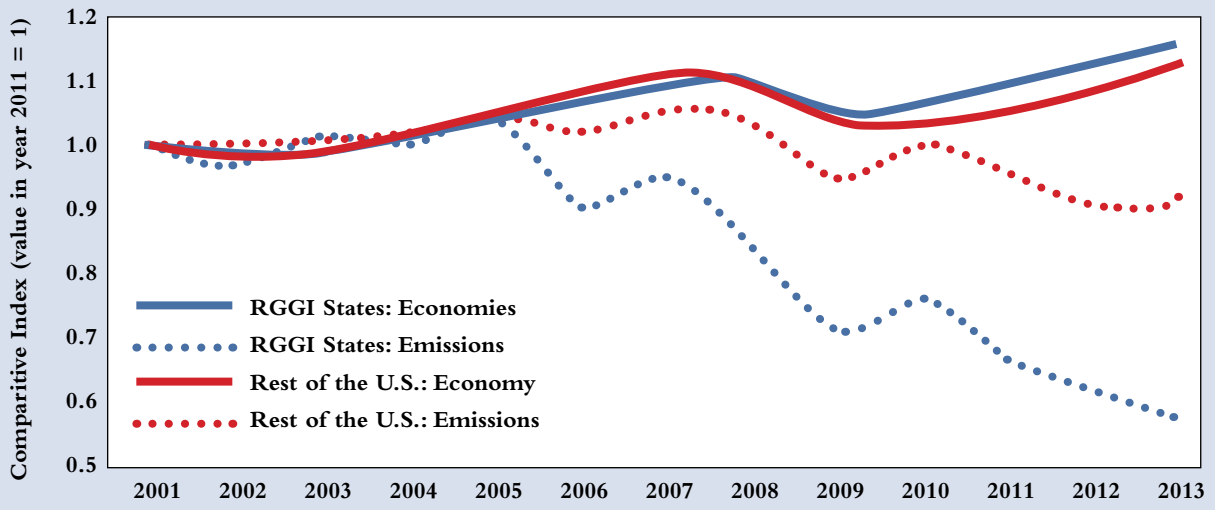
210 *Ibid.*

211 Figure taken from Shattuck et al., *supra* note 199.

212 Jonathan Camuzeaux & Tim O'Connor, *Cap and Trade under AB 32, Now it's an "Official Success,"* November 5, 2015, http://blogs.edf.org/californiadream/2015/11/05/cap-and-trade-under-ab-32-now-its-an-official-success/.

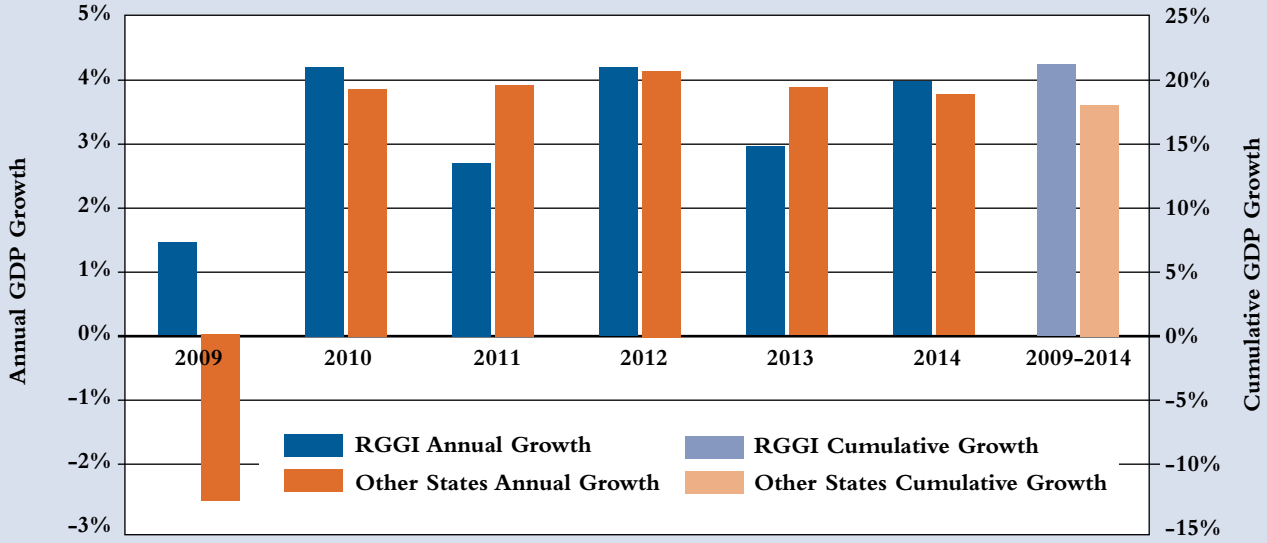
example, a substantial portion of revenues from allowance auctions are reinvested directly into RE and EE deployment. In addition, generated revenues can be reinvested in other economic needs and goals of the state. This could include investment in job training or other programs to support communities impacted by the shift in energy resources. Among RGGI states, a total of approximately $1.365 billion in revenues was generated from allowance auctions between September 2008 and June 2013. Of that total, approximately 7% was used for program administration; 64% was invested in RE, EE and other climate change related efforts; 16% was used for consumer assistance programs; and, about 12% was tapped to reduce state budget deficits.[213]

Figure 6.2 **Emissions Reductions and Economic Growth in RGGI States Compared to Remaining U.S. States**[214]



Sources: ENE analysis of data from Federal Reserve Bank of Philadelphia, RGGI, Inc., and EPA Clean Air Markets

Figure 6.3 **GDP Growth Rates in RGGI States Compared to Other States**[215]



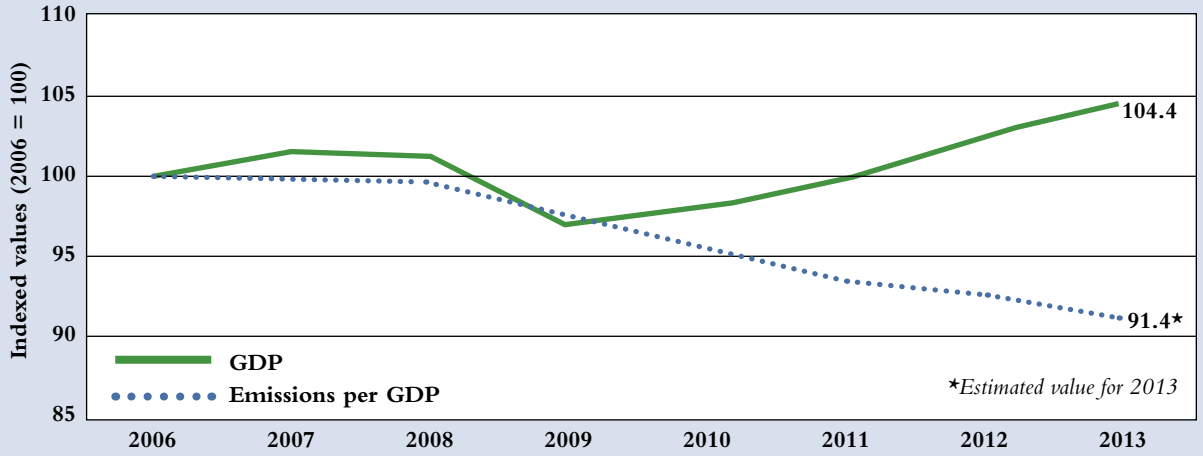
Acadia Center Analysis of data from Bureau of Economic Analysis

213 Jonathan L. Ramseur, *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Policy Makers,* Congressional Research Service, November 14, 2014.

214 Shattuck et al., *supra* note 199.

215 Shattuck & Stutt, *supra* note 209. Note that "Other States" includes all non-RGGI states with the exception of California.

Figure 6.4 **GDP and GHG Emissions in California Under AB 32 Cap-and-Trade**[216]
California economy continues to grow while becoming more efficient



Another important observation gained from existing trading programs is the decoupling of economic growth from emissions increases. While traditionally, increasing gross domestic product has been associated with increased fossil-fuel combustion and CO_2 emissions, the opposite trend has been observed for both RGGI and the California AB 32 programs. An overall positive economic trend, outpacing the rest of the nation, has been correlated with implementation of these programs. Under RGGI, CO_2 emission reductions outpaced the rest of the nation on a per-capita basis for the period 2000 to 2009, while the regional growth in gross domestic product (GDP) was double that of the non-RGGI states.[217]

In California, a job growth rate of almost 3.3% was observed during the first year and a half of the AB 32 program, compared to a 2.5% national growth rate. California GDP growth outpaced the national rate in 2011, 2012, and 2013, increasing by almost 6.6% during that time period. This economic growth was at least in part supported by the clean energy industry. Between 2006, when AB 32 was signed into law, and 2013, the first compliance year of the program, California saw more investment in clean energy technology than the rest of the nation combined ($21 billion in California vs. $19 billion for all other states). Advanced energy jobs grew 5% in 2014, with workers building solar panel arrays earning an average of $78,000 a year plus benefits.[218]

6.1.3 Additional Considerations Related to Trading Programs

Given the considerable benefits associated with market-based trading programs and the significant accommodations EPA has made in the final rule to encourage states to allow trading as a compliance mechanism, it is reasonable to ask why a state would consider adopting a plan that would limit or forego trading as a CPP compliance mechanism. Prior to discussing potential considerations that might persuade a state to restrict trading, it is worthwhile to reiterate that compliance flexibility is a basic tenet of the BSER emission guidelines. For most states, some mechanism for, and some degree of, averaging or trading flexibility will be necessary. Indeed, it is important to recognize that the form and level of the emission guidelines inherently demand that affected EGUs be granted a reasonable level of flexibility to achieve compliance. Considering the BSER strategies on which the emission guidelines are based, the form of the rate-based performance guidelines, and the performance levels reflected in the guidelines, it is evident that individual fossil fuel-fired EGUs in most cases would be unable to achieve the

216 *Ibid,* copied from Figure 1-1.

217 Rob Kerth & Rob Sargent, *A Record of Leadership, How Northeastern States Are Cutting Global Warming Pollution and Building a Clean Economy,* Environment Connecticut Research & Policy Center, April 2012, http://www.environmentconnecticut.org/sites/environment/files/reports/A%20Record%20of%20Leadership%20vCT.pdf.

218 Katherine Hsia-Kiung & Erica Morehouse, Carbon Market California, *A Comprehensive Analysis of the Golden State's Cap-and-Trade Program, Year Two: 2014,* Environmental Defense Fund, 2015, http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf.

Table 6.1 **Comparison of Existing Source Emission Guidelines to New and Reconstructed EGU NSPS Performance Standards and 2012 Baseline Performance**

Affected Source Type	NSPS UUUU Existing Units (lb/MWh-net)	NSPS TTTT New Units (lb/MWh-gross)	NSPS TTTT Reconstructed Units (lb/MWh-gross)	2012 Baseline Performance Eastern Interconnect (lb/MWh-gross)
Steam Generating Units and IGCC (generally coal-fired)	1,305	1,400	1,800 (>2,000 MMBtu/hr)	2,204
Stationary Combustion Turbines, Combined Cycle/Base Load (generally natural gas-fired)	771	1,000	2,000 (≤2,000 MMBtu/hr) 1,000	894

applicable performance standard, whether expressed as an emission rate or a mass limit, without reliance on some type of performance averaging, emissions crediting, and/or emissions trading. For example, the subcategory performance rates of Table 1 of Subpart UUUU are adjusted CO_2 emission rates that must take into account applied ERCs for replacement generation or avoided generation with zero associated CO_2 emissions. To implement these performance rates as emission standards, the state plan must at a minimum provide affected EGUs a mechanism for adjusting their CO_2 emission rates by applying qualified ERCs for demonstrating compliance.

Further, the levels of the Table 1 performance rates are well below the corresponding NSPS standards for new and reconstructed sources, and the alternative forms of the guidelines are designed to be equally as stringent. As shown in Table 6.1 below, the emission guideline for existing coal-fired steam units is lower than the corresponding guideline for new or reconstructed coal-fired steam units. The NSPS for new steam generating EGUs is based on the performance level expected for new, highly efficient, supercritical pulverized-coal units, with 20% of the emissions controlled by CCS. For existing sources, EPA determined that a greater level of emission reductions could be achieved through the application of flexible compliance mechanisms that allow for crediting of low- and zero-emitting power generation, and the BSER emission guidelines incorporate that presumption of compliance flexibility, relying in part on shifting or avoiding generation.

Thus, in planning to achieve compliance with the CPP, states will need to decide how to provide for compliance flexibility such that owners and operators of affected EGUs can meet the applicable emission standards. In addition, states will need to find ways to achieve a reduction in generation from existing fossil-fueled EGUs while still meeting the demand for electricity in a safe, reliable and affordable manner. One mechanism that can serve these multiple functions as part of a state plan is a trading program.

Given that flexibility is an indispensable component for affected EGUs to achieve compliance, and that interstate trading is a proven mechanism to provide flexibility, a trading approach may be a strong candidate for the state plan design. Nonetheless, there are several important considerations that could, for some states, at least raise the question of whether trading should be limited to some degree or should be rejected in furtherance of other goals. Some of those relevant considerations are discussed in this section.

6.1.3.1 Shift in Location of Environmental and Socioeconomic Co-benefits

CO_2 is a global pollutant, and the location of an emissions source does not affect the location or level of environmental harm resulting from the emissions. This is a key reason why a regional trading program is appropriate for reducing CO_2 emissions. However, CO_2 emissions resulting from fossil-fuel combustion are released in combination with other combustion pollutants that have a direct local impact on public health and welfare. Therefore, one important consideration related to emissions trading programs is that actions taken to reduce emissions are dispersed across a broad region, and may not occur in or near the localized community where the highest-emitting affected EGUs are located, or where the greatest exposure to localized emissions occurs. To the extent emission reductions are shifted away from local communities where they otherwise would occur without the benefit of trading, a loss of localized air quality co-benefits may occur in some places. These co-benefits would include significant reduc-

tions in particulate matter (PM), nitrogen oxides (NO_X) and sulfur dioxide (SO_2), as well as hazardous air pollutants. While these other pollutants are addressed by separate federal and state regulations and standards, including the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and permitting programs such as Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR), implementation of the CPP will bring additional reductions beyond those other programs. EPA's Regulatory Impact Analysis estimated that the nationwide impacts of implementing the final emission guidelines on a state-by-state basis would include reductions on the order of 300,000 tons per year of SO_2 and NO_X by 2030, when compared to a base case that presumes implementation of CSAPR, MATS, and other finalized or proposed regulations.

While these co-benefits would not be lost under a plan that provides for regional trading, the specific locations of the reductions could be shifted to different locations. A similar shift may occur for other environmental co-benefits, such as reduced impacts from wastewater effluent to receiving streams and water bodies.

Reduced use of fossil-fuel power generation can bring other co-benefits in addition to environmental improvements, and these other co-benefits may also be shifted to different locations or recipients under a market-based trading program as compared to a more direct "command and control" approach. For example, where trading of ERCs is allowed across a region, new renewable-generation facilities will be sited based on a number of factors, and could be located hundreds of miles from the generation source whose utilization is being reduced.[219] The investment to construct a new RE facility will bring other socioeconomic benefits to the area where the facility is located, such as temporary and permanent jobs, taxes, and purchases to support its construction, operation and maintenance. Programs to improve demand-side energy efficiency may occur in communities other than those where the highest-emitting EGUs are located, and those programs can bring increased property values and lower energy bills to the recipients.

However, concerns regarding local impacts can often be addressed through complementary programs or policies at the local or state level. The state can offer incentives to encourage investment in new RE construction within the state or within particular areas, to drive investment in particular renewable resources such as wind or solar energy, or to support innovative advancements in and deployment of technologies such as power storage or other transmission and distribution advancements. Furthermore, the trading program itself can be used to generate revenues for implementing such measures to avoid or mitigate shifts in co-benefits that might otherwise occur.[220]

State planners must also remain mindful that an overly rigid compliance approach adopted in the interest of preserving the co-benefits of CO_2 reductions from affected EGUs within the state or within localized communities could impact the cost of compliance.[221] Thus, to the extent a state is concerned about the potential for a loss or displacement of co-benefits under a trading-based state plan, the planning process should utilize modeling to evaluate projected differences in impacts based on differing plan approaches. Evaluation of different outcomes could include consideration of co-benefits, as well as compliance costs, power generation resource adequacy and grid reliability.

6.1.3.2 State Role in Selecting and Achieving Reduction Strategies

The state regulatory agency has a fundamentally different role under a plan that relies on a market-based trading program than under a more traditional or direct regulatory scheme. When a "command and control" or direct regulatory scheme is implemented, the regulatory authority generally specifies the control technology, equipment design, fuel specifications or work practices that will be applied to achieve the environmental goal. By contrast, with a market-based trading program, the regulatory authority specifies the environmental goal and the regulated entities typically have much broader freedom to elect the compliance strategies used to achieve the goal. In general, the market drives the reduction strategies relied upon to achieve the goal, although the state can exert influence on the market through policies, incentive programs, and other measures. In general, the broader the geographic region in which trading is allowed, the less control the state will have over how and where reduction strategies are employed.

219 Note that RE located in a mass-based state must demonstrate the renewable power is meant to be distributed for sale in the rate-based state issuing the ERC.

220 One example of such a program is the Clean Energy Incentive Program (CEIP), an opt-in program states can adopt that offers federal matches for set-asides used to incentivize early reductions, as incorporated in the final emission guidelines.

221 *See, e.g.,* Dallas Burtraw et al., *State and Regional Comprehensive Carbon Pricing and Greenhouse Gas Regulation in the Power Sector Under EPA's Clean Power Plan,* Resources for the Future, November 2014.

This is particularly true under an emissions budget cap-and-trade program, where the traded commodity is an allowable quota of emissions and affected entities can take whatever combination of means available and appropriate to align their emissions with their allowance holdings. The state retains somewhat more control under a rate-based trading program, because the traded commodity, an ERC, must meet pre-specified qualifying criteria. Thus, for example, the state can designate certain types of RE generation or EE programs as qualifying resources for ERCs, thereby requiring reduction strategies to occur within those parameters.

Viewed from a slightly different perspective, some states have already invested significant resources and effort to adopt and implement energy, economic and environmental policies whose success could be supported or hindered by the choice of reduction strategies to comply with the CPP. A state with specific energy, environmental or economic policy goals that are supported by particular CO_2 reduction strategies may consider those goals incompatible with a broadly applied trading program. However, there are many ways to achieve specific policy goals while still allowing trading. Also, a trading program can be used to drive certain policy goals. As noted above, under a rate-based plan, the state can qualify particular programs for ERC issuance. Under a mass trading program, allowance set-asides can be used to drive investment in desired RE or EE strategies. In either case, a state could retain or adopt complementary state measures such as RPS or EERS to implement specific energy goals. This can be accomplished either outside the state plan under an emission standards approach, or within the state plan under a state measures approach.

Some states may take the view that the full burden of compliance with a shift in energy and fuel resources should not rest with the power sector, but should instead be shared by all stakeholders. Where a state prefers to share the responsibility for success of achieving the CPP emission guidelines, a plan approach that incorporates state measures may be more appropriate. Alternatively, a shift in or sharing of responsibility for compliance could be achieved under a rate-based emission limit plan that relies upon administrative adjustments of CO_2 emission rates made by the state to apply ERCs in the compliance demonstration.

6.1.3.3 Legal Authority, Administrative Infrastructure and Implementation Costs

Some states may be concerned that their regulatory agencies do not have sufficient legal authority to adopt and implement a market-based trading program, in particular if the program will be used to generate revenue through an auctioning of allowances. This question should be examined early on in the planning process to allow adequate time for new or clarifying statutory provisions to be adopted by the state legislature, if necessary. Even where the legal authority to implement trading is clear, there may be a need to create new administrative infrastructures to support a trading program. In this regard, many states already have market-based cap-and-trade programs in place, which can serve as models and provide good information about the administrative costs associated with maintaining the trading systems.

In relation to identifying and assessing administrative requirements and costs associated with a trading program, it is important to note that the state's role does not include creating a marketplace or an infrastructure for trades to occur. The state regulatory agency need not broker ongoing sales of allowances or ERCs—this will occur outside of the environmental regulatory structure and in the context of an open and transparent marketplace. EPA notes that in cases where the state plan provides for the use of a trading instrument to achieve compliance, an organized and liquid market will naturally emerge to take advantage of the opportunities presented. As was observed during implementation of the Acid Rain Program, although Congress adopted statutory provisions to ensure that regulated sources could purchase allowances directly from EPA in the event a market did not develop, those provisions went unused. Sources engaged in trades directly with one another, and market brokers offered services to bring buyers and sellers together.[222]

Rather, the state's obligation includes providing and maintaining an electronic tracking system, assuring the system is adequately administered, and implementing all compliance and enforcement-related aspects of the plan. EPA cites accountability as a "critical principle" of a trading program, including both accurate measurement and reporting of emissions and online transparency of "complete, unrestricted data on trading, emissions, and compliance."[223] Ready access to complete and accurate data promotes the confidence of the public, as well as the business community, in the environmental and financial integrity of the program. It also facilitates enforcement,

222 80 Fed. Reg. at 64,731.

223 EPA, *Cap and Trade, Critical Principles,* http://www3.epa.gov/captrade/principles.html, accessed November 9, 2015.

allows for assessment of the effectiveness of the trading program, and supports the state's reporting obligations to EPA under the CPP.

The allowance or ERC tracking system must electronically record the issuance, transfers, surrender and retirement or cancellation of compliance instruments. The tracking system also must provide internet-based public access with functionality to generate reports. Notably, EPA has committed to the development of a tracking system that meets the approvability criteria, thus eliminating this administrative cost for the states. EPA is also considering what level of ongoing support might be provided in relation to the EPA tracking system, such as maintenance and technical support to user states.

In addition to the data necessary for tracking and accounting for allowances or ERCs, administrative systems to handle emissions-related data are critical. Here, again, EPA has normalized the required monitoring, record-keeping and reporting and has tied CPP emissions tracking to a federal program already in place for power plants under 40 C.F.R. Part 75. Having consistent, complete and accurate emissions data for sources subject to the program is important to ensure the integrity of any trading system. For purposes of a CO_2 trading program, the same data that would otherwise be required under the CPP to demonstrate compliance with a CO_2 rate-based or mass-based emission limit will be required.

While administrative costs will undoubtedly be incurred despite the added support provided by EPA in the final CPP, the costs of implementing and enforcing a trading-based program may be comparable to the costs of administering a more traditional approach. Review of self-reported emissions and compliance data, compliance evaluations and inspections, and enforcement action as needed will be necessary regardless of the plan approach. As seen in the RGGI program, only about 7% of the revenues generated from allowance auctions went toward the administrative costs to implement the program.[224]

6.1.3.4 Uncertainty Surrounding Regional Plans and Available Trading Partners

Perhaps one of the greatest concerns for states in making decisions regarding the adoption of a market-based trading program to achieve the CPP emission guidelines is uncertainty regarding what approach other states in the region will adopt, as well as what states would be available as partners for interstate trading. This concern can be met only through collaborative communications and sharing of information in the planning process. Toward that end, many groups are facilitating planning and information-sharing platforms, conferences, and periodic meetings. Coordinated planning exercises to evaluate mass vs. rate approaches and other aspects of potential regional vs. state-level compliance will prove valuable in reaching key planning decisions. For example, several nongovernmental organizations, including the Center for the New Energy Economy, the Great Plains Institute, the Nicholas Institute for Environmental Policy Solutions, the Georgetown Climate Center and the Bipartisan Policy Center, have facilitated meetings. ISOs and grid organizations are also coordinating planning and modeling work, including MISO, Midcontinent States Environmental and Energy Regulators and the PJM Interconnection.

6.1.3.5 Establishing Predetermined Penalties

Another important consideration in relation to a market-based program to drive compliance with the state's CPP performance limits is the cost of noncompliance. Under section 111(d), state plans must "provide for the implementation and enforcement of [the] standards of performance" adopted to implement the emission guidelines. Longstanding EPA guidance states, *"Stringent penalties for noncompliance are an integral feature of a well-functioning cap and trade program. These should be applied automatically in cases where a source does not have sufficient allowances to cover mass emissions during the compliance period."*[225] In general, the owner and operator of an affected EGU subject to a trading program would be subject to civil penalties under the CAA for any violation of the applicable emission standard, with each ton of unauthorized emissions and each day of the compliance period constituting a separate violation.[226] Nonetheless, enforcement under CAA provisions is subject to considerable discretion at the state level, with penalties determined on a case-by-case basis through consideration of several penalty factors. For a market-based program, adopting (1) predetermined penalties, or (2) explicit criteria for assessing penalties that would apply in the event of noncompliance with the applicable performance rate or allowance holding requirement will help to provide certainty, stabilize market signals, and establish an even playing field across states. Predetermined penal-

224 Ramseur, *supra* note 213.

225 EPA, *Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control,* EPA 430-B-03-002, June 2003.

226 *See* 80 Fed. Reg. at 65,031 (preamble to proposed federal plan requirements, section V.F.5).

ties could be set based on the level of emissions exceedance over the performance period, but could also take into account other factors or extenuating circumstances. Penalties can also take a form other than direct monetary payments. For example, the RGGI program includes a provision that failure to hold sufficient allowances to cover emissions at the end of a performance period will trigger a penalty requiring the source to provide allowances equal to three times the excess emissions during the subsequent performance period.[227] In addition, violators are subject to injunctive relief under the CAA enforcement provisions. Injunctive relief is generally determined for each case, and different states may arrive at different conclusions.

The need for a consistent approach to address noncompliance is one consideration that may raise concerns with adoption of a "ready-for-trading" approach in which the trading partners are not predetermined. Significant differences in the cost of noncompliance could compromise the benefits provided by a regional program, undermining the level playing field created by the normalized emission limitations, trading instruments, monitoring, recordkeeping and reporting, EM&V, tracking system, and other program elements. To address this concern, states may want to discuss enforcement provisions of the program with potential trading partners during the planning process. One approach a state could take in assessing penalties for noncompliance is to mirror the provisions that EPA adopts in a future final rule for the federal plan requirements that will apply in any state that fails to submit or adequately implement a state plan. In the proposed federal plan published alongside the final CPP, EPA proposed to establish automatic allowance deductions equivalent to two tons for each ton of unauthorized emissions.[228]

6.2 Rate vs. Mass Considerations and Decisions

The choice between a rate-based or a mass-based performance goal is one of the key decisions each state will face in designing the state plan. Several factors distinguish the application of a rate-based performance goal from application of a mass-based performance goal under the CPP, with each approach having some apparent advantages. The decision regarding which form of the performance standard to adopt is interdependent on other key state plan decision points, such as whether the state will elect a single-state or a multi-state plan; whether the state will utilize a trading program; or whether and how the state desires to incorporate RPS or EERS in the plan. Of course, existing state programs will also influence this decision. Other considerations may include the profile of the existing state energy sector and the state's energy policies. The choice of a mass- vs. a rate-based approach may in turn influence other aspects of the state plan and the compliance strategies implemented by affected sources. While the final CPP incorporates two different forms of rate-based standards as well as two different expressions of mass-based standards that are all intended to represent equivalent application of BSER, their implementation could result in differing levels of compliance flexibility, availability of trading partners, costs and ease of compliance, future fuel mix, and energy efficiency.

This section provides a discussion of rate-based and mass-based plan performance goals in the context of state plan design and implementation.

6.2.1 Rate vs. Mass Considerations for State Measures Plans

Any state measures plan must be mass-based, meaning that the plan must demonstrate compliance with the state's Table 3 or Table 4 mass-based emission goal, or combined multi-state mass goal, or approved state-derived mass goal with an alternative new source complement. The requirement to adopt a mass-based statewide compliance goal for a state measures plan could introduce certain challenges. For example, a state that intends to rely on state measures setting specific targets for RE and EE to be achieved by the state, by utility companies, or by other entities may find a rate-based goal better suited for implementing and tracking these measures. Similarly, if the state elects to adopt state-enforceable requirements for affected EGUs to achieve EPA's application of BSER Building Block 1 (heat rate performance) and Building Block 2 (generation shifting to existing NGCC units), a rate-based compliance demonstration may be more compatible. However, compliance demonstrations under the state plan will be based on mass emissions from affected EGUs, as opposed to compliance with the rate-based state measures. Due to the case-by-case nature of the state measures plan type, the discussion in this section is primarily focused on rate- and mass-based emission standards plans and may not be applicable to a state measures plan.

227 *Tools of the Trade*, *supra* note 225.

228 80 Fed. Reg. at 65,031 (preamble to proposed federal plan requirements, section V.F.5).

6.2.2 General Considerations for Rate- vs. Mass-based Performance Goals

Program impacts resulting from the choice between a rate-based and mass-based program are wide ranging. Differences in the two approaches could affect virtually every aspect of the state plan, from the ease of assuring adequate state legal authority, to the framework of the plan design, to the ease of implementation, compliance demonstrations and enforcement. State energy policy and the state's role in directing energy policies and shifts in energy profiles could also be impacted by this decision, including incentivizing of RE and EE, influencing trends in coal-based generation, incentivizing of new natural gas-fired EGUs, accommodating future energy demand load growth, and the response of the electricity market in terms of electricity cost and reliability. Notably, the state's desire to participate in a regional trading program could be a major influencing factor on the choice of rate- vs. mass-based performance goals, as states may only trade with other states using the same compliance metric.

Table 6.2 below provides an overview comparison of the two approaches for several areas of program impact. Keeping in mind that the implications of adopting a mass-based vs. a rate-based goal will be program-specific and interdependent on many other factors, this summary table is intended only as a starting point for a more robust analysis by stakeholders involved in the planning process. A more detailed discussion of each of the program impact areas shown in Table 6.2 is provided in the following sections.

Table 6.2 **Overview Comparison of Rate-based vs. Mass-based State Plans**

Program Impact	Rate-based	Mass-based
Performance Metric Options	1. Table 1 subcategory rate standards, with or without interstate ERC trading 2. Table 2 statewide rate-based goals applied uniformly, without interstate ERC trading 3. State-customized rate-based limits to achieve Table 2 goals, without interstate ERC trading 4. Table 2-based combined weighted goal under multi-state plan with multi-state ERC trading For all four options, compliance demonstration will involve adjusting actual emission rates with qualifying ERCs.	1. Table 3-based cap and allowance-holding standard under cap-and-trade program 2. Table 4-based cap and allowance-holding standard under cap-and-trade program 3. Table 3 plus state-derived new source complement cap and allowance-holding standard under cap-and-trade program 4. Standards under cap-and-trade program with broader source coverage or other flexibility features 5. Mass-based emission limits applied directly to affected EGUs to achieve Table 3 goals 6. State measures adopted to achieve Table 3 goals, with or without mass-based emission limits
Compliance Flexibility for Affected EGU Owners/Operators	Options 1 and 4: Strong flexibility when interstate or multi-state trading allowed. Can be somewhat less than cap-and-trade because state chooses which resources qualify for ERCs. (See Section 6.1.3.2) Options 2 and 3: Moderate flexibility can be achieved, but less than interstate trading programs because only "home state" ERCs can be used. Also can be somewhat less than cap-and-trade because state chooses which resources qualify for ERCs.	Options 1 through 4: Greatest flexibility provided by interstate/multi-state allowance-based cap-and-trade, because affected owners/operators can invest in any available measure to reduce emissions at any affected EGU, provided collective allowance holdings are below the cap. Moderate flexibility can be achieved by intrastate cap-and-trade. Choices may be limited to a degree by complementary state measures such as RPS and EERS that require affected EGUs to invest in particular strategies. Option 5: Mass emission limits with no trading can greatly restrict compliance options for individual affected EGUs. Option 6: Level of flexibility depends on state measures.

Table 6.2 **Overview Comparison of Rate-based vs. Mass-based State Plans,** *continued*

Program Impact	Rate-based	Mass-based
State Control over Compliance Strategies	Higher than mass-based because state determines what resources qualify for ERCs	Lower than rate-based because EGUs have more freedom to elect most cost-effective methods. However, state can assert influence or control through set-asides or complementary measures such as RPS or EERS, at the expense of flexibility.
Cost of Compliance	EPA modeling studies predict rate-based compliance costs to be approximately 60% higher than mass-based compliance costs.	EPA modeling studies predict mass-based compliance costs to be approximately 40% lower than rate-based compliance costs.
State Administrative Burden	Typically greater for rate-based plans, due to the need for ERC resource qualification, ERC credit application review and issuance, and ERC program verification and auditing.	May be less than for a rate-based program, because state is not directly responsible for administering RE and EE measures. Administrative burden is increased by creation of auctions or other state-administered allocation programs, set-asides, incentive programs and other measures.
Plan Demonstrations and Integrity Measures	Rate-based plans are not required to address leakage to new sources.	All mass-based trading plans must include provisions to address leakage to new sources or include plan performance demonstrations to justify why such provisions are not needed. Mass-based trading plans with broader source coverage or other flexibility features must include several additional plan components and demonstrations.
Compliance Metrics	May be more complicated than mass-based. Always involves accounting for ERC adjustments. Can bank ERCs for future compliance.	Options 1, 2 and 3 compliance demonstration is based on compliance with allowance retirements being equal to actual CO_2 emissions. Can bank allowances for future compliance. For Options 4, 5 and 6, compliance demonstration is based on stack CO_2 emissions compared to applicable state mass goal. Option 4 requires adjustments to account for net imports/exports of allowances.
Accommodation of Load Growth	• Rate limits adjust to accommodate demand growth—emission limit expands with utilization. Potential increase limited by level of unused capacity and availability of ERCs to meet performance rate. • CPP rate standards include increase in existing NGCC utilization to 75% summer capacity factor. • Increase in non-NGCC generation available through ERC market.	• Mass limits do not adjust to reflect change in demand on utilization for existing units. Increased utilization is limited by availability of allowances for purchase. • CPP mass goals include increase in existing NGCC utilization to 75% summer capacity factor. • Increase in non-NGCC generation available up to level of "excess Building Block 3" emissions (see discussion).
Impact on Future Power Fuel Mix	May favor existing NGCC generation over new NGCC generation, with reduction in coal and increase in RE likely equivalent to mass-based. (EPA RIA)[229]	Depending on how leakage is addressed, may favor new NGCC generation over existing NGCC generation, with reduction in coal and increase in RE likely equivalent to rate-based. (EPA RIA)

229 EPA, *Regulatory Impact Analysis for the Clean Power Plan Final Rule,* EPA-452/R-15-003, August 2015, replaced on October 23, 2015, Executive Summary.

Figure 6.5 **Relative Compliance Flexibility Among Plan Types**

6.2.3 Rate vs. Mass Compliance Flexibility

As discussed in Section 6.1, when compliance flexibility is increased, compliance costs are typically reduced. Therefore, states that aim to minimize compliance costs and impacts on consumer cost of electricity will likely weigh the level of compliance flexibility as a strong factor in the selection of a mass-based or rate-based plan.

Figure 6.5 depicts the relative level of compliance flexibility as a function of representative plan types. This figure provides a general guide or overview. Other types of plans are conceivable, and the compliance flexibility afforded by any specific plan will depend on the totality of the plan provisions and the particular circumstances of the affected EGUs.

Of note, the degree of compliance flexibility for affected EGUs is inversely related to the degree of control the state has over specific reduction strategies employed, at least to the extent market-based trading programs provide the compliance platform. For plan designs that impose mass emission limits on affected EGUs with few or no options for averaging or trading to achieve compliance, however, the affected EGU owner/operator has a more limited range of compliance options, and the state has little or no control over which of those limited options are utilized to comply.

6.2.3.1 Compliance Flexibility of Rate-based Plans

All rate-based plans, by the nature of the CPP emission guidelines, must provide for the qualification, issuance and application of ERCs to adjust actual emission rates from affected EGUs. This will necessarily involve the use of ERCs from low- or zero-emitting non-affected EGUs (e.g., RE sources) and/or avoided generation through EE measures. Thus, the state plan must provide for some form of ERC trading (i.e., investment in RE/EE projects, purchase or holding of title to ERCs), at least within the state where the affected EGUs are located. The consideration for increasing flexibility within a rate-based plan, then, has to do with whether the state elects to allow for interstate or multi-state trading of ERCs. A single-state rate-based plan that provides for interstate trading must utilize the Table 1 subcategory performance standards. Alternatively, a state can elect to participate in a multi-state plan, with a predetermined and closed set of participating trading partners, which can adopt a combined, generation-weighted, rate-based multi-state goal.[230] Either an interstate trading or a multi-state plan approach could increase compliance flexibility, lower cost, and support grid reliability.

In considering rate-based plans, it is important to keep in mind the distinction between criteria that qualify a resource for issuance of ERCs by a state, and criteria that allow the ERCs, once issued, to be traded among affected EGUs or other parties. ERCs may be issued for grid-connected qualifying resources[231] that occur in any rate-based state, and for new RE generation that occurs in a mass-based state but that is intended to serve load in a rate-based state.[232] If the state plan incorporates a particular type of resource and approves the particular provider as a qualified ERC resource, then the state can issue ERCs for the measure even if the avoided or replacement generation occurs in another state. Importantly, however, each MWh of qualifying resource can only be issued a single ERC, and

230 A multi-state plan could be revised to include additional states or exclude original participating states over time.

231 40 C.F.R. § 60.5800. Qualifying resources may include RE, EE, incremental NGCC or nuclear generation, and other measures as specified at 40 C.F.R. § 60.5800.

232 See *Chapter 7, Rate-based Emission Standards Plans* for a detailed discussion of limitations on qualifying ERC resources.

only by one state program (or multi-state entity).[233] Therefore, EGUs subject to a state program that does not allow interstate trading and is not participating in a multi-state plan can rely only on ERCs issued by the state in which they are located, although the ERC could conceivably represent avoided or reduced generation that occurred in a different state. Thus, the state plan can incorporate some opportunity for "interstate flexibility" even if interstate or multi-state trading is not allowed. Under an interstate or multi-state program, once issued by a participating state, an ERC can be purchased and relied upon for compliance by affected EGUs in any state that is participating in the trading program, regardless of where the avoided or reduced generation occurred.

6.2.3.2 Compliance Flexibility of Mass-based Plans

A mass-based plan can provide a great degree of compliance flexibility, or conversely could provide the lowest degree of compliance flexibility, depending on the design of the plan. If the state elects to adopt a mass-based plan that imposes a directly enforceable emission limit on each affected EGU, and makes no provision for averaging or trading, then the affected owners and operators must identify a compliance strategy that reduces emissions of each affected EGU to the required level. This could consist of a combination of heat rate improvements, CO_2 control measures, or a reduction in utilization. Reduced utilization could be accommodated through RE, EE or other measures that occur outside the affected EGU, but such measures would need to offset generation to the level required to achieve compliance at each affected EGU. Under a single-state plan that doesn't allow market-based trading, somewhat more compliance flexibility can be provided by allowing emissions averaging among affected EGUs within a facility, or by allowing averaging among affected EGUs under common control of the same owner/operator. In most cases, a single-state plan could offer greater flexibility through a market-based allowance trading program within the single state than could be achieved through emissions averaging. Clearly the greatest compliance flexibility for a mass-based plan is afforded through a regional trading market, which could be accomplished either through a multi-state plan or through a single-state plan that trades on an EPA-approved trading platform.

The compliance flexibility inherently provided by a mass-based trading program can be constrained to some degree through plan provisions or through out-of-plan parallel measures that limit or direct the compliance strategies employed by affected EGUs. For example, set-asides may limit the availability of allowances by requiring investment in particular strategies as a condition of obtaining the set-aside tranches. Or, establishment of a state-enforceable RPS can limit compliance flexibility by requiring the development of RE resources of a particular type or to a particular level. Thus, it cannot be assumed that a mass-based trading program will always afford more compliance flexibility than a rate-based trading program; rather, the particular circumstances and all interrelated program elements must be considered in context.

6.2.4 Rate vs. Mass Relative Cost

When rate-based and mass-based interstate trading schemes are compared across the same geographic boundaries, mass-based compliance has been found to provide virtually the same emission reductions at substantially lower cost than rate-based compliance. Lower cost impacts is one of the factors that lead many experts and stakeholders to prefer a mass-based approach.[234] For example, a modeling study of the proposed CPP performed by the Nicholas Institute for Environmental Policy Solutions concludes that the costs of a regional mass-based trading program are approximately 30% lower than costs under a regional rate-based trading program over the first ten to twenty years of the program.[235] Similarly, EPA's Regulatory Impact Analysis of the final CPP modeled illustrative examples of both a rate-based and mass-based flexible compliance approach. The analysis predicted almost identical emissions reductions for the two approaches, but estimated an incremental cost for the mass-based approach almost 40% less than the incremental cost of the rate-based approach.[236]

233 80 Fed. Reg. at 64,987; 80 Fed. Reg. at 64,907 ("State plan requirements must ensure that only one ERC is issued for each verified MWh. This is addressed through registration in the tracking system of programs and projects that have been qualified for the issuance of ERCs, to ensure that documentation is submitted only once for each RE/EE action, and to only one state program.").

234 *See, e.g.,* Georgetown Climate Center, *Clean Power Plan Implementation: Single-State Compliance Approaches with Interstate Elements,* May 2015; Resources for the Future, *State and Regional Comprehensive Carbon Pricing and GHG Regulation of the Power Sector Under EPA's Clean Power Plan,* November 2014; Michael Schnitzer, *Central Regional Technical Conference on EPA's Clean Power Plan (AD15-4) Pre-Filed Statement of Michael Schnitzer on behalf of Entergy,* March 31, 2015.

235 David Hoppock, Nicholas Institute for Environmental Policy Solutions, *Options and Implications of Multistate Coordination under the Clean Power Plan,* April 2015

236 *Regulatory Impact Analysis for the Clean Power Plan Final Rule, supra* note 229, at pp. ES-6 through ES-10.

Table 6.3 **Comparison of Emission Reductions and Costs of Rate-based and Mass-based Compliance for Final CPP, Based on EPA Integrated Planning Modeling**[237]

Projected 2030 Results	Rate-based Approach	Mass-based Approach
CO_2 Emission Reductions Below Base Case	-415 million short tons	-413 million short tons
Incremental Cost, from Base Case (2011 Dollars)	$8.4 billion	$5.1 billion

The cost of compliance and corresponding impact to consumer power costs may prove a compelling reason for states to choose a mass-based over a rate-based plan design. Still, it is important to consider the particular state or group of states in evaluating relative costs of compliance strategies, since these models reflect illustrative examples only.

6.2.5 Rate vs. Mass Administrative Burden

Another consideration for states in making the rate vs. mass decision is the relative initial and ongoing administrative burden of these two approaches, and the available funding resources to provide for implementation.

The development of a rate-based plan will require several initial administrative efforts. A number of regulatory and administrative infrastructure components are required for the generation and use of ERCs. First, the state must develop regulations to identify what resources will be allowed to generate ERCs, to establish eligibility rules and criteria for qualifying resources, and to define the procedural requirements for submittal, review, approval, registration and tracking of ERC eligibility applications. In addition, the state must adopt EM&V guidelines or regulations to define the minimum required protocols for verifying zero or avoided generation. The scope of these protocols will expand to the degree necessary for addressing all types of qualifying ERC resources, and could include a wide range of activities and technology across a broad variation of settings, from industrial to commercial to governmental to residential. Third-party verification providers will be required to accommodate all types of qualifying ERC resources. The state will also need to provide for the review of ERC credit applications and for the issuance and tracking of ERCs, and will need to assure that staff are provided for the ongoing review of applications as well as for data management. Determination of compliance under a rate-based plan will require review of affected EGU mass emissions, net generation, and ERC adjustments. The integrity and accuracy of operations, monitoring and reporting for both affected EGUs and ERC providers contribute to compliance, greatly expanding the potential need for state or third-party inspections and audits.

For a mass-based plan that relies upon cap-and-trade, fewer administrative and regulatory components are involved due to the inherent difference between ERCs and allowances. Nonetheless, the state will still need to create and/or adopt several infrastructure components for the program. First, regulations will be needed to establish the system for creating, allocating, issuing and tracking allowances. The tracking system will require staffing for system and data management and maintenance. If the state elects to use an auction system, provisions will be needed to establish and administer the auctions. Similarly, if set-asides are created, there will be an administrative process for awarding set-asides. Also, if the state will use revenues from allowance auctions to fund new energy programs or other new programs, additional administrative costs will be associated with those programs. Compliance and enforcement may be less resource-intensive under a mass-based program than a rate-based program, because emissions and allowance holdings are the only parameters that determine compliance. Also under a mass-based trading program, although non-affected EGU parties can hold and sell allowances, those parties do not directly impact compliance in the same way that ERC resources do under a rate-based program. Therefore, the potential scope of the compliance monitoring and auditing program is limited to the allowance tracking system and the affected EGUs.

With regard to funding the associated costs of a rate- or mass-based program, different mechanisms may be employed. For a rate-based program, ERC application fees can be one source of revenue for program administration. Demand-side energy efficiency program costs are typically collected through a standard per kWh surcharge to

237 *Ibid*. Data taken from Tables ES-2, ES-3 and ES-5.

the ratepayer.[238] For a mass-based program, revenues from allowance auctions have been successfully used to cover program costs.

Given the wide variety of specific plan design choices impacting program costs, revenues, and infrastructure requirements, a comparison of administrative burden and net cost to the state based solely on the selection of rate- vs. mass-based plan design is not conclusive. EPA estimated state costs for compliance, assuming two full-time staff equivalents, or 4,160 hours/year, would be needed to oversee program implementation, assess progress, develop possible contingency measures, perform state plan revisions and host public meetings, and prepare annual EPA reporting. Based on this estimate, EPA arrived at a nationwide state cost of compliance equal to $14,767,881 (2011$) for year 2030. EPA's state cost analysis did not distinguish between costs for a rate-based or mass-based program.[239]

6.2.6 Rate vs. Mass Plan Demonstrations and Integrity Measures

One factor to consider in choosing between a rate-based and mass-based approach is the difference in requirements for plan components and plan demonstrations. As is the case for the level of compliance flexibility and other plan performance characteristics, this consideration is interconnected with the decision of how trading is addressed by the plan design. In general, if a rate-based or mass-based plan is designed such that compliance with the Table 1, Table 2, Table 3 or Table 4 emission goals is mathematically assured (i.e., a streamlined plan), then plan performance demonstrations and plan component requirements are minimized. Otherwise, more detailed plan performance demonstrations are required and the plan must include corrective action triggers and, for state measures plans, federally enforceable backstop measures.

Some differences between rate- and mass-based plan demonstration requirements do exist, however. One notable difference between rate- and mass-based plans is that any state adopting a mass-based trading plan must incorporate plan provisions that address leakage to new fossil-fueled EGUs, or provide a demonstration that leakage would not occur at a level necessitating such provisions.[240] A rate-based plan that incorporates trading is not required to include specific requirements to address leakage to new sources, nor is a rate-based plan required to make a demonstration that leakage would not occur.

Several other plan component and plan demonstration requirements also apply to certain types of mass-based trading programs. Specifically, if a state relies upon a mass-based trading program that applies to a broader universe of sources than the Subpart UUUU-affected EGUs plus new EGUs, or that includes provisions that could have the effect of expanding the mass emissions cap for affected EGUs (such as cost containment provisions), then the plan is considered a state measures plan and must include a detailed performance demonstration of how the plan will achieve the Table 3 or Table 4 interim and final performance goals. Such mass-based plans must also include:

1) any emission standards applicable to affected EGUs as federally enforceable measures;
2) an accounting of net allowance imports and exports among affected EGUs across state boundaries;
3) corrective action triggers for imposing additional measures in the event interim and final goals are not obtained; and
4) a self-effectuating federally enforceable backstop that would apply in the event the plan fails to meet performance goals.

6.2.7 Rate vs. Mass Compliance Metrics

Substantial differences in the compliance metrics for rate-based and mass-based plans are apparent simply in the form of the respective standards. In all rate-based plans, compliance is demonstrated by actual monitored CO_2 emissions and monitored net generation at affected EGUs, adjusted by the application of ERCs. For rate-based plans, the compliance demonstration includes only "valid operating hours," which are hours for which both mass emissions and electric output monitoring data are valid. Rate-based plans may allow for the banking of ERCs to be used in future compliance periods. In this way, rate-based plans are temporally flexible, allowing affected EGUs to overperform in one compliance period and rely on that overperformance to offset underperformance in a future compliance period. Note that for a rate-based plan, "overperformance" may mean market generation of more ERCs than needed during a compliance period, as opposed to any relative improvement in the actual lb/MWh emission rate of the affected EGUs.

238 *Ibid.* at pp. 3-16. In addition, see EPA, Demand-Side Energy Efficiency Technical Support Document, August 2015, https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-demand-side-ee.pdf, for detailed annualized costs by state, by year, of an illustrative EE program scenario.

239 *Ibid.*, pp 3-18.

240 40 C.F.R. § 60.5790(b)(5).

Under a mass-based plan, the performance metrics required for demonstrating compliance vary with the specific plan design. For mass-based plans that directly impose mass emission limits on affected EGUs without a market-based trading program, compliance would be demonstrated based on actual monitored CO_2 emissions during the compliance period, as compared to the applicable emission limit. This approach does not afford temporal flexibility, except through the provision of multi-year compliance periods.

Under a mass-based allowance trading system, the requirement for each affected EGU to hold and retire allowances equal to the actual monitored CO_2 emissions during a compliance period constitutes the applicable emission standard. For mass-based plans where the cap, or emissions budget, is equal to or less than the state's mass CO_2 goal for affected EGUs (or for affected EGUs plus the approved new source complement), compliance with the plan performance goal is demonstrated based on compliance of the affected EGUs with the allowance holding requirement.[241] This plan type also affords forward-looking temporal flexibility, with unused allowances available for use in future compliance periods.

Notably, the compliance metrics that must be employed are significantly different for a plan relying on mass-based trading across a broader source coverage, including sources other than affected EGUs and new source EGUs, or with flexibility features that could effectively expand the cap, as well as for a plan with interstate links to such an expanded trading program. In these cases, affected EGUs must comply with the allowance holding and retirement emissions standard of the trading program. However, compliance with the allowance holding requirement is not sufficient for the state to demonstrate compliance with the Subpart UUUU mass emission goal. For these plans, compliance must be demonstrated based on affected EGUs' actual monitored CO_2 emissions as compared to the state mass emission goal for the compliance period, after adjustment for net imports and exports of interstate allowances.[242] This particular mass-based plan design does not afford the temporal flexibility generally achieved under trading programs, and further restricts the lateral flexibility usually achieved by the trading of allowances across a geographic region.

6.2.8 Rate vs. Mass Accommodation of Load Growth

A commonly cited distinction between implementing a rate-based and a mass-based plan is that rate-based plans are better able to accommodate load growth. This expectation is based on the fact that, under a rate-based plan, an increase in the utilization of affected EGUs will automatically result in a corresponding increase in the amount of CO_2 emissions allowed to demonstrate compliance. Of course, the level of increase in allowable emissions is bound by the level of unused capacity of the affected EGU inventory. In addition, under a rate-based plan increased utilization is bound by the availability of ERCs (e.g., incremental RE) needed to adjust the actual emission rate associated with the generation growth.[243]

In contrast, under a mass-based plan, the level of allowable CO_2 emissions from regulated EGUs is fixed for a given performance period and does not increase to meet an increase in load. Thus, compliance with a rate-based goal is not dependent on power demand that occurs during the performance period in the same way that compliance with a mass-based goal theoretically would be.[244]

It is useful to note, however, that in the final CPP, EPA has provided mass-based performance goals that are designed to minimize this difference between a rate-based and mass-based plan. First, both plan types provide the same level of load growth accommodation for existing NGCC units. Specifically, an increase in utilization of existing NGCC units up to 75% of the unit's summer capacity factor is an element of BSER. This level of NGCC load growth is presumed for in both rate-based and mass-based plans and is included in the development of the corresponding emission standards. Furthermore, any state adopting a mass-based plan must take steps to assure this generation shift to existing NGCC will occur by addressing potential leakage to new NGCC units. Therefore, increased generation for the existing NGCC category is not better accommodated under a rate-based vs. mass-based plan.

Additionally, each state's interim and final mass emission goals specifically incorporate incremental load growth from existing non-NGCC EGUs. The equation for deriving the mass goals sums two emissions components. The first component is the emissions determined by multiplying the state emission rate goal times the baseline (2012) affected EGU generation. The second component represents the emissions associated with the ability of

241 40 C.F.R. § 60.5825; 80 Fed. Reg. at 64,890.

242 40 C.F.R. § 60.5740; 80 Fed. Reg. at 64,891-94.

243 See *Chapter 7, Rate-based Emission Standards Plans,* for further discussion of ERCs needed to accommodate growth.

244 This is not meant to ignore the fact that the rate of emissions from a given EGU can be affected by utilization, as discussed in Section 9.4, Heat Rate Improvements.

affected EGUs to expand their output under a rate-based plan, if they were to deploy the amount of RE quantified under the application of Building Block 3 (replacement of fossil-fuel generation with incremental RE), and assuming "beyond compliance" cost-effective RE were deployed in the amount not included in developing the source category Table 1 performance rates.[245]

In developing the final emission guidelines, EPA utilized a regional approach, first calculating the effect of Building Block 3 for each of three regional interconnects based on that region's RE deployment potential. Because EPA selected the least stringent resulting regional value for each source category for each year as the CPP emission guideline, a certain level of cost-effective potential for RE deployment was untapped (each year, on a national scale) for compliance with the BSER emission guidelines. Under a rate-based plan, as described above, this incremental "excess" RE could be used to accommodate an increase in utilization of affected EGUs. To afford affected EGUs subject to mass-based plans this same opportunity to increase utilization, EPA quantified the RE potential that was untapped in developing the source category performance rate standards, and apportioned the total nationwide availability among the states based on each state's proportion of 2012 affected EGU generation. For each state, these RE MWh were converted to mass emissions at two times the state emission rate goal, and added as the second component of the state's mass-based goal.[246] EPA used this approach to develop the final mass-based emission goals for each state and for each compliance period, thereby reducing the potential for inequities in accommodating growth between rate-based and mass-based plans.

Thus, the CPP minimizes the potential differences between the rate-based and mass-based goals in two important ways: first, by providing equally for increasing existing NGCC load under both rate and mass goals; and second, by adding emissions to the state mass goals that represent cost-effective RE deployment untapped in setting the rate-based goals. Some difference in the potential to accommodate load growth between rate- and mass-based plans may remain, however, particularly because under a rate-based plan, qualified resources for issuance of ERCs are not restricted to RE, but can include EE and other measures.[247]

A state can estimate the potential remaining difference in load growth accommodation available under a rate-based plan as compared to a mass-based plan, and the amount of ERCs that would be required to access this potential by using the approach illustrated in Figure 6.6. Note that this simplified exercise is only intended to estimate a likely upper bound on the additional load growth that could be accommodated under a rate-based plan. States should also consider whether consumer demand for electricity is projected to grow, and to what level, in assessing the merits of a rate-based vs. a mass-based plan. More robust modeling to project the likely load growth that could be accommodated, or that might occur, would consider system constraints, generating resource reliability, potential for RE and other ERC resource deployment, and other factors. Nonetheless, this simple exercise can provide states with a preliminary assessment for planning purposes.

6.2.9 Rate vs. Mass Implications for the Future Power Generation Profile

For both the rate- and mass-based performance goal approaches, the profile of the power supply that is utilized to meet future power demand will have a significant impact on compliance. However, impacts on the supply profile could be different under the two approaches.

The Table 2 final performance goals for sixteen (16) states and one (1) tribe are more stringent than the final NSPS for new large natural gas stationary combustion turbines (i.e., <1,000 lb/MWh), and the remaining 31 states and 2 tribes have Table 2 final goals between 1,000 and 1,305 lb/MWh. Thus, most states simply could not meet the rate-based performance goals without reliance on RE and/or EE adjustments even if all coal- and oil-fired units were retired, and even if the remaining inventory of existing natural gas units performed at or near the new source NSPS standards. Therefore, under a rate-based performance program, states will see a reduction in generation from existing fossil-fuel units and an increase in generation from RE units, and/or avoidance of load growth through EE, which can be relied upon for purposes of CPP compliance demonstrations. Thus, for most states, the choice to rely on the EPA rate-based performance standard is a definitive commitment to deploy new RE generation and/or EE measures that will take the place of existing fossil-fuel generation. Under a mass-based program, reducing a portion of the generation

245 *See* EPA, *Clean Power Plan Goal Calculation Viewer and EPA, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule,* No. EPA-HQ-OAR-2013-0602, August 2015, both available at http://www2.epa.gov/cleanpowerplantoolbox.

246 *Ibid.*

247 For example, qualified biomass, waste-to-energy, CHP, and others. *See* 40 C.F.R. § 60.5800.

Figure 6.6 Example Calculation a State Could Use to Estimate the Potential for Accommodating Load Growth Under a Rate-based Plan vs. a Mass-based Plan

Step 1. Determine total available unused capacity of non-NGCC affected EGU fleet.[248]

Σ Summer CF (MW)*75%*8760 (hr) - Σ Baseline Generation (MWh) = Total Available Load Growth Capacity (MWh)

37,498,932 MWh – 33,314,157 MWh = 4,184,775 MWh total available non-NGCC existing load growth capacity

Step 2. Determine load growth accommodated under EPA mass-based goals as excess Building Block 3 generation.[249]

2,127,240 MWh = state share of not-captured BB3 generation, 2030

Step 3. Calculate unused capacity that was not accounted for in mass-based goal, which could potentially be accessed under a rate-based plan through reliance on ERCs not included in BSER.

4,184,775 MWh – 2,127,240 MWh = 2,057,535 MWh additional capacity available under rate-based plan that is not included in the mass-based goal

Step 4. Calculate the amount of ERCs required to access the additional unused capacity under a rate-based plan.[250]

First, estimate the adjusted MWh needed in the rate equation for each MWh of fossil generation to meet the Table 1 rate-based performance goal.

Average Baseline Performance Rate for non-NGCC ÷ 2030 Rate-based Performance Goal = Adjusted MWh Needed in Denominator for Each MWh of Fossil Generation

2,251 lb/MWh ÷ 1305 lb/MWh = 1.73 adjusted MWh

The adjusted MWh needed in the rate equation is 1 MWh fossil generation plus the required ERC. Subtract the 1 MWh of fossil generation from the adjusted MWh value to obtain the amount of ERCs needed for each MWh of increased fossil generation.

Adjusted MWh – 1 MWh Fossil Generation = MWh of ERCs Needed for Each MWh of Fossil Generation

1.73 MWh – 1 MWh = 0.73 required ERC per MWh increased fossil generation

Multiply the required ERCs per MWh fossil generation by the total available remaining capacity to obtain the total ERCs that would be need under a rate-based plan in order to access the maximum potential for load growth from existing units not accounted for in the mass budget.

Required ERCs (MWhERC/MWhF) * Available Capacity (MWhF) = Total ERCs Needed

0.73 MWhERC/MWhF * 2,057,535 MWhF = 1,491,819 ERCs

In this example, the rate-based plan would allow for up to 2,057,535 MWh of load growth from affected EGUs that is not accounted for in the mass-based goal. To access that load growth, 1,491,819 ERCs would be needed.

248 This example uses 75% of the summer capacity factor (CF) to represent potential usable capacity for existing non-NGCC EGUs (excluding retired units and NGCC units). Actual conditions and system constraints can vary widely. NGCC generation is not included in the analysis because both rate and mass CPP emission goals already account for increase in load on NGCC units to 75% summer CF.

249 This value is obtained directly from EPA's *Clean Power Plan State Goal Visualizer (XLSM),* Mass Goals Step 2 (tab titled "MG Step 2"), https://www.epa.gov/sites/production/files/2015-08/clean-power-plan-state-goal-visualizer_0.xlsm.

250 Note that this example does not consider the cost-effectiveness or availability of ERCs, and does not account for decreases in system load resulting from EE measures generating ERCs.

by existing fossil fuel-fired units will still be necessary to meet the performance goal, assuming that the mass-based goals are functionally equivalent to the corresponding rate-based goals. However, there could be more flexibility to utilize a wider mix of supply to make up the load shifted from existing units under a mass-based program, because load could be met (or demand reduced) by resources that would not qualify for ERCs under a rate-based program.

One aspect of fuel mix that may be of interest to states in comparing the results of a rate- vs. mass-based approach is the resulting capacity factor of the existing fleet under the two plan types. EPA's Integrated Planning Model (IPM) analysis of two illustrative compliance approaches, one a rate-based and one a mass-based strategy, projected less impact to fuel mix from the mass-based approach as compared to the business as usual (BAU) case. It should be noted that, while the two model cases are intended to be illustrative of state plan flexibility under the CPP emission guidelines, EPA notes the results may not be indicative of likely differences between the approaches as implemented by states and affected EGUs, given the wide discretion states have to design plans with varying components. Rather, the two sets of analyses are intended to illustrate two contrasting implementation approaches.[251] See Table 6.4 below for a summary of these results.

Table 6.4 **2030 Capacity Factor Impacts on Existing Fossil EGU Capacity Factor for Rate-based and Mass-based Compliance with Final CPP, Based on EPA Integrated Planning Modeling**[252]

Projected 2030 Results	Existing Coal Steam	Existing NGCC
Base Case	79%	51%
Rate-based	69%	61%
Mass-based	75%	54%

Table 6.5 presents the results of EPA's 2015 Integrated Planning Model (IPM) analysis of the 2030 U.S. generation mix. Under the mass-based case, existing coal steam utilization was at 75% CF and existing NGCC utilization was at 54% CF in 2030. Under the rate-based model, 2030 existing coal fell to 69%, while existing NGCC was at 61%.[253] While there appears to be a noticeable difference in impact on capacity factor or utilization rate for existing coal steam EGUs under a rate-based vs. a mass-based program, the projected generation level is nearly identical between the two scenarios, apparently reflecting a greater

Table 6.5 **2030 Projected Generation Mix for Rate-based and Mass-based Compliance with Final CPP, Based on EPA Integrated Planning Modeling**[254] **(Thousand GWh)**

Generation Type	Base Case	Rate-based	Mass-based
Coal	1,466	1,131	1,144
NGCC existing	1,042	1,230	1,090
NGCC new	324	100	207
Combustion Turbine	22	27	32
Oil/Gas Steam	22	11	11
Non-hydro Renewable	450	488	485
Hydro	340	341	340
Nuclear	783	777	785
Other	17	17	17
Total	4,467	4,122	4,110

rate of retirement under the rate-based scenario. In addition, the 2030 total load demand under the two scenarios is the same, with both rate-based and mass-based programs showing an 8% load reduction from the base case scenario. The projected total load as compared to the base case may reflect model inputs, which included the same incremental EE assumptions for both scenarios.

Relative outputs of existing NGCC units, new NGCC units and combustion turbines are notably different. As seen in Table 6.5, under the illustrative rate-based case, existing NGCC generation increased by 18% over the base case while new NGCC generation decreased by 69%. Mass-based compliance resulted in the same directional trend for NGCC generation, but to a much lesser degree, with existing NGCC generation increasing by only 5% compared to the base case and new NGCC generation decreasing by 36%, roughly half the increase seen under the rate-based model. This serves to illustrate the potential for leakage to new NGCC units to occur under a mass-based program; note that leakage was not specifically constrained under either model scenario. Neither scenario favored deployment of new RE as compared to the other,

251 *Regulatory Impact Analysis for the Clean Power Plan Final Rule, supra* note 229, at p. ES-4.

252 *Ibid.* Data taken from Table 3-10.

253 *Ibid.*, pp. 3-24 to 3-25.

254 *Ibid.* Data taken from Table 3-11.

with both approaches increasing RE over the base case by approximately 8% to 9%.

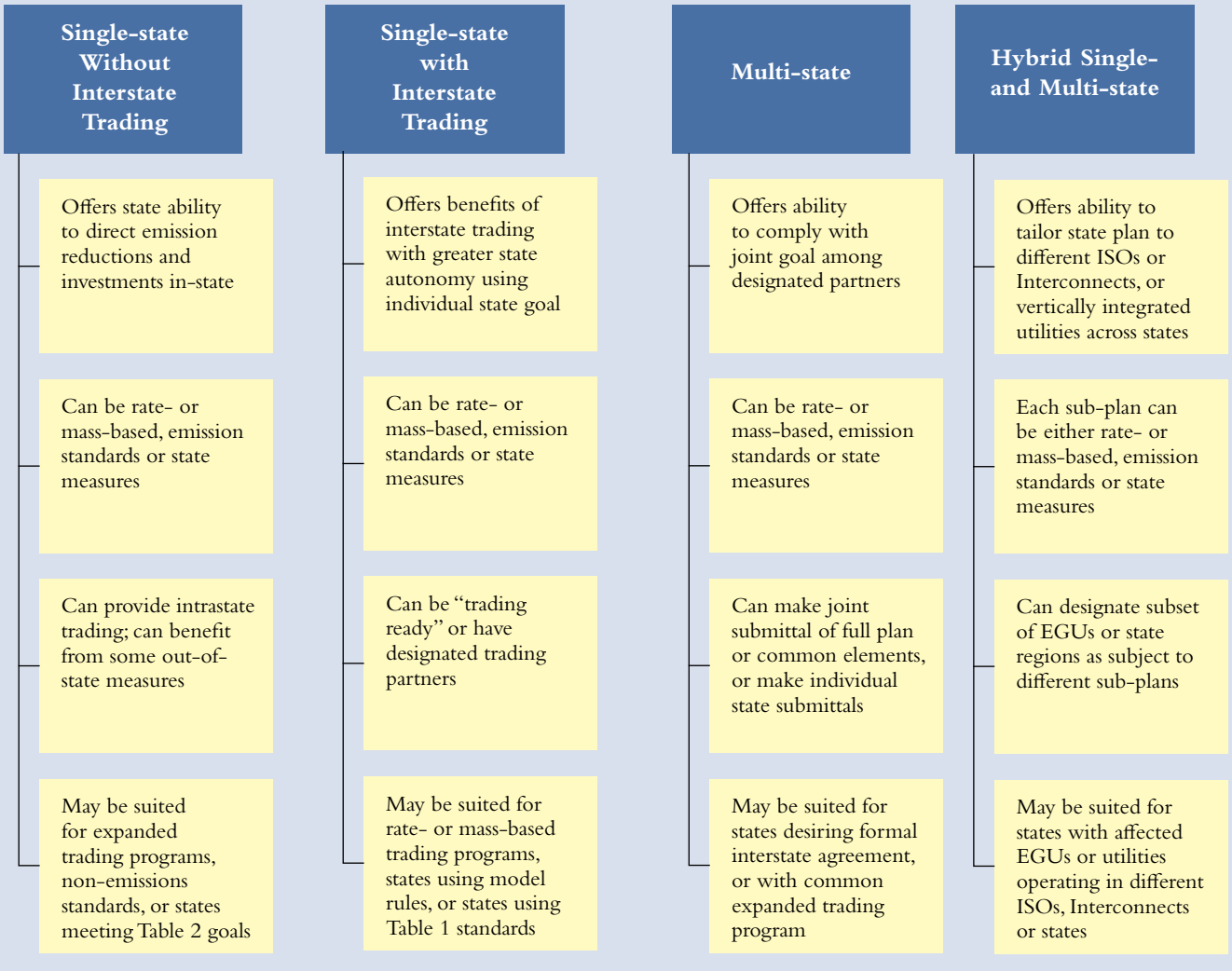
While illustrative only, EPA's IPM analysis supports the premise that both a rate-based and a mass-based program design can accommodate load growth, while still achieving the CPP emission goals.

6.3 Single vs. Multi-state Considerations and Decisions

CO_2 emissions have a global effect in contributing to climate change. Furthermore, the system by which electricity is generated, transmitted and distributed is a highly integrated interstate system operating across broad geographic regions (even including international exchange). In addition, several states are already working collaboratively to reduce CO_2 emissions from power plants on a regional basis. In consideration of these and other factors, Subpart UUUU provides that two or more states may coordinate or develop a plan with other states to implement the Subpart UUUU emission guidelines.

With regard to interaction with other states, the CPP provides states with a number of plan design options, ranging from a plan with no interaction to a plan with broad linkage across multiple state lines. First, the plan may be either a single-state or a multi-state plan. The primary distinction between a single-state and multi-state plan is that a single-state plan retains the individual state goal, while a multi-state plan establishes a joint goal. Within the single-state plan type, the plan can either be self-contained, with no interactions involving affected EGUs in other states, or it can provide for interstate trading of ERCs or allowances. In addition to these different approaches for single- or multi-state plans, a state can implement a plan

Figure 6.7 **Single-state and Multi-state Plan Options**



with single-state characteristics across parts of the state or affected EGU fleet while also joining in a multi-state plan for other portions of the state or affected EGU fleet.

Figure 6.7 provides an illustrative map of the various ways in which a state can plan or coordinate with other states. This section provides an overview of these different options available to states, with a discussion of the relevant factors states may want to consider in deciding which option will best suit their circumstances.

6.3.1 Single-state Plans

The single-state plan allows a state to act independently, designing the plan in consideration of the state's own policy and practical goals without the need to reach consensus among a group of states. The individual state is wholly responsible for designing, implementing and enforcing measures to comply with the emission performance goals, and for every other aspect of CPP compliance. Also, the state has no liability for failure of another state to meet compliance deadlines, performance goals, or other compliance requirements. In addition to maintaining state independence, a single-state plan approach will likely take less time to develop. Single-state plans are afforded all of the flexibility allowed under Subpart UUUU for selecting any feasible CO_2 reduction strategies; for selecting an emission standards plan or a state measures plan; and for demonstrating compliance with rate-based or mass-based goals.

Independence in decision-making, responsibility and accountability may prove a compelling reason for some states to develop and submit a single-state plan. Incompatibility of energy and environmental policies and goals within the region could make a multi-state effort seem a daunting task. Some state air administrators may conclude that there is simply not enough time to obtain the authorization at the state level for entering into a multi-state compact, or that there is not sufficient time to coordinate, reach consensus, and adopt a multi-state plan. Also, each individual state must be prepared to act independently to comply with the CPP requirements in the event a multi-state coalition dissolves, or some members withdraw or fail to meet commitments under the multi-state agreement.

In addition to these largely administrative and policy-based considerations, some states may conclude that a single-state plan best fits their needs due to the infrastructure of their energy sector. Notably, a few states remain largely self-contained with regard to electricity generation and/or distribution. In Texas, for example, the ERCOT region (one of the three North American grid interconnections) covers 75% of the land area of Texas and 85% of the state's electricity load, including approximately 22 million people. ERCOT does not extend outside of Texas. Other examples of states with a power generation and/or distribution infrastructure that is largely or entirely self-contained include California, Hawaii, Alaska, New York and Vermont. Interestingly, several of these states have already joined multi-state initiatives, demonstrating that a self-contained infrastructure does not always outweigh the potential benefits of regional collaboration.

6.3.1.1 Single-state Plans Without Interstate Trading

A single-state plan can be designed to be fully self-reliant, in the sense that all affected EGUs within the state would be required to demonstrate compliance with emission standards without the trading of allowances or ERCs across state lines. This type of plan provides affected EGUs less compliance flexibility than other plan types, while affording the state greater autonomy in customizing emission standards as well as greater control in directing CO_2 reduction strategies and economic investments to occur within the state. A single-state plan without interstate trading could be an attractive option for a state with an affected EGU fleet that collectively could meet the Subpart UUUU emission goals through in-state strategies in a reliable and cost-effective manner. Such a plan can still provide for compliance flexibility through averaging or trading provisions among affected EGUs within the state, which could provide the best balance of concerns for some states.

Although a self-reliant single-state plan would not accept allowances or ERCs issued by another state, affected EGUs in the state could still benefit from actions that occur in a different state. Due to the interconnected nature of the power sector, it is possible, and perhaps even likely, that new RE deployed in another state or EE programs implemented in another state could reduce generation from affected EGUs in a state with a plan not participating in an interstate trading program. If the plan is a mass-based intrastate cap-and-trade program, even though out-of-state allowances would not be available, the need for allowances may nonetheless be reduced through actions taken in other states. A state that is a net exporter of energy and that adopts a mass-based plan may be most likely to benefit from out-of-state EE and RE deployment through reduced demand on the affected EGU fleet. States that are net importers of power are less likely to see a reduction in emissions from their affected EGUs when consumers in other states reduce demand, or when RE is deployed in another state.

A rate-based single-state plan without interstate trading could also take advantage of out-of-state RE deployment, if it occurs in an interconnected mass-based state and a power purchase agreement or contract for delivery of power to the state is executed. In such a case, the RE resource could qualify for the issuance of ERCs by the state where the electricity would be delivered[256] and could sell those ERCs to affected EGUs in the state without the need for interstate trading. Note, however, that if interconnected states in the region are also rate-based, new RE deployment can only be issued ERCs by the state in which the RE resource is located, regardless of where the power is delivered, and those ERCs could not be relied upon by EGUs in another state that does not allow interstate trading.

As discussed in Section 6.1.3, there are some possible advantages of a single-state plan that involves only intrastate trading, and perhaps one of the most significant is its ability to target the co-benefits of compliance within the state. If affected EGUs must rely on actions taken at the affected EGUs, together with new RE, EE or other measures occurring within the state, then the capital invested in those measures will also be made within the state, generating in-state economic benefit. Similarly, if allowances from out of state cannot be used to match actual emissions occurring within the state, then the CO_2 mass emission reductions required for compliance, together with corresponding reductions of other pollutants, must occur within the state as well. The desire to keep the co-benefits of CPP compliance "at home" could be a major driving factor in a state's decision to adopt a single-state, self-reliant plan, particularly if the potential for in-state emission reductions and/or RE and EE resource deployment is sufficient to achieve compliance at a reasonable cost and without sacrificing grid reliability.

For a state that wishes to adopt a rate-based plan, an additional consideration for a single-state plan with no interstate trading is that the Subpart UUUU Table 2 statewide performance rates could be used as the compliance goal. Since the source-category emission-rate performance standards must be used for intrastate trading among rate-based states, the ability to average performance across coal and natural-gas EGUs is lost with rate-based interstate trading. For some states, the ability to rely on a combined performance rate across the statewide fleet of affected EGUs through intrastate trading could make compliance much easier to achieve and could offset the benefits of interstate trading. A similar circumstance could exist if the state wishes to develop customized rate-based performance standards (e.g., based on technology, fuel, age, past performance or other factors) that would be enforced to achieve compliance with the Table 2 statewide performance standard or with the Table 3 or Table 4 mass emission goals.

Another plan type that may lend itself to consideration of a single-state plan without interstate trading is a state measures plan. State measures plans can be broadly grouped into two types:

1) Plans that involve an expanded trading program (i.e., a trading program that applies to a broader universe of sources than affected EGUs and new fossil EGUs, and/or that includes provisions such as offset or cost containment provisions which could effectively expand the emissions budget); and
2) Plans that involve emission strategies that are not emission standards, such as operating limits, RPS, EERS, or other measures.[257]

If a state is implementing an expanded trading program, some additional demonstrations and restrictions would apply if other state plans link to the state measures plan through an intrastate trading platform. In particular, such an intrastate trading program would require tracking and reporting of net imported/exported allowances, and reliance on actual emissions adjusted to reflect net imports/exports to demonstrate compliance against the statewide Subpart UUUU Table 3 or Table 4 mass emission goal, in lieu of reliance on allowance holdings to demonstrate compliance. Thus, the implementation and compliance demonstration of a single-state plan without intrastate trading would be easier and in some ways more flexible if the plan is restricted to intrastate trading. For a state measures plan that employs enforceable emission reduction strategies that are not emission standards, intrastate trading is less likely to enhance compliance flexibility and could add unnecessary complexity to the program.

In summary, the following state strategies or circumstances could warrant consideration of a single-state plan without intrastate trading:

1) A state having an affected EGU fleet that collectively could meet the Subpart UUUU emission goals through in-state strategies in a reliable and cost-effective manner;
2) A state that is well-positioned to benefit from out-of-state actions without the need for intrastate trading of allowances or ERCs;

256 40 C.F.R. § 60.5800.

257 A state measures plan could combine both of these approaches.

3) A state that prioritizes keeping economic, social and environmental co-benefits of compliance within the state;
4) A state for which use of the Subpart UUUU Table 2 performance rates and/or customized emission standards facilitates compliance;
5) A state that intends to implement an expanded trading program involving non-affected EGUs or special provisions such as offsets or cost containment measures; and/or
6) A state that intends to rely on state measures deployed within the state that are not emission standards, such as operating limits, RPS, or EERS.

This list is intended only to illustrate some of the circumstances for which a self-reliant, single-state plan may offer benefits to the state. There may be other circumstances that would lead a state to consider and adopt a single-state plan without interstate trading, as discussed in Section 6.1. Also, a single-state plan without interstate trading would not necessarily be the best solution for a state in every case where one of the above circumstances applies.

6.3.1.2 Single-state Plans with Interstate Trading

A state may submit a single-state plan that provides for interstate trading. This plan type can provide all of the benefits of interstate trading, without the need for a formal agreement among state trading partners and without combining the individual state goals for purposes of demonstrating compliance. Through this plan type, a state remains more autonomous in developing legislation, regulations, and other plan components than with a multi-state plan, and remains solely responsible for compliance with the CPP emission goals. Another state's failure to meet targets would not trigger corrective actions or federal backstops.

As discussed in detail in Section 6.1, interstate trading as a mechanism to achieve CPP compliance offers numerous and substantive benefits. In summary, those benefits can include:

1) Enhanced compliance flexibility;
2) Lower compliance costs;
3) Supporting grid reliability;
4) Incentivizing technology innovation;
5) Enhancing emission reductions;
6) Generating revenues; and
7) Enhancing the social and economic benefits of compliance.

While an intrastate trading program can offer some of all of these same benefits, trading across a wider geographic region and among a larger universe of affected EGUs and third parties in a more open market can increase the level of benefits provided. Single-state plans can be designed to provide for interstate trading through two options. First, the plan can be made "trading-ready" by including provisions to authorize trading with any other state that has an EPA-approved plan and by meeting minimum criteria, as described below. Alternatively, the plan can designate specific approved trading partners.

Individual rate-based state plans can allow for interstate trading of ERCs, meaning that an ERC issued by one state could be used for compliance by an affected EGU in a different state, only if the state plan adopts the Subpart UUUU Table 1 source category emission standards as the compliance metric.[258] Furthermore, the state plan can only recognize ERCs issued by a state with an EPA-approved plan that also adopts the Subpart UUUU Table 1 emission standards. States participating in interstate ERC trading must link with their trading partners through an ERC tracking system that is either a joint system, an interoperable system, or an EPA-administered tracking system. Similarly, a single-state mass-based plan can provide for interstate trading of allowances, provided that the trading program of each participating state is part of an EPA-approved state plan and that each participating trading program is implemented using an EPA-approved or EPA-administered allowance tracking system. EPA will review the adequacy of the tracking system as part of the plan review and approval process.

Both single-state rate-based interstate trading programs and single-state mass-based interstate trading programs can be designed either to be "trading-ready" or to specify designated trading partners.[259]

Single-state Plans that Are "Trading-Ready"

A "trading-ready" program is one that does not specify designated trading partners, but instead specifies a designated ERC or allowance tracking system, which must be EPA-approved or EPA-administered. A rate-based "trading-ready" single-state plan must include regulations recognizing ERCs issued by any state with an EPA-approved plan that also relies on the designated EPA-approved joint or interoperable tracking system, or the designated EPA-administered tracking system. A

258 40 C.F.R. § 60.5750(d)(2).

259 80 Fed. Reg. at 64,892.

mass-based "trading-ready" single-state plan will include regulations recognizing allowances issued by any state with an EPA-approved plan that also relies on the designated EPA-approved or EPA-administered tracking system. Because state trading partners need not be designated by name, the group of trading partners could change over time, i.e., with additional state plans being approved as "trading-ready," without the need for each participating state to revise the state plan.[260]

This approach is the simplest design to provide for interstate trading, since it does not require a formal agreement with other participating states and furthermore does not require identifying the trading partners upfront. In addition, EPA has proposed, and plans to finalize, a model rule for both a "trading-ready" rate-based and mass-based interstate program, which will be presumptively approvable once finalized. This further simplifies designing this type of program. On the other hand, with a "trading-ready" approach that does not designate trading partners, the state may have little certainty about which other states or how many other states will participate. This can make planning difficult, since the availability of ERCs or allowances from outside the state cannot readily be projected. Further, for mass-based interstate trading programs there are additional considerations that add complexities to plan design and implementation, even for "trading-ready" plans. Those additional complexities are discussed later in this section.

Single-state Plans with Designated Trading Partners

In lieu of a "trading-ready" interstate trading program, a state plan could designate one or more approved state trading partners whose ERCs or allowances could be used by affected EGUs within the state to demonstrate compliance. Such designated trading partners would use a shared joint tracking system, interoperable tracking systems, or EPA-administered tracking system.[261] With the designated-partners approach, individual state plans would be submitted and approved separately, and the approval of one plan would not hinge on the approval of another (although trading could only occur among state partners with EPA-approved plans). Each state plan may require revisions to include additional trading partners or remove trading partners over time.

States with materially consistent rate-based trading regulations that designate trading partners and elect to use a shared ERC tracking system could also implement a joint ERC issuance program. Under such a program, ERC resources in all participating states would submit a common application for qualification and issuance of ERCs, and issued ERCs would be available for use by affected EGUs across all states.[262]

Single-state trading plans with designated trading partners offer greater certainty for affected EGUs, and can allow states to better project availability of ERCs or allowances for compliance. Under a rate-based program, the designated-partners approach also offers participating states greater control over the specific types and location of ERC resources that will be relied upon for compliance, and can provide a greater level of confidence in the administration of ERC application reviews and ERC issuance. Implementation of a joint ERC tracking system and joint ERC issuance program could further enhance consistency in ERC application reviews and issuance, and could reduce administrative costs. Under a mass-based program, a designated-partners approach still affords participating states control over the protocol that will be used for the allocation of allowances within the state budget, including any set-asides and investment of any revenues generated from allowance auctions.

Special Considerations for Single-state Mass-based Interstate Trading Plans

As noted above, there are some additional considerations for mass-based interstate trading programs that must be addressed in planning and designing the state program. For linked mass-based trading programs, participating states could be subject to different approval criteria, and different metrics may be used by EPA to determine compliance, depending on the structure and scope of each individual state's plan.[263] These differences have to do with whether the individual state plans apply to affected EGUs only, to affected EGUs plus new fossil fuel-fired EGUs, or to a broader set of fossil-fuel combustion sources that are not subject to Subpart UUUU or Subpart TTTT. Figures 6.8 and 6.9 illustrate the plan compliance demonstration requirements that apply to specific types of single-state mass-based plans, based on the types of sources subject to their program and their linkage to other state plans.

State plans that apply only to affected EGUs and state plans that apply to affected EGUs plus new fossil fuel-

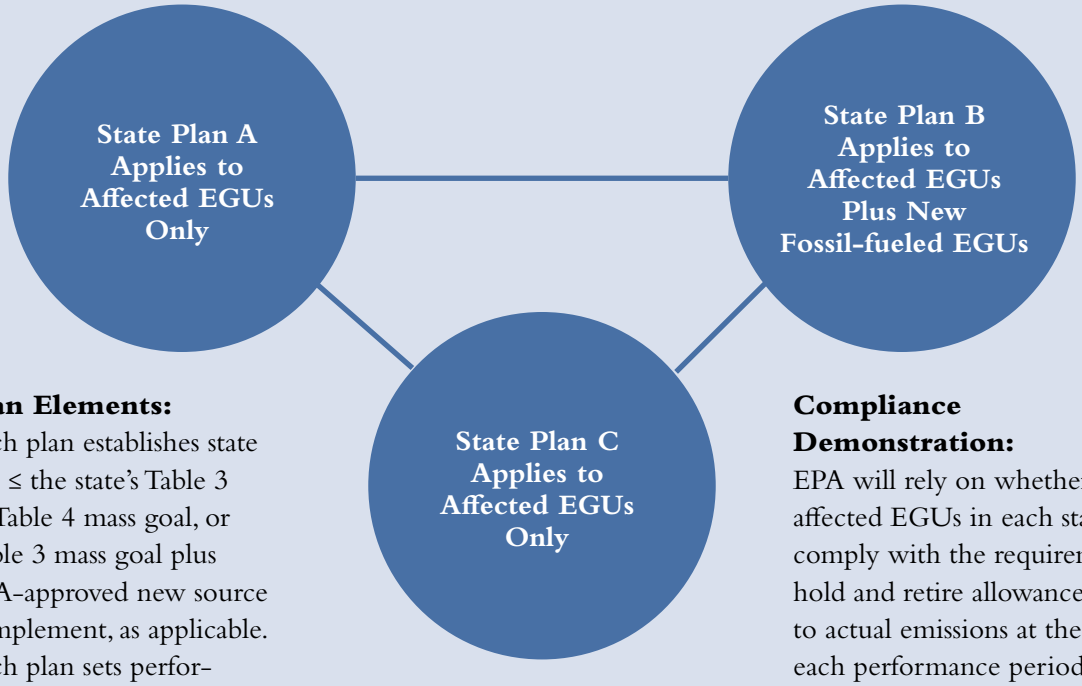
260 80 Fed. Reg. at 64,910-11.

261 It is possible that the shared or interoperable ERC tracking system could use the same software as the EPA-administered tracking system, or states could customize applications to meet their needs.

262 80 Fed. Reg. at 64,910-11. EPA refers to this approach as a "specified bilateral linkage."

263 80 Fed. Reg. at 64,893-94.

Figure 6.8 **Linkages Among Mass-based Programs that Apply to Affected EGUs Only or to Affected EGUs Plus New Fossil-fueled EGUs**



Plan Elements:
Each plan establishes state cap ≤ the state's Table 3 or Table 4 mass goal, or Table 3 mass goal plus EPA-approved new source complement, as applicable. Each plan sets performance periods the same as CPP interim and final performance periods.

Compliance Demonstration:
EPA will rely on whether affected EGUs in each state comply with the requirement to hold and retire allowances equal to actual emissions at the end of each performance period. Use of allowances banked from prior performance periods can be used in this demonstration.

fired EGUs are treated essentially the same, and may link to each other with no special or additional requirements. For plans that apply to new fossil-fueled EGUs, this is true whether the plan adopts EPA's new source complement (i.e., uses the Table 4 mass goals) or adopts a state-derived new source complement that is approved by EPA. For linkages among these types of plans, provided each state's compliance periods are consistent with the interim and final CPP performance periods, and provided each state's mass emissions cap is less than or equal to the Table 3, Table 4 or Table 3 plus EPA-approved new source complement mass goal level, as applicable, then compliance with the state's emission goals is demonstrated if the affected EGUs hold and retire allowances equal to their actual reported emissions. Allowances may be banked and used for compliance in a future compliance period if the state plan allows.

For interstate trading involving any single-state mass-based trading programs with broader applicability (i.e., programs that also cover emission sources beyond affected EGUs and new fossil fuel-fired EGUs), different requirements apply. During the individual state plan review process for linked state trading programs where one or more of the trading programs has expanded applicability, EPA will review each linked plan to evaluate whether the linkages would allow the affected EGUs (and new fossil-fueled EGUs, if appropriate) in each to meet the state's mass-based emission goals.[263]

Once approved, for each plan with a trading program that does not have broader applicability, achievement with the state's applicable mass emission goal will be demonstrated by that state's affected EGUs' compliance with the allowance-holding and retirement provisions of the trading program (i.e., with the mass emissions standard to which they are subject).[264]

For each plan with a trading program that does include a broader set of emission sources, compliance

263 80 Fed. Reg. at 64,893.

264 80 Fed. Reg. at 64,893 ("The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources…").

Figure 6.9 **Compliance Demonstration for a State with an Expanded-applicability Mass-based Interstate Trading Program: Accounting for Net Imports and Exports, Example 1**

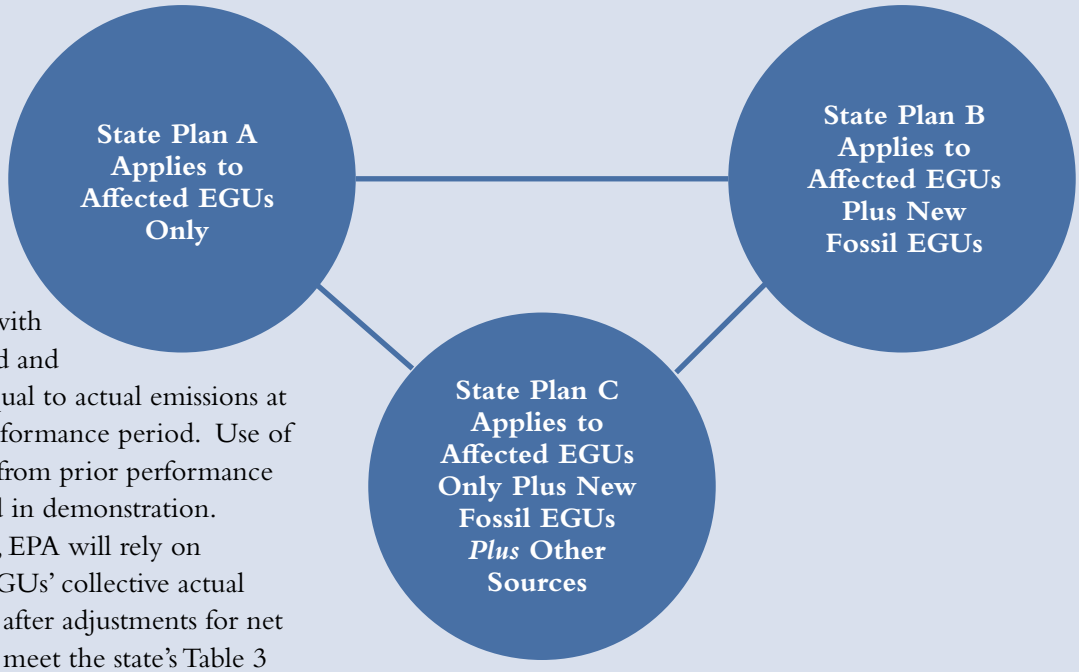
State A – Trading Program Applicability to Affected EGUs Only
State B – Trading Program Applicability to Affected EGUs Plus New Fossil EGUs
State C – Trading Program Expanded Applicability, Including Other Fossil Combustion Sources

State C Compliance Demonstration with Interim Goal
State C Interim Emission Goal (2022–2029) = 300,000,000 tons
Affected EGU Cumulative Actual Emissions (2022–2029) = 285,000,000 tons
State C Imported Allowances from States A and B = 75,000,000 tons
State C Exported Allowances to States A and B = 85,000,000 tons
State C Net Allowance Transfer = 85,000,000 tons exported – 75,000,000 tons imported
State C Net Allowance Transfer = Net 10,000,000 tons exported
State C Adjusted Interim Emission Goal (2022–2029) =
300,000,000 tons – 10,000,000 net export = 290,000,000 tons
Affected EGU Cumulative Emissions = 285,000,000 tons ≤ 290,000,000 tons
Therefore, compliance with the Interim Emission Goal is demonstrated.

will be evaluated based on an assessment of whether the affected EGUs' actual CO_2 emissions, as monitored and reported under the program, are at or below the state's applicable mass emission goal, after adjustments to account for interstate imported and exported allowances. It is important to note that net allowance imports and exports are determined based on total allowance holdings in the compliance accounts of affected EGUs, and not on the allowances retired to "true up" with actual emissions.[265]

The need for EPA to assess, during plan review and

Figure 6.10 **Linkages Among Mass-based Trading Programs When One or More Programs Apply to Affected EGUs (with or Without New Fossil-fueled EGUs) AND to Other Fossil Combustion Sources**



Compliance Demonstration: For Plan Types A and B, EPA will rely on whether affected EGUs in each state comply with requirement to hold and retire allowances equal to actual emissions at the end of each performance period. Use of allowances banked from prior performance periods can be used in demonstration.

For Plan Type C, EPA will rely on whether affected EGUs' collective actual reported emissions, after adjustments for net imports or exports, meet the state's Table 3 mass goal (see Figure 6.9).

265 80 Fed. Reg. at. 64,894.

Figure 6.11 **Compliance Demonstration for a State with an Expanded-applicability Mass-based Interstate Trading Program: Accounting for Net Imports and Exports, Example 2**

State A – Trading Program Applicability to Affected EGUs Only
State B – Trading Program Applicability to Affected EGUs Plus New Fossil EGUs
State C – Trading Program Expanded Applicability, Including Other Fossil Combustion Sources

State C Compliance Demonstration with Interim Goal
State C Interim Emission Goal (2022–2029) = 300,000,000 tons
Affected EGU Cumulative Actual Emissions (2022–2029) = 285,000,000 tons
State C Imported Allowances from States A and B = 75,000,000 tons
State C Exported Allowances to States A and B = 100,000,000 tons
State C Net Allowance Transfer = 100,000,000 tons exported – 75,000,000 tons imported
State C Net Allowance Transfer = Net 25,000,000 tons exported
State C Adjusted Interim Emission Goal (2022–2029) =
300,000,000 tons – 25,000,000 net export = 275,000,000 tons
Affected EGU Cumulative Emissions = 285,000,000 tons > 275,000,000 tons
Therefore, compliance with the Interim Emission Goal is NOT demonstrated.

approval, whether imported allowances coming from a state with an expanded mass budget would adversely impact a state's affected EGUs' achieving the state mass emission goals could create significant uncertainty for states implementing a single-state mass-based plan, and could be a dissuading factor in considering such a state as a trading partner.

Likewise, the additional requirements for plan demonstration and use of a compliance accounting method that relies on an adjusted state mass emission goal, rather than affected EGUs' compliance with the cap-and-trade allowance holding and retirement standards, could be a significant impediment for states that may otherwise consider adopting an expanded program or linking their expanded program with other state trading partners. In our example, State C would have no control over the number of exported allowances from its affected EGUs and other subject sources that may be held in the compliance accounts of sources in States A and B for future compliance periods. Yet, these exported allowances would be a debit against State C's mass emission goal (because they would effectively be expanding the budget of States A and B for affected EGUs, where the allowances are held), and could result in failure of State C to demonstrate compliance, thereby triggering the federally enforceable backstop (see Figure 6.11). To address these concerns, a state could adopt, as part of its state plan, special provisions that restrict trading to "one-way" transactions between affected EGUs (and new fossil EGUs if applicable) and other sources, such that affected EGUs could sell unneeded allowances under the CPP mass goal to other non-EGU subject sources, but could not purchase additional allowances above the CPP mass goal from other non-EGU subject sources. Such an approach would add considerable complexity to the market, however, creating the need to identify and track "EGU allowances" as distinguishable from "non-EGU allowances," and leading to sub-markets of multiple classes of trading instruments.

6.3.2 Multi-state Plans

States may elect to develop and submit a multi-state plan for any plan type, including a rate-based or mass-based emission standards plan or a state measures plan, provided that all states participating in the multi-state plan have the same plan type. With a multi-state plan, the participating states must be identified in advance and the states' rate-based or mass-based emission goals are joined for purposes of making plan demonstrations for EPA review and approval, and for purposes of making compliance demonstrations during plan implementation.

For a rate-based plan, the states may implement the Table 1 subcategory performance rate standards as the applicable emission standard for all affected EGUs across the multi-state region, or alternatively may develop a joint emission goal by deriving a weighted average emission rate using each individual state's Table 2 emission rate and their 2012 baseline generation for affected EGUs. Under a rate-based multi-state plan, all states must have functionally equivalent requirements for issuance of ERCs to affected EGUs, including ERCs for EGUs whose performance is better than the emission rate standard and ERCs for NGCC EGUs to reflect generation shift from coal and oil

steam units (i.e., Building Block 2).[266]

For a mass-based plan, the joint multi-state emission goal is the sum of each individual state's Table 3 emission goal, or of each state's Table 3 emission goal plus new source complement, as applicable.[267] Under a mass-based multi-state plan, all states must have functionally equivalent requirements for new sources.[268]

A multi-state plan requires greater coordination during planning and the adoption of state regulations, authorities and plan infrastructure elements than a single-state plan with interstate trading. Agreement on the reduction strategies and plan elements, which must be functionally equivalent across all participating states, may make joint planning more difficult for states with divergent energy or economic policy goals. In addition to reaching a formal agreement to enter into a multi-state plan, individual states will need to demonstrate adequate authority to implement and enforce the plan requirements within their state. Therefore, states will likely need to individually adopt state regulations and/or legislation that are substantively equivalent. States using a multi-state plan may gain efficiency by adopting a shared tracking system for ERCs or allowances, as well as a shared auction system (if desired), ERC application, review and issuance system, and other common elements.

A multi-state plan may be best suited for states that have a clearly defined regional affiliation (i.e., a clearly bound geographical region) for which modeling or projections indicate compliance costs, grid reliability, or other energy and economic goals can be optimized through a joint compliance goal. In particular, a multi-state plan is the only plan type that can allow for a rate-based approach with interstate trading while implementing a uniform rate-based emission goal (as derived from the Table 2 statewide performance goals) in lieu of the Table 1 subcategory goals. Therefore, states that prefer a rate-based approach with a uniform emission standard may be interested in developing a multi-state plan.

Implementation of a multi-state plan can also provide a great opportunity to combine resources, goals and strategies for achieving growth in EE deployment. This is particularly true for multi-state regions that share large metropolitan areas and common transportation systems, where an EE program could readily be marketed across an interstate area by a common third-party program administrator. Similarly, regions that have similar opportunities and preferences for RE growth can achieve economies of scale by shared implementation of consistent RPS requirements and schedules. RE incentive programs can also be enhanced using consistent policies and legal instruments and a common administrative approach. State energy offices could collaborate across the multi-state area to share experience, materials, and information in working toward a common goal.

A multi-state plan could also be a preferred option for states that wish to implement an expanded trading program across a multi-state region. Because the mass-based goal for each performance period would be a single, joint emissions budget, the need to account for net imports and exports would be eliminated. However, if a multi-state state measures plan is implemented, all participating states would be subject to corrective measures and/or the federally enforceable backstop provisions in the event those are triggered.[269]

States that elect to submit multi-state plans have three submittal options, as follows:[270]

1) The states would make a single joint submittal, signed electronically by an authorized official for each of the participating states. The single comprehensive submittal would address all required plan components for all states, including all common or joint plan components (such as the plan description, EGU inventory, plan demonstrations, emission standards, implementation milestones, and performance periods) and any plan components that are specific to individual states (such as state legislative authority and state implementing regulations).
2) The states would make a joint submittal signed by an authorized official for each of the participating states, which would include all common plan components. Each state would also make an individual submittal that would address state-specific plan components.
3) Each state would make an individual plan submittal that addresses all plan components, including all elements of the multi-state plan. All individual plan submittals must be materially consistent for all common plan elements of the multi-state plan. The individual state submittals must address each of the required federally enforceable plan elements at 40 C.F.R. § 60.5740.

266 40 C.F.R. § 60.5795(c).

267 80 Fed. Reg. at 64,839.

268 40 C.F.R. §§ 60.5750(a) & 60.5790(b)(5).

269 80 Fed. Reg. at 64,867.

270 40 C.F.R. § 60.5750(b).

The ability to prepare and submit all or some of the elements of the plan submittal separately could greatly facilitate the states' compliance with the submittal schedules, and could considerably reduce the level of coordination needed in executing the plan development and adoption process. In addition, separate submittals minimize the potential for adverse impacts on participating states in the event EPA determines any aspect of one or more states' individual plan elements are not approvable. In such an instance, EPA could proceed with approval of the common plan elements. EPA has also clarified that states submitting multi-state plans can include severability clauses that allow all severable portions of their plan to remain intact in the event a participating state fails to submit a plan or submits an unapprovable plan.[271]

Modifications of multi-state plans can be made to add or remove a state. Adding or removing a state involves the recalculation of the joint emission goal, and may also require revision to the federally enforceable backstop, if applicable. Plan modification submittals by participating or joining states may be made at any time; however, the effective date of the change must occur at the beginning of a performance period.[272]

6.3.3 Hybrid State Plans

The final multiple-state plan development option that a state may consider is a hybrid plan approach. Under this option, the state would divide the affected EGU fleet into two or more distinct groups, with each group subject to a different plan. For instance, the state could participate in two different multi-state plans for two different groups of affected EGUs. Or, the state could implement a single-state plan with linkages to an interstate trading program for one group of EGUs, and participate in a multi-state plan for a different group of EGUs. The state must specify in the plan submittal(s) which affected EGUs are subject to which plan. Each affected EGU may be subject only to one plan in a hybrid plan approach.

Under a hybrid plan approach, the state must document that all affected EGUs are covered. The emission standards or state measures adopted must address the relative portion of the state's rate-based or mass-based emission goals (or impose the Table 1 subcategory performance rate standards) for the affected EGUs included in each of the plans that comprise the hybrid plan approach. Each of the plans must include all required plan components and each is subject to the same requirements as described for single-state plans with or without interstate trading and for multi-state plans, as applicable, as described above.

A hybrid plan approach may be a necessary or preferred option for a state whose affected EGUs are served by more than one ISO or RTO. Or, a state with vertically integrated utilities whose service areas do not coincide across the same groups of states may find that a hybrid plan best provides needed flexibility for all affected EGUs.[273]

271 80 Fed. Reg. at 64,860.

272 80 Fed. Reg. at 64,861.

273 80 Fed. Reg. at 64,840.

SECTION II:

The Primary Plan Types and Example Plan Provisions

7. Rate-based Emission Standards Plans

An emission standards plan relies on federally enforceable CO_2 emission standards that are directly applicable to affected EGUs as the means of achieving and demonstrating compliance with the Subpart UUUU emission guidelines. A rate-based emission standards plan is a plan that establishes enforceable emission limits and demonstrates compliance using a performance rate metric, in units of pounds of CO_2 emitted per net megawatt-hours of power provided to the grid (lb/MWh-net).[274] Any rate-based state plan is an emission standards plan. This chapter discusses rate-based emission standards plans components and provides example model rule language for aspects of implementing a rate-based plan.

7.1 Rate-based Emission Standards Available Pathways

A state can select from two primary pathways in developing a rate-based plan. First, the state can rely upon the Subpart UUUU Table 1 performance rates as the applicable emission standards for affected EGUs. Second, the state can develop a plan that relies on the Subpart UUUU Table 2 statewide emission goals (or alternative EPA-approved Table 2 statewide emission goals) as the CPP compliance metric.[275] Plans that rely on the Table 2 statewide emission goals can be further divided into two sub-pathways: they can either (i) apply the emission goal performance rates directly to all affected EGUs as the enforceable emission standards, or (ii) establish customized emission standards for affected EGUs. Figure 7.1 depicts the available pathways for a rate-based plan. This section discusses each of the rate-based plan available pathways in more detail.

7.1.1 Table 1 Performance Rate Standards

The subcategory emission performance rates adopted by EPA in Table 1 of Subpart UUUU constitute the direct application of BSER to affected EGUs and are the chief regulatory requirement of the emission guidelines. Therefore, the most direct pathway for state compliance is a state plan that adopts the Table 1 performance rates as the applicable rate-based emission limits for affected EGUs in each respective subcategory. All other state plan approaches are alternative metrics that states may use to demonstrate compliance, and states must ultimately demonstrate that any other approach is equivalent to the application of the Table 1 performance rates.

A state plan that adopts the Table 1 performance rates as the applicable EGU emission limits is a streamlined plan, because compliance by all affected EGUs with the plan will mathematically assure compliance with the applicable subcategory performance rates. Under this plan pathway, the state is not required to include corrective measure triggers or a federally enforceable backstop, and it is not required to develop a plan-specific performance demonstration. State plans using this pathway are also considered "ready for interstate trading." Using this plan pathway, the state has the option to adopt either a "trading-ready" approach that does not explicitly designate trading partners, but instead recognizes and allows the use of ERCs issued by any other state with an EPA-approved plan that relies on the same joint or interoperable EPA-approved or EPA-administered trading platform. Alternatively, using this plan pathway the state could designate specific trading partners that rely on the same or joint or interoperable EPA-approved or EPA-administered trading platform. Also, states may join together to adopt a multi-state plan that utilizes the Table 1 performance standards as the applicable emission standards for affected EGUs across the multi-state group.

274 Subpart UUUU does not explicitly prohibit a state from using a form of emission limit or reduction strategy that is different from the form of the state plan compliance metric (i.e., rate- or mass-based). Adoption of a rate-based compliance metric (e.g., the Table 2 statewide emission goals) with mass-based emission limits is considered an unlikely approach and is not addressed in this document.

275 As discussed further in this section, a state relying on the statewide goal approach can, under certain circumstances as defined in Subpart UUUU, revise the state's Table 2 interim and/or final statewide emission goal.

EPA has proposed model rule language for a single-state rate-based program that relies on the Table 1 subcategory performance rates as the applicable affected EGU limits, and that provides for interstate trading with other states using the same approach.[276]

7.1.2 Table 2 Statewide Emission Goals

EPA derived and adopted the Table 2 statewide rate-based emission goals as a presumptively approvable alternative for states that would prefer to rely upon a statewide compliance metric. There are two primary ways that states can rely on the Table 2 emission goals in their state plans: (1) use the Table 2 goals as uniform affected EGU emission standards; or (2) use the Table 2 goals for the statewide compliance metric, with affected EGUs subject to emission standards that are different from the statewide emission goals.

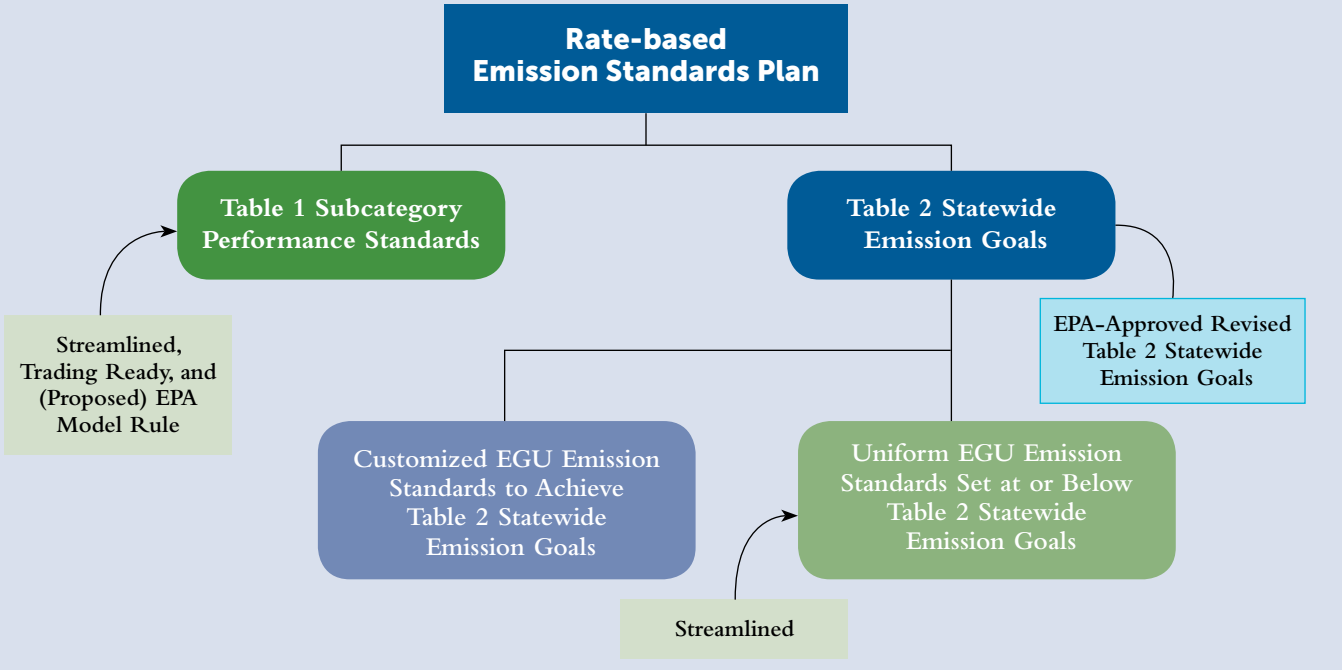
7.1.2.1 Uniform Table 2 Emission Standards

One available pathway for use of the Table 2 emission goals is a plan that applies the state's Table 2 statewide emission goal (or a more stringent rate) for each performance period as a uniform emission standard, enforceable directly against each affected EGU regardless of the unit's subcategory or other characteristics. A state plan that adopts the Table 2 performance rates as the applicable emission limits for all affected EGUs across the state is a streamlined plan, because compliance by all affected EGUs with the plan will mathematically assure compliance with the Table 2 emission goals. Under this plan pathway, the state is not required to include corrective-measure triggers or a federally enforceable backstop, and it is not required to develop a plan-specific performance demonstration.[277]

State plans using this pathway can provide flexibility through a facility-wide averaging provision, or through averaging across all affected EGUs owned or operated by a common entity, or through intrastate trading. However, a single-state plan that relies upon the Table 2 statewide emission goals cannot participate in interstate trading of ERCs. Interstate trading could be available using the Table 2 emission goals as uniform emission standards through a multi-state plan. Under the multi-state approach, a weighted-average joint emission goal would be derived for all participating states for each performance period, to serve as the uniform emission standard and as the joint compliance metric for participating states.

Rate-based Rule Example 1, located at the end of this Section 7.1, provides rule language for incorporation of the Table 2 statewide emission goals as the applicable affected EGU emission standards.

Figure 7.1 **Rate-based Plan Available Pathways**



276 80 Fed. Reg. at 65,090 (proposed to be codified at 40 C.F.R. Part 62, Subpart NNN).

277 40 C.F.R. § 60.5740(2)(i)(B); 80 Fed. Reg. at 64,833.

7.1.2.2 Customized Affected EGU Emission Standards

Another pathway available to states that adopt a rate-based emission standards plan involves establishing customized performance rates for affected EGUs or for categories of affected EGUs that are different from the Table 1 performance standards or the Table 2 emission goals. This approach is more complex than reliance on the Table 1 or Table 2 Subpart UUUU emission performance rates as the applicable emission standards, and such a plan is not a streamlined plan. Also, a plan of this type could not incorporate interstate trading, except through a multi-state plan that would demonstrate compliance against a combined weighted-average emission goal.

A state could use a variety of methods for establishing customized emission standards. For example, the emission standards could be based in part on the potential for heat rate improvement for each affected EGU, reflecting a greater reduction from baseline performance where the potential for heat rate improvement is determined to be higher. As another example, the customized emission standards could be based on baseline performance rates, reflecting the same percent improvement over baseline performance for each affected EGU.

Under the customized emission standards approach, the state would rely on the Table 2 statewide rate-based emission goals (or, if applicable, the joint multi-state Table 2 emission goals) as the performance metric for the state plan. That is, the statewide group of affected EGUs collectively and on average must meet the Table 2 interim and final emission goals for each plan performance period. A projection of future generation levels of affected EGUs is necessary to establish emission standards that demonstrate compliance with the statewide goals, and the accuracy of those projections is critical to achieving compliance as the plan is implemented. Even if each affected EGU meets its applicable emission standard, if the relative utilizations of the affected EGUs is different from those employed in the plan projections, the statewide emission goal could be exceeded. Because this plan type does not mathematically assure compliance with the emission goals, a rate-based plan with customized affected EGU emission standards must incorporate corrective action triggers. Specifically, corrective actions must be triggered if the plan performance exceeds the Interim Step 1 or Interim Step 2 goals by more than 10%, does not meet the interim performance period emission goal, or does not meet the final emission goal during any final performance period.

Rate-based Rule Example 2, located at the end of this Section 7.1, provides example rule language for incorporation of customized rate-based emission standards for affected EGUs, with the Table 2 statewide emission goals as the state plan compliance metric.

7.1.3 Alternative Emission Rate Standards and Goals

States adopting rate-based plans have the flexibility to set their own interim step performance rates for affected EGUs. States can also set their own interim step statewide goals, if the state plan relies on statewide goals. With regard to the interim period and final period, states relying on the Table 1 EGU subcategory performance standards cannot adjust the Table interim period or final period standards. However, a state relying on the statewide goal approach can, under certain circumstances as defined in Subpart UUUU, revise the state's Table 2 interim and/or final statewide emission goal.

7.1.3.1 Alternative Interim Period Standards and Goals

A state may derive alternative emission goals to replace the EPA-adopted Subpart UUUU Table 2 interim and final emission goals only to address changes in the affected EGU inventory.[278] For example, if an applicability review determines that the state's baseline inventory relied upon by EPA in setting the Table 2 goals is inaccurate, or if the state's inventory of affected EGUs changes in the future due to the retirement or reconstruction of units such that they are no longer subject to the state plan, the state can demonstrate the need to adjust the Table 2 goals through its initial state plan submittal or a subsequent plan revision. Changes to the Table 2 goals must be reviewed and approved by EPA. Once a revised goal is approved, the alternative emission goal would effectively substitute for the Table 2 emission goal and could be used in the same manner. That is, EPA-approved alternative goals could either be applied directly as the uniform emission standard for all affected EGUs, or could be used as the statewide compliance metric against which plan performance would be measured for a plan that imposes customized emission standards on affected EGUs.

278 40 C.F.R. § 60.5855(d)(1).

7.1.3.2 Alternative Interim Step Period Standards and Goals

States also have the flexibility to establish a set of interim step emission standards and/or corresponding statewide interim step emission goals that are different from the interim step performance rates proposed by EPA in the proposed model state rule (proposed to be codified at 40 C.F.R. Part 62, Subpart NNN) and different from the state-specific interim step rate-based emission goals developed by EPA and published as Table 12 of the preamble to the final Subpart UUUU.[279] This flexibility applies regardless of whether changes occur to the baseline or future affected EGU inventory. The interim step goals developed by the state must still achieve the applicable 8-year average performance standard or emission goal (i.e., the interim period Table 1 performance standard, the Table 2 interim

Rate-based Rule Example 1
Adopting Subpart UUUU Table 2 Emission Goals as the Applicable EGU Emission Standards

C. Affected EGU Emission Standards.

1. Each affected EGU as defined in Paragraph A of this Section shall comply with the emission standards in Table 1 for each compliance period. Compliance shall be demonstrated in accordance with Paragraphs C.2 and C.3 of this Section.

Table 1 **CO_2 Emission Limits for Affected Electric Generating Units Adjusted Output-weighted Average Pounds of CO_2 per net MWh (lb/MWh-net)**

	Interim 1 2022–2024 3-year average	Interim 2 2025–2027 3-year average	Interim 3 2028–2029 2-year average	Final, beginning 2030–2031 2-year average
CO_2 Emission Limit (lb/MWh-net)	1,638	1,472	1,355	1,283

2. Compliance Periods.

The responsible party for each affected EGU shall demonstrate compliance with the emission standards in Table 1 using the equation in paragraph B.3 of this section, on an adjusted output-weighted average basis over the entire length of each compliance period. Compliance periods are as specified below:

Interim 1: The 3-year period from January 1, 2022 through December 31, 2024
Interim 2: The 3-year period from January 1, 2025 through December 31, 2027
Interim 3: The 2-year period from January 1, 2028 through December 31, 2029
Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year.

3. Compliance Calculation.

Compliance with the emission standards in Table 1 shall be determined using the following equation:

$$\textbf{CO}_2\textbf{ emission rate} = \frac{\Sigma\, M_{CO2}}{\Sigma\, MWh_{op} + \Sigma\, MWh_{ERC}}$$

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 lbs summed over the compliance period for an affected EGU.
MWh_{op} = Total net energy output over the compliance period for an affected EGU in MWh.
MWh_{ERC} = ERC replacement generation for an affected EGU in MWh.

279 40 C.F.R. §§ 60.5745(a)(2)(i) & 60.5770; 80 Fed. Reg. at 64,667, 64,823-25 & 64,828.

period statewide emission goal, or an EPA-approved alternative interim period statewide emission goal).

Also, the interim step plan performance periods must be the same as those specified under Subpart UUUU. The corresponding compliance periods for affected EGUs during each interim step and for the final compliance periods may be shorter than the specified interim step and final plan performance periods, provided the schedules of compliance collectively end on the same schedule as each interim step and final plan performance period, and provided emission standards are imposed for the entire performance period. For example, during Interim Step 1 (2022–2024) the state could establish three increasingly more stringent emission standards with one-year compliance periods, in lieu of a single emission standard to be met on a three-year average.

Rate-based Rule Example 3, located at the end of this Section 7.1, provides example rule language for incorporation of the Table 2 statewide emission goals as the applicable affected EGU emission standards, with interim step goals that differ from the EPA-derived goals and with shorter compliance periods.

Rate-based Rule Example 2
Adopting Customized Emission Standards for Affected EGUs to Achieve the Subpart UUUU Table 2 Emission Goals

C. Affected EGU Emission Standards.

1. Each affected EGU as defined in Paragraph A of this Section shall comply with the emission standards in Table 1 for each compliance period. Compliance shall be demonstrated in accordance with Paragraphs C.2 through C.5 of this Section.

Table 1 **CO_2 Emission Limits for Affected Electric Generating Units**
Adjusted Output-weighted Average Pounds of CO_2 per net MWh (lb/MWh-net)

	Interim 1 2022–2024 3-year average	Interim 2 2025–2027 3-year average	Interim 3 2028–2029 2-year average	Final, beginning 2030–2031 2-year average
CB1	1,825	1,472	0	0
CB2	1,775	1,675	1,425	1,305
CB3	1,780	1,550	1,375	1,305
NGCC1	1,000	855	800	771
NGCC2	900	825	775	771

2. Compliance Periods.

The responsible party for each affected EGU shall demonstrate compliance with the emission standards in Table 1 using the equation in paragraph B.3 of this section, on an adjusted output-weighted average basis over the entire length of each compliance period. Compliance periods are as specified below:

Interim 1: The 3-year period from January 1, 2022 through December 31, 2024
Interim 2: The 3-year period from January 1, 2025 through December 31, 2027
Interim 3: The 2-year period from January 1, 2028 through December 31, 2029
Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year.

3. Compliance Calculation.

Compliance with the emission standards in Table 1 shall be determined using the following equation...

Rate-based Rule Example 3
Adopting Annual Emission Standards for Affected EGUs to Achieve the Subpart UUUU Table 2 Interim Emission Goal

C. Affected EGU Emission Standards.

1. Each affected EGU as defined in Paragraph A of this Section shall comply with the emission standards in Table 1 for each calendar year. Compliance shall be demonstrated in accordance with Paragraphs C.2 and C.3 of this Section.

Table 1 **CO_2 Emission Limits for Affected Electric Generating Units Adjusted Output-weighted Average Pounds of CO_2 per net MWh (lb/MWh-net)**

Calendar Year	2022	2023	2024	2025	2026	2027	2028	2029	Final
CO_2 Emission Limit	1,640	1,610	1,580	1,540	1,500	1,450	1,400	1,320	1,238

2. Compliance Periods.

The responsible party for each affected EGU shall demonstrate compliance with the emission standards in Table 1 using the equation in paragraph B.3 of this section, on an adjusted output-weighted annual average basis for each compliance period. For calendar years 2022 through 2029, each compliance period is a single calendar year commencing on January 1 and ending on December 31. Compliance with the final emission limit of 1,238 lb/MWh-net shall be determined on a 2-year average basis beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year. .

3. Compliance Calculation.

Compliance with the emission standards in Table 1 shall be determined using the following equation:

$$\text{CO}_2 \text{ emission rate} = \frac{\Sigma\, M_{CO2}}{\Sigma\, MWh_{op} + \Sigma\, MWh_{ERC}}$$

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 lbs summed over the compliance period for an affected EGU.

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

MWh_{ERC} = ERC replacement generation for an affected EGU in MWh.

7.2 Setting the Slope to Compliance: Interim Steps

As noted, each rate-based state plan must establish a series of emission standards applicable to affected EGUs that will apply in a step-wise fashion over the eight-year interim period. Also, for state plans that rely on the statewide emission goal pathway, the state plan must establish interim step emission goals. The interim step emission standards and goals effectively set the "slope" or "glide path" for compliance with the interim and final standards and goals, creating a gradual compliance path from 2022 to 2030. The interim step standards and interim step goals adopted in the state plan must result in achieving the Table 1 interim performance rates or the interim statewide emission goal, as applicable, over the eight-year interim period. That is, the time-weighted average of the interim step performance rates must be equal to or less than the applicable interim period performance rate.[280]

280 40 C.F.R. § 60.5855.

EPA published presumptively approvable interim step statewide goals in Table 12 of the preamble to the final CPP,[281] which illustrate one approach states may take in adopting interim step statewide emission performance rates. Similarly, for the Table 1 subcategory interim performance rates, EPA published interim step performance rate standards in the proposed federal plan and model rule,[282] which would be presumptively approvable as adopted if and when that rule is finalized. States could adopt either of these approaches, as appropriate for their plan pathway. Alternatively, a state may elect to set its own interim step goals or emission standards, including performance rate goals or standards that are more stringent than the emission guidelines or that are equally as stringent as demonstrated by the time-weighted eight-year interim period average. In deciding whether to adopt EPA's published interim step performance metrics or to establish different goals or standards, it is helpful to understand the assumptions and methods EPA relied upon in its derivation. Then, a state can consider whether the state's specific circumstances or needs differ in ways that would lead to different interim step goals and standards.

7.2.1 EPA's Interim Step Emission Standards and Statewide Goals

This section describes EPA's methodologies used to derive the two sets of interim step emission performance rates (subcategory standards and statewide goals), and the assumptions EPA applied about the timing and rate at which emission reductions will occur. States that wish to establish interim steps that are different from those on Table 12

7.2.1.1 EPA Interim Step Performance Standards for EGU Subcategories

The EPA-derived Interim Step EGU subcategory performance standards are taken directly from the stepwise calculations relied upon to set the Table 1 interim and final performance standards. EPA applied the BSER building blocks to the affected EGU baseline inventory for each of the three interconnect regions on a year-by-year basis. For each EGU subcategory, EPA selected the least stringent regional performance rate for each year, and averaged these rates over the three-year and two-year interim step periods to arrive at the proposed interim step period performance-rate standards for the rate-based federal plan and rate-based model state rule. Table 7.1 provides the EPA-derived interim step subcategory performance rates.

The annual reductions in emission rates calculated by EPA for each subcategory and region are based on several factors and assumptions, each of which affect the slope of the glide path to the final-period emission standard. Figure 7.2 shows the slope of emission reductions calculated by EPA for each region and subcategory. The lines shown in blue, for the fossil steam subcategory, and red, for the stationary combustion turbine subcategory, represent the slope of compliance year-to-year for the performance rates that are the basis of the Subpart UUUU Table 1 interim and final subcategory performance standards, representing the application of BSER. EPA's published interim step standards are an average of the points on the blue and red lines, respectively, for the years in each interim step period. Table 7.2 provides these annual performance rate values, which form the basis of the interim step emission rates,

Table 7.1 **EPA Subcategory Interim Step, Interim and Final Performance Rates for Subcategories (Adjusted lb/MWh-net)**[283]

EGU Subcategory	Interim Step 1 2022–2024 (3-yr average)	Interim Step 2 2025–2027 (3-yr average)	Interim Step 3 2028–2029 (2-yr average)	Interim Period 2022–2029 (8-yr average)	Final Period 2030–ongoing (2-yr average)
Steam Generating Units and IGCC	1,671	1,500	1,380	1,534	1,305
Stationary Combustion Turbines	877	817	784	832	771

281 80 Fed. Reg. at 62,824, Table 12.

282 80 Fed. Reg. at 64,990, Table 6; 80 Fed. Reg. at 65,116, Table 1.

283 80 Fed. Reg. at 64,990, Table 6; 80 Fed. Reg. at 65,116 (Table 1 to proposed 40 C.F.R. Part 62, Subpart NNN).

Table 7.2 **BSER Annual Performance Rates, Basis for EPA-Published Subcategory Interim Step, Interim and Final Performance Rates**

EGU Subcategory	Annual Category-Specific Rates 2022	2023	2024	2025	2026	2027	2028	2029	Interim 2022–2029	Final 2030
Steam Generating Units and IGCC	1,741	1,681	1,592	1,546	1,500	1,453	1,404	1,355	**1,534**	**1,305**
Stationary Combustion Turbines	898	877	855	836	817	798	789	779	**832**	**771**

as well as the Subpart UUUU Table 1 interim period and final period performance rate standards for subcategories.

For example, the fossil steam subcategory Interim Step 1 rate is the average of the annual performance rates for 2022, 2023, and 2024, as follows:

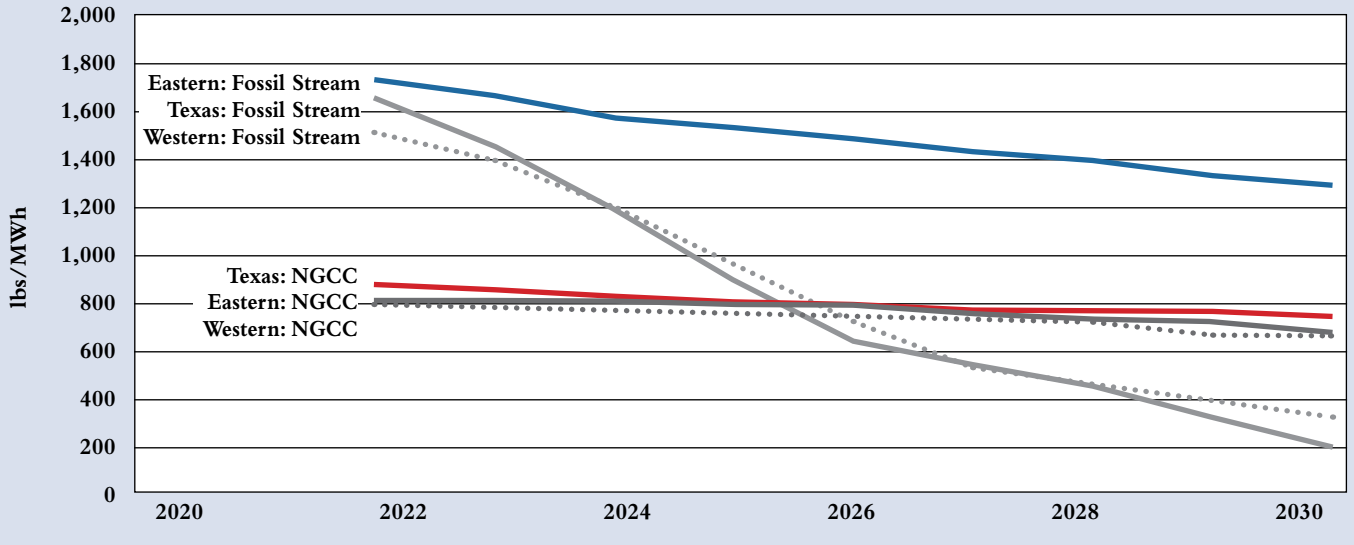
(1,741 lb/MWh + 1,681lb/MWh + 1,592 lb/MWh) ÷ 3 = 1,671 lb/MWh

Regional source-category specific rates for each of three regions, 2022–2030. The least stringent (i.e., the highest) fossil steam and NGCC emission rate among the three regions is identified and used to establish the emission performance rates described in Section VI of the preamble. Because the least stringent emission rate determines BSER, for the two non-binding regions for each technology source, the amount of BB1, BB2, and BB3 potential assumed in the previous steps reflects only building block potential—not the amount of building block levels assumed in BSER, as those potential amounts resulted in rates beyond BSER.

The least stringent regional rate for each year appears in color. For the fossil steam rate, the Eastern Interconnection is the limiting region in all years. For the NGCC rate, the Texas Interconnection is the limiting region for 2022 through 2026, and the Eastern Interconnection is the limiting region for 2027 through 2030.

Some of the key assumptions EPA made in deriving the subcategory interim step performance rates include

Figure 7.2 **Annual CO_2 Emission Performance Rates by Region by Subcategory, Based on Application of BSER**[284]



284 Graph and notes taken from EPA, *Clean Power Plan State Goal Visualizer,* Step 8, available at http://www.epa.gov/cleanpowerplantoolbox.

the following:

1) All BSER heat rate improvement occurs prior to 2022. Starting with year 2022, coal EGU actual performance rates are decreased from the baseline level consistent with Building Block 1 (i.e., 4.3% for the Eastern Region), and remain at that level through the interim period.
2) Total generation from affected EGUs in the fossil steam subcategory is reduced gradually through the interim period, reflecting a shift to NGCC as well as replacement by RE.
3) Total generation from affected EGUs in the stationary combustion turbine NGCC subcategory is increased gradually through the interim period, with an increase equal to 22% of the increment from the baseline utilization rate to the 75% summer capacity utilization rate applied in 2022, and increasing steadily by an additional 5% each year.
4) Total generation from the combined affected EGU inventory sees a gradual net decrease throughout the interim period, and a significant decrease occurs from the baseline year 2012 and the first performance period year 2022.
5) Replacement generation from incremental RE deployment (or, avoided generation from other qualifying ERC resources) is available each year, beginning in 2022, in quantities to match the net decrease in total affected EGU generation, such that the total load served (plus any load avoided) by the affected EGU inventory is unchanged from the 2012 baseline year.

7.2.1.2 EPA Interim Step Rate-based Statewide Emission Goals

The Subpart UUUU Table 2 rate-based statewide emission goals were derived by applying the Table 1 subcategory performance rate standards to the statewide baseline generation (MWh-net) for each subcategory, summing the emissions to determine the fleet-wide projected emissions, and dividing by the total generation to obtain the blended statewide performance rate goal. To derive the interim step statewide emission goals, EPA performed this calculation using the subcategory interim step performance rates shown in Table 7.1 above. Thus, the statewide interim step goals are equivalent to the subcategory performance rate standards, applied in each state to the baseline inventory. The statewide interim step emission goals therefore incorporate the same set of assumptions applied in the derivation of the subcategory interim step performance rates.

7.2.2 State-Derived Interim Step Emission Standards and Statewide Goals

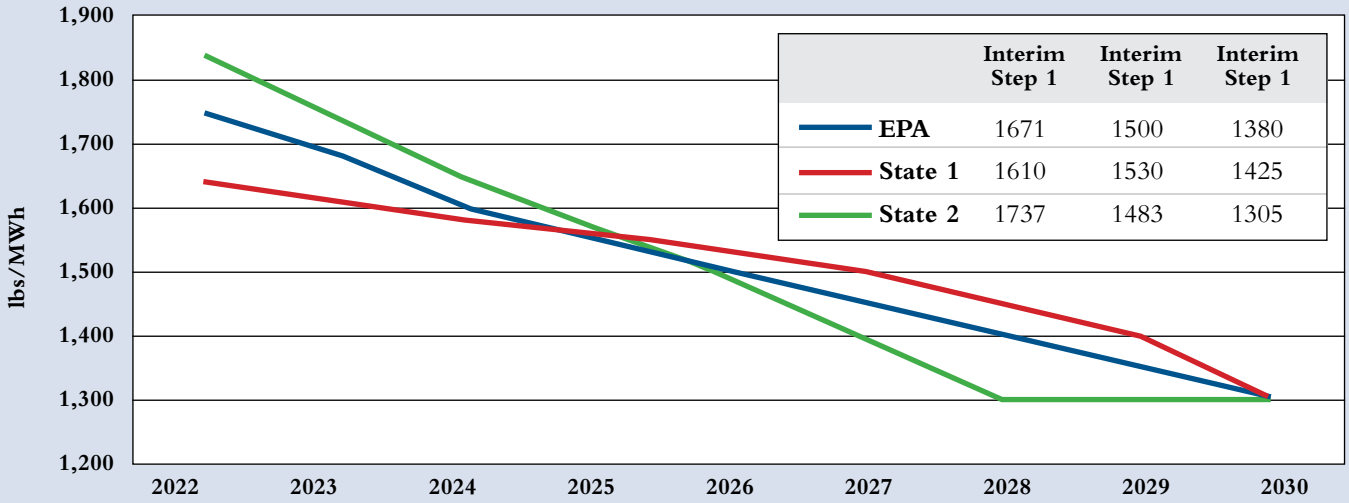
A state may determine that a different glide path is more appropriate for its particular circumstances. As a general matter, if a state elects to shift the starting point of the compliance path upward for the first years of the interim period, then the applicable EGU performance rates for the later years would be shifted in the opposite direction to compensate, in order to achieve the same 8-year average interim period performance rate. That is, if the applicable performance rates are made less stringent for Interim Step 1, then more stringent performance rates would most likely be required in Interim Step 2 and/or Interim Step 3.

Conversely, if the state elects to make the Interim Step1 standards more stringent than the EPA-derived Interim Step 1 rates, then the Interim Step 3 rates could generally be less stringent than those derived by EPA, while still demonstrating that the interim period performance rate is met, on average, over the interim period. Again, the degree of the shift that can be allowed for later years will be influenced by the degree of shift in the early years.

Figure 7.3 presents three different glide paths, and corresponding interim step performance rates, to arrive at the final CPP steam EGU performance rate of 1,305 lb/MWh. The three glide paths represent EPA's proposed interim step performance rates (EPA) and two hypothetical state-derived interim step performance rate curves (State 1 and State 2), each of which are projected to result in achieving the Subpart UUUU Table 1 8-year average interim period performance rate of 1,534 lb/MWh. Each of the interim step glide paths depicted in Figure 7.3 assumes that total annual generation in the denominator of the rate-based compliance equation (that is, EGU actual generation plus ERCs representing avoided or replaced generation) remains unchanged for affected EGUs throughout the interim period. This assumption is consistent with EPA's methodology in deriving the interim period and interim step period performance rates. Figure 7.3 illustrates the concept that an upward shift of the curve at one end of the interim period is compensated by a downward shift at the opposite end, and vice versa, in order to arrive at the same 8-year interim period average.

In the scenarios depicted in Figure 7.3, State 1 has elected to increase the performance standard stringency of Interim Step 1 as compared to the EPA compliance

Figure 7.3 **Alternate Compliance Glide Paths and Interim Step Performance Rates**



curve, allowing for a reduced stringency of the Interim Step 2 and Interim Step 3 performance standards and a more gradual slope to compliance with the interim and final period emission standards. State 2, on the other hand, has elected to decrease the stringency of the emission standard for Interim Step 1. This results in a sharper decline of the compliance slope, leading to an Interim Step 3 emission standard that is equivalent to the final period emission standard (i.e., requiring compliance with the final limit two years early), in order to achieve compliance with the 8-year average interim period emission standard.

Several fundamental factors could influence a state's anticipated optimum slope of compliance, including the following:

1) The actual performance rate of the affected EGU inventory in the planning years (2015–2017) as compared to the baseline;
2) The projected potential for and timing of actual performance rate improvements at affected EGUs;
3) The projected shifts in affected EGU generation over time, including projected retirements and generation shifts among affected EGUs; and
4) The timing of availability of qualified ERCs for adjusting actual performance rates.

For example, a state may determine that the EPA-derived Interim Step 1 performance rate could already be met by affected EGU coal units in year 2016, based on the actual performance of the units as adjusted by incremental NGCC utilization and post-2012 RE deployment. If so, the state may elect to shift the Interim Step 1 performance standard downward, as depicted for State 1 in Figure 7.3. This shift for Interim Step 1 by itself would create a flatter glide path, which better assures compliance with the 8-year average interim period standard if generation levels of affected EGUs change (see further discussion of this in Section 7.8.3, State Plan Performance Reviews). In addition, a more stringent Interim Step 1 standard could allow for a less stringent Interim Step 2 and/or Interim Step 3 standard. While this adjustment would increase the "drop" from the Interim Step 3 to the final period performance standard, it would also provide additional time for creation of ERCs to meet the more stringent final performance standard.

As another example, a state may determine that the projected supply of qualifying ERCs in years 2022 and 2023 is somewhat constrained, but that significant planned RE projects, providing substantial levels of qualifying ERCs to the market, will become available for deployment during year 2024. Under this scenario, the state may elect to adjust the Interim Step 1 performance rate upward (i.e., make it less stringent than the EPA-derived level), and to adjust the Interim Step 2 performance rate downward by a corresponding amount. This approach could help to level the cost of compliance by more closely matching ERC supply to ERC demand, while still projecting compliance with the 8-year average interim performance standard.

The examples above relate to interim step emission standards for affected EGUs in the fossil steam and IGGC subcategory subject to the Subpart UUUU Table 1 interim period and final period performance rate standards. Some of the same concepts generally apply for a state plan relying on statewide emission goals rather than the Table 1 subcategory rate standards. Specifically, a shift in one direction at the beginning of the interim period leads to a shift in the other

direction at the end of the interim period because the 8-year average interim period emission goal must be achieved.

When setting the slope of the compliance curve, states will want to consider the potential effects on overall plan performance and periodic reporting of the collective EGU performance in comparison to the interim step goals and in achieving the interim period goal. This is particularly important for plans that must include corrective action triggers if the eight-year interim performance rate or emission goal is not achieved collectively by all affected EGUs.

Specifically, it is worth considering that changes in the level of total net power generation year-to-year during the interim period can influence whether the interim period emission goal is achieved. This is because the performance rate for periods with higher generation will carry more weight in the collective average performance than periods where generation is lower. Assuming that total affected EGU generation will decline over the course of the interim period, the earlier years (e.g., Interim Step 1) will be weighted more heavily in the 8-year interim period average. This could result in failure to meet the interim period goal even in cases where each interim step period goal is achieved. The risk is greater for fossil steam unit subcategory performance, which is more likely to see a reduction in utilization and which is subject to a greater decrease in performance rates over time. The risk is also greater for plans that adopt a steeply declining compliance glide path, because the years with greater generation are also associated with interim step performance goals that are incrementally higher than the eight-year average. The effect of declining generation on overall plan performance is lessened by the averaging of both NGCC and fossil steam performance to determine the statewide average emission rate, as is the case with plans that are designed to achieve the Table 2 statewide blended emission goals. Accordingly, particularly for plans that must include corrective measures, evaluation and selection of the compliance glide path and interim step emission goals should take into account projected decreases in generation over the course of the interim period.

7.3 Rate-based Trading Programs

Subpart UUUU Table 1 rate-based performance rates and Table 2 rate-based emission goals are adjusted CO_2 emission rates, meaning that compliance by affected EGUs is determined by adjusting the actual performance rate through the use of ERCs. Specifically, the adjusted performance rate is obtained by dividing the CO_2 emissions from the affected EGU by the sum of the unit's net energy output plus ERCs representing replacement generation or avoided generation from qualifying resources, denominated in MWh, per the equation below.[285]

$$\textbf{CO}_2\textbf{ emission rate} = \frac{\Sigma\ \mathbf{M_{CO2}}}{\Sigma\ \mathbf{MWh_{op}} + \Sigma\ \mathbf{MWh_{ERC}}}$$

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 lbs summed over the compliance period for an affected EGU.

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

MWh_{ERC} = ERC replacement generation for an affected EGU in MWh.

The form of the emission guidelines contemplates that affected EGUs can either meet the applicable performance rate based on their actual operation, or obtain ERCs generated by another source to demonstrate compliance. Under the emission guidelines, states *must* incorporate the use of ERCs in a rate-based plan. Specifically, states must adopt in their plan the criteria for qualifying ERC resources, verifying emission reductions, issuing ERCs, and tracking their use.[286] However, states are not required to provide a platform for market-based trading of ERCs, nor are states obligated to "create" an ERC market. Nonetheless, market-based trading is a natural outcome of a rate-based program that is dependent on the use of ERCs. This is because in many cases, if not most, the ERCs will be generated through resources other than the affected EGUs and at locations other than the power plants where the affected EGUs are located. Also, many parties in addition to the affected EGU owners or operators are well positioned to make the initial investments required for the creation and implementation of qualifying resources.

A rate-based plan that does not provide for trading (i.e., that does not provide for the issuance of ERCs to non-affected EGU parties and does not recognize the transfer of ERC ownership through the sale and purchase of ERCs after issuance) would likely be a cumbersome, inefficient and costly approach. If a state rate-based plan does not

285 40 C.F.R. § 60.5790.

286 40 C.F.R. §§ 60.5790(c), 60.5795, 60.5800, 60.5805, 60.5810, 60.5830 & 60.5835.

accommodate issuing ERCs except to the responsible parties for affected EGUs, then affected EGU responsible parties without additional non-affected zero carbon-emitting generation facilities (e.g., eligible nuclear, wind or solar facilities) will likely have to establish contracts for the purchase of the ERC-qualifying aspects of resources with the resource provider in advance of their creation. The affected EGU responsible party would then be obligated to make the eligibility application, register the resource in its name, and submit the verification report for the issuance of the ERCs. If excess ERCs generated by the third-party resource and registered, but not ultimately needed for compliance, by the affected EGU could not be traded (i.e., sold to another affected EGU), then cost and compliance efficiencies could not be realized.

Given that a market for investment in ERCs will naturally occur to meet EGU demand, and furthermore, that implementation of a plan that fails to recognize and accommodate this market would be inefficient at best, most states electing a rate-based plan are expected to incorporate trading provisions to recognize third-party creators of ERCs and to provide for the transfer of ERCs among affected EGUs and other ERC owners.

7.3.1 ERC Trading Program Available Options

ERC trading can be incorporated into state plans through four different options, listed below.

1) Interstate ERC trading among participating states with EPA-approved plans (or with an EPA-approved multi-state plan) that are implementing the Table 1 performance rates as the applicable emission standards for their affected EGUs, and that are relying on a joint or interoperable EPA-approved or EPA-administered tracking system. This approach can be implemented through a streamlined plan and using EPA's model rule as finalized.
2) Interstate ERC trading among participating states implementing a multi-state plan that relies on a single, weighted-average multi-state emission goal, derived from the states' respective Table 2 emission goals or EPA-approved alternative goals. This approach can be implemented through a streamlined plan, provided the multi-state joint goals are used as the affected EGU emission standards.
3) Intrastate ERC trading within the state that issues the ERCs and where the affected EGUs subject to the plan are located, under a plan that imposes the Table 2 statewide emission goals (or EPA-approved revised Table 2 emission goals if applicable) as the enforceable emission standards. This approach can be implemented as a streamlined plan, provided the Table 2 emission goals are used as the affected EGU emission standards.
4) Intrastate ERC trading of ERCs within the state that issues the ERCs and where the affected EGUs subject to the plan are located, under a plan that imposes the Table 1 performance rates as the enforceable emission standards. This approach could be implemented as a streamlined plan, using EPA's proposed model rule with some modifications.

For all of the trading program options described above, it is important to note that the ERC-qualified resource does not need to be located within the state that issues the ERCs; that is, an intrastate trading program can trade ERCs that are generated by resources in another state. However only one state can issue an ERC for each equivalent MWh of qualifying zero-emission generation or avoided generation. For further discussion about the acceptable geographic locations of ERC resources, see Section 7.4.3.3.

Rate-based Rule Example 4, located at the end of this Section 7.3, provides example rule language to implement intrastate ERC trading for a state plan relying on the Table 2 statewide emission goals as the applicable affected EGU emission standards (number 3 in the list above). This rule language could be readily modified to accommodate a multi-state plan with interstate trading, as described in number 2 above.

The EPA proposed model trading rule provides regulatory language to implement interstate ERC trading for option number 1 above, among participating states using the Table 1 subcategory performance rates. This proposed rule language could be readily modified to accommodate an intrastate trading program that relies on the Table 1 subcategory performance standards, as described in option number 4 above.

7.3.2 Intrastate ERC Trading Approaches

A state plan that adopts the Table 2 emission goals as the affected EGU emission standards cannot participate in interstate trading, except through a formal multi-state plan using joint, blended Table 2 goals. Nonetheless, a single-state plan relying on the Table 2 goals can provide for compliance flexibility and ERC availability through a number of options.

One important consideration is the distinction between the place of ERC issuance and the place where the underlying MWh were generated or avoided. Specifically, "interstate" trading refers to the recognition of ERCs

that are issued by another state, and has no bearing on the state or territory where the underlying MWh are generated or avoided. Subpart UUUU allows a state to issue ERCs to qualifying resources located across a broad geography, including resources located in other states and countries (see Section 7.4.3.3 for a more detailed discussion on this topic). Therefore, a state that provides only for intrastate trading could still take advantage of a broad distribution of ERC resources, extending outside state borders. It should be kept in mind, however, that ERC resource providers will likely be incentivized to register with a state that provides ample market opportunities for the ERCs they are generating, and a single-state plan that allows for only intrastate trading could offer a limited market for trading. This concern could potentially be relieved through advance sales contracts or other guarantees of purchase.

States should also evaluate whether favoring the purchase of ERCs for which the underlying generation is located in-state may ease compliance for affected EGUs in the state. This could occur because the underlying MWh for such "local ERCs" may offset demand for electricity from in-state EGUs, thereby reducing emissions and the number of ERCs needed for compliance. At the other extreme, states that submit trading-ready rate-based plans will have no way to predict the physical location of increased RE generation spurred by the ERC market. Because impacts on the actual operation of affected EGUs will be affected by the physical location of the underlying RE, this uncertainty could complicate the planning process. Of course, the same dynamic applies to other ERC-generating resources, such as nuclear power plants that increase their generation capacity

Rate-based Rule Example 4
Intrastate Trading for Affected EGUs to Meet the Subpart UUUU Table 2 Emission Goals as the Applicable Emission Standards

C. Use of Emission Rate Credits (ERCs).

1. An ERC qualifies for use in the compliance demonstration specified in Paragraph B.3 of this Section if the ERC meets the requirements of paragraphs C.1 (i) through (vi) of this section.
   a. The ERC has a unique serial number.
   b. The ERC represents one MWh of actual energy generated or saved with zero associated CO_2 emissions, and no duplicate ERC representing the same MWh of actual energy generated or saved has been issued by this State or by any other entity.
   c. The ERC was issued to an eligible resource that meets the requirements of Section 1085 of this Chapter, or to an affected EGU that meets the requirements of Section 1083.
   d. The ERC was issued by this State or its State agent through the State-designated EPA-approved ERC tracking system.
   e. The ERC was issued for a year in the compliance period for which it is used to demonstrate compliance, or for a year in a prior compliance period.
   f. The ERC was surrendered and retired only once for purpose of compliance with the emission standards of paragraph B.1 of this Section, through the State-designated EPA- approved ERC tracking system.
2. An ERC does not qualify for the compliance demonstration specified in paragraph B.3 of this section if it does not meet the requirements of paragraph B.4 of this section; or, if it represents a MWh of energy generated or saved from a future compliance period; or, if any party in another State or Territory has used that same ERC for purposes of demonstrating compliance with a state plan under 40 CFR part 60 subpart UUUU, or with a federal plan under 40 CFR part 62 subpart NNN administered by the EPA Administrator or the Administrator's agent.
3. Any ERC determined to have been improperly issued or improperly used for the compliance demonstration specified in paragraph B.3 of this section shall be revoked by this State or its designated Agent. Any responsible party of an affected EGU who has relied upon, for the compliance demonstration specified in paragraph B.3 of this section, an ERC that is subsequently revoked shall be subject to potential enforcement action in accordance with Chapter 10 of this Administrative Code.

A second way in which single-state plans with intrastate trading can provide compliance flexibility is to establish ERC holding accounts at the level of the affected EGU owner/operator (e.g., the investor-owned utility, independent power producer, public utility district, or electric cooperative). This in effect allows responsible parties of multiple affected EGUs to "bundle" ERCs across units for compliance planning purposes, and to apply the ERCs on an as-needed basis unit-by-unit at the end of the compliance period. It also provides for a more seamless transfer of ERCs generated by affected EGUs to those requiring the use of ERCs within the same owner/operator fleet. ***Rate-based Rule Example 5,*** located at the end of this Section 7.3, provides example rule language to establish ERC holding accounts at the responsible party level.

A state plan that incorporates intrastate trading must still meet all of the minimum requirements under Subpart UUUU for qualifying ERC resources, providing for evaluation, measurement and verification, issuing ERCs, and tracking ERCs from issuance to retirement. The following sections discuss these aspects in more detail.

7.4 Emission Rate Credit Resources

The CPP emission guidelines establish relatively detailed minimum criteria each rate-based state plan must meet with regard to ERC requirements, including qualifying ERC resources, the ERC issuance process, and the ERC tracking system.[288] Additionally, the emission guidelines establish the minimum criteria for evaluation, measurement and verification (EM&V) plans and reports.[289] While providing minimum requirements

Rate-based Rule Example 5
Establishing a Single Compliance Account for All Affected EGUs with a Common Owner or Operator

D. ERC Tracking and Compliance System Accounts.

1. The owner(s) and operator(s) of each affected EGU must select and designate a single designated representative for the affected EGU, and may select and designate one alternate designated representative, to act on behalf of and to represent the owner(s) and operator(s), and through his or her actions and representations to legally bind the owner(s) and operator(s) in all matters related to the ERC Tracking and Compliance System (ETCS).
   a. Each designated representative and alternate designated representative shall be registered in accordance with Section 1130 of this Chapter.
   b. The same designated representative may be registered to represent multiple affected EGUs with common owner(s) or operator(s).
2. ETCS Compliance Accounts. The State or the State's designated agent having responsibility of the administration of the ETCS shall create a compliance account for each affected EGU, upon receipt and processing of the designated representative registration.
   a The designated representative and any alternate designated representative shall be the authorized account representative and alternate authorized representative, respectively, of the compliance account.
   b. If requested by the designated representative or alternate designated representative, a single compliance account may be created for multiple affected EGUs with common owner(s) or operator(s) and with a common designated representative and alternate designated representative. Where a single compliance account is established for multiple affected EGUs, each facility with one or more affected EGUs and each affected EGU represented must have individual subaccounts.
   c. The compliance account shall hold ERCs intended for surrender by a designated representative when demonstrating an affected EGU's compliance with the emission standards in Paragraph B.3 of this Section.
3. ETCS General Accounts. Any person, including but not limited to, designated representatives of affected EGUs, authorized account representatives of ERC-eligible resources, may submit an application for an ECTS general account, for the purpose of holding and transferring ERCs, in accordance with Section 1130 of this Chapter….

288 40 C.F.R. §§ 60.5795 through 60.5810.

289 40 C.F.R. §§ 60.5830 & 60.5835.

to assure a baseline level of consistency across states and to assure the integrity of ERC programs, the emission guidelines still provide considerable flexibility to states, particularly in selecting the emission reduction measures that will qualify for ERC issuance. Measures that can be qualified for the issuance of ERCs fall into two main categories: affected EGUs and other resources, each of which are discussed in this section.

7.4.1 Generation of ERCs by Affected EGUs

Affected EGUs can qualify for the issuance of ERCs through two potential avenues, and the mechanism for awarding ERCs is different depending on the type of rate-based program the state adopts. EPA has established these ERC-qualifying mechanisms as minimum requirements for a state plan, and states are required to incorporate appropriate accounting methods and provisions to implement the issuance of ERCs to affected EGUs that qualify.[290]

1) Under a state plan that sets a uniform emission standard applicable to all affected EGUs (e.g., the Table 2 emission goal), any affected EGU that operates at a performance rate better than the applicable emission standard qualifies for the issuance of ERCs based on the degree to which its performance is better than the emission standard.
2) Under a state plan that sets separate emission standards for subcategories of affected EGUs (e.g., the Table 1 performance standards), different avenues for ERC generation are available for each subcategory.
   a. Affected fossil steam EGUs that operate at a performance rate better than the applicable fossil steam subcategory emission standard qualify for the issuance of ERCs based on the degree to which their performance is better than the fossil steam subcategory emission standard.
   b. Affected NGCC EGUs that operate at a performance rate better than the applicable NGCC subcategory emission standard qualify for the issuance of ERCs based on the degree to which their performance is better than the NGCC subcategory emission standard.
   c. In addition, all affected NGCC EGUs potentially qualify for the issuance of ERCs based on three factors: (1) a factor reflecting regional incremental NGCC generation corresponding to the implementation of Building Block 2 (generation shift from fossil steam units to NGCC units); (2) the NGCC unit's generation during the performance period; and (3) a factor reflecting the degree to which the NGCC unit's performance is better than the *fossil steam subcategory emission standard*.

The equation used to determine the number of ERCs either needed for compliance or generated by an affected EGU under a program that applies uniform emission standards to all affected EGUs is as follows:

$$\text{ERCs} = \frac{(\text{EGU emission standard} - \text{EGU performance rate})}{\text{EGU emission standard}} * \text{EGU Generation}$$

If the affected EGU's actual performance does not meet the applicable emission standard, this equation will return a negative number, representing the number of ERCs the EGU needs to demonstrate compliance. On the other hand, if the affected EGU's actual performance is better than the applicable emission standard, this equation will return a positive number, representing the number of ERCs generated by the affected EGU. The state implementing the program is required to issue ERCs in this amount to the affected EGU.[291] In programs where the same uniform emission standard applies to all affected EGUs for each compliance period, the EGU emission standard is the same for all EGUs, regardless of their subcategory. Illustrative examples are provided below for a case where the Interim Step 1 emission standard is 1,638 lb/MWh. In the first example, the affected EGU is an NGCC unit that outperforms the emission standard. In the second example, the affected EGU is a coal-fired utility boiler with a performance rate not meeting the emission standard.

Example 1. An affected NGCC unit generates 1,000,000 MWh at a performance rate better than the applicable emission standard and qualifies to receive 267,399 ERCs.

$$\frac{(1{,}638\ \text{lb/MWh} - 1{,}200\ \text{lb/MWh})}{1{,}638\ \text{lb/MWh}} * 1{,}000{,}000\ \text{MWh} = 267{,}399\ \text{ERCs}$$

290 40 C.F.R. § 60.5795; 80 Fed. Reg. at 64,905.

291 40 C.F.R. §§ 60.5790(a) & 60.5795; 80 Fed. Reg. at 64,905; see also EPA's proposed federal plan and model rule at 80 Fed. Reg. 64,991.

Example 2. An affected coal steam EGU generates 1,000,000 MWh at a performance rate not meeting the applicable emission standard and needs 98,901 ERCs to comply.

$$\frac{(1{,}638\ \text{lb/MWh} - 1{,}800\ \text{lb/MWh})}{1{,}638\ \text{lb/MWh}} * 1{,}000{,}000\ \text{MWh} = 98{,}901\ \text{ERCs}$$

In a program that applies separate emission standards to each subcategory of affected EGUs, the equation presented above can still be used to determine the number of ERCs needed or generated by fossil steam EGUs. The emission standard to be used in the equation (i.e., the "reference rate") is the fossil steam subcategory-applicable emission standard for the compliance period. Similarly, affected NGCC units under a program with subcategory emission standards can determine the amount of ERCs needed or generated using this equation, but with the applicable NGCC emission standard as the reference rate.

7.4.2 Options for Calculating Gas Shift ERCs

As noted above, Subpart UUUU requires that each rate-based state plan that adopts separate subcategory emission standards include provisions for awarding ERCs to affected NGCC units specifically to reflect and incentivize incremental generation shifted from fossil steam units, as contemplated in Building Block 2—referred to as "Gas Shift ERCs" or GS-ERCs. The emission guidelines do not prescribe the specific accounting method and procedures a state plan must incorporate, leaving some discretion to the states in this regard. EPA has proposed one approach for calculating this category of ERCs in the proposed federal plan and model state rule.[292] States are not required to use the same accounting method and equation proposed by EPA, and EPA has suggested other methods that may be appropriate. This section discusses various possible approaches and provides model rule language for an alternative to those proposed by EPA.

7.4.2.1 EPA's Proposed Method for Issuance of GS-ERCs

The method and equation proposed by EPA is summarized by the equation below.

$$\text{GS-ERCs} = \text{NGCC Generation} * \text{Incremental Generation Factor} * \text{GS-ERC EF}$$

Where:

GS-ERCs is the number of ERCs the affected NGCC unit would receive. Note that if the equation returns a negative number, no ERCs would be issued.

NGCC Generation is the net generation, in MWh, produced by the NGCC unit during the year.

Incremental Generation Factor is a factor determined by EPA, representing the incremental increase in NGCC generation over the 2012 baseline needed to fulfill Building Block 2, as determined for the region with the least-stringent incremental generation factor.

GS-ERC EF is the individual NGCC's calculated emission factor, representing the degree to which the NGCC unit performs better than the fossil steam emission standard, equal to 1 – (NGCC Emission Rate/Fossil Steam Emission Standard).

7.4.2.2 Alternative GS-ERC Methods Discussed by EPA

In the proposed federal plan and proposed model rule, EPA discussed and requested comment on other possible options for calculating GS-ERCs. Several of those options are variations of the method described above. For example, EPA requested comment on calculating an Incremental Generation Factor for each region using that region's data, rather than applying the least-stringent regional incremental generation factor to all regions. EPA also requested comment on using a constant GS-ERC Emission Factor, calculated by using the least stringent region's baseline 2012 emission rate.

Another approach that EPA discussed in the proposed federal plan involves crediting NGCC units for generation over a baseline level, rather than using the NGCC's generation multiplied by the incremental generation factor as proposed by EPA.[293] The baseline generation level could be the individual NGCC unit's 2012 baseline level, in MWh. Using this approach, the affected NGCC unit would receive GS-ERCs for each MWh of generation above its 2012 generation level, multiplied by the NGGC unit's level of performance in relation to the fossil steam emission standard. This approach would reward any NGCC unit that increased generation over the baseline year, regardless of the unit's generation level during the baseline year. This approach also rewards better-performing

292 80 Fed. Reg. at 64,991-93 & 65,093 (proposed to be codified at 40 C.F.R. § 62.16434).

293 80 Fed. Reg. at 64,993.

NGCC units, whose GS-ERC emission factors would be higher. This equation is shown below.

$$\text{GS-ERCs} = (\text{NGCC Generation} - \text{NGCC 2012 Generation}) * \text{GS-ERC EF}$$

Alternatively, the baseline level could be the aggregate capacity factor of NGCC units in the least stringent region during the baseline period. Using this approach, an affected NGCC unit would be rewarded only to the extent that its individual capacity factor during the compliance period exceeds the least-stringent regional capacity factor during the 2012 baseline. This approach avoids disproportionately rewarding NGCC units whose historical utilization was low, but also may provide a lesser incentive to those units to increase their utilization. This approach also incentivizes smaller NGCC units proportionally to larger NGCC units, by using capacity factor as the benchmark.

$$\text{GS-ERCs} = (\text{NGCC CF} - \text{2012 Baseline CF}) * \text{NGCC Generation} * \text{GS-ERC EF}$$

7.4.2.3 Alternative GS-ERC Methods Not Discussed by EPA

In the preamble to the proposed federal plan and model rules, EPA noted that using a baseline generation level as the benchmark for issuance of GS-ERCs, rather than a prorated incremental generation factor, creates a system in which GS-ERCs can be awarded based on shifting generation among affected NGCC units, without achieving the shift away from fossil steam EGUs and the associated emission reductions intended under Building Block 2.[294] One way a state could address this concern would be to establish a two-tiered baseline test. The first tier of the baseline test would be to award GS-ERCs only when the collective NGCC capacity factor exceeds the least-stringent regional 2012 baseline capacity factor. The second tier of the baseline test would be applied at the individual NGCC-unit level as described above, using either the individual NGCC 2012 baseline or the least-stringent regional 2012 baseline capacity factor. The two-tiered test would provide greater assurance that GS-ERCs represent generation shifted (or avoided) from fossil steam units, while also rewarding only affected NGCC units whose incremental generation contributes to the emission reductions anticipated from Building Block 2. The equation used for this approach would be the same as the equation shown above, but the state would make the determination for each compliance period as to whether GS-ERCs would be issued based on the collective utilization of all affected NGCC units.

Another approach to implement a two-tiered benchmark accounting method would be for a state to determine, for each compliance period, the total quantity of GS-ERCs available based on collective affected NGCC capacity factor in comparison to the least-stringent regional 2012 capacity factor. Each NGCC unit would then be awarded GS-ERCs in proportion to its fraction of the total NGCC generation, and the degree to which its performance is better than the fossil steam emission standard. Example equations to implement this approach are provided below.

First, calculate the total unadjusted GS-ERCs available for the compliance period. This quantity represents the total MWh of NGCC utilization above the least-stringent regional baseline capacity factor, without adjusting for the proportion of CO_2 emissions from NGCC units as compared to fossil steam EGUs. To provide certainty for each compliance period and facilitate timely issuance and availability of GS-ERCs, the calculation for each compliance period could be based upon the NGCC utilization during the prior performance period.

$$\text{GS-ERCs Total} = (\text{Combined NGCC CF} - \text{2012 Baseline CF}) * \text{Total NGCC Gen.}$$

Next, determine the portion of total available GS-ERCs to be awarded to each affected NGCC unit.

$$\text{GS-ERCs NGCC} = \text{GS-ERCs Total} * \frac{\text{NGCC Generation}}{\text{Total NGCC Gen.}} * \text{GS-ERC EF}$$

In the proposed federal plan and model rule, EPA incorporated provisions that would establish GS-ERCs as a special category of ERCs. Specifically, the proposed EPA model rule would prohibit any affected NGCC unit from using GS-ERCs to demonstrate compliance. Instead, GS-ERCs may only be used by fossil steam EGUs. EPA recommended this approach because, under its proposed methodology, use of the GS-ERCs by NGCC units could simply facilitate shifting generation from one NGCC EGU to another. This concern arises primarily because the proposed method relies on prorating the Building Block 2 level of incremental NGCC generation available across all affected NGCC units, without consideration of whether

294 80 Fed. Reg. at 64,994.

or to what extent incremental generation above the BSER baseline has actually occurred. EPA's proposed approach could create a circumstance where an affected NGCC unit must purchase ERCs to demonstrate compliance with the applicable NGCC emission standard, even though it may have generated GS-ERCs in sufficient quantities to demonstrate compliance during the same or an earlier compliance period. The approach discussed above, which assures that each GS-ERC issued represents a MWh of NGCC generation above the 2012 baseline and therefore appropriately reflects implementation of the BSER Building Block 2, alleviates or minimizes any concerns regarding use of the GS-ERCs by affected NGCC units. Any GS-ERCs issued represent implementation of BSER Building Block 2 that has actually occurred. Furthermore, the accounting method adjusts the amount of ERCs issued for each MWh of shifted generation to award GS-ERCS only for that portion of incremental generation associated with "zero" emissions—by factoring into the equation the ratio of the individual NGCC unit's performance rate to the fossil steam emission standard as the GS-ERC Emission Factor. Therefore, GS-ERCs under this approach should be fully fungible with any other ERCs representing zero-emitting or avoided fossil generation.

Rate-based Rule Example 6, provided in the text boxes on the following pages, implements the two-tiered baseline threshold approach described above.

Rate-based Rule Example 6
GS-ERCs Accounting Procedure Using Two-tiered Baseline Threshold for a State Plan Imposing Table 1 Subcategory Performance Rates as the Applicable EGU Emission Standards

B. Affected NGCC GS-ERC Generation.

1. Any NGCC EGU that is an affected EGU subject to the emission standards of this Chapter will qualify for the issuance of Gas Shift ERCs (GS-ERCs) for qualified generation representing a shift of generation from affected EGU steam generating units, to the extent the generation also represents a reduction in CO_2 emissions, in accordance with paragraphs B.2 through B.5 of this Section.
2. For each compliance period under this Chapter, the total amount of GS-ERCs available for issuance to all affected NGCC EGUs shall be calculated by the administrative authority and published at www.statedeq.gov/cpp/ERC no later than ninety days after the close of the prior compliance period.
   a. The calculation of total GS-ERCs shall be performed using the following equation, beginning with the Interim 2 compliance period (2025–2027):

GS-ERCs Total = (Combined NGCC CF – 2012 Baseline CF) * Total NGCC Generation

Where:

GS-ERCs Total is the total quantity of GS-ERCs available for issuance over the current compliance period. GS-ERCs Total shall be divided by the number of years in the current compliance period to determine the GS-ERCs Annual Total available for issuance each calendar year;

Combined NGCC CF is the collective capacity factor of all affected NGCC EGUs during the previous compliance period, calculated by dividing the sum of all affected NGCC net power generation (MWh) by the sum of all affected NGCC Summer Capacity (MWh);

2012 Baseline CF is a constant value representing the lowest regional capacity factor among the three regional interconnects during calendar year 2012, equal to ***XXXX***; and,

Total NGCC Generation is the sum of all affected NGCC net power generation for the previous compliance period.

   b. For the Interim 1 compliance period, the calculation of total GS-ERCs shall be performed using the equation in paragraph B.2.i of this Section, except that the time period "January 1, 2019 through December 31, 2021" shall be substituted for "the previous compliance period" wherever that term is found.

Rate-based Rule Example 6, *continued*

3. GS-ERCs shall be issued to each qualifying affected NGCC EGU under this Chapter in the first quarter of each calendar year, beginning in 2023, for qualifying net energy output generated during the previous calendar year.
   a. GS-ERCs shall be calculated using the following equation:

$$\textbf{GS-ERCs NGCC} = \textbf{GS-ERCs Annual Total} \star \frac{\textbf{NGCC Generation}}{\textbf{Total NGCC Gen.}} \star \textbf{GS-ERC EF}$$

Where:

GS-ERCs NGCC is the amount of GS-ERCs to be issued to an individual NGCC EGU, denoted in MWh and rounded to the nearest integer;

GS-ERCs Annual Total is the total amount of GS-ERCs available for issuance to all affected NGCC EGUs for the compliance period, as determined under Paragraph B.2 of the Section, divided by the number of years in the current compliance period;

NGCC Generation is the reported net electric output of the individual NGCC EGU (MWh) during the previous calendar year (e.g., 2022 net electric output for GS-ERCs issued in the first quarter of 2023);

Total NGCC Generation is the sum of all affected NGCC net power generation for the previous calendar year; and,

GS-ERC EF is the individual NGCC EGU's GS-ERC Emission Factor, representing the degree to which the performance rate of the affected NGCC EGU is better than the fossil steam EGU emission standard, and calculated according to the equation in paragraph B.3.ii of this Section.

   b. The GS-ERC Emission Factor shall be calculated for each affected NGCC EGU using the following equation:

$$\textbf{GS-ERC EF} = 1 - \frac{\textbf{NGCC Emission Rate}}{\textbf{Fossil Steam Emission Standard}}$$

Where:

NGCC Emission Rate is the reported unadjusted emission rate of the individual NGCC EGU for the previous calendar year, expressed in lb/MWh-net; and,

Fossil Steam Emission Standard is the applicable emission standard for affected EGUs in the fossil steam subcategory, as listed in Table 1 of this Chapter.

4. GS-ERCs issued to an affected NGCC EGU in accordance with this Paragraph B are in addition to any ERCs issued to the affected NGCC EGU in accordance with Paragraph A, *Affected EGU ERC Generation for Performance Better than the Applicable Emission Standard,* of this Section.
5. GS-ERCs issued in accordance with this Paragraph B may be held or used in the same manner and for the same purposes as any other ERC issued under this Chapter, including being banked, traded or used for compliance demonstrations by an affected EGU in accordance with the provisions of this Chapter.

7.4.3 Other ERC-Eligible Resources

In addition to ERCs generated by affected EGUs, the state may designate other resources as eligible for receiving ERCs for the replaced or avoided energy they generate. States have broad discretion to select the energy savings and replacement strategies they desire to provide ERCs for use in compliance demonstrations by affected EGUs.

7.4.3.1 Types of Resources a State May Identify as ERC-Eligible

Under Subpart UUUU, the following types of resources may be included in a state plan as eligible ERC resources:[295]

1) RE generation using wind, solar, geothermal, hydro, wave, or tidal resources;

295 40 C.F.R. § 60.5800. Note as well that the low- or zero-emitting power generation and energy-savings measures that are eligible for ERC issuance under a rate-based plan are also reduction strategies states may elect to rely upon as state measures under a state measures plan. *Chapter 9, State Measures Plans,* includes further discussion of RE, qualified biomass, CHP, and waste-to-energy replacement energy generation, as well as specific EE measures including EERS, building energy codes and above-code building certifications, energy savings performance contracting, and industrial energy efficiency.

2) Qualified biomass;
3) Waste-to-energy (biogenic portion only);
4) Nuclear power;
5) Non-affected combined heat and power (CHP), including waste heat power;
6) Demand-side energy efficiency (EE) or demand-side energy management measures calculated on the basis of quantified ex post savings; and
7) Any other category that meets the general criteria listed above, is identified by a state in the state plan, and is approved by EPA to generate ERCs.

EPA's proposed model rule for a rate-based trading program would include as eligible measures for ERC issuance all of the power-generating measures listed above. In addition, EPA's proposed model rule would include demand-side EE and management measures as eligible ERC resources.[296]

Subpart UUUU also specifies three categories of resources that *cannot* be included in a state plan as eligible for ERC issuance. These are:

1) EGUs that are subject to 40 C.F.R. Part 60, Subpart TTTT for new, modified or reconstructed power plants, except combined heat and power units that meet all qualifying criteria;
2) Fossil-fuel fired EGUs that are not affected EGUs addressed in a state plan under Subpart UUUU, or that are excluded under Subpart UUUU from being affected EGUs;
3) Measures that reduce CO_2 emissions outside the electric power sector, such as projects representing emission reductions that occur in the forestry sector or in the transportation sector.

7.4.3.2 General Criteria to Qualify as an ERC-Eligible Resource

Three general criteria must be met by all energy or energy-savings providers to qualify for the issuance of ERCs.

1) The electricity generation or savings (MWh) must be produced on or after January 1, 2022.
2) The resource generating or saving the electricity must be incremental to 2012. Specifically, the resource must be new generating capacity or a capacity uprate of existing generation, or new energy-savings measures, installed or implemented on or after January 1, 2013. If a generating resource has a capacity uprate, only the incremental increase in generation capacity resulting from the uprate is eligible for ERC issuance, and the uprate must not have followed a derate that occurred on or after January 1, 2013.
3) The resource must be connected to, and must deliver energy to or save energy from, the electric grid in the contiguous United States.

7.4.3.3 Geographic Location Requirements for ERC Resources

The requirements regarding geographic location of an ERC-eligible resource are specific to the resource type. As discussed above, the state or other jurisdiction (e.g., tribe or EPA) that issues the ERCs does not need to be the state or other jurisdiction in which the energy resource is located, nor does the jurisdiction issuing the ERCs need to be the same rate-based jurisdiction that the power was intended to supply. Once ERCs are issued by a state or other authority, the question of where those ERCs can be traded and used for compliance depends upon the state plan under which compliance is determined. Specifically, the state plan must specify any interstate trading provisions, including the ERC tracking system(s) from which ERCs are recognized for compliance.

For renewable energy-generating facilities using wind, solar, geothermal, hydro, wave or tidal resources, the resource must either be located in (i) a state implementing a rate-based plan; or (ii) a state implementing a mass-based state plan, a state with no affected EGUs, or another country that is connected to the U.S. grid, *provided* the resource demonstrates that the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load in a region that includes a state with a rate-based plan.[297]

For other qualifying energy generating resources such as biomass, waste-to-energy, nuclear, or CHP, geographic location criteria are the same as for those renewables described above, except that these resources may not be located in a mass-based state.[298]

Geographic location requirements for EE and other non-BSER power-saving measures are the most restrictive. For these resource types, the resource must be located (i) in a state or other jurisdiction implementing a rate-based plan, or (ii) on tribal-jurisdiction land without affected EGUs, provided the

296 80 Fed. Reg. at 64,994; 80 Fed. Reg. at 65,093 (proposed to be codified at 40 C.F.R. § 62.16435).

297 40 C.F.R. § 60.5800; EPA, *Clean Power Plan Fact Sheet, Allowable Scope of Geographic Eligibility for Emission Rate Credits (ERCs) Under a Rate-based Approach,* https://www.epa.gov/sites/production/files/2015-11/documents/erc_geographic_eligibility_fact_sheet_-_final.pdf.

298 *Ibid.*

tribal land is located within the borders of a rate-based state.[299]

In all cases, the ERC resource must meet the three general criteria listed in Section 7.4.3.2, as well as the geographic location requirements. The geographic location requirements can be summarized as follows:

1) Any type of qualifying energy generating or savings ERC resource may be located in a state implementing a rate-based state plan, including on tribal jurisdictional land without affected EGUs where the tribal land is located within the borders of a rate-based state.
2) Any qualifying energy-generating ERC resource, including wind, solar, geothermal, hydro, wave tidal, qualified biomass, waste-to-energy biogenic, nuclear, or qualifying CHP, may alternatively be located in a state or tribal jurisdiction with no affected EGUs or in another country that is connected to the U.S. electric grid, provided the resource demonstrates that the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load in a region that includes a state with a rate-based plan.[300]
3) RE wind, solar, geothermal, hydro, wave or tidal resources only, may alternatively be located in a state implementing a mass-based state plan, provided the resource demonstrates that the electricity generated is delivered with the intention to meet load in a state with a rate-based plan, and was treated as a generation resource used to serve regional load in a region that includes a state with a rate-based plan.

EPA's proposed model rule for a rate-based trading program would restrict the geographic scope of eligible resources to a greater extent than required under the CPP.[301]

Rate-based Rule Example 7 provides example rule language to specify the geographic scope of ERC-eligible resources consistent with Subpart UUUU requirements.

Rate-based Rule Example 7
ERC-Eligible Resources and Allowable Geographic Locations

C. Qualification Criteria for Eligible Resources other than Affected EGUs.

1. A resource other than affected EGUs may qualify for the issuance of ERCs for qualified generation or energy savings only if the resource meets all qualifying criteria described in paragraphs C.2 through C.5 of this Section. The designated representative of a qualifying resource must submit an application for eligibility in accordance with Paragraph D of this Section.
2. The energy generation or savings occurs on or after January 1, 2022, and the resource producing the generation or savings is installed or implemented on or after January 1, 2013. Both new generating capacity and capacity uprates of existing generating units may qualify. If a resource has a capacity uprate, only the incremental increase in generation capacity resulting from the uprate is eligible for ERC issuance, and the uprate must not have followed a derate that occurred on or after January 1, 2013.
3. The resource is connected to, and delivers energy to or saves energy from, the electric grid in the contiguous United States.
4. Geographic location of qualifying resources.
   a. Qualifying resources need not be located in this State to apply for eligibility; however, a qualifying resource shall not apply both to this state and to another jurisdiction for eligibility.
   b. For demand-side energy efficiency and management measures qualifying resource types listed in Paragraph C.5, the resource must be located either:
      i. in a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
      ii. on tribal jurisdictional land without affected EGUs that is located within the borders of a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN.

299 *Ibid.*

300 *Ibid.*

301 80 Fed. Reg. at 65,094 (proposed to be codified at 40 C.F.R. § 62.16435(a)(3)).

Rate-based Rule Example 7, *continued*
ERC-Eligible Resources and Allowable Geographic Locations

c. For renewable energy (RE) generating resources using wind, solar, geothermal, hydro, wave, or tidal generating technologies as listed in Paragraph C.5, the resource must be located either:
   i. in a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
   ii. on tribal jurisdictional land without affected EGUs that is located within the borders of a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
   iii. if the resource does not meet the location criteria described in Paragraph C.4.c(i) or (ii) and the resource demonstrates, through a power purchase agreement, contract for delivery, or other equivalent documentation, that the electricity generated is delivered with the intention to meet load in, and treated as a regional load-serving generation resource in a region that includes, a State whose affected EGUs are subject to an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN, then the resource may be located in, either:
      (1) a State with affected EGUs subject to an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
      (2) a State or tribal Indian Country with no affected EGUs; or,
      (3) another country that is connected to the U.S. electric grid.

d. For energy-generating resources using qualified biomass, waste-to-energy, nuclear power, or combined heat and power technologies as described in Paragraph C.5, the resource must be located either:
   i. in a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
   ii. on tribal jurisdictional land without affected EGUs that is located within the borders of a state or other jurisdiction implementing an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN; or,
   iii. if the resource does not meet the location criteria described in Paragraph C.4.c(i) or (ii) and the resource demonstrates, through a power purchase agreement, contract for delivery, or other equivalent documentation, that the electricity generated is delivered with the intention to meet load in, and treated as a regional load-serving generation resource in a region that includes, a State whose affected EGUs are subject to an EPA-approved or EPA-administered rate-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN, then the resource may be located in, either:
      (1) a State or tribal Indian Country with no affected EGUs; or,
      (2) another country that is connected to the U.S. electric grid.

7.5 Determining the ERCs Needed for Compliance and Growth

Under a rate-based state CPP implementation approach, each affected EGU must meet either the appropriate subcategory performance rate (Table 1) or rate-based state goal (Table 2) according to the following adjusted CO_2 emission rate equation:[302]

$$CO_2 \text{ emission rate} = \frac{(\Sigma\, M_{CO2})}{(\Sigma\, MWh_{op} + \Sigma\, MWh_{ERC})}$$

Where:

ΣM_{CO2} = Measured CO_2 mass in units of pounds summed over the compliance period for the affected EGU

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

ΣMWh_{ERC} = ERC replacement generation for an effected EGU in units of MWh

Though the above compliance equation can accommodate growth in total net energy output over time,

302 40 C.F.R. § 60.5790(c)(1).

affected EGUs operating above their compliance rate must pay for that growth with additional ERC replacement generation.

Setting the CO_2 emission rate term in the above equation equal to the applicable emission standard or statewide emission goal, called here the "rate of compliance" (R_{Comp}), and rearranging terms, the number of ERCs required for compliance can be expressed as a function of megawatt hours generated:

$$\Sigma MWh_{ERC} = \Sigma MWh_{op} * \left(\frac{R_{op}}{R_{Comp}} - 1 \right)$$

Where:

R_{op}=(ΣM_{CO2})/(ΣMWh_{op}) = Unadjusted operating rate of the affected EGU

R_{Comp} = Compliance goal for the affected EGU or state (e.g., the subcategory performance rates (Table 1) or rate based state goals (Table 2), or alternative EPA-approved goal)

Note that this equation can be used either for an individual affected EGU to determine the number of ERCs needed for compliance or generated, or at the state level to determine the amount of ERCs that would be required collectively for all affected EGUs to meet the state goal performance rate at a given operating rate.

The rearranged equation illustrates the following features of a rate-based compliance approach:

- The number of ERCs required to meet the compliance goal grows with each additional MWh generated. The number increases at a rate proportional to the ratio between the unadjusted rate and the compliance target.
- No ERCs are needed for compliance when R_{op} equals R_{Comp} (i.e., the affected EGU is generating MWh at the compliance rate).
- Surplus ERCs are created when R_{op} is less than R_{Comp} (i.e., an affected EGU with an unadjusted rate below its compliance rate will generate ERCs).

The ERC requirements to accommodate load growth are further illustrated as a function of operating rate in the following two graphs, which plot the number of ERCs required for affected EGUs operating at four different unadjusted rates (R_{op}) with two different compliance goals (R_{Comp}). Figure 7.4 plots the ERCs that would be generated or required for compliance by an EGU operating at performance rates ranging from 800 to 2300 lb/MWh, and subject to an emission standard of 1,305 lb/MWh.

Figure 7.4 **ERC Requirements as a Function of MWh Generated**
R_{Comp} = 1,305 lbs CO_2 / MWh

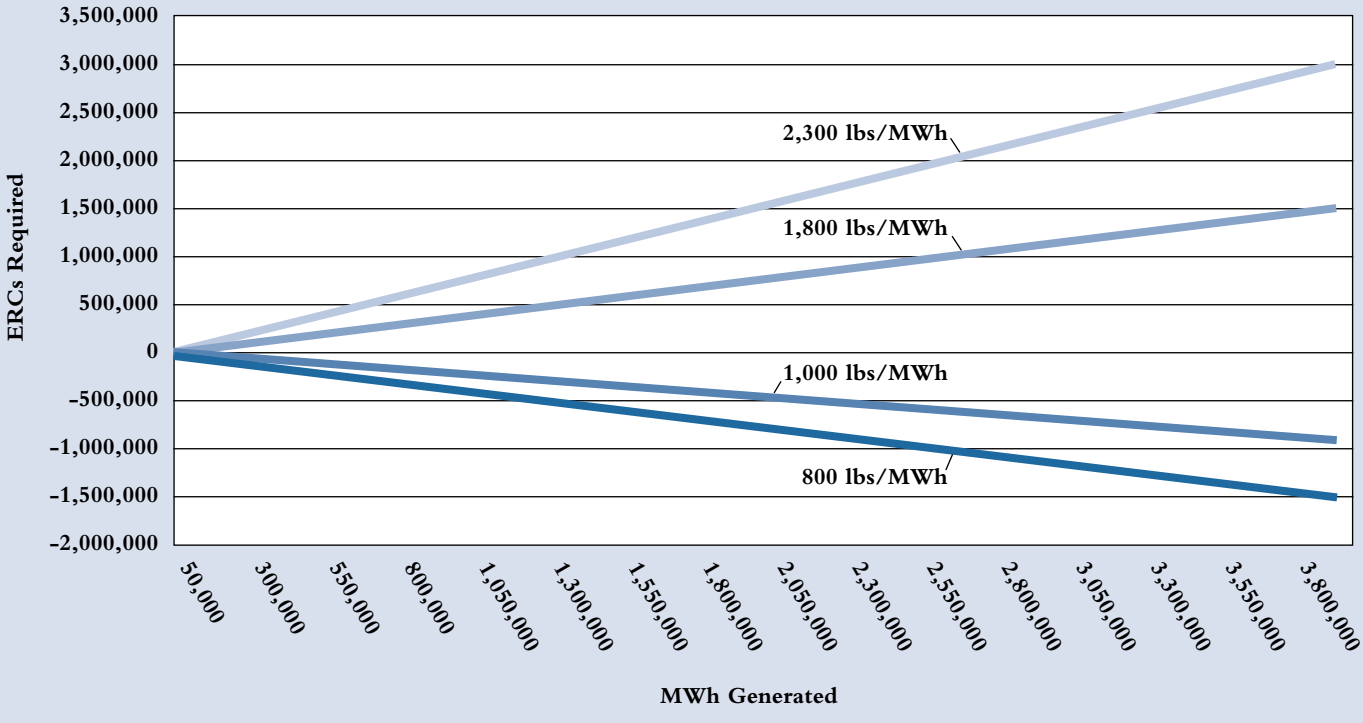


Figure 7.5 **ERC Requirements as a Function of MWh Generated**
R_{Comp} = 771 lbs CO_2 / MWh

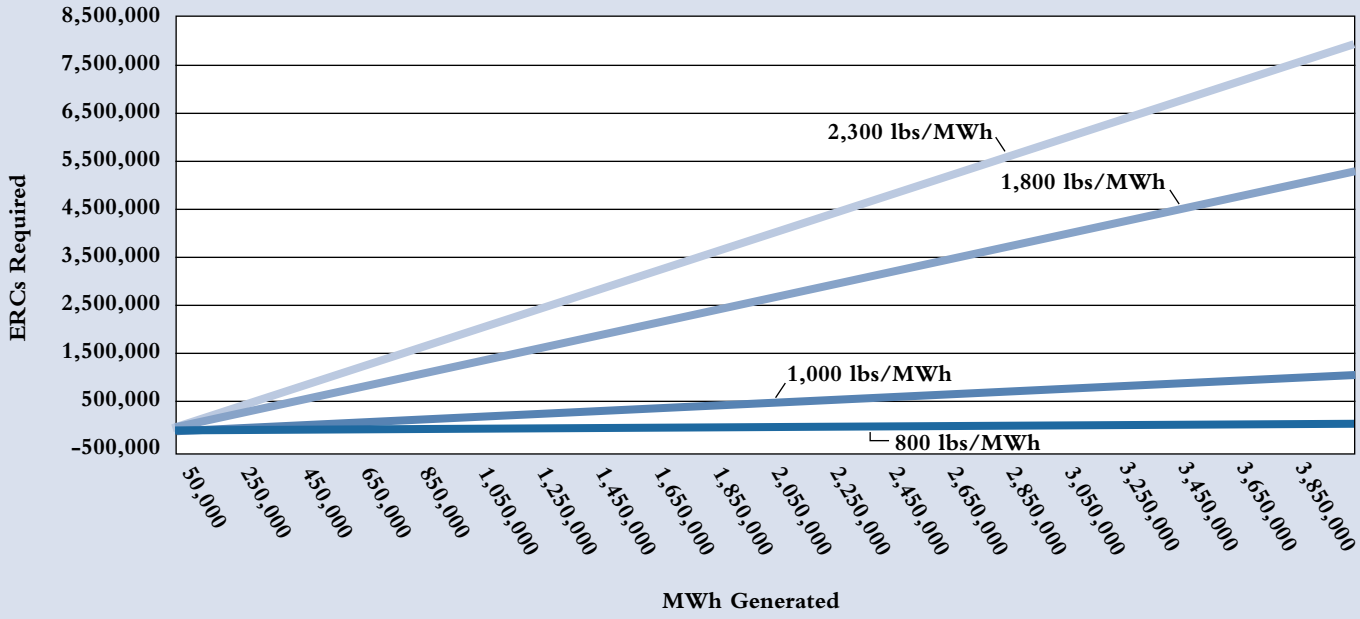


Figure 7.5 plots the ERCs that would be required for compliance by an affected EGU operating at the same performance rates and across the same range of generation, but subject to an emission standard of 771 lb/MWh.

7.6 ERC Issuance and Tracking

Each rate-based state plan must include provisions for ERC issuance and tracking that meet the minimum requirements specified in Subpart UUUU.[303] ERCs may be issued only through an ERC tracking system approved by EPA as part of the state plan.

ERC issuance procedures include two stages: (1) application, approval and registration of the resource as ERC-eligible; and (2) measurement and verification of the replacement MWh generated or avoided MWh, and issuance of the ERCs.

First, the ERC resource must submit an eligibility application to the state administrative authority or the state's designated agent that is administering the ERC eligibility review process. The eligibility application must document that the resource meets the requirements for eligibility under the approved state plan. For ERC resources other than affected EGUs, such as RE or demand-side EE projects or programs, the application must include certification that the resource has not applied to any other state, multi-state or interstate ERC trading program. The application must also include an evaluation, measurement and verification (EM&V) plan, and a verification report from an independent verifier that the resource and EM&V plan meet all state plan requirements for ERC eligibility. Upon approval of the eligibility application and EM&V plan, the ERC-eligible resource must be registered with the designated ERC tracking system.

Once qualified MWh have been generated or avoided by a registered ERC resource, and prior to issuance of any ERCs, a monitoring and verification (M&V) report must be submitted in accordance with the approved EM&V plan. The report must be verified by an independent verifier. Upon approval of the M&V report and verification report, the state or the state's designated agent will issue ERCs on the basis of the MWh actually generated or saved. ERCs must be issued in whole integers (MWh) only, and only one ERC may be issued for each verified MWh.

ERCs must be issued and tracked by use of an ERC tracking system that meets the requirements of Subpart UUUU and that has been approved by EPA as part of the state's plan. States participating in interstate trading, including plans that are "trading ready," that have designated trading partners, or that are part of a formal multi-state plan, may utilize a joint tracking system or interoperable tracking systems. The ERC tracking system must electronically record each stage in the life cycle of each ERC,

303 40 C.F.R. § 60.5805.

including issuance, transfers among accounts, surrender for compliance purposes, and retirement. The state plan and ERC tracking system must also provide for adjustment of ERCs in the event of any errors in issuance, and revocation of ERCs in the event ERCs are determined to have been improperly issued or used.

In addition to tracking the life cycle of each ERC, the ERC tracking system must include an electronic repository that contains each eligibility application, EM&V plans, M&V reports and independent verifier reports, and must document and track the qualification status of eligible resources and independent verifiers. The ERC tracking system must also provide for internet-based public access to information related to the eligibility of ERC resources and issuance of ERCs, with reporting functionality.

Model rule language for a state plan to incorporate ERC issuance and tracking procedures, including the establishment of an ERC tracking system, is provided in EPA's proposed rate-based trading program model state rule.[304] When finalized by EPA, these provisions would be presumptively approvable in their final form.

7.7 Evaluation, Measurement and Verification (EM&V)

Each rate-based plan must provide for the use of ERCs in compliance demonstrations, and must implement an ERC issuance and tracking system to administer the use of ERCs. Integral to the ERC procedures, all rate-based state plans must require all applicants for eligibility as an ERC resource to submit an EM&V plan to quantify and verify the electricity generated or saved for purposes of ERC issuance. The EM&V plan must be reviewed by an independent verifier and receive certification that it meets the state plan requirements.

State plans must specify required content for EM&V plans based on the type of eligible resource. For energy-generating resources, the EM&V plan must provide for physically measuring generation on a continuous basis (e.g., with a revenue-quality meter). For demand-side EE, the state plan must require that each EM&V plan include the following:

- Procedures to quantify and verify electricity savings on a retrospective (ex-post) basis using industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings;
- An assessment of the independent factors that influence the electricity savings, the expected life of the savings (in years), and a baseline that represents what would have happened in the absence of the demand-side EE activity;
- A demonstration of how the industry best-practices protocol and methods are applied to the specific activity, project, measure, or program covered in the EM&V plan, how these approaches will be applied for the purposes of quantifying and verifying MWh results, and an explanation of why these protocols or methods were selected; and
- A reporting plan for initial and subsequent monitoring and verification (M&V) reporting of demand-side EE savings values using the procedures presented in the EM&V plan.

The initial M&V report submitted after ERC-qualifying energy generation or savings has occurred must include documentation that the ERC resources were installed or implemented consistent with the description in the approved eligibility application. Each M&V report submitted must include the time period covered by the report, a description of how the EM&V plan was applied, and documentation (and supporting data) of the energy savings or generation for which ERCs are being requested. The M&V report must also report any change in the ERC resource from the description of the resource in the approved eligibility application not previously reported, the date on which the change occurred, and, if a change has occurred, a demonstration that the eligible resource continues to qualify for ERC generation.[305]

In addition to the minimum requirements for state plans adopted in Subpart UUUU, EPA has published draft guidance on EM&V procedures for categories of ERC resources. First, the proposed federal plan and model state rule include provisions that, as finalized, would be presumptively approvable for state plans.[306] In addition, the preamble to the proposed federal plan and model state rule includes more specific guidance and makes several definitive statements regarding presumptively approvable approaches a state can adopt for EM&V for specific resources.[307] Also, EPA has published a 72-page draft document, *Evaluation Measurement and Verification (EM&V)*

304 80 Fed. Reg. at 65,094-96 (proposed to be codified at 40 C.F.R. §§ 62.16440–62.16450).

305 40 C.F.R. § 60.5835.

306 80 Fed. Reg. at 65,096 (proposed to be codified at 40 C.F.R. § 62.16455).

307 80 Fed. Reg. at 65,002-08.

Guidance for Demand-Side Energy Efficiency (EE), for public comment and input.[308]

EPA's general approach is to rely upon the prevailing industry best practices for measuring and verifying generation and saved energy, to balance accuracy and reliability with the cost of EM&V, and to avoid excessive interference with robust measures already in place. A general summary of the draft and proposed EM&V requirements by ERC resource is provided in Table 7.3. Alternative approaches and a more detailed discussion of EM&V protocols are not included in this document, given that the federal guidelines and regulations regarding presumptively approvable EM&V protocols are, at the time of this writing, at a draft stage.

Table 7.3 **Summary of EPA-proposed EM&V by ERC Resource Category**

ERC Resource Type	Approach	EM&V
RE and Nuclear >10 kW	Measure generation continuously, electronic data collection	A revenue-quality meter or EPA-approved alternative
RE ≤ 10 kW	Measure generation at least monthly	Use software or algorithms based on the unit's capacity, estimated capacity factors, and an assessment of the local conditions that affect generation
Qualified Biomass Feedstocks	Measure generation as for RE, and meet requirements specific for the feedstock	The monitoring and reporting requirements for biogenic CO_2 emissions in 40 C.F.R. Part 98 (40 C.F.R. §§ 98.3(c), 98.36(b)-(d), 98.43(b) & 98.46) are presumptively approvable.[309]
Waste-to-Energy	Measure generation as for RE, and determine the portion of energy from biogenic waste	
Combined Heat & Power (CHP) >25 kW	Measure generation continuously, electronic data collection	Meet monitoring requirements for affected EGUs
CHP ≤25 kW	Measure generation per 40 C.F.R. Part 75	Meet the low mass unit monitoring requirements of 40 C.F.R. Part 75
CHP ≤1 kW	Monthly records of thermal output and record of baseline thermal efficiency per manufacturer data	Keep monthly cumulative records of useful thermal output and fossil fuel input
Transmission and Distribution Loss Avoidance	Estimate savings based on customer meter readings or state annual-average T&D loss	Use lower of 6% of loss at customer meter, or USEIA statewide average loss
EE, General	Quantify savings on ex-post basis or real-time basis using industry-specific best practice protocol; identify the effective useful life of savings and potential sources of double-counting	Use project-based measurement and verification, comparison group approaches, or deemed savings; measure savings in specified time intervals based on EE measure (e.g., 4-year intervals for building codes)
EE Comparison Group Approach	Quantify the difference between comparison group's and EE program group's energy use	Use randomized control trials and/or quasi-experimental methods per industry best practice
EE Deemed Savings Approach	Apply approved deemed savings for specific climate zone, building type, etc., based on industry best practice	Document deemed savings in an online technical reference manual that has undergone public and expert review

308 EPA, August 3, 2015, available at https://www.epa.gov/cleanpowerplantoolbox/evaluation-measurement-and-verification-emv-guidance-demand-side-energy.

309 80 Fed. Reg. at 65,005.

It should be noted that, while the state plan must include minimum requirements for ERC resources, for EM&V plans, and for M&V reporting, the specific EM&V plan for each eligible resource will be submitted and approved as part of the eligibility application and approval process. Therefore, as further guidelines are developed and as industry practices evolve, EM&V plans can be adopted that reflect the most current best practices and most appropriate approach for the particular RE or EE resource under consideration.

7.8 Compliance, Enforcement and Plan Performance

The successful implementation of a rate-based state plan relies on the interdependent actions of the state, owners and operators of affected EGUs, ERC resource providers, and energy consumers. The owners and operators of affected EGUs bear the primary compliance obligation, and they will need to identify the extent to which cost-effective and timely "inside-the-fenceline" reduction measures can contribute to compliance and the level and timing of ERCs that are necessary to close the compliance gap. Many interacting measures must be incorporated in the plan to create a robust infrastructure of ERC providers, independent verifiers, ERC issuance and tracking, and EM&V that will provide reliable, sufficient and timely ERCs for compliance by affected EGUs.

CPP requirements and state plan provisions to track plan performance and compliance by affected EGUs, and to institute corrective action where necessary, have bearing on ERC providers and independent verifiers, owners and operators of affected EGUs, and the state. Each of these areas is discussed in this section.

7.8.1 Affected EGU Compliance Demonstrations and Enforcement

As discussed above, rate-based plans are emission standards plans that place the full obligation of achieving the state's CPP emission goals directly upon the affected EGUs. Each rate-based plan must include emission standards applicable to each affected EGU for each interim step period and for each two-year final period. States may elect to set shorter compliance periods within each interim step or final period, provided the emission standards are imposed for the entirety of each plan period and the end date of the last compliance period within each plan period coincides with the end of the corresponding interim step or final plan period.

The compliance demonstration methodology is the same for affected EGUs under any rate-based plan, regardless of whether the plan (i) is a streamlined plan, (ii) relies on Table 1 or Table 2 performance rates, (iii) applies uniform subcategorized or customized emission standards, or (iv) allows for interstate or intrastate trading. Under all rate-based plans, affected EGUs demonstrate compliance using their actual reported emissions and generation, together with the surrender of sufficient ERCs to meet the applicable emission standard, if needed.

The owner or operator of an affected EGU that fails to meet its applicable emission standard based on its actual emissions and generation and also fails to secure and surrender sufficient ERCs to adjust its actual performance rate to meet the emission standard by the compliance deadline for the performance period is subject to enforcement action. Specifically, each emission standard and other affected EGU compliance obligation under the state plan must be enforceable by the state, pursuant to state law and the CAA, by EPA pursuant to CAA section 113, and by third parties pursuant to CAA section 304.[310] Potential enforcement actions include imposition of corrective action, penalties and injunctive relief.

The owner or operator of an affected EGU also bears enforcement liability for the use of any ERCs that are subsequently determined to be invalid, regardless of whether the ERCs were facially valid at the time of use and were properly secured from a registered ERC resource or account holder, transferred and tracked in the designated ERC tracking system, and surrendered and retired timely for compliance purposes. The use of invalid ERCs to demonstrate compliance would constitute an exceedance of the applicable emission standard, to the extent invalid ERCs were applied.[311]

7.8.2 ERC Providers and Independent Verifiers—Performance Assurance

State plans must require that any party wishing to provide ERCs must register with the designated ERC tracking system. To register, the ERC provider must submit an eligibility application demonstrating that all qualifying criteria are met, including an EM&V plan. The EM&V plan and all subsequent M&V reports must be reviewed and certified by an independent verifier. Independent veri-

310 40 C.F.R. § 60.5775(f).

311 80 Fed. Reg. at 65,092.

fiers must also meet qualifying criteria and be registered with the ERC tracking system.

State plans must include provisions to suspend or permanently revoke the qualification status of an ERC provider such that they can no longer be issued ERCs at least for the duration that the party fails to meet all qualifying criteria, in the event any lapse or deficiency in qualifications is discovered.[312] Provisions must also be included in the state plan to suspend or revoke the qualification status of an independent verifier to review eligibility applications, EM&V plans or M&V reports. In addition, each state plan must include mechanisms to adjust the number of ERCs issued in the event any errors are discovered. In its proposed federal plan and model state rule, EPA included several provisions specifically related to adjusting or freezing the accounts of ERC providers and temporarily or permanently prohibiting the party from further participation in the program, in the event the ERC resource is determined to be ineligible.

EPA's proposed federal plan and model state rule would include the following corrective actions:

1) In the event of error or misstatement of quantified MWh for which ERCs have been issued, adjust the number of ERCs issued in a subsequent reporting period to address the error or, if the final report has been filed, revoke ERCs from the general account held by the eligible resource, in an amount necessary to correct the error. In the event that the general account holds an insufficient number of ERCs, require the ERC resource to provide a number of ERCs necessary to correct the error or misstatement. Failure to provide sufficient replacement ERCs would result in prohibition from further participation in the program.
2) In the event of (or pending investigation of) improper issuance of ERCs based on a misrepresentation or misstatement in an eligibility application or M&V report, freeze the general account of the ERC resource.
3) In the event an ERC resource is found to be ineligible, (1) freeze the general account to prevent further transfers of ERCs, (2) revoke and deduct ERCs held in the general account in a number equal to those issued for the ineligible resource, and (3) if the general account has insufficient ERCs, require the ERC resource to submit the number of ERCs necessary to fully account for all ERCs issued for the ineligible eligible resource. Failure to provide sufficient ERCs within 30 days would result in prohibition from further participation in the program.
4) In the case of repeated error or misstatements, or in the case of an intentional misrepresentation in a submitted M&V report, temporarily or permanently suspend the issuance of ERCs to the ERC resource.

Thus, while non-affected EGU ERC providers are not directly subject to enforcement under the CAA, they could nonetheless be liable for serious consequences for errors or misconduct, depending upon the specific provisions for error adjustments adopted in the state plan.

7.8.3 State Plan Performance Reviews, Reporting and Corrective Measures

As discussed earlier in Section 7.2 of this chapter, the emission standards incorporated in each rate-based state plan must be designed to achieve the Table 1 performance rates or Table 2 emission goals for the interim period and final period. With regard to the interim period, this requires that the emission standards imposed on each affected EGU for each interim step period collectively result in an average performance rate equal to or better than the subcategory Table 1 interim performance rate or statewide Table 2 interim emission goal, or revised Table 2 emission goal, as applicable for the plan.

During plan implementation, each state must report periodically to EPA on its plan performance, checking the progress of its affected EGUs collectively in advancing toward meeting the interim and final Table 1 or Table 2 performance rates, or approved alternative performance rates, as applicable. For rate-based plans, as shown in Table 7.4, plan performance reports must be submitted by July 1 of the year following the close of each interim step period and two-year final performance period.

For rate-based plans, the CPP emission guidelines require each state to conduct comprehensive periodic program reviews and to report the results as part of the state report to EPA. The program assessment must address all aspects of the administration of the state plan and overall program, including state evaluations and regulatory decisions regarding eligibility applications for ERC resources and M&V reports (and associated EM&V activities), and issuance of ERCs. The program review must assess whether

312 40 C.F.R. § 60.5805.

313 80 Fed. Reg. at 65,095 (proposed to be codified at 40 C.F.R. § 62.16450).

Table 7.4 **Rate-based State Plan Performance Periods and State Reporting Schedule**

Report	Performance Period Dates	State Report Due
Interim Step Period 1	January 1, 2022–December 31, 2024	July 1, 2025
Interim Step Period 2	January 1, 2025–December 31, 2027	July 1, 2028
Interim Step Period 3	January 1, 2028–December 31, 2029	July 1, 2030
Interim Performance Period	January 1, 2022–December 31, 2029	July 1, 2030
Final Performance Period	January 1, 2030–December 31, 2031 Ongoing 2-year periods	July 1, 2032 July 1 every 2nd year

the program is being administered properly in accordance with the approved plan, whether reported generation and savings from qualified ERC resources are being properly quantified, verified, and reported in accordance with approved EM&V plans, and whether appropriate records are being maintained. The program review must also address determination of the eligibility of verifiers by the state and the conduct of verifiers, including the quality of verifier reviews. In addition to the state's review of the program, EPA may conduct audits of the program.[314]

State reports to EPA must identify whether each affected EGU is in compliance with its applicable emission rate for the relevant plan performance period. In addition to reporting on individual EGU compliance, the Interim Step Period 1 and Interim Step Period 2 state reports to EPA must include a comparison of the state's applicable interim step period performance rate or emission goal vs. the collective affected EGU average adjusted performance rate, as achieved by all affected EGUs, and must identify whether all affected EGUs are collectively on schedule to meet the applicable interim period performance rate or emission goal.

Consequences of plan failure to achieve the interim step, interim period or final period performance rates or emission goals depend on the plan design. For streamlined plans, where the emission standards for applicable EGUs mathematically demonstrate compliance with the applicable plan performance metrics, no corrective action triggers are required in the plan. In such a case, if the plan fails to achieve the statewide collective EGU performance rate, the remedy would most likely rest with enforcement action against any noncompliant affected EGU owners and operators. For plans that include corrective measure triggers, corrective actions must be adopted and instituted to correct plan deficiencies. Corrective actions are triggered if the plan fails to achieve an EPA-approved interim step goal or the interim period goal by more than 10%, if the interim period goal is not met, or if any final reporting period emission goal is not met.

314 40 C.F.R. § 60.5870(b)(4); 80 Fed. Reg. at 64,908.

8. Mass-based Emission Standards Plans

An emission standards plan relies on federally enforceable CO_2 emission standards that are directly applicable to affected EGUs as the means of achieving and demonstrating compliance with the Subpart UUUU emission guidelines. A mass-based emission standards plan establishes enforceable emission limits and demonstrates compliance using a mass emissions metric, in units of tons[315] of CO_2 emitted per year or over a multi-year compliance period.[316] Mass-based state plans can be designed either as an emission standards plan or as a state measures plan. This chapter discusses mass-based emission standards plan components and provides example model rule language for aspects of implementing a mass-based plan.

8.1 Mass-based Emission Standards Plans – Available Pathways

A state can select from two primary pathways in developing a mass-based emission standards plan. First, the state can rely upon the Subpart UUUU Table 3 statewide emission goals (or alternative EPA-approved Table 3 statewide emission goals) as the total aggregate emission level that affected EGUs must collectively meet for each plan performance period. Second, the state can develop a plan that relies on the Subpart UUUU Table 4 statewide emission goals (or alternative EPA-approved Table 4 statewide emission goals) as the CPP compliance metric.[317] Further, each of these primary pathways can be implemented through two distinct forms of mass-based emission standards. The mass-based emission standards that the state imposes on affected EGUs (and new sources, if using the Table 4 goals) can either be direct emission limits that each affected EGU must meet (e.g., allowable tons per year, or over a specified compliance period), or a requirement to hold and surrender allowances equal to the affected EGU's total emissions under a cap-and-trade program. Figure 8.1 depicts the available pathways for a mass-based emission standards plan. This section discusses each of the available pathways in more detail.

8.1.1 Table 3 Statewide Emission Goals

EPA adopted the Table 3 statewide mass-based emission goals as a presumptively approvable alternative, equivalent to the Table 1 subcategory performance rates, for states that would prefer a mass-based statewide compliance metric. Table 3 provides state-specific, eight-year cumulative emission goals (tons of CO_2) for the interim period, and two-year cumulative emission goals (tons of CO_2) for each two-year block in the final period. States may design plans to achieve the Table 3 interim and final emission goals (the plan performance metric) by adopting emission standards for the affected EGUs that result in total emissions, collectively from all affected EGUs, less than or equal to the Table 3 statewide emission goal for each performance period.

States can translate the Table 3 emission goals to emission standards for affected EGUs in their state plans in two ways:

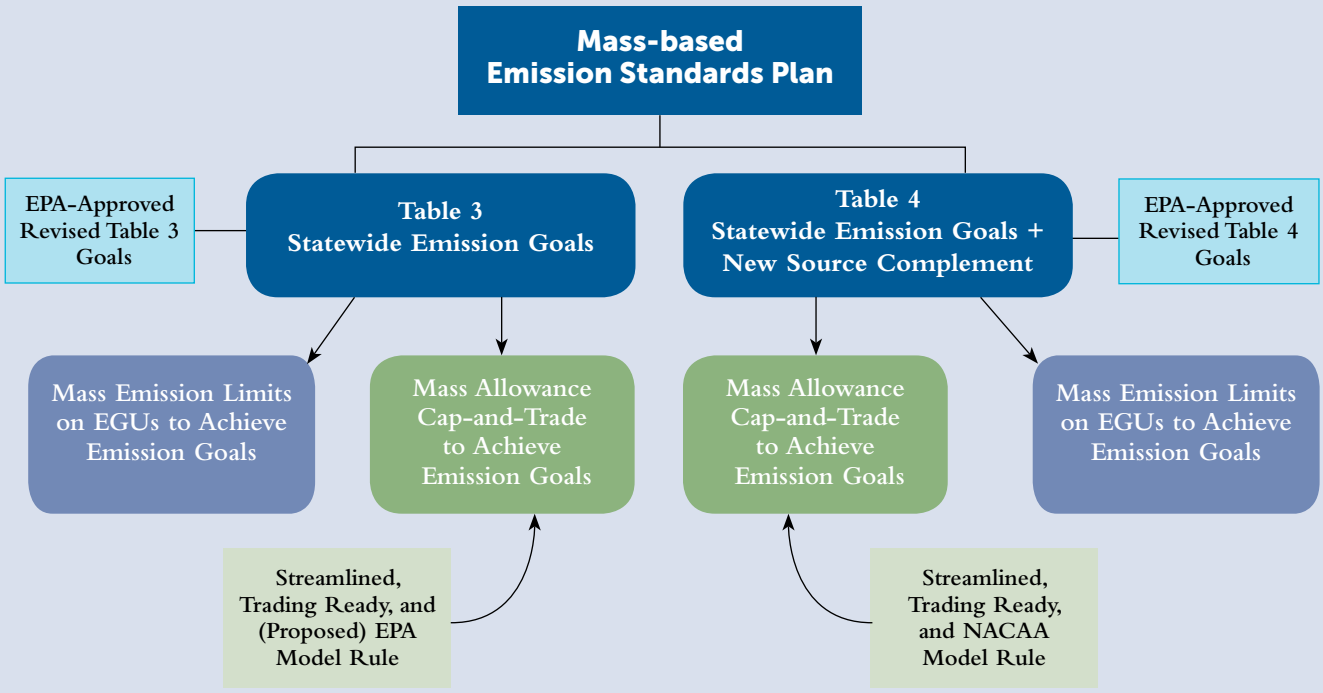
1) Set a mass emission limit (e.g., tons per year, or tons per two-year period) for each affected EGU such that the sum of all mass emission limits is equal to or less than the Table 3 goal; or
2) Adopt the Table 3 emission goal as a statewide cap for total allowances in a mass allowance cap-and-trade program.

315 Throughout this document, all references to "tons" are short tons, unless otherwise noted.

316 Subpart UUUU does not explicitly prohibit a state from using a form of emission limit or reduction strategy that is different from the form of the state plan compliance metric (i.e., mass- or rate-based). Adoption of a mass-based compliance metric (e.g., the Table 3 statewide emission goals) with a rate-based regulatory approach is considered an unlikely approach, and if implemented would most likely occur in the form of a state measures plan.

317 As discussed further in this section, a state relying on the statewide goal approach can, under certain circumstances as defined in Subpart UUUU, revise the state's Table 3 or Table 4 interim and/or final statewide emission goals.

Figure 8.1 **Mass-based Emission Standards Plan – Available Pathways**



8.1.1.1 Table 3-based Direct Emission Limit Standards

One available pathway for use of the Table 3 emission goals is a plan that applies individual mass-based emission limits to each affected EGU, enforceable directly against each affected EGU. A state plan that adopts mass emission limits for affected EGUs that sum to a total mass emission rate less than or equal to the Table 3 emission goals is a streamlined plan, because compliance by all affected EGUs with the plan will mathematically assure compliance with the Table 3 emission goals. Under this plan pathway, the state is not required to include corrective measure triggers or a federally enforceable backstop, and it is not required to develop a plan-specific performance demonstration.[318]

This plan approach is relatively inflexible, as compared to an allowance cap-and-trade program, and would tend to restrict the options available to individual affected EGUs to reduce emissions. To the extent CO_2 reductions must be achieved via generation replacement or demand-side energy savings, if the state plan predetermines the level of emissions each individual affected EGU must achieve, the utilization of those units is effectively also predetermined. A state plan using this pathway could provide some flexibility through a facility-wide aggregation provision, or by allowing aggregation of emissions across all affected EGUs owned or operated by a common entity to demonstrate compliance. However, a plan that relies upon the direct emission limit approach eliminates the opportunity for leveraging compliance costs and reduction strategies across the state or across an interstate region.

Given these constraints, a direct mass emission limit plan approach is likely to be selected only in limited circumstances. For example, if a state with a small inventory of affected EGUs has determined that retirements will be occurring during the interim period to a degree that would assure compliance with the Table 3 statewide emission goals, this approach could be suitable. Or, if a state's affected EGU inventory has already reduced emissions prior to 2022 to levels near or below the Table 3 goals, for example because of pre-existing robust RE and EE measures at the state level, then the state may conclude the direct emission limit approach is an expedient way to meet CPP requirements without unduly restricting affected EGU operations.

Mass-based Rule Example 1, located at the end of this Section 8.1.1, provides rule language for incorporation of direct emission limits for individual affected EGUs, with flexibility provisions including facility-wide or fleet-wide aggregation, to achieve the Table 3 statewide emission

318 40 C.F.R. § 60.5740(2)(i)(B); 80 Fed. Reg. at 64,833.

goals. This rule example relies on actual statewide emission goals and affected EGU emission data for the state of New Hampshire. The example scenario assumes that all coal units are scheduled to retire during the course of the interim period, between 2022 and 2029. At the end of the interim period, all affected NGCC EGUs are authorized to emit at levels equivalent to a utilization of 85% summer capacity in order to meet the statewide final emission goal. Provisions in the rule to allow revisions to individual affected EGU emission standards, in addition to the flexibility to demonstrate compliance using facility-wide or owner/operator fleet-wide aggregation, could accommodate earlier or later retirements or other changes from projections. In addition, the reliability safety valve provision could accommodate short-term operation of an affected EGU above the emission standard in the event of power system emergencies.

A leakage demonstration for a plan of this type could also be relatively simple without invoking set-asides or imposing state-enforceable emission limits on new NGCC units. Again, using New Hampshire baseline data as an example, an assessment of baseline utilization and unit capacity in relation to BSER could serve to demonstrate that leakage is not a concern. ***Leakage Demonstration Example 1*** provides an example of state plan supporting documentation for a leakage demonstration that corresponds to the ***Mass-based Rule Example 1*** scenario.

8.1.1.2 Table 3-based Cap-and-Trade

The second pathway a state can elect for achieving the Table 3 mass-based emission goals is to implement a cap-and-trade program, setting the cap for each plan performance period and each affected EGU compliance period equal to or lower than the corresponding Table 3 mass emission goal. In concert with the cap, the state would adopt a requirement that each affected EGU hold and surrender allowances equal to its total emissions at the end of each compliance period. The requirement to hold and surrender allowances equal to total emissions constitutes the applicable emission standard for each affected EGU.

A state plan that adopts this approach is a streamlined plan, because compliance by all affected EGUs with the allowance-holding emission standard will mathematically assure compliance with the Table 3 emission goals. Under this plan pathway, the state is not required to include corrective measure triggers or a federally enforceable backstop, and it is not required to develop a plan-specific performance demonstration. This approach can also be adopted as a "trading-ready" plan, by including a provision to recognize allowances from other states with an EPA-approved trading program using a joint or interoperable EPA-approved or EPA-administered trading platform. Alternatively, a streamlined cap-and-trade program can accommodate interstate trading by naming designated trading partners in the single-state plan, or by joining together with other states in a multi-state plan. In all cases, trading partners must rely upon an EPA-approved or EPA-administered joint or interoperable trading platform.

EPA has proposed model rule language for a state mass-based trading program using the Table 3 emission goals as the allowance cap that provides for interstate trading with other states using the same approach.[319] As noted above, EPA proposed to use set-asides to incentivize RE resources and generation shift to NGCC units as the mechanism to constrain leakage. Section III of this document includes a model trading rule that is designed to achieve compliance using the Table 4 emission goals as the mechanism to address leakage.

319 80 Fed. Reg. at 65,060 (proposed to be codified at 40 C.F.R. Part 62, Subpart MMM).

Mass-based Rule Example 1
Direct Emission Limits on Affected EGUs, with Flexibility Provisions

Section 1040. Emission Standards for Affected EGUs

A. Affected EGU Emission Standards.

1. The Administrative Authority shall set CO_2 emission standards for each affected EGU to assure the sum of authorized emissions from all affected EGUs under this chapter does not exceed the emission goals set forth in Table 1 for each performance period.

Table 1. **Statewide Emission Goals (Short Tons of CO_2)**

	Interim Performance Period January 1, 2022–December 31, 2029 Aggregate 8-year Total	Final Performance Periods Beginning with January 1, 2030–December 31, 2031 Aggregate Total for each 2-year Block Period
Sum of Emissions from All Affected Sources	33,947,936	7,995,158

2. Each affected source shall comply with the emission standards as specified in Table 2 for each compliance period, unless a revised emission standard applies as provided in Paragraph 1040.C of this Section. If a revised emission standard has been approved by the Administrative Authority for any compliance period for an affected EGU, pursuant to Paragraph 1040.C, then the affected EGU shall comply with the revised emission standard in lieu of the emission standard in Table 2.

Table 2 **Emission Standards for Affected Sources by Compliance Period (Short Tons of CO_2)**

Affected Source	Station	Period 1 2022–2024 3-year Total	Period 2 2025–2027 3-year Total	Period 3 2028–2029 2-year Total	Final Periods (2-year blocks starting with 2030-2031) 2-year Total
Pleiades ST1	Copper Canyon	650,661	0	0	0
Orion ST2	Copper Canyon	1,503,513	1,292,504	557,699	0
Big Rock CST	Candy Mountain	104,965	0	0	0
Whiskey River	Candy Mountain	107,144	127,266	53,536	0
Cedar Creek 1	Cedar Creek	167,316	0	0	0
Trojan 1	Odysseus	2,034,953	2,034,953	1,356,636	1,441,425
Trojan 2	Odysseus	2,034,953	2,034,953	1,356,636	1,441,425
Athena 1	Odysseus	2,144,951	2,144,951	1,429,967	1,519,340
IPP1	Strawberry Fields	1,333,574	1,392,844	948,319	1,007,589
IPP2	Strawberry Fields	1,333,574	1,392,844	948,319	1,007,589
IPP3	Strawberry Fields	1,938,946	2,025,121	1,378,806	1,464,981
Total Authorized Emissions All Affected Sources		13,354,550	12,445,436	8,029,917	7,882,350

Mass-based Rule Example 1, *continued*
Direct Emission Limits on Affected EGUs, with Flexibility Provisions

B. Compliance Demonstrations

1. The owner or operator of an affected EGU shall demonstrate compliance with the applicable emission standards of Paragraph A.2 of this Section using the sum of the unit's total emissions for the compliance period, as reported pursuant to Section 1085 of this chapter.
2. Facility-wide Aggregation. The owner or operator of multiple affected EGUs located at the same facility may elect to demonstrate compliance with applicable emission standards of Paragraph A.2 of this Section by aggregating the emissions across all affected EGUs at the facility and demonstrating that the total aggregated reported emissions for all affected EGUs at the facility is equal to or less than the sum of the emission standards for the affected EGUs during the compliance period.
3. Owner/Operator Fleet-wide Aggregation. The owner or operator of multiple affected EGUs under common control located in the State may elect to demonstrate compliance with applicable emission standards of Paragraph A.2 of this Section by aggregating the emissions across some or all such affected EGUs and demonstrating that the total aggregated reported emissions for all affected EGUs being aggregated is equal to or less than the sum of the emission standards for the affected EGUs during the compliance period.

C. Revisions to Emission Standards

1. Emission standards for individual affected EGUs may be revised by the Administrative Authority, provided that the revised emission standard(s) result in the sum of the emission limits of all affected EGUs remaining at or below the emission goals specified in Table 1 of this Section and provided that the sum of the emission limits of all affected EGUs, after any revisions, does not exceed the emission goals specified in Table 3 of this Section by ten percent or more.

Table 3. **Statewide Step Period Emission Goals (Short Tons of CO_2)**

	Step Period 1 January 1, 2022–December 31, 2024 Aggregate 3-year Total	Step Period 2 January 1, 2025–December 31, 2027 Aggregate 3-year Total
Sum of Emissions from All Affected Sources	13,384,705	12,488,941

2. Any revision to an emission standard approved by the Administrative Authority shall be made no later than twelve months before the ending date of the compliance period for which the revised emission standard would apply.
3. The owner or operator of an affected EGU may request a revision to an applicable emission standard under this Chapter by submitting an application for a significant modification to revise the facility's Title V Operating Permit, pursuant to Chapter 9, Operating Permits for Major Sources.
4. The Administrative Authority may initiate a revision to an applicable emission standard for an affected EGU under this Chapter by issuing a notice to reopen the facility's Title V Operating Permit, pursuant to Chapter 9, Operating Permits for Major Sources.

D. Reliability Safety Valve

1. Notwithstanding any other provision of this Section, emissions from an affected source in excess of the unit's applicable emission standard resulting from operation to provide power in response to a power system emergency or catastrophic event, for a period not to exceed ninety days, as reported and approved by the Administrative Authority pursuant to Section 1085 of this chapter, shall not be counted toward the sum of emissions from all affected EGUs in comparison to the emission goals in Table 1 or Table 3 of this Section.

Leakage Demonstration for Mass-based Rule Example 1
Supporting Documentation that Leakage Is Unlikely to Occur

Note: The final CPP emission guidelines require that each state submitting a plan designed to meet the state mass-based CO_2 goals for affected EGUs demonstrate that the plan addresses and mitigates the risk of potential emission leakage to new sources. In this context, EPA defines "leakage" as the potential for implementation of BSER through mass-based emission goals to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur with implementation of BSER using rate-base subcategory performance standards. The emission guidelines present three options from which a state may choose to make the leakage demonstration. This demonstration for the state plan relies on Option 3:

> *"Provide a demonstration in the state plan, supported by analysis, that emission leakage is unlikely to occur due to unique state characteristics or state plan design elements that address and mitigate the potential for emission leakage."*

See 80 Fed. Reg. at 64,822 & 64,887-88.

Leakage to New Sources Subject to 40 CFR Part 60 Subpart TTTT.

1. Characteristics of State Affected EGU Inventory

The State inventory of affected EGUs comprises 11 total units. Of these, 4 are coal steam units, 1 is an oil/gas steam unit, and 6 are NGCC units. Table 1 presents the affected EGU inventory, with an analysis of baseline generation and generation capacity.

Table 1. **Affected EGU Inventory Unit Type, Baseline Generation, Summer Capacity**

Affected Source	Station	Unit Type	2012 Generation (MWh)	Summer Capacity (MW)	Summer Capacity (MWh)	2012 Gen as % Summer Capacity
Pleiades ST1	Copper Canyon	CST	346,838	108	946,080	37%
Orion ST2	Copper Canyon	CST	839,298	330.5	2,895,180	29%
Big Rock CST	Candy Mountain	CST	47,456	47.5	416,100	11%
Whiskey River	Candy Mountain	CST	47,749	47.9	419,604	11%
Cedar Creek 1	Cedar Creek	OGST	72,614	400.2	3,505,752	2%
Trojan 1	Odysseus	NGCC	1,608,280	222	1,944,720	83%
Trojan 2	Odysseus	NGCC	1,608,280	222	1,944,720	83%
Athena 1	Odysseus	NGCC	1,608,280	234	2,049,840	78%
IPP1	Strawberry Fields	NGCC	650,452	152	1,331,520	49%
IPP2	Strawberry Fields	NGCC	650,452	152	1,331,520	49%
IPP3	Strawberry Fields	NGCC	821,125	221	1,935,960	42%
		Total NGCC	**6,946,869**	**1,203**	**10,538,280**	**66%**
		Total Affected EGUs	**8,300,824**	**2,137**	**18,720,996**	**38%**

As can be seen from Table 1, in 2012, NGCC units provided 6,946,869 MWh of electricity, or 84% of the total generation in the state, with the steam unit subcategory providing only 16%. Also, 3 of the NGCC EGUs operated at levels greater than the BSER target of 75% summer capacity, with the collective average utilization of NGCC units at 66% summer capacity. Full implementation of BSER Building Block 2, with average NGCC generation at the 75% summer capacity level, would equate to NGCC generation at 7,903,710 MWh. Notably, retirement plans

Leakage Demonstration for Mass-based Rule Example 1, *continued*
Supporting Documentation that Leakage Is Unlikely to Occur

have been announced for all steam units, with retirements anticipated either prior to 2022 or during the interim period of 2022–2029.

Baseline capacity factors for steam units relative to NGCC units, together with planned retirements for steam units, provide a strong indication that generation shift from affected steam EGUs to existing NGCC units is already occurring and is incentivized by factors other than the Emission Guidelines. Available capacity of existing NGCC units is sufficient to support a continuation of this trend at baseline generation levels. The total generation of steam units in 2012 was 1,353,955 MWh, while NGCC units had up to 3,591,411 MWh of unused summer capacity remaining.

2. State Plan Design Elements Mitigating Potential for Leakage

A. Mass Emission Limits on Affected EGUs

The design of the State plan involves implementing direct emission limits on each affected EGU that mathematically assure achieving the State emission goals for the interim and final plan performance periods. Affected EGU compliance periods are wholly aligned with the Emission Guideline plan performance periods, with compliance periods of 3 years (2022–2024), 3 years (2025–2027), and 2 years (2028–2029) during the interim period, and final compliance periods of 2 years beginning with 2030–2031. Emission standards for each period were developed by calculating annual emission rates for each affected EGU for each calendar year, and summing the emission rates for each compliance period to arrive at the total allowable emissions for the affected EGU for the compliance period.

The individual EGU emission limits reflect the planned retirement of affected steam units, with generation shifting to affected NGCC units over the interim period, up to and beyond the levels anticipated by BSER Building Block 2. Due to the specific circumstances of the State baseline inventory and generation levels, this design incentivizes existing NGCC units to increase utilization to BSER levels while achieving the emission reductions required by the Emission Guidelines. Both the emission factors and utilization rates assumed in developing the individual NGCC unit emission standards serve to mitigate the potential for leakage.

1) NGCC Emission Factors

Individual affected EGU emission standards rely on the 2012 baseline emission factor (lb/MWh) for each respective NGCC unit. That is, the annual EGU emission rate is equal to the "incentive utilization rate" (MWh) for that year times the unit's baseline performance rate (lb/MWh). For example, for affected EGU IPP1, the 2012 emissions were 289,535 tons CO_2 and 2012 generation was 650,452 MWh. The incentive utilization rate for IPP1 during 2022 is 75% summer capacity, which equates to annual generation of 998,640 MWh. The 2022 annual emission rate for IPP1 is calculated as follows:

998,640 MWh x 289,535 tons/650,452MWh = 444,525 tons CO_2

Using this approach, affected NGCC units need not make investments in emission reduction strategies to operate at the incentive utilization rates. Also, because the target rates are direct emission limits rather than adjusted performance rates, the state plan imposes no requirement that affected NGCC units purchase ERCs in order to operate at or above the BSER anticipated utilization level.

2) Incentive Utilization Rates

The emission standards for all NGCC units are intentionally designed to incentivize NGCC utilization at or above BSER Building Block 2 levels beginning in the first year of plan performance. The NGCC unit utilization rate used to establish the annual emission rate, called the "incentive utilization rate," increases over the interim period, reaching a level of 85% summer capacity for each affected NGCC unit in the final period. For year 2022, the incentive utilization rates for the three Strawberry Fields Power Station NGCC

Leakage Demonstration for Mass-based Rule Example 1, *continued*
Supporting Documentation that Leakage Is Unlikely to Occur

units were set at 75% summer capacity. The 2022 incentive utilization rates for the three Odysseus Power Station NGCC units were set at 81% summer capacity, reflecting the station's average baseline utilization rate. These incentive utilization levels result in levels of total incentivized NGCC generation at 99.5% of the total State affected EGU baseline generation level for Interim Step Period 1, increasing to 108% of the 2012 affected EGU generation level by 2030. Table 2 summarizes the State plan design incentive utilization rates for affected NGCC units.

Table 2. **State Plan Design Incentive Utilization Rates for Affected NGCC Units Annual Average by Compliance Period, in MWh and % Summer Capacity**

	Interim Step 1 Incentive Generation (MWh)	Interim Step 1 as % Summer Capacity	Interim Step 2 Incentive Generation (MWh)	Interim Step 2 as % Summer Capacity	Interim Step 3 Incentive Generation (MWh)	Interim Step 3 as % Summer Capacity	Final Incentive Generation (MWh)	Final Period as % Summer Capacity
Trojan 1	1,575,223	81%	1,575,223	81%	1,575,223	81%	1,653,012	85%
Trojan 2	1,575,223	81%	1,575,223	81%	1,575,223	81%	1,653,012	85%
Athena 1	1,660,370	81%	1,660,370	81%	1,660,370	81%	1,742,364	85%
IPP1	998,640	75%	1,043,024	78.33%	1,065,216	80%	1,131,792	85%
IPP2	998,640	75%	1,043,024	78.33%	1,065,216	80%	1,131,792	85%
IPP3	1,451,970	75%	1,516,502	78.33%	1,548,768	80%	1,645,566	85%
Total	8,260,067	78.4%	8,413,367	79.8%	8,490,017	80.6%	8,957,538	85%
% 2012 Total Affected EGU Gen.	**99.5%**		**101%**		**102%**		**108%**	

Given that the mass emission limits for affected NGCC units are specifically designed to accommodate and incentivize full implementation of BSER Building Block 2, no incentive for emission leakage from existing to new NGCC units results from the mass-based form of the emission standards. Both the emission factors and utilization rates relied upon in developing the NGCC emission standards mitigate the potential for leakage. Therefore, as described in this analysis, emission leakage is unlikely to occur due to the unique characteristics of the State's affected source inventory and generation, and these plan design elements.

8.1.2 Table 4 Statewide Emission Goals

The Table 4 statewide emission goals are derived from the Table 3 statewide emission goals for affected EGUs, with incremental emissions (i.e., the new source complement) added to the goals representing emissions for new fossil-fueled EGUs. A state plan using the Table 4 goals as the CPP compliance metric imposes federally enforceable emission standards on all affected EGUs, plus state-enforceable emission standards on all new sources subject to Subpart TTTT. The Table 4 statewide emission goals are a presumptively approvable option to address potential leakage to new source EGUs, obviating the need for allowance set-asides or for further demonstrations that leakage would not be a concern. If the state adopts the Table 4 statewide emission goals, plan performance will be evaluated by EPA by comparing existing plus new source emissions, summed collectively, to the Table 4 emission goals. It is not required that affected source emissions be at or below the affected source portion of the goal, provided total affected and new source emissions are at or below the Table 4 affected plus new source complement emission goal.[320]

320 80 Fed. Reg. at 64,887-90 (preamble to final CPP, section VIII.J.2.b).

Table 14 of the preamble to the final CPP sets forth the state-specific new source complements for the interim and final plan performance periods.[321] To calculate the new source complements added to the Table 3 emission goals for each state, EPA started with a projection of total load growth over the 2012 baseline for each regional interconnect, subtracted the portion of the demand increase that would be met by capacity under construction and from the anticipated application of BSER, and then apportioned the remaining load growth among states in each region based on their proportion of total regional generation in the 2012 baseline year. This incremental load growth is the estimated demand to be met in each state by new fossil-fueled EGU capacity. The emissions associated with the incremental load growth to be met by new fossil fuel EGUs was determined by applying the NGCC Subpart TTTT performance rate standard to the state's incremental fossil generation for each year.

States can translate the Table 4 emission goals to emission standards for affected EGUs and new sources in two ways:

1. Set a federally enforceable mass emission limit (e.g., tons per year, or tons per two-year period) for each affected EGU and a state-enforceable mass emission limit for each new source, such that the sum of all mass emission limits is equal to or less than the corresponding Table 4 goal; or
2. Adopt the Table 4 emission goal as a statewide cap for total allowances in a mass allowance cap-and-trade program.

8.1.2.2 Table 4-based Direct Emission Limit Standards

A state could rely on the Table 4 emission goals to design a plan that imposes direct emission limits for each affected EGU and for new sources subject to Subpart TTTT. This approach could be an option to address leakage for a state whose circumstances support the adoption of direct emission limits on affected EGUs as a viable and preferred approach to CPP compliance. As discussed above, however, a direct emission limit approach that does not provide for trading would create constraints on affected EGU operations in most cases. Including new sources in the program could extend those constraints to any newly constructed NGCC units if the new source complement is insufficient to accommodate their potential utilization. On the other hand, if a state's existing affected EGU fleet is projected to readily meet the Table 3 mass emission goals, and the long-term projections for new NGCC construction are within the new source complement, this approach could be a simple and expedited pathway to CPP compliance. A plan using this direct emission limit approach is a streamlined plan, provided that, taken together, the affected source plus new source emission standards mathematically assure compliance with the Table 4 statewide mass emission goals.[322]

8.1.2.3 Table 4-based Cap-and-Trade

A state plan that uses the Table 4 affected EGU plus new source complement emission goals as the state budget to implement a cap-and-trade program must create federally enforceable provisions for its Subpart UUUU affected EGUs, while establishing state-enforceable provisions for new sources. One way to accomplish this strategy would be to adopt the regulations to implement the trading program as state-only regulations, with a provision requiring affected EGUs to codify the emission standard in the facility's Title V permit. The supporting documentation included with the state plan submittal would describe and document the state regulations that address the new sources.[323]

A state plan that uses the Table 4 emission goals as the state's allocation budget for an interstate cap-and-trade program is a streamlined plan and a trading-ready plan. A trading program that applies to both affected EGUs and new sources can link with other states whose programs also apply to both affected EGUs and new sources, as well as with states whose programs apply only to affected EGUs, without triggering the need to account for net exports or imports of allowances in the plan compliance demonstration.[324]

Mass-based Rule Example 2, located at the end of this Section 8.1.2, provides example rule language to implement allowance trading for a state plan relying on the Table 4 statewide emission goals as the applicable allowance cap, and to require affected EGUs to include the allowance-holding emission standard as an applicable requirement for Title V permitting. Also, a comprehensive model state plan using this approach is provided in Section III.

321 80 Fed. Reg. at 64,888-89.

322 40 C.F.R. § 60.5740(a)(2)(i)(C).

323 80 Fed. Reg. at 64,887-88.

324 See Section 6.3.1 for more detailed discussion.

Mass-based Rule Example 2
Allowance-holding Emission Standards and Enforceability for Existing Affected Sources and New Sources

Section 2010. Emission Standards for Affected Electric Generating Units

A. Applicability.

1. The requirements of this chapter apply to the owners and operators of any affected *electric generating unit (EGU)* located in the State. The owners and operators of each affected EGU shall assign and register a designated representative, and may also assign and register an alternate designated representative, in accordance with Section 2020 of this chapter.
2. Affected EGUs under this chapter (interchangeably referred to as affected sources) include any existing affected EGU and any new affected EGU that meets the applicability criteria described in Paragraph A.3 of this Section, with the exception of any source excluded pursuant to Paragraph A.4 of this Section.
   a. An existing affected EGU is any affected EGU that commenced construction on or before January 8, 2014 and that is not subject to 40 CFR part 60 subpart TTTT.
   b. A new affected EGU is any affected EGU that commenced construction, modification or reconstruction after January 8, 2014 and that is subject to 40 CFR part 60 subpart TTTT.
3. Except as provided in Paragraph A.4 of this Section, affected EGUs include those EGUs described in Paragraphs A.3.i and A.3.ii of this Section:
   a. Any fossil fuel-fired EGU, including steam generating units and IGCC units, that:
      i. serves a generator that is connected to a utility power distribution system and has a nameplate capacity of 25 MW-net or greater; and,
      ii. has a design heat input capacity greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel alone or of fossil fuel in combination with any other fuel;
   b. Any stationary combustion turbine meeting the definition of *combined cycle stationary combustion turbine or combined heat and power stationary combustion turbine* that:
      i. serves a generator that is connected to a utility power distribution system and has a nameplate capacity of 25 MW-net or greater; and,
      ii. has a design heat input capacity greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel alone or of fossil fuel in combination with any other fuel.
4. EGUs that are excluded from being affected EGUs include:
   a. Steam generating units and IGCC units that are currently and always have been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;
   b. Non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;
   c. Stationary combustion turbines not capable of combusting natural gas (e.g., not connected to a natural gas pipeline);
   d. Any EGU that is a combined heat and power unit that has always historically limited, or is subject to a federally enforceable permit currently limiting and always historically limiting, annual net-electric sales to a utility distribution system to the design efficiency times the potential electric output or 219,000 MWh (whichever is greater), or less;
   e. Any EGU that serves a generator along with other steam generating unit(s), IGCC unit(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of

Mass-based Rule Example 2, *continued*
Allowance-holding Emission Standards and Enforceability for Existing Affected Sources and New Sources

the base load rating of each steam generating unit, IGCC unit, or stationary combustion turbine) is 25 MW or less;

f. Any EGU that is a municipal waste combustor unit that is subject to 40 CFR part 60 subpart Eb; and,

g. Any EGU that is a commercial or industrial solid waste incineration unit that is subject to 40 CFR part 60 subpart CCCC.

B. State and Federal Enforcement Authority

1. To the extent requirements under this chapter apply to existing affected EGUs, all such requirements shall be enforceable under both the State Environmental Quality Act and the federal Clean Air Act. All requirements applicable to existing affected EGUs shall be federally applicable requirements under SAC 55 Regulation V, Chapter 5, Operating Permits for Major Sources, and shall be incorporated into the Title V permit for the facility at the next permit renewal, reopening, or permit modification, but no later than December 31, 2020. Minor modification procedures may be used to incorporate the requirements of this chapter in the Title V permit.
2. To the extent requirements under this chapter apply to new affected EGUs, all such requirements shall be enforced solely under the State Environmental Quality Act and shall not be federally enforceable requirements under the federal Clean Air Act or under any other federal law or regulation.

C. Emission Standards for Affected EGUs

1. Allowance-holding and Surrender Emission Standard. As of the allowance transfer deadline for each compliance period specified in Paragraph C.2 of this Section, the owners and operators of each affected EGU shall hold allowances in the compliance account for the affected EGU, in an amount not less than the total tons of CO_2 emissions from the affected EGU, which shall be surrendered for compliance upon transfer by the Administrative Authority. In cases where a facility compliance account has been established for multiple affected EGUs located at the same facility and under common control of the same owners or operators, the owners or operators shall hold allowances, as of the allowance transfer deadline for the compliance period, in an amount not less than the total tons of CO_2 emissions during the compliance period from all affected EGUs named under the facility account, which shall be surrendered for compliance upon transfer by the Administrative Authority.
2. Compliance Periods. The allowance-holding and surrender emission standard specified in Paragraph C.1 of this Section shall apply to each affected EGU for the following compliance periods:
   a. Interim 1: The 3-year period from January 1, 2022 through December 31, 2024;
   b. Interim 2: The 3-year period from January 1, 2025 through December 31, 2027;
   c. Interim 3: The 2-year period from January 1, 2028 through December 31, 2029;
   d. Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year.
3. Allowance Budgets. The allowance budgets as specified in Table 2 of this chapter shall apply for each compliance period. The allowance budget for a given compliance period shall constitute the full complement of new allowances available for issuance by the Administrative Authority, including allowances allocated to existing and new affected EGUs and any allocation set-asides established for the compliance period in accordance with Section 2050 of this chapter. Allowance budgets do not include any allowances held in general accounts or compliance accounts at the end of a previous compliance period.

Mass-based Rule Example 2, *continued*
Allowance-holding Emission Standards and Enforceability for Existing Affected Sources and New Sources

Table 2. **CO_2 Allowance Budgets (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons per 3-year period)	Interim 2 2025–2027 (total tons per 3-year period)	Interim 3 2028–2029 (total tons per 2-year period)	Final, beginning 2030–2031 (total tons per 2-year period)
108,604,371	100,568,769	63,583,444	61,371,058

4. Allowance Denomination and Constitution of Authorization. Each allowance shall be denominated as a single ton, and shall constitute a limited authorization to emit one ton of CO_2 for an affected EGU under this chapter, or for an affected source in another State or jurisdiction as designated under an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart NNN in a state or other jurisdiction that provides for interstate trading of allowances and utilizes an Allowance Tracking and Compliance System designated as authorized for trading by the Administrative Authority.

8.1.3 Alternative Mass-based Emission Goals

States adopting mass-based plans have the same flexibility as states adopting rate-based plans to set their own statewide goals that differ from the Table 3 or Table 4 statewide emission goals. Also, a state can develop and adopt interim step emission goals that differ from those derived by EPA.

8.1.3.1 Alternative Interim Period Emission Goals

A state may derive alternative emission goals to replace the EPA-adopted Subpart UUUU Table 3 or Table 4 interim and final emission goals only to address changes in the affected EGU inventory.[325] For example, if an applicability review determines that the state's baseline inventory relied upon by EPA in setting the Table 3 goals is inaccurate, the state can choose to propose an adjustment to the Table 3 or Table 4 goals through its initial state plan submittal or a subsequent plan revision. Changes to the goals must be reviewed and approved by EPA. Once a revised goal is approved, the alternative emission goal would effectively substitute for the Table 3 or Table 4 emission goal and could be used in the same manner. That is, EPA-approved alternative goals could be used as the limiting sum of all allowable emissions, either by setting individual EGU emission limits or by implementing a cap-and-trade program. However, if the state develops and adopts its own new source emissions budget, EPA will evaluate the state plan performance by comparing existing source emissions to the Table 3 emission goals instead of by comparison to the existing-source plus new-source-complement collective total emissions.[326]

8.1.3.2 Alternative Interim Step Period Emission Goals

EPA developed state-specific mass-based interim step emission goals for affected EGUs corresponding to the mass emission goals adopted in Table 3 for each state, which are published in Table 13 of the preamble to the final emission guidelines.[327] Also, Table 8.2 of this chapter provides the interim step emission goals that correspond to the Subpart UUUU Table 4 interim emission goals, which are derived from the data EPA developed in calculating the new source complements.[328]

325 40 C.F.R. § 60.5855(d)(1). Note that a state can choose to meet more stringent emission goals than those adopted in Subpart UUUU.

326 80 Fed. Reg. at 64,889.

327 80 Fed. Reg. at 64,825. Table 13 is reproduced at the end of Chapter 3, as Table 3.13 of this document.

328 EPA, Technical Support Document for CPP, *Data File: New Source Complements Appendix (XLSX)*, available at http://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

Under a mass-based program, states have the flexibility to establish a set of interim step emission goals that are different from the interim step emission goals published in Table 13 of the preamble to the final Subpart UUUU or the affected source plus new source interim step goals in Table 8.2.[329] This flexibility applies regardless of whether changes occur to the baseline or future affected EGU inventory. The alternative interim step goals developed by the state must still achieve the applicable 8-year cumulative emission goal (i.e., Table 3 or 4 interim period statewide emission goal, or an EPA-approved alternative interim period statewide emission goal). Although a state may alter the level of the interim step goals, the interim step periods for plan performance must be the same as those specified under Subpart UUUU. The corresponding compliance periods for affected EGUs during each interim step period and for the final compliance periods may be shorter than the required interim step and final plan performance periods, provided the last compliance period within each plan performance period ends on the same date as the corresponding interim step and final plan performance period, and provided emission standards are imposed for the entirety of each plan performance period.

8.2 Setting the Slope to Compliance – Interim Steps

Each mass-based emission standards state plan must establish a series of statewide interim step goals, as well as emission standards applicable to affected EGUs, that will apply in a step-wise fashion over the eight-year interim period, setting the slope from 2022 to 2030 to achieve the cumulative interim period emission goal and to reduce emissions to the level of the final statewide goal. As noted above, the interim step goals adopted in the state plan must sum to an 8-year cumulative emission level, for all affected EGUs (or affected EGUs plus new sources) that is less than or equal to the Table 3 or Table 4 interim statewide emission goal (or alternative Table 3 or Table 4 interim emission goal, as approved by EPA), as applicable, over the eight-year interim period.[330]

States have the option to adopt the EPA-derived interim step period goals, as discussed in Section 8.1.3.2, for existing affected EGUs or for existing plus new sources, as appropriate for their plan pathway. Alternatively, a state may elect to set its own interim step goals.

8.2.1 EPA's Mass-based Interim Step Goals

This section discusses the assumptions and methods EPA relied upon in its derivation of the mass-based interim step goals, to assist states in assessing whether their specific circumstances or needs differ in ways that would lead to different interim step goals and standards.

8.2.1.1 EPA's Interim Step Goals for Table 3 (Affected EGUs Only)

To develop the Table 3 mass-based emission goals, EPA began with the rate-based emission goals; therefore, the same assumptions used to develop the rate-based goals are inherently incorporated in the mass-based goals. Those assumptions are delineated in Section 7.2.1.

The equation EPA utilized for deriving the mass goals sums two emissions components. The first component is the emissions quantity determined by multiplying the state emission rate goal (lb/MWh) times the 2012 baseline affected EGU generation (MWh). The second component represents the emissions associated with increased generation from affected EGUs, as could occur under a rate-based plan, assuming the state were to deploy the amount of RE representing the potential for each region that was not included in developing the source category Table 1 performance rates. That is, because the least stringent region was used to establish the Table 1 performance rates, a quantified amount of cost-effective potential RE is "beyond compliance" with the emission guidelines but remains available for supporting growth through ERC issuance under a rate-based plan.[331] To afford affected EGUs subject to mass-based plans this same opportunity to increase utilization as under a rate-based plan, EPA quantified the RE potential that was untapped in developing the source category performance rate standards, and apportioned the total nationwide availability among the states on the basis of each state's proportion of 2012 affected EGU generation. For each state, these RE MWh were converted to mass emissions at two times the state emission rate goal, and added as the second component of the state's mass-based goal.[332] EPA used this approach to develop the mass-based emission goals for each state and for each interim step compliance period.

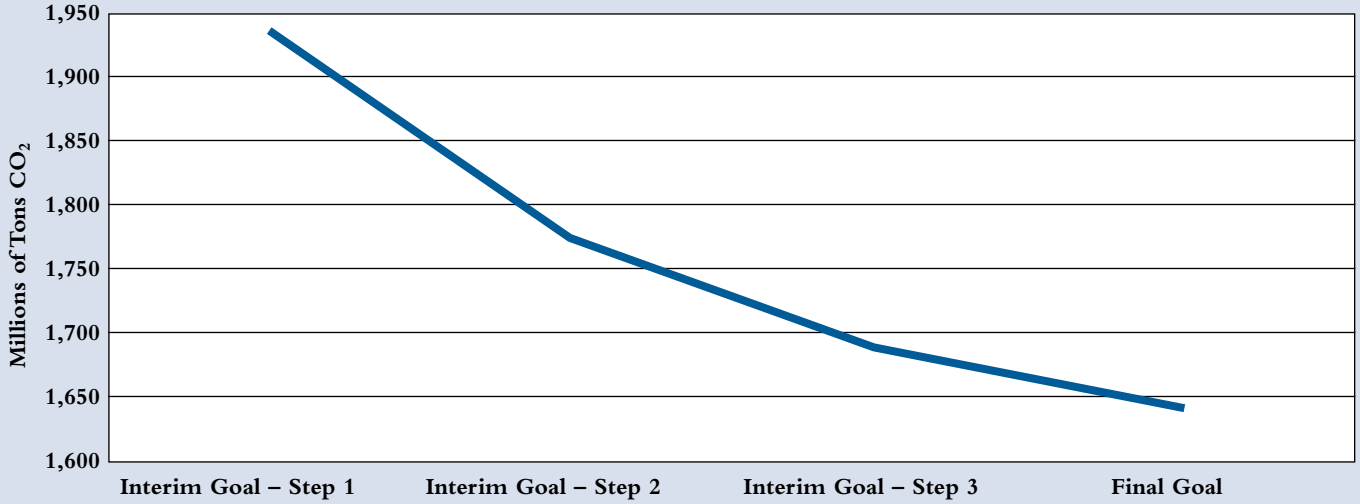
329 40 C.F.R. §§ 60.5745(a)(2)(i) & 60.5770; 80 Fed. Reg. at 64,667, 64823-25 & 64,828.

330 40 C.F.R. § 60.5885.

331 See Chapter 6 for a more detailed discussion. Also, see EPA, *Clean Power Plan Goal Calculation Viewer and CO_2 Emission Performance Rate and Goal Computation Technical Support Document*, both available at http://www2.epa.gov/cleanpowerplantoolbox.

332 *Ibid*.

Figure 8.2 **Compliance Slope for Table 3 Mass Emission Goals, All States**



The compliance slope represented by EPA's interim step emission goals for mass-based plans is depicted in Figure 8.2. The data plotted in Figure 8.2 are the sums of the interim step mass goals for all states (million tons CO_2).

8.2.1.2 EPA's Interim Step Goals for Table 4 (Affected EGUs plus New Sources)

Interim step emission goals for affected EGUs plus new source complements are presented in Table 8.2. EPA did not publish these mass goals in the preamble to the final CPP or in Subpart UUUU, but did provide the components that are summed to create the goals that are listed in Table 8.2. Specifically, these mass goals plus new source complements are a sum of the EPA-derived new source complements and EPA-derived affected EGU emission goals for each state for each interim step period. In developing the interim period and final mass-based new source complements and Table 4 emission goals for each state, EPA first developed annual new source complements for each year from 2022 to 2030 for each state. These annual new source complements are summed for each interim step period to provide interim step new source complements (2022–2024, 2025–2027, and 2028–2029).[333] When added to the EPA-derived existing source interim step emission goals, the results comprise interim step goals that correspond to the Table 4 interim period statewide emission goals. For example, the derivation of the Interim Step 1 goal plus new source complement for Iowa is shown in Table 8.1.

The assumptions and methodology EPA relied upon in calculating the new source complements include the following:[334]

1) EPA started with a projected total load growth for each region for each year (2022 to 2030), as presented in the Energy Information Administration's (EIA's) 2015 Annual Energy Outlook (AEO2015);[335]
2) A portion of the load growth is presumed to be met by sources under construction in 2012, and a portion is presumed to be met by affected EGUs

Table 8.1 **Example Calculation (Iowa Data) of Interim Step 1 Emission Goals Plus New Source Complements, Corresponding to the Subpart UUUU Table 4 Interim Emission Goals (Short Tons of CO_2)**

Emission Goal Component	2022	2023	2024	Interim Step 1 2022–2024
Affected EGU Emission Goal	31,713,035	30,531,749	28,980,270	91,225,056
New Source Complement	-	94,685	273,321	368,007
Total	31,713,035	30,626,434	29,253,591	91,593,063

333 EPA, *Data File: New Source Complements Appendix (XLSX), supra* note 328.

334 *Ibid.*

335 DOE/EIA-0383(2015), April 2015, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

and RE deployment at the levels accounted for in the Table 3 mass goals;

3) The remainder of the projected load growth for each region is presumed to be met by new NGCC capacity operating at the Subpart TTTT NSPS performance rate; and

4) Demand growth in each region is presumed to be met by individual states in the same proportion as the state's contribution to the regional 2012 generation.

Table 8.2 **Statewide Mass-based Emission Goals Plus New Source Complements, Cumulative by Period (Short Tons of CO_2)**[336]

State	Cumulative Mass-based Goals Plus New Source Complement				
	Interim Step 1 2022–2024	Interim Step 2 2025–2027	Interim Step 3 2028–2029	Interim Period 2022–2029	Final Period 2030–2031
Alabama	199,547,850	186,314,097	118,672,556	504,534,496	115,272,348
Arizona	107,607,201	102,210,075	66,078,682	275,895,960	64,760,392
Arkansas	108,604,371	100,568,769	63,583,444	272,756,584	61,371,058
California	164,574,366	160,418,625	105,995,834	430,988,832	105,647,272
Colorado	109,130,577	102,396,048	65,495,770	277,022,392	63,645,750
Connecticut	22,834,062	21,887,760	14,264,378	58,986,200	14,121,986
Delaware	16,142,151	15,216,741	9,774,802	41,133,688	9,562,772
Florida	360,299,832	339,545,472	218,058,738	917,904,040	213,283,190
Georgia	163,607,577	152,378,034	96,841,338	412,826,944	93,888,810
Idaho	4,981,470	4,905,471	3,268,322	13,155,264	3,278,028
Illinois	242,195,766	222,773,442	139,984,588	604,953,800	134,398,350
Indiana	277,188,756	255,002,136	160,260,370	692,451,264	153,885,208
Iowa	91,593,063	84,087,771	52,745,930	228,426,760	50,563,762
Kansas	80,612,076	73,969,944	46,378,108	200,960,128	44,441,646
Kentucky	231,198,390	212,221,524	133,102,136	576,522,048	127,580,002
Lands of the Fort Mojave	1,963,815	1,933,854	1,288,450	5,186,120	1,292,276
Lands of the Navajo	80,506,851	74,892,783	47,539,204	202,938,840	45,911,608
Lands of the Uintah & Ouray	8,397,087	7,811,526	4,958,470	21,167,080	4,788,708
Louisiana	126,701,823	117,394,839	74,260,314	318,356,976	71,708,644
Maine	6,803,787	6,529,170	4,259,170	17,592,128	4,219,936
Maryland	52,552,488	48,237,333	30,252,786	131,042,608	28,996,874
Massachusetts	40,359,351	38,470,914	24,952,164	103,782,432	24,606,746
Michigan	171,330,525	158,270,715	99,845,174	429,446,408	96,188,606
Minnesota	82,262,193	75,795,699	47,703,120	205,761,016	45,862,348
Mississippi	87,327,306	82,076,622	52,586,098	221,990,024	51,332,926
Missouri	202,761,882	186,251,709	116,890,966	505,904,560	12,105,626
Montana	41,933,316	39,009,138	24,761,576	105,704,032	23,913,816
Nebraska	67,005,189	61,476,135	38,539,994	167,021,320	36,926,890
Nevada	46,332,249	44,972,082	29,611,736	120,916,072	29,436,214
New Hampshire	13,472,628	12,785,547	8,261,108	34,519,288	8,121,182
New Jersey	55,110,477	52,624,728	34,184,048	141,919,256	33,752,728
New Mexico	45,124,401	42,428,487	27,188,706	114,741,600	26,459,850
New York	107,123,361	100,967,115	64,849,970	272,940,448	63,436,364
North Carolina	183,779,505	170,121,999	107,523,428	461,424,928	103,753,714

336 Small differences in the interim period and final goals between this table and Subpart UUUU Table 4 result from differences in rounding and methodology among EPA technical support documents.

Table 8.2 **Statewide Mass-Based Emission Goals Plus New Source Complements, Cumulative by Period (Short Tons of CO_2),** *continued*

State	Cumulative Mass-based Goals Plus New Source Complement				
	Interim Step 1 2022–2024	Interim Step 2 2025–2027	Interim Step 3 2028–2029	Interim Period 2022–2029	Final Period 2030–2031
North Dakota	76,661,529	70,305,672	44,057,958	191,025,160	42,199,356
Ohio	266,706,450	246,060,207	155,045,428	667,812,080	149,215,952
Oklahoma	143,448,147	133,408,191	84,674,726	361,531,064	82,001,706
Oregon	27,942,456	27,054,780	17,777,376	72,774,616	17,644,106
Pennsylvania	319,796,136	296,835,933	188,073,234	804,705,304	181,863,276
Rhode Island	11,521,116	11,069,670	7,228,578	29,819,360	7,168,032
South Carolina	93,501,132	86,442,828	54,572,106	234,516,064	52,606,510
South Dakota	12,750,813	11,780,373	7,432,516	31,963,704	7,161,038
Tennessee	102,796,659	94,727,802	59,625,124	257,149,584	57,329,988
Texas	671,018,139	631,148,511	405,190,144	1,707,356,792	396,210,500
Utah	86,844,810	81,456,291	52,085,518	220,386,616	50,601,386
Virginia	94,424,655	88,842,024	56,974,204	240,240,888	55,660,348
Washington	37,948,164	36,224,412	23,519,164	97,691,744	23,127,324
West Virginia	188,413,332	172,792,347	108,282,560	469,488,232	103,714,616
Wisconsin	100,966,116	93,229,179	58,790,284	252,985,576	56,617,766
Wyoming	117,282,297	109,141,734	69,300,820	295,724,848	66,945,204

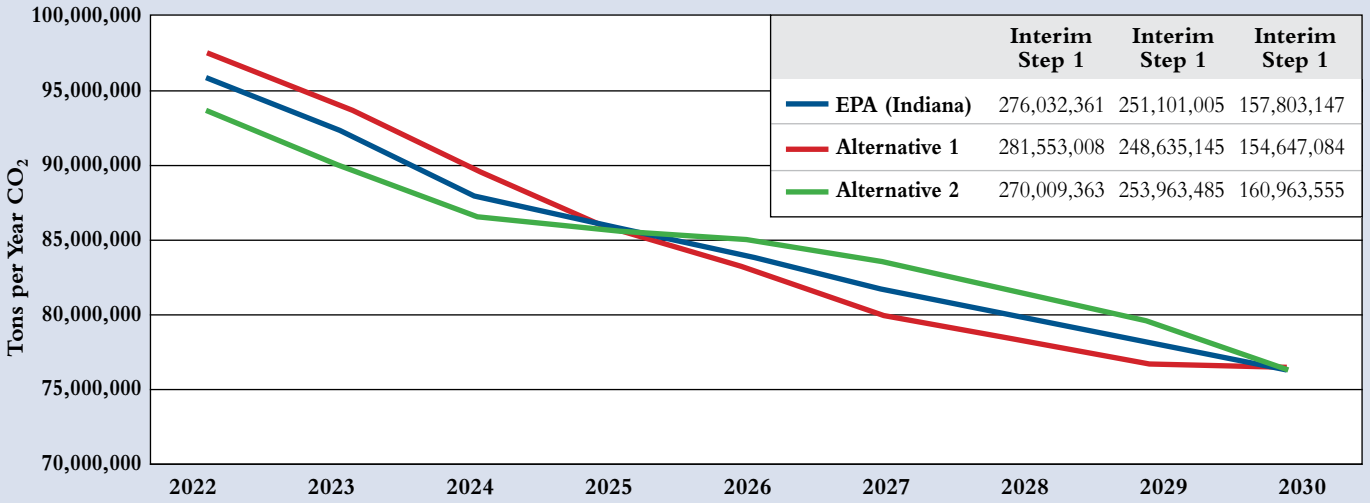
8.2.2 State-Derived Interim Step Emission Standards and Statewide Goals

Just as was discussed for rate-based plans in Chapter 7, a state adopting a mass-based plan may determine that a different glide path is more appropriate for its particular circumstances. Under a mass-based approach, the interim step emission goals are cumulative mass emissions (tons) that must sum to a total less than or equal to the 8-year cumulative mass interim emission goal. Thus, any increase in emissions in one interim step period must be compensated by an equal decrease in emissions in another interim step period. In short, changes to the interim step emission goals are a zero-sum game.

Figure 8.3 presents three different glide paths, and corresponding interim step emission goals, to arrive at the final Table 3 emission goal, using Indiana data as an example. The three glide paths represent EPA's Table 13 interim step emission goals (EPA) and two hypothetical state-derived interim period emission goal curves (Alternative 1 and Alternative 2), each of which are projected to result in achieving the Subpart UUUU Table 3 eight-year cumulative interim period emission total. Figure 8.3 illustrates the concept that an upward shift of the curve at one end of the interim period is compensated by a downward shift at the opposite end, and vice versa, in order to arrive at the same 8-year interim period total. Because the interim period is eight years and the level of overall decrease in emissions is approximately 20% or less for most states over the interim period, the compliance curve can only accommodate a shift by about 2% or less in the early years to maintain a relatively gradual decrease and avoid having annual emission goals of less than the final goal in the final years of the interim period.

As previously discussed with regard to rate-based interim step goals, a state may determine that such a change is warranted if, for example, concerns are identified regarding the deployment of sufficient reduction measures to assure compliance with the Interim Step 1 period emission goal derived by EPA. A small increase in the Interim Step 1 period mass emission goal (e.g., a small increase in the statewide cap for the first compliance period under a cap-and-trade program) could help to alleviate compliance concerns. However, the increase would have to be offset by decreases in the budget in later years. (See Figure 8.3, Alternative 1) Conversely, if the affected EGUs in the state are clearly on track to achieve the EPA-derived emission goals for 2022, 2023 and 2024, the state may elect to reduce the budget for Interim Step 1 in order to provide a more gradual decrease in the cap over time. (See Figure 8.3, Alternative 2).

Figure 8.3 **Alternate Mass-based Interim Step Goals**



	Interim Step 1	Interim Step 1	Interim Step 1
EPA (Indiana)	276,032,361	251,101,005	157,803,147
Alternative 1	281,553,008	248,635,145	154,647,084
Alternative 2	270,009,363	253,963,485	160,963,555

8.3 Options for Addressing Leakage

A key consideration extending across all mass-based plan pathways is the requirement for each mass-based plan to address leakage.[337] The term "leakage," as used in this context, refers to shifts in generation from affected EGUs to new fossil-fueled EGUs that are not affected sources, resulting in increased emissions relative to emissions that would occur with the application of the Table 1 performance rate standards to each subcategory of affected EGUs.

The CPP establishes the subcategory CO_2 emission performance rates in Table 1 of Subpart UUUU as the quantitative application of BSER to affected EGUs. That is, these performance rates are the level of emissions achieved when BSER is employed. To allow a greater degree of state discretion in implementing the emission guidelines, EPA also established the statewide emission goals provided in Tables 2, 3 and 4 of Subpart UUUU that are equivalent expressions of applying BSER reduction strategies to the affected source inventory for each state. Tables 3 and 4 establish mass-based goals, as an alternative to the rate-based expression of BSER. Mass-based emission goals offer states an approach that limits mass emissions of CO_2, and in particular, accommodates a mass allowance cap-and-trade pathway to CPP compliance. To ensure that the mass emission goals, as implemented, are an equivalent application of BSER (i.e., will achieve equivalent reductions as would the application of the Table 1 subcategory performance rates), mass-based plans must be designed to ensure affected EGUs are not incentivized to shift generation to new, unaffected fossil-fueled EGUs to a greater extent than would occur under a rate-based plan.

As discussed in Chapter 5, the CPP provides three options that states can use to demonstrate a mass-based plan will not unduly incentivize leakage to new sources. The options are briefly summarized below.

1) **Direct regulation of new sources.** The state can elect to regulate new non-affected EGUs, through state-only enforceable requirements, in the same manner as existing EGUs under the mass-based program. To facilitate this approach, EPA has adopted the Table 4 mass emission goals that include a new source complement of mass emissions. EPA's derivation of the Table 4 new source complements is discussed in Sections 8.1 and 8.2. Example rule language to implement this option is provided in Section 8.1.2 of this chapter, ***Mass-based Rule Example 2, Allowance-holding Emission Standards and Enforceability for Existing Affected Sources and New Sources.*** In addition, an illustrative comprehensive state plan utilizing this approach is included in Section III of this document.
2) **Allocation schemes to counter leakage.** The state plan can include an allocation scheme that minimizes or counterbalances incentives for leakage to new sources, without imposing direct requirements on new sources. In the proposed federal plan for CPP implementation, EPA included two

337 Note that the regulatory language of Subpart UUUU applies this requirement specifically to "a mass-based emission trading program." 40 C.F.R. § 60.5790(b)(5). Nonetheless, in some places, the preamble discussion states that the requirement applies more broadly to "states adopting a mass-based state plan." *See, e.g.,* 80 Fed. Reg. at 64,823.

allocation schemes that could be used to accomplish this effect. The first set-aside provides allowances to target RE deployment, thereby incentivizing increased shift to new RE units and reducing or balancing the incentive for generation shift to new fossil fuel-fired EGUs. The second set-aside included in the proposed federal plan directly rewards increased utilization of existing NGCC units by allocating allowances to be awarded based on an NGCC unit's level of generation, offsetting the incentive to shift to new fossil EGUs that are subject to rate-based standards under Subpart TTTT.[338]

3) **State-determined customized approach.** This approach can take two different paths:
   a. The state can develop its own new source complement budget or an equivalent method for addressing new sources. Further discussion of this option is provided in the next section.
   b. The state could demonstrate, through the plan submittal and supporting documentation, that leakage to new fossil fuel-fired EGUs is not anticipated. Example language and state plan supporting documentation demonstrating that leakage is not anticipated to occur is provided in Section 8.1.1, ***Leakage Demonstration for Mass-based Rule Example 1, Supporting Documentation that Leakage Is Unlikely to Occur.***

8.3.1 Direct Regulation of New Sources

The first option to address leakage is the direct regulation of new sources in a manner that imposes a mass-based emission standard on new sources under state law, in conjunction with federally enforceable mass-based emission standards for affected EGUs, thereby eliminating or countering the incentive for affected EGUs to shift generation to new sources that could result if new sources were regulated only under a rate-based performance standard.

Table 4 sets the total combined emission goal for new and affected sources under this approach, but the emission guidelines do not prescribe how a state must allocate emissions to new and affected EGUs within this goal. As previously noted, plan performance is judged by whether existing and new sources together meet the total mass budget. This facilitates open trading of allowances between new and affected EGUs under a cap-and-trade program, and raises the question of how a state will elect to allocate initial allowances between the two groups. A few possible methods for determining allocations to new sources are presented below. Variations of these methods and other methods could also be derived by a state to reflect particular policy goals or state circumstances.

8.3.1.1 New Source Set-asides

One option for allocating allowances between the affected and new EGU groups is to carve out a new source set-aside in an amount equal to the new source complement for the compliance period, and issue allowances from the set-aside only for new sources deployed during a given compliance period. In a system where unused portions of the new source set-aside are not released at large, this method would have the effect of limiting the affected EGU budget to the Table 3 mass emission goal level. This would avoid "inflating" the affected EGU emission budget in cases where new sources are not deployed at the levels assumed in setting the new source complement. On the other hand, this method could also discourage deployment of remaining available capacity of existing EGUs at levels "beyond compliance" with BSER Building Block 2 and instead incentivize construction of new fossil-fueled NGCC EGUs in order to access allowances for compliance.

8.3.1.2 New Source EGU Allocations at Projected Capacity Factor

Another option is to maintain a combined budget for new and affected EGUs, and include new sources in the allocation scheme at levels based on a project capacity factor. Affected EGUs would receive allowances based on the state-selected allocation scheme (e.g., based on their proportion of historic generation—see Section 8.5 for further discussion of options). With this method, the state would not set aside a specified portion of the allowance budget available only to new sources; however, the new source allocations would essentially come "off the top" of the total budget. This scheme can be coupled with a limit on total new source allocations for any compliance period in an amount not to exceed the corresponding new source complement, thereby limiting the degree to which the scheme would favor new fossil fuel development that would compete with existing NGCC units.

Mass-based Rule Example 3 at the end of this Section 8.3 provides example rule language to implement this option. This is the new source allocation scheme presented in the example model rule in Section III.

338 80 Fed. Reg. at 64,887-90 (preamble to final CPP, section VIII.J.2.b).

8.3.1.3 Allocations Based on Past Operations with No New Source Allocations

A third option for distributing allocations between existing and new source groups is to assign the entire budget to existing affected EGUs (less any other set-asides the state has elected, such as Clean Energy Incentive Program or RE set-asides). Affected EGU allocations could be based on historical generation, historical emissions, unit capacity, or other approaches as discussed in Section 8.5. Under this approach, no initial allocations are provided to new sources that did not operate in the prior compliance period. Once operating, new sources would be treated the same as affected EGUs with regard to the use of historical operational data to determine initial allocations for the current compliance period. Thus, new sources would have to "buy in" to the budget system by purchasing allowances to cover their entire emissions quantity for the initial compliance period during which they operate. This approach places a premium startup cost on new source construction and deployment, which could serve to incentivize higher utilization of existing fossil-fueled EGUs or the deployment of new RE sources and EE measures in lieu of new fossil-fueled EGUs.

8.3.1.4 Auction System in Lieu of Allocations

A fourth option is to implement an allowance auction system in lieu of an allocation-and-trade system. This approach places new and existing sources on a more even playing field with respect to obtaining allowances, by distributing allowances to those that are most willing to pay for them. The RGGI program provides an example of the use of an auction system to distribute allowances.

8.3.2 Allocation Schemes to Counter Leakage

EPA proposed two allocation schemes to address leakage in the proposed federal plan and model state mass-based rule, which would be presumptively approvable options for state plans if adopted as finalized by EPA. The first scheme is a set-aside of allowances to be allocated to providers of RE development. EPA notes that, because the availability of RE generation can serve to reduce the incentive for new fossil-fuel generation, a set-aside to incentivize RE is an acceptable method to address leakage. EPA further notes that a set-aside for EE program implementation could serve the same function.[339] Although RE and EE set-asides could reduce or counterbalance the incentive to construct new NGCC EGUs, these methods do not incentivize generation shift to affected NGCC units, and in fact could serve to reduce the incentive to increase affected NGCC utilization consistent with BSER Building Block 2. EPA's second proposed allocation provision, an "updating output-based" set-aside for affected NGCC, directly addresses the implementation of Building Block 2. This allocation scheme is the mass-based corollary of the Gas Shift ERC issuance to affected NGCC EGUs under a rate-based plan. Under this approach, affected NGCC units are rewarded with increased allowances for increasing their utilization.

8.3.3 State Customized Leakage Demonstration

The CPP provides two ways for a state to develop its own approach to leakage. The first is for the state to develop its own new source complements, and then directly regulate new sources as under option 1. The second is for the state to develop an approach that is specific to the state circumstances and state plan design, and provide an analysis with the plan submittal demonstrating that, based on the state's specific circumstances and plan design, leakage is unlikely to occur.

8.3.3.1 Reasons and Methods for Developing a Customized New Source Complement Budget

If a state elects to directly regulate new sources by setting mass emission limits or implementing a cap-and-trade program with a new source complement, a variety of circumstances could lead the state to conclude that customized or revised new source complements are warranted. EPA's derivation of the Table 4 new source complements is discussed in Section 8.2, and is summarized again below.

1) EPA started with a projected total load growth for each region for each year (2022 to 2030), as presented in the Energy Information Administration's (EIA's) 2015 Annual Energy Outlook (AEO2015);[340]
2) A portion of the load growth is presumed to be met by sources under construction in 2012, and a portion is presumed to be met by affected EGUs and RE deployment at the levels accounted for in the Table 3 mass goals;
3) The remainder of the projected load growth for each region is presumed to be met by new NGCC capacity operating at the Subpart TTTT NSPS performance rate; and

339 80 Fed. Reg. at 64,889-90.

340 DOE/EIA-0383(2015), April 2015, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

4) Demand growth in each region is presumed to be met by individual states in the same proportion as the state's contribution to the regional 2012 generation.

Refinements or changes to EPA's methodology and assumptions that could lead to different new source complements might include, for example:

1) Changes to the projections for total and regional load growth, such as the use of projections from a different analysis, or updated annual EIA projections for total load growth in years 2022 to 2030, or extension of the use of the EIA projections out to 2040 to revise new source complements for years 2031 to 2040;
2) Corrections or updates to the baseline affected EGU inventory that result in changes to the Table 3 emission goals, or refinements to assumptions regarding projections of the capacity factor for EGUs under construction;
3) Changes to assumptions regarding the type of new fossil fuel-fired EGUs that would comprise the new source inventory, e.g., the announcement of plans to construct a new IGCC EGU; or
4) Corrections or changes to assumptions regarding the proportion of regional generation projected to be supplied by the state in future years, in lieu of reliance on the state's 2012 relative contribution to regional generation.

Of these possible reasons for revising the EPA-derived new source complements, the most likely areas of change are changes to the total regional projected load growth and changes to the state's portion of the regional load growth. With regard to the former, at least one updated year of projections will be available during initial plan development and submittal. The 2016 EIA Annual Energy Outlook (AEO) will include updated electricity load growth projections that could be considered by states in assessing the new source complement. It is worth noting that the 2014 EIA Annual Energy Outlook projected higher load growth over the 2022-to-2030 timeframe than did the 2015 AEO.[341] Or, if a state performs its own projections of load growth or relies on a different source that it believes is more representative, these projections may lead to different new source complements. With regard to the state's proportion of regional generation, a state may find that the 2012 regional generation profile is not the most representative for its state. For example, it could be that the 2012 contribution is lower than anticipated for future years due to the known distribution within the region of planned retirements, affected EGU available incremental capacity, under-construction EGUs, and/or planned new RE or NGCC deployment.

It must be kept in mind, however, that replacement of the EPA-derived new source complements with state-derived new source complements comes with a trade-off in plan flexibility, even if the revision to the new source complement is well justified. That is, if the state plan is designed to achieve the EPA-provided mass budgets in Table 4, EPA will evaluate plan performance based on whether existing and new sources together meet the total mass budget. However, if a state develops and adopts its own new source complement, then EPA will evaluate the state plan performance by comparing existing-source emissions to the Table 3 emission goals instead of by comparison to the existing-source plus new-source-complement collective total emissions.[342] This caveat not only eliminates any flexibility of existing and new sources sharing the same budget, but could also lead to the elimination of inherent trading program flexibilities—i.e., allowance holdings as the means to demonstrate compliance, in lieu of tracking stack emissions as reported against the Table 3 mass emission goals.

8.3.3.2 State-specific Plan Design and Analysis

An example of this approach is provided in Section 8.1 of this chapter, including both example rule language and an example state leakage demonstration and analysis. See ***Mass-based Rule Example 1, Direct Emission Limits on Affected EGUs, with Flexibility Provisions and Leakage Demonstration for Mass-based Rule Example 1, Supporting Documentation that Leakage Is Unlikely to Occur.*** This example involves a state plan that does not directly regulate new sources, but sets direct emission limits on affected EGUs in a manner that incentivizes generation increases at affected NGCC EGUs at levels up to and beyond the Building Block 2 target of 75% summer capacity. The design of the plan counters or eliminates any incentive to construct new NGCC units in lieu of increasing utilization at existing existing NGCC EGUs.

341 DOE/EIA-0383(2015), April 2015, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

342 80 Fed. Reg. at 64,888-89.

Mass-based Rule Example 3
Regulation of New Sources with New and Existing Source Allocations

Section 2010. Emission Standards for Affected Electric Generating Units

D. Allocation of Allowances to Existing and New Affected EGUs

1. No later than June 1 in the year prior to the beginning of each compliance period, the Administrative Authority will allocate allowances to affected EGUs under this chapter for the upcoming compliance period. The total number of allowances allocated to affected EGUs shall be the budget for the compliance period specified in Table 2 of this Section minus any set-asides as specified in Paragraph E of this Section.
   a. In determining the allocation of allowances to new and existing affected EGUs under this Paragraph, the Administrative Authority shall start with the total budget for the compliance period specified in Table 2 of this Section, and first adjust the total budget by the total number of any set-asides as specified in Paragraph E of this Section.
   b. The Administrative Authority shall then determine the total number of allowances for new affected EGUs, as adjusted for any new affected EGU where required, in accordance with Paragraph D.2 of this Section. The total number of new affected EGU allocations shall not exceed the new source budget for any compliance period as specified in Table 3 of this Section.
   c. The remainder of the budget for the compliance period, after subtracting set-asides and new affected EGU allocations, shall be allocated and issued to existing affected EGUs in accordance with Paragraph D.3 of this Section.
2. Allocations to New Affected EGUs.
   a. The determination of allocations of allowances to a new affected EGU shall be dependent on the startup date of the new affected EGU in relation to the compliance period for which allocations are being determined. For purposes of this paragraph, the startup date is the first day on which the affected EGU delivers power to the grid for transmission and distribution.
   b. For any new affected EGU with an initial startup date on or before January 1, 2019, the new affected EGU shall be treated as an existing affected EGU for purposes of allocating allowances, and the calculated allowances for all compliance periods shall be determined the same as for existing affected EGUs and Qualified EGUs in accordance with Paragraph F of this Section. However, allocations of allowances to the new affected EGU shall be adjusted if required in accordance with Paragraph E.5 and E.6 of this Section.
   c. For any new affected EGU with an initial startup date after January 1, 2019, but before January 1, 2022, allowance allocations for the Interim 1 period shall be calculated as follows:

$$\mathbf{A_{Calc}} = \left(\frac{\mathbf{MWh_{EGU}}}{\mathbf{MWh_{Affected\ EGUs}} + \mathbf{MWh_{Qualifying\ EGUs}}}\right)\left(\frac{(1096/}{\mathbf{Days_{SU})}}\right) * \mathbf{Budget_{R1}}$$

Where:

$\mathbf{A_{Calc}}$ is the calculated number of allowances to be issued to the new affected EGU, in whole tons;

$\mathbf{MWh_{EGU}}$ is the net energy output of the affected EGU for the period January 1, 2019 to December 31, 2021, in MWh;

$\mathbf{MWh_{Affected\ EGUs}}$ is the total amount of MWh-net, as defined under this chapter, reported by affected EGUs for the period January 1, 2019 to December 31, 2021;

$\mathbf{MWh_{Qualified\ EGUs}}$ is the total amount of MWh-net, as defined under this chapter, reported by all registered qualified EGUs under this chapter, for the period January 1, 2019 to December 31, 2021;

1096 is the total number of days in the period January 1, 2019 through December 31, 2021;

$\mathbf{Days_{SU}}$ is the total number of days from initial startup of the new affected EGU through December 31, 2021; and,

$\mathbf{Budget_{R1}}$ is the budget for the Interim 1 period as specified in Table 2 of this chapter, minus any set-asides under Paragraph C and minus allocations to energy efficiency resources under Paragraph D of this Section.

Mass-based Rule Example 3, *continued*
Regulation of New Sources with New and Existing Source Allocations

d. For any new affected EGU with an initial startup date on or after January 1, 2022, allowance allocations shall be calculated as follows.

i. The owner or operator shall notify the Administrative Authority of the planned startup date for the unit no later than March 1 of the year prior to the beginning of the first compliance period during which the new affected EGU will first operate. Failure to timely notify the Administrative Authority shall result in the forfeiture of allowance allocations for the first compliance period of operation.

ii. For the first compliance period during which a new affected EGU is scheduled to operate, the number of calculated allowances for allocation to the new affected EGU shall be determined using the following equations:

$$A_{CALC} = 0.55C * H * 0.50$$

Where:

A_{CALC} is the calculated number of allowances to be issued to the new affected EGU, in whole tons;

C is the nameplate capacity of the new affected EGU, in MW;

H is the total number of hours in the compliance period after the scheduled startup date of the new affected EGU, in units of hours; and,

0.50 is the performance standard for new NGCC EGUs subject to 40 CFR part 60 subpart TTTT, in units of tons/MWh.

iii. For the second compliance period during which the new affected EGU is in operation, the number of allowances to be allocated shall be shall be determined the same as for existing affected EGUs in accordance with Paragraph F of this Section, except that the allocation shall be adjusted as necessary to subtract the number of any excess allowances allocated for the previous compliance period based on the difference between the dates of actual startup and planned startup. In addition, allocations of allowances to the new affected EGU shall be adjusted if required in accordance with Paragraphs E.5 and E.6 of this Section. If startup of a new affected EGU occurred later than the startup date relied upon for issuance of allowances in the first compliance period of operation, then the number of unadjusted allowances calculated in Paragraph E.4.b of this Section shall be adjusted by subtracting any allowances issued for days in the prior compliance period prior to actual startup date of the new affected EGU. The adjustment shall be calculated as follows:

$$A_{ADJ} = 0.55C * 24 * Days_{ADJ} * 0.50$$

Where:

A_{ADJ} is the calculated allowance adjustment, that is, the number of allowances to be subtracted from the number of allowances calculated in accordance with Paragraph F of this Section, in whole tons;

C is the nameplate capacity of the new affected EGU, in MW;

24 is the number of hours in a day, in hours;

$Days_{ADJ}$ is the number of days from the date of planned startup relied upon to issue allowances for the first compliance period of operation to the date of actual startup for the affected EGU; and,

0.50 is the performance standard for new NGCC EGUs subject to 40 CFR part 60 subpart TTTT, in units of tons/MWh.

iv. For all subsequent compliance periods after the second compliance period of operation for a new affected EGU, the new affected EGU shall be treated as an existing affected EGU for the purpose of calculating allowances, and the total number of allowances to be allocated to the new affected EGU shall be calculated in the same manner as for existing affected EGUs, in accordance with Paragraph F of this Section. In

Mass-based Rule Example 3, *continued*
Regulation of New Sources with New and Existing Source Allocations

addition, any existing affected EGU that becomes a new affected EGU as a result of reconstruction shall be treated as an existing affected EGU for the purpose of calculating allowances. However, allocations of allowances to a new affected EGU under this subparagraph shall be adjusted if required in accordance with Paragraph E.5 and E.6 of this Section (i.e., any such new affected EGU shall be considered as consuming allowances under the new affected EGU's allowance budget).

e. Total allowance allocations for new affected EGUs shall not exceed the new source budget specified in Table 3 for any compliance period.

Table 3. **CO_2 Allowance Not-to-Exceed Budgets for New Affected EGUs (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons per 3-year period)	Interim 2 2025–2027 (total tons per 3-year period)	Interim 3 2028–2029 (total tons per 2-year period)	Final, beginning 2030–2031 (total tons per 2-year period)
506,358	1,708,206	1,075,956	725,794

f. In determining initial allocations of allowances for new affected EGUs, the Administrative Authority shall first calculate allocations for new affected EGUs in accordance with Paragraphs E.2 through E.4 of this Section, and for existing affected EGUs and qualified EGUs in accordance with Paragraph F of this Section. The total calculated allocations for all new affected EGUs shall then be summed and compared to the new source budget for the compliance period.
   i. In the event the sum of the total calculated allowances for all new affected EGUs as determined in accordance with Paragraphs E.2 through E.4 of this Section is greater than the new source budget for the compliance period, then the calculated allowance allocation for each new affected source shall be reduced in equal proportion by the ratio of the new source budget to the sum of the calculated allowances. Such adjustments to the calculated allocations for new affected EGUs shall be determined as shown in the following equation:

$$\mathbf{A_{ADJ}} = \left(\frac{\mathbf{Budget_{NS}}}{\Sigma\,\mathbf{A_{Calc}}}\right) \star \mathbf{A_{Calc}}$$

Where:

$\mathbf{A_{ADJ}}$ is the calculated adjusted number of allowances to be issued to the new affected EGU, in whole tons;

$\mathbf{Budget_{NS}}$ is the budget for new affected sources for the compliance period as specified in Table 3 of this chapter;

$\mathbf{A_{Calc}}$ is the number of calculated allowances for the EGU as determined in accordance with Paragraphs E.2 through E.4, in whole tons; and,

$\Sigma\,\mathbf{A_{Calc}}$ is the sum of the calculated allowances for all new affected EGUs for the compliance period, as determined in accordance with Paragraphs E.2 through E.4 of this Section.

All allocations taken to make the adjustments in this Paragraph E.6, including adjustments from any new affected EGUs that were treated as existing affected EGUs and for which the initial allocation was determined under Paragraph F of this Section, shall be applied to increase allocations to the existing affected EGUs only, in equal proportion to the generation of those existing affected EGUs for the previous compliance period.

Mass-based Rule Example 3, *continued*
Regulation of New Sources with New and Existing Source Allocations

ii. Allocations to Existing Affected EGUs. For each existing affected EGU for each compliance period, the number of allowances to be issued by the Administrative Authority shall be determined based on the unit's portion of total statewide affected EGU generation, using the following equation:

$$A = \left(\frac{MWh_{EGU}}{\sum MWh_{AEGU}}\right) * Budget$$

Where:

A is the calculated number of allowances to be issued to the existing affected EGU, in whole tons;

$\mathbf{MWh_{EGU}}$ is the net energy output of the affected EGU for the prior compliance period, in MWh;

$\mathbf{MWh_{AEGU}}$ is the net energy output of all existing affected EGUs under this chapter for the prior compliance period, in MWh; and,

Budget is the budget as specified in Table 2 of this Section, minus any set-asides, and minus allocations to new affected EGUs as determined in Paragraph D.2, for the compliance period.

8.4 Mass-based Trading Program Available Options

States implementing mass-based trading have a high degree of freedom to incorporate trading of allowances across state lines and to recognize allowances issued under other state plans as compliance instruments for their affected EGUs. The state plan must include provisions for the issuance of allowances prior to the start of each compliance period, and for adjusting allocations to correct errors if allocations were incorrectly made. The state plan must also specify whether banking of allowances for use in future compliance periods is allowed; however, states cannot allow the borrowing of allowances from future compliance periods.[343]

To authorize affected EGUs and other parties to engage in interstate trading of allowances, the state must simply indicate in its plan that it will recognize allowances issued under other EPA-approved mass-based trading programs, and that allowances must be issued and tracked through an EPA-approved or EPA-administered joint or interoperable trading platform. A state can enter into interstate trading of allowances under either a single-state or multi-state plan. The state plan can adopt a "trading-ready" approach that designates the trading platform but does not specify other state participants; or the state plan can designate specific approved trading partners.

Single-state mass-based programs are free to interact through trading of allowances regardless of whether they take the same approach to leakage, and regardless of how the individual programs allocate the state budget of allowances among affected sources. One state may regulate affected EGUs only under the trading program, and another may regulate both affected EGUs and new sources subject to Subpart TTTT. One state may rely on an auction system to issue allowances, while another may issue allowances on an historic generation basis. One state may create RE or EE incentives through set-asides, and another may offer updating output allocations to affected NGCC units. The key requirements for interstate trading among mass-based programs are: (1) each program must use an allowance, denominated in a unit of one ton of CO_2 emissions, as the tradable instrument; and (2) each program must be EPA-approved and must issue, transfer and track allowances using a joint or interoperable EPA-approved or EPA-administered tracking system.

Section 6.3.1.2 of Chapter 6 provides a more detailed discussion of plan requirements and plan performance demonstrations for mass-based trading programs. As discussed in Chapter 6, state plan approval criteria and plan performance metrics depend on the structure and scope of each individual state's plan, and not on the design of the plans with which the individual state plan is linked for trading.[344] Different requirements and plan performance

343 40 C.F.R. § 60.5815

344 80 Fed. Reg. at 64,893-94.

metrics will be applied by EPA based on whether the individual state plan regulates affected EGUs only, affected EGUs plus new fossil-fired EGUs subject to Subpart TTTT, or a broader set of fossil-fuel combustion sources that are not subject to Subpart UUUU or Subpart TTTT. State plans that apply only to affected EGUs and state plans that apply to affected EGUs plus new fossil EGUs subject to Subpart TTTT are treated essentially the same, and may link to each other with no special or additional requirements. This is true for plans that apply to new fossil EGUs, whether the plan adopts EPA's new source complement (i.e., uses the Table 4 mass goals) or adopts a state-derived new source complement that is approved by EPA. For linkages among these types of plans, provided each state's compliance periods is consistent with the interim and final CPP performance periods, and provided each state's mass emissions cap is less than or equal to the Table 3, Table 4 or Table 3 plus EPA-approved new source complement mass goal level, as applicable, then compliance with the state's emission goals is demonstrated if the affected EGUs hold and retire allowances equal to their actual reported emissions. Allowances may be banked and used for compliance in a future compliance period if the state plan allows.

For interstate trading involving any single-state mass-based trading programs with broader applicability (i.e., other fossil combustion sources are subject facilities, beyond affected EGUs and Subpart TTTT affected new fossil EGUs), different requirements apply. During the individual state plan review process for linked state trading programs where one or more of the trading programs has expanded applicability, EPA will review each linked plan to evaluate whether the linkages would allow the affected EGUs (and new fossil EGUs, if appropriate) in each to meet the state's mass-based emission goals.[345]

Once approved, for each plan that does not have expanded applicability, achievement of the state's applicable mass emission goal will still be demonstrated by compliance of that state's affected EGUs with the allowance-holding and retirement provisions of the trading program (i.e., with the mass emission standard to which they are subject).[346] For each plan that has expanded applicability, compliance will be evaluated based on an assessment of whether the affected EGUs' actual CO_2 emissions, as monitored and reported under the plan, are at or below the state's applicable mass emission goal, after adjustments to account for interstate imported and exported allowances. It is important to note that net allowance imports and exports are determined based on total allowance holdings in the compliance accounts of affected EGUs, and not on the allowances retired to "true up" with actual emissions.[347] A more detailed explanation and illustrative examples of this plan performance requirement is provided in Chapter 6.

8.5 Options for Allowance Distribution – How, Who and How Much?

A state plan that incorporates an allowance trading program must be designed to achieve the emission goals in Table 3, Table 4, or alternate EPA-approved emission goals, for the eight-year interim period and each final plan performance period. In addition, the state plan must set emission standards for each affected EGU for each interim step period and for each final performance period. Under a cap-and-trade program, the mass emission goals are effectively translated to statewide caps, or allowance budgets, with the allowance-holding and retirement requirement serving as the emission standard for each compliance period on affected EGUs.

A key element of the design of an allowance trading program is the process of initial distributions of allowances under the cap. Given that the CPP does not specify any required distribution method or allocation scheme, the state has ample discretion to devise and adopt a distribution system that reflects state circumstances and furthers state policy goals. The initial distribution of allowances introduces the tradeable compliance instruments into the market; it does not establish an emission limitation for individual EGUs, because allowances can be bought and sold after the initial distribution to authorize emissions as needed under the cap. Also, cap-and-trade programs generally do not restrict who can purchase and sell allowances once they are on the market—provided the trader is registered with the recognized allowance tracking system and all transfers are made through the system. However, the initial distribution of allowances can serve to incentivize actions, including influencing market dynamics, boosting investments in certain sectors relative to others, and shifting the balance among competing market incentives. These influences may affect the forward-looking generation profile and thereby also affect the emissions profile.

345 80 Fed. Reg. at 64,893.

346 80 Fed. Reg. at 64,893 ("The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources…").

347 80 Fed. Reg. at 64,894.

In addition to the furtherance of state energy and environmental goals, an important aspect states may consider in relation to the allocation scheme is the concept of equity. Because allowances are limited in number, they have an inherent value. In essence, a monetary value is assigned to a commodity that previously was without a direct cost (i.e., the authorization to emit CO_2 created by the generation of electricity from fossil fuels). Consequently, the free distribution of allowances raises important questions of fairness and equity regarding who should receive allocations and in what proportion.[348] Other factors state planners will want to weigh and balance in designing the allowance allocation scheme are cost and reliability of electricity, retaining the value of allowances in the state or region, and potential impacts to achieving the CPP emission goals.

The question of initial distribution of allowances is three-fold: how, who, and how much? How will allowances be distributed? Who will be eligible to receive allowances? How much of the budget will be allocated to different recipient groups?

8.5.1 Options for Distribution Methods – Allocations, Set-asides, Auctions and Sales

Allowances distributions can be accomplished through three primary avenues: direct allocation; set-asides; and auctions or fixed-price sales. Numerous variations of these methods could be devised to fit a state's particular situation, and wholly different methods may be possible. The CPP does not prescribe or prohibit any particular approach, provided the mechanism selected does not have the effect of expanding the budget or creating other plan deficiencies, such as rendering the allowance-holding emission standard unenforceable.

Direct allocations involve the assignment and issuance of allowances to a defined set of recipients for each compliance period. Direct allocations are a free grant of allowances to the recipients, meaning that there is no fee or cost imposed for their receipt, and no revenues generated for the state by their distribution.

Set-asides refer to the process of reserving a defined portion of the total emissions budget (expressed either as a percentage or a specified quantity) to be awarded to qualifying resources. In the case of set-asides, allowances are not sold for a price, but are given away, typically in exchange for some action or service on the part of the recipient—for example, under the Acid Rain Program, utilities could earn set-aside allowances for undertaking qualified energy conservation or RE projects.[349] The set-aside method incorporates the concept of eligibility, which may require a system of application, approval, monitoring, measurement and verification. In this respect, set-asides create the need for administrative procedures and infrastructure that are similar to the ERC resource eligibility system for a rate-based program.

Auctions and sales distribute allowances through an "open access" platform, with proceeds going directly to the state (or other designated program administrator). Auctions must be administered through a regimented, robust system to assure the integrity of allowances and to maintain a fluid and transparent market. Proceeds can be used as a revenue stream to supplement the state general budget, directly invested by the state in priority areas, or redirected to support or incentivize third-party investments. Auctions and direct sales can be components of a single distribution system. For example, Rhode Island regulations authorize the Department of Environmental Management to conduct both auctions and sales for the distribution of CO_2 allowances.[350]

Consignment auctions are direct allocations accompanied by a requirement that the recipient sell its allowances at auction. This approach provides a platform for discovering allowance prices and guaranteeing access to allowances for new entrants or others while the value of allowances accrues to their initial holders. A consignment auction raises no revenue for the government and may be run by a third party. For example, the Title IV sulfur dioxide trading program initially distributed emissions allowances for free to incumbent firms, but required that 2.8 percent of the allowances be consigned to an auction with revenues returned to the firms. California's economy-wide CO_2 trading program relies on a consignment auction after initially distributing electricity-sector allowances to local distribution companies.[351] The privately owned companies are required to consign their allowances to auction for purchase by generating companies with a compliance obligation and to use the auction revenue to benefit ratepayers. A consignment auction is a useful complement to approaches that directly allocate allowances to a defined set of recipients.

348 80 Fed. Reg. at 65,015.

349 80 Fed. Reg. at 65,020.

350 Rhode Island Department of Environmental Management, Office of Air Resources, *Air Pollution Control Regulation No. 47, CO_2 Budget Trading Program Allowance Distribution,* http://www.dem.ri.gov/pubs/regs/regs/air/air47_08.pdf.

351 Cal. Code Regs. tit. 17, § 95892.

Each of these methods for allowance distribution has been used successfully in practice for environmental emission reduction programs, and these methods can be combined in a number of ways to customize a distribution system that best meets the needs of the state. For example, both direct allocation and set-asides were used in the Acid Rain Program.[352] Also, RGGI states use an auction platform that incorporates a set-aside system.

8.5.2 Options for Recipients of Allowance Allocations

Ultimately, of course, allowances must be obtained and used by affected EGUs or new sources with compliance obligations under the trading program. Nonetheless, initial allocations of allowances need not be restricted to affected EGUs, and could be made to a number of entities in a variety of ways. Recipients may include other existing power generators, including RE producers, as well as producers using qualified biomass, waste-to-energy, non-affected CHP generators, or nuclear. A state may also choose to issue allocations to investors in projects to develop new power stations using RE or low-emitting technologies. Recipients could also include state, county or municipal government entities, such as agencies that administer demand-side EE programs or employment assistance programs targeting displaced energy workers. Initial distribution of allowances can also be made indirectly to the power customers (consumers) through a local distribution company (LDC) or load-serving entity (LSE). Finally, the state could elect to make the initial distribution of allowances through a state auction, effectively allocating the value of the allowances to the state, which would be the recipient of auction revenues. In summary, the state could elect to distribute allowances or to assign the value of allowances to any combination of the following groups or entities, and the relative distribution of allowances among these groups will reflect and influence state policies and goals:

1) Affected EGUs (which may include new sources subject to 40 C.F.R. Part 60, Subpart TTTT);
2) Non-affected existing power generators, including zero- and low-emitting technologies;
3) Investors in new zero- and low-emitting power generation or EE programs;
4) State, county and local government entities; and
5) Energy consumers, through the LDC or LSE.

8.5.3 Options for Allocating Allowances to Affected EGUs and Other Power Generators

Potential methods for distributing allowances among affected EGUs and other existing EGUs generally fall into four categories: (1) backward-looking methods, which determine allocations based on historical data; (2) forward-looking methods, which set allocations based on a predicted generation profile or to incentivize a desired outcome; (3) time- and emissions-neutral methods, which assign allocations based on EGU capacity; or (4) an equal access strategy, i.e., distribution of allowances through an auction.

One type of backward-looking allocation scheme is "grandfathering" of allocations based on historical emissions. This method works by assigning each EGU a portion of the available budget equal to the EGU's portion of emissions during a baseline period. With grandfathering, the EGU's share of allocations remains fixed, but the number of allocations received is reduced over time as the cap is reduced.[353] The benefit of this methodology, from an equity perspective, is that it assigns the same level of "free" authorized emissions to all EGUs on a percent reduction basis. That is, if the cap for the initial compliance period is 15% below the fleet-wide baseline period total emissions level, each EGU receives an initial allocation, or authorization to emit, at 85% of its baseline level. EGU owners and operators can either reduce emissions by 15%, reduce emissions by more than 15% and sell excess allowances, or purchase additional allowances to emit at levels greater than 85% of their baseline. One criticism of this approach is that it rewards the highest emitters with the greatest number of allowances. Also, if this method is used for the full distribution of allowances without any set-asides or additional recipients of allocations, the approach does not directly incentivize investments in low- or zero-emitting technologies or generation shifts to lower-carbon fossil fuels. The Acid Rain Program is an example of using the grandfathering approach for allocating allowances. It is worth noting that, in the case of the Acid Rain Program, the emission reduction strategies generally involved application of pollution control technologies directly on the affected EGUs; therefore, incentivizing investments in RE or EE deployment did not have the same significance as for

352 80 Fed. Reg. at 65,019.

353 Dallas Burtraw, *Economic and Administrative Considerations for the Initial Distribution of Allowances,* Resources for the Future, October 2015.

CPP compliance.

Another backward-looking allocation scheme involves distribution of allowances based on each EGU's portion of fleet-wide total generation during the baseline period. This approach is "emissions neutral" in that it does not reward higher emitters over lower or zero-emitters. Also, if desired, existing non-fossil fueled EGUs, including RE and low-emitting technologies, can readily be included in the allocation scheme because it is based on generation as opposed to emissions. In the proposed federal plan, EPA proposed to use a default allocation methodology (to be implemented for states under a federal plan that elect not to set their own allocation scheme) based on an historical generation data approach. Specifically, EPA proposed to allocate most of the budget for a given compliance period to affected EGUs based on each EGU's relative contribution to the state's historical generation levels, using a three-year baseline period of 2010–2012.[354] Alternatively, a state could choose a more recent historic baseline.

A variation on the use of historical data is an "updating output-based" methodology, which updates the allocation portions for affected EGUs for each compliance period based on generation data from the prior compliance period. This approach is still backward-looking; it relies on past data and does not base allocations on projections of generation or emissions. Under the proposed federal plan, EPA proposed to use this approach specifically to enhance allocations for affected NGCC EGUs through the use of a set-aside, or reserved portion of the total allowance budget. The effect of this allocation method is to incentivize affected NGCC EGUs to increase generation (or reduce disincentives to do so), by rewarding increased generation with increased allowances for the next compliance period. In essence, this scheme helps owners and operators of affected NGCC EGUs to recoup the cost of implementing BSER Building Block 2. ***Mass-based Rule Example 3 – Regulation of New Sources with New and Existing Source Allocations*** provides example rule language using an updating output-based allocation scheme for all existing affected EGUs. In this example, the updating output-based allocation scheme for existing affected EGUs is combined with an allocation method for new sources regulated under the cap-and-trade program based on their generating capacity, using a capacity factor of 55%. ***Mass-based Rule Example 4 – Direct Allocations to Qualified Renewable Energy and Low-emitting EGUs*** provides an additional example of an updating output-based allocation scheme. This example includes qualifying renewable and low-emitting EGUs in the allocation formula with affected EGUs, assigning allocations to non-affected EGUs based on the eligible portion of generation. Mass-based Rule Example 4 is an excerpt from the comprehensive model mass-based trading rule in Section III.

Forward-looking allocation methods may rely on projections of power generation to assign allowances; by, for example, shifting the relative proportions of allocations to natural gas units over subsequent compliance periods if the use of natural gas is projected to increase. Alternatively, forward-looking allocation schemes may be driven by a desired future outcome. For example, the state could elect to allocate allowances to affected NGCC EGUs at a level equivalent to utilization at 75% summer capacity, as a means of acknowledging the BSER Building Block 2 gas shift. However, it is important to understand that such an allocation would not provide an incentive to increase generation, as the NGCC units could sell allocated allowances should they choose to reduce operations.

Another generation-based allocation scheme that would also be emissions-neutral is an approach that assigns allocations based on generating capacity rather than output. Under this approach, each EGU would be allocated allowances in relative proportion to its peak generating capacity, regardless of technology or fuel type. This scheme has the advantage of rewarding, or providing value to, low- or zero-emitting technologies, by providing them with allocations that can be sold. Here, RE technologies would hold allowances that would be needed by higher-emitting technologies. This provides a cost differential of twice the value of the CO_2 allowance to the RE technology (as the cost of an allowance is deducted from the books of a fossil-fueled EGU and credited to the books of an RE EGU), giving the RE technology a marketplace advantage in power sales.

Alternatively, a state can elect to hold auctions or direct sales at a fixed price for the initial distribution of allowances. This approach brings revenue to the state, which can be used or redistributed through various avenues. Another advantage of using an auction or sales approach is that it treats all affected EGUs (and other interested investors) equally by providing open access to the acquisition of allowances. Under an auction system, the state would set a reserve price (a minimum sales price) in advance of each auction, and sales would be made at a price ultimately determined by the market demand. The RGGI program provides a successful example of an auction-based allo-

354 80 Fed. Reg. at 65,016.

cation system.[355] A direct sales system could be used in conjunction with one of the allocation schemes discussed above, by using an allocation method (e.g., historic generation or targeted generation) to determine the number of allowances that would initially be offered for direct sale at a fixed price to each EGU owner/operator.

8.5.4 Options for Allocating Allowances to Incentivize RE, EE and Other Reduction Strategies

The investment of the value associated with CO_2 emissions in RE, EE and other CO_2 reduction strategies can provide a significant boost in the development of clean energy and help to achieve the CPP emission goals. The California AB 32 cap-and-trade program provides an example of clean energy sector growth coupled with enhanced emission reductions through cap-and-trade. Between 2006, when AB 32 was signed into law, and 2013, the first compliance year of the program, California saw more investment in clean energy technology than the rest of the nation combined ($21 billion in California vs. $19 billion in all other states). Advanced energy jobs grew 5% in 2014, with workers building solar panel arrays earning an average of $78,000 a year plus benefits.[356]

Under a cap-and-trade program, the establishment of a total cap on CO_2 emissions and the creation of an allowance trading program, with a requirement for affected EGUs to hold allowances equal to emissions, will cause the owners and operators of affected EGUs to seek out and implement the most cost-effective means of compliance with the emission reduction requirements. Thus, some states may be confident that RE and EE investments will occur without providing for additional incentives. The allocation of allowances or of proceeds from the sale of allowances to fund investments in RE, EE and other related measures, however, can serve purposes beyond helping to assure compliance with the emission goals. As previously noted, the creation of the cap-and-trade program creates a commodity with value, and that economic value will be realized by one or more entities. Providing direct allocations or set-asides to RE, EE and other programs is one way of assuring that some of the economic value created by the system will accrue to energy advancements or other selected recipients. Allocations and set-asides are a way of directing or sharing the profit to those areas the state wants to advance. In addition to assuring some portion of the proceeds are directed toward RE or EE in general, allocations and set-asides can be used to advance very specific technologies or policy goals. ***Mass-based Rule Example 5 – Direct Allocations to Qualified EE Energy Savings*** is an excerpt from the comprehensive model mass-based trading rule in Section III. This example rule language is an example of an allocation scheme that provides direct allocations to EE resources based on the verified energy savings during the prior compliance period.

355 For details and documentation related to the RGGI program auctions, including state statutory authorities, state regulations, auction platform and participation guidelines, and investments of auction proceeds, see http://www.rggi.org/market/co2_auctions.

356 Katherine Hsia-Kiung & Erica Morehouse, *Carbon Market California, A Comprehensive Analysis of the Golden State's Cap-and-Trade Program, Year Two: 2014,* Environmental Defense Fund, 2015, http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf. For a more detailed discussion of the economic and emission reduction benefits associated with investments from cap-and-trade, see Section 6.1.2, Benefits of Trading Programs to Meet CPP Emission Guidelines.

Mass-based Rule Example 4
Direct Allocations to Qualified Renewable Energy and Low-emitting EGUs

F. Allocations to Existing Affected EGUs and Qualified EGUs

1. For each existing affected EGU, each new affected EGU to be treated as an existing affected EGU for purposes of allocating allowances in accordance with Paragraph E of this Section, and each registered qualified EGU, the number of allowances to be issued by the Administrative Authority shall be determined based on the unit's eligible generation relative to total statewide generation during the prior compliance period. For the Interim 1 compliance period of 2022 through 2024, the term "previous compliance period" as used in this Paragraph F shall mean the period January 1, 2019 through December 31, 2021.
2. For each qualified EGU that utilizes qualified biomass feedstock, including each qualified EGU that is a WTE facility, allocations shall only be provided for generated electricity derived from the qualified biomass feedstock or biogenic portion of the waste feedstock, as applicable. Also, for each qualified CHP that utilizes fossil fuel to produce electricity or useful thermal or mechanical output, the EGU's net electrical output must be adjusted in accordance with Section 1019 to determine the portion of the MWh that is eligible for allocation of allowances. Accordingly, for purposes of determining allocations under this Section, for such qualified EGUs, the terms "MWh," "$MWh_{Qualified\ EGUs}$" or "net energy output" refer only to the portion of energy generated by the qualified EGU that is eligible to receive allocations of allowances, as reported in accordance with this chapter.
3. Allocation of allowances shall be determined using the following equation:

$$A_{Calc} = \left(\frac{MWh_{EGU}}{MWh_{Affected\ EGUs} + MWh_{Qualified\ EGUs}} \right) * Budget_{R2}$$

Where:

A_{Calc} is the calculated number of allowances to be issued to the EGU, in whole tons;

MWh_{EGU} is the net energy output of the EGU for the prior compliance period, in MWh (using only the portion of output eligible for allocations for each qualified EGU);

$MWh_{Affected\ EGUs}$ is the total amount of MWh-net, as defined under this chapter, reported by affected EGUs for the previous compliance period;

$MWh_{Qualified\ EGUs}$ is the total amount of MWh-net eligible for allocations, reported by all registered qualified EGUs under this chapter, for the previous compliance period;

$Budget_{R2}$ is the budget for the compliance period for which allocations are being calculated, as specified in Table 2 of this chapter, minus any set-asides, minus allocations to qualified energy efficiency resources, and minus allocations to new affected EGUs, as determined in Paragraphs B, C and D of this Section.

Mass-based Rule Example 5
Direct Allocations to Qualified EE Energy Savings

D. Allocations to Qualified Energy Efficiency Resources (EERs)

1. Qualified energy efficiency resources shall be allocated allowances for each compliance period based on the amount of verified energy avoided or saved, in MWh-net, during the prior compliance period, as demonstrated in accordance with applicable EM&V plan and annual M&V report under Section 1021 of this chapter and certified by the National Energy Efficiency Registry or other entity approved by the Administrative Authority. For the Interim 1 compliance period of 2022 through 2024, the term "previous compliance period" as used in this Paragraph D shall mean the period January 1, 2019 through December 31, 2021.
2. Allocations for qualified energy efficiency resources shall be calculated by multiplying the total MWh of verified and certified energy saved times an emission factor, which shall be the average emission rate (tons/MWh-net) of new and existing EGUs and other qualified EGUs during the previous compliance period. The formula for determining the emission factor and for calculating allowances to be allocated to a qualified energy efficiency resource are as follows:

$$EF = \frac{CO2_{Affected\ EGUs}}{MWh_{Affected\ EGUs} + MWh_{Qualified\ EGUs}}$$

$$A_{EER} = MWh_{Certified} * EF$$

Where:

EF is the emission factor used to calculate allocations for each qualified energy efficiency resource;

$\mathbf{CO2_{Affected\ EGUs}}$ is the total amount of CO_2 reported for the previous compliance period for affected EGUs, in whole tons;

$\mathbf{MWh_{Affected\ EGUs}}$ is the total amount of MWh-net, as defined under this chapter, reported by affected EGUs for the previous compliance period;

$\mathbf{MWh_{Qualified\ EGUs}}$ is the total amount of MWh-net eligible for allocations of allowances, as reported by all registered qualified EGUs under this chapter, for the previous compliance period;

$\mathbf{A_{EER}}$ is the calculated number of allowances to be issued to the qualified energy efficiency resource, without including any fraction of a ton that results from the calculation; and,

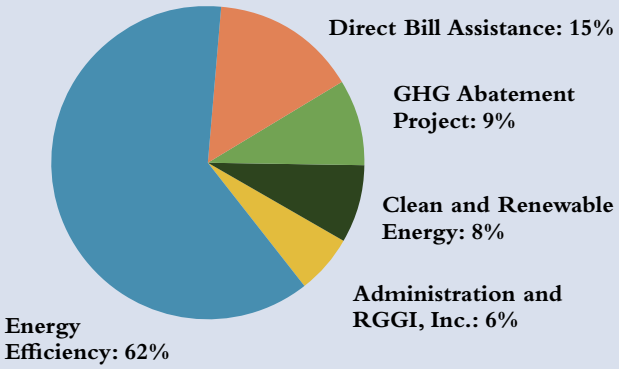
$\mathbf{MWh_{Certified}}$ is the total amount of verified and certified energy savings provided by the qualified energy efficiency resource during the previous compliance period, as documented in accordance with Section 1021 of this chapter.

3. The total amount of allowances allocated to qualified energy efficiency resources shall not exceed 15% of the budget remaining after any set-asides are deducted for any compliance period. In the event the sum of the total calculated allowances for all qualified energy efficiency resources, as determined in accordance with Paragraphs D.2 of this Section, is greater than 15% of the budget remaining after any set-asides are deducted, the Administrative Authority shall reduce the calculated allocation of allowances for each qualified energy efficiency resource in equal proportion by the ratio of 15% of the budget remaining after set-asides are deducted to the sum of the calculated allowances.

8.5.4.1 Directing Allowance Proceeds from Auctions or Sales

The RGGI states provide a specific example of the use of proceeds from CO_2 auctions or sales to fund energy programs in general, as well as specific targeted projects. From 2008 to 2013, RGGI states generated approximately $1.57 billion in CO_2 allowance auction proceeds, and invested more than $1 billion of those proceeds in energy programs, including direct energy bill assistance. At the same time, RGGI states experienced economic growth and CO_2 emission reduction rates that outperformed the national average. RGGI states also use allowance proceeds to fund specific energy projects and as seed money to garner private investments. A wide variety of programs and projects are funded. For example, GHG abatement programs have included fuel cell-powered municipal buses, grants for industrial process improvements, and forestry projects that enhance wildlife habitats while increasing carbon sequestration. Each GHG abatement program is designed to select and support specific projects that will significantly reduce GHG emissions. Figure 8.4 illustrates the overall cumulative distribution of RGGI auction proceed investments in energy-related programs.[357]

Figure 8.4 **RGGI Proceed Investments Cumulative Percentages, 2008–2013**



8.5.4.2 Incentivizing Investments through Direct Allocations or Set-asides

States that do not elect to use an allowance auction or fixed price sale as the initial distribution platform still have several options to direct investments in RE, alternative energy, and EE development. As discussed above, allowances can be directly allocated to existing EGUs, including RE, biomass, waste-to-energy, CHP and nuclear, as a means of providing funding for continued operation or expansion of those facilities and sectors. Or, set-asides can be created within the total allowance budget.

The set-aside approach reserves a specified portion of the total allowance budget to be awarded only to qualifying resources that meet certain criteria. Set-asides can provide states with a vehicle to encourage investments in particular strategies—for example, solar, wind, or other technologies that are prioritized for state policy or economic reasons. As noted above, EPA proposed to use a set-aside for RE investment as one of the allocation schemes to address leakage in the proposed federal plan.

One possible concern regarding set-aside programs is the level of added administrative burden and cost incurred by the need for eligible resource registries, measurement and verification, and other related systems. Subpart UUUU requires that state plans with trading programs including set-asides contain provisions to ensure that eligible resources meet the same requirements as ERC-eligible resources under a state rate-based program. These include requirements for eligibility applications and registration, EM&V plans, M&V reports, and third-party verification.[358]

Another important consideration for states considering set-asides as an element of a mass-based trading program is the question of EPA approval and federal enforceability. Most state plans implementing mass-based allowance trading as the Subpart UUUU compliance strategy will be submitting a streamlined emission standards plan that mathematically assures compliance through the imposition of the allowance-holding requirement to authorize emissions up to and not exceeding the Table 3, Table 4, or EPA-approved alternative emission goals. Accordingly, no additional emission reduction strategies are needed to demonstrate plan performance.[359] Specifically, because these measures are not relied upon to achieve compliance, the state plan does not need to include RE programs or requirements, EE programs or investment mechanisms, or any other similar measures as a state plan component. However, if set-asides for RE, EE or other measures are incorporated into the trading program, those measures may become subject to EPA approval, oversight and enforceability. If this is not a desired outcome, the state may find it beneficial to consult with the EPA regional office regarding methods of carving out set-aside programs that

357 Regional Greenhouse Gas Initiative, *Investment of RGGI Proceeds through 2013,* April 2015, https://www.rggi.org/docs/Proceeds-Report/Investment-RGGI-Proceeds-Through-2013.pdf.

358 40 C.F.R. § 60.5815(c).

359 80 Fed. Reg. at 64,887.

are designed to further state-only policy goals from the federally enforceable elements of the plan. Alternatively, the state could adopt or continue to implement state RE and EE incentive programs that remain entirely outside of the cap-and-trade program.

8.5.4.3 Clean Energy Incentive Program (CEIP)

The Clean Energy Incentive Program (CEIP) is a set-aside program designed to encourage early action and investment in low-income communities, which states may elect to incorporate in their state plans and for which EPA will provide matching allowances. The CEIP will provide incentives for qualifying RE and EE projects implemented in low-income communities that provide zero-emitting generation or avoided generation in years 2020 and 2021. Qualifying RE projects must commence construction, and EE projects must commence implementation, after the date of the state's final plan submittal to EPA. Details of CEIP implementation have not yet been developed by EPA; however, EPA has proposed an allocation scheme for creating the set-aside pool and for assigning the size of the CEIP set-aside for each state. As proposed, allowance set-asides would come from the emissions budget for the first interim step period. A table of proposed state-specific set-asides (expressed in annual tons of allowances per year, for each year over the three-year interim step period) is provided in the proposed federal plan.[360]

8.5.5 Options for Allocating Allowances to Government Entities or Consumers

States that operate auction or sales systems for distribution of allowances may elect to establish provisions for pass-through of funds to specified county or municipal governments, or to entities that can direct funds to utility customers. For example, funding could be designated for job training or employment programs for areas that may be impacted by energy sector transitions from coal to natural gas or renewables. Or, funding could be directed to county governments for administration of demand-side EE programs. Municipal government entities that have made prior investments in municipal power generation from non-traditional energy, such as waste-to-energy facilities, could be also assisted by investments of auction proceeds.

Options for passing the value of allowances on to consumers could include direct rebates issued by the state, or allocations or revenues directed to the load-serving entity or local distribution company, which would then pass the funding on to the consumers. If the state decides to direct CO_2 program proceeds to the public at large, care should be taken to avoid incentivizing greater energy consumption. For example, if a rebate system is adopted, prorating the rebate to the level of energy consumption could incentivize greater energy use. On the other hand, a lump sum rebate distributed to all consumers would reduce net costs without the same incentive.[361]

8.6 Allowance Tracking Systems

Allowances must be issued and tracked by use of an allowance tracking system that meets the requirements of Subpart UUUU and that has been approved by EPA as part of the state's plan.[362] States participating in interstate trading, including states with plans that are trading ready, that have designated trading partners, or that are part of a formal multi-state plan, may utilize a joint tracking system or interoperable tracking systems. The allowance tracking system must electronically record each stage in the life cycle of each allowance, including issuance, transfers among accounts, surrender for compliance purposes, and retirement. The state plan and allowance tracking system must also provide for adjustments in the event of any errors in issuance or improper use of allowances.

In addition to tracking the life cycle of each allowance, if the state program includes set-asides, then the tracking system must document and track all information related to eligible resources, including providing an electronic repository for each eligibility application, EM&V plan, M&V reports, and independent verifier reports, and it must document and track the qualification status of eligible resources and independent verifiers. The tracking system must also provide for internet-based public access to information related to the eligible resources and allowances, with reporting functionality.

Model rule language for a state plan to incorporate allowance tracking procedures is provided in EPA's proposed mass-based trading program model state rule.[363] These provisions would be presumptively approvable upon finalization by EPA.

360 80 Fed. Reg. at 65,026.

361 Dallas Burtraw, *Economic and Administrative Considerations for the Initial Distribution of Allowances,* Resources for the Future, October 2015.

362 40 C.F.R. § 60.5820.

363 80 Fed. Reg. at 65,060 (proposed to be codified at 40 C.F.R. Part 62, Subpart MMM).

Model rule language to incorporate allowance allocation and to provide for an allowance tracking system is also provided in Section III of this document, as part of the comprehensive model state plan for a mass-based plan relying on the Table 4 statewide emission goals.

8.7 Compliance, Enforcement and Plan Performance

Under a mass-based emission standards plan, the owners and operators of affected EGUs bear the primary compliance obligation. Regardless of any incentive programs or direct investments the state or other parties commit to RE projects, EE programs or other reduction strategies, ultimately it is the owners and operators of affected EGUs that must assure a sufficient number of allowances are held in the EGU compliance account to cover all emissions at the end of the compliance period. For a mass-based trading program, a robust and highly regimented tracking system is needed to track allowances. If the state trading program elects to incorporate and rely upon set-asides as a compliance measure, including the incorporation of set-asides to opt into the CEIP program, then the plan must include infrastructure and regulatory provisions to manage and track eligible resources that would be the recipients of the set-asides.

8.7.1 Affected EGU Compliance Demonstrations and Enforcement

Mass-based emission standards plans place the full obligation of achieving the state's CPP emission goals directly upon the affected EGUs. Each mass-based plan must include emission standards applicable to each affected EGU for each interim step period and for each two-year final period. States may elect to set shorter compliance periods within each interim step or final period, provided the emission standards are imposed for the entirety of each plan period and the end date of the last compliance period within each plan period coincides with the end of the corresponding interim step or final plan period.

Under all mass-based plans, affected EGUs demonstrate compliance using their actual reported emissions. If the state plan is a direct emission limit plan, the reported emissions are compared to the applicable emission limit to determine compliance. If the state plan relies on a cap-and-trade program, then the reported emissions are used to determine the number of allowances the owners and operators of each affected EGU must hold in the compliance account for the affected EGU for surrender at the end of the compliance period.

The owner or operator of an affected EGU that fails to meet its applicable emission standard based on its actual emissions is subject to enforcement action. Specifically, each emission standard and other affected EGU compliance obligation under the state plan must be enforceable by the state, pursuant to state law and the CAA, by EPA pursuant to CAA section 113, and by third parties pursuant to CAA section 304.[364] Potential enforcement actions include imposition of corrective action, civil penalties and injunctive relief.

8.7.2 Eligible Resource Providers for Set-asides and Independent Verifiers Performance Assurance

If a state mass-based trading program incorporates set-asides, eligible resources must meet all of the same qualifying criteria and requirements as eligible ERC resources under a rate-based plan. Any party wishing to be an eligible resource must file an eligibility application, including an EM&V plan, and register with the designated tracking system. The EM&V plan and all subsequent M&V reports must be reviewed and certified by an independent verifier. Independent verifiers must also meet qualifying criteria and be registered with the designated tracking system. State plans must include provisions to suspend or permanently revoke the qualification status of an eligible resource that fails to meet all qualifying criteria, in the event any lapse or deficiency in qualifications is discovered.[365] Provisions must also be included in the state plan to suspend or revoke the qualification status of an independent verifier to review eligibility applications, EM&V plans or M&V reports.

8.7.3 State Plan Performance Reviews, Reporting and Corrective Measures

The emission standards incorporated in each mass-based state plan must be designed to achieve the Table 3 or Table 4 emission goals, or EPA-approved alternative emission goals, for the 8-year interim period and each 2-year final period. With regard to the interim period, this requires that the emission standards imposed on each affected EGU for each interim step period collectively result in a cumulative total level of emissions (tons) no higher than state's interim emission goal.

364 40 C.F.R. § 60.5775(f).

365 40 C.F.R. § 60.5815, referencing § 60.5805.

Table 8.3 **Mass-based Emission Standards Plans State Plan Performance Periods and State Reporting Schedule**

Report	Performance Period Dates	State Report Due
Interim Step Period 1	January 1, 2022–December 31, 2024	July 1, 2025
Interim Step Period 2	January 1, 2025–December 31, 2027	July 1, 2028
Interim Step Period 3	January 1, 2028–December 31, 2029	July 1, 2030
Interim Performance Period	January 1, 2022–December 31, 2029	July 1, 2030
Final Performance Period	January 1, 2030–December 31, 2031 Ongoing 2-year periods	July 1, 2032 July 1 every 2nd year

During plan implementation, each state must report periodically to EPA on its plan performance, checking the progress of its affected EGUs collectively in making progress toward meeting the applicable interim and final emission goals. The schedule for state reporting to EPA for mass-based emission standards plans is the same as for rate-based emission standards plans.[366] As shown in Table 8.3, plan performance reports must be submitted by July 1 of the year following the close of each interim step period and two-year final performance period.

For mass-based emission standards plans, state reports to EPA must include the status of implementation of affected EGU emission standards, including the aggregate affected EGU emissions as compared to the interim period emission goals, as well as individual EGU emissions as compared to the applicable emission standards. The report must include compliance demonstrations for each affected EGU (e.g., documentation of the holding and surrender of allowances in sufficient quantity to cover reported emissions) for the relevant plan performance period. In addition to reporting on individual EGU compliance, the Interim Step Period 1 and Interim Step Period 2 state reports to EPA must include a comparison of the state's applicable interim step period emission goal vs. the collective affected EGU aggregate emissions, as achieved by all affected EGUs, and identify whether all affected EGUs are collectively on schedule to meet the applicable interim period emission goal.

Plan performance criteria for state plans that rely on allowance trading programs differ, depending on the sources regulated under the trading program and the emission goals included in the state plan.

For streamlined mass-based plans with trading programs that apply to affected EGUs only, EPA will rely on a demonstration of compliance with the applicable emission standards (i.e., whether the affected EGUs hold allowances sufficient to cover actual emissions) to assess plan performance. Plans that set the total emissions cap for each performance period at or below the corresponding emission goal, such that compliance with the allowance-holding requirement by all affected EGUs mathematically assures the emission goal will be met, are streamlined plans. If the state plan allows banking of allowances from prior compliance periods, or if the state plan allows trading of allowances with other EPA-approved state plans or states operating under a federal plan, all valid allowances may be used in the compliance demonstration. In other words, actual reported aggregated emissions of a state's affected EGUs during a plan performance period may exceed the applicable emission goal, and the plan would still meet the performance demonstration criteria, provided all affected EGUs are in compliance with the trading program emission standard to hold and surrender allowances.[367]

Streamlined mass-based plans with trading programs that apply to both affected EGUs and new sources will be assessed in the same manner as streamlined plans that apply to affected EGUs only. EPA will rely on the compliance demonstration with the applicable emission standards (i.e., the requirement to hold and surrender allowances equal to actual emissions) to assess plan performance, regardless of the level of actual emissions from EGUs during the plan performance period. However, for plans that regulate both affected EGUs and new sources, EPA

366 40 C.F.R. § 60.5870.

367 80 Fed. Reg. at 64,866. Note that a plan is not a streamlined plan if the trading program includes any provisions that would effectively expand the emissions cap beyond the state's emission goals, such as a cost containment provision allowing the introduction of additional allowances beyond the emission goal if an allowance price threshold is triggered. Such plans are considered state measures plans. 80 Fed. Reg. at 64,891.

will use a different metric for assessing the compliance demonstration depending on the new source complement adopted by the state. For plans that are designed to achieve the Table 4 emission goals (the EPA-provided new source complements), EPA will assess whether affected EGUs and new sources collectively demonstrate compliance with the Table 4 total mass emission budgets.[368] For plans that include a new source complement developed by the state, EPA will assess whether affected EGUs collectively meet the Table 3 emission goals for affected EGUs only.[369]

If the state plan involves a mass-based trading program that applies more broadly to sources beyond affected EGUs plus new sources subject to Subpart TTTT, or that includes provisions that could functionally expand the budget to exceed the emission goal, the plan is considered a state measures plan as opposed to an emission standards plan.[370] For such a plan, EPA will evaluate plan performance by assessing whether the applicable mass-based emission goals are achieved. That is, EPA will compare the collective aggregate actual reported emissions of affected EGUs (or affected EGUs plus new sources, if applicable) against the state's Table 3 or Table 4 emission goals, or against alternative EPA-approved emission goals. If the emission goals are not achieved, the federally enforceable backstop measures must be implemented.[371]

Consequences of plan failure to achieve the interim step, interim period or final period performance rates or emission goals depend on the plan design. For streamlined plans, where the emission standards for applicable EGUs mathematically demonstrate compliance with the applicable plan performance metrics, no corrective action triggers are required in the plan. In this case, if the plan fails to achieve the statewide collective EGU performance rate, the remedy would most likely rest with enforcement action against any noncompliant affected EGU owners and operators. For plans that include corrective measure triggers, corrective actions must be adopted and instituted to correct plan deficiencies. Corrective actions are triggered if the plan fails to achieve an EPA-approved interim step goal or the interim period goal by more than 10%, if the interim period goal is not met, or if any final reporting period emission goal is not met.

368 80 Fed. Reg. at 64,866 & 64,888.

369 80 Fed. Reg. at 64,889.

370 80 Fed. Reg. at 64,891.

371 For further discussion, see *Chapter 9, State Measures Plans*, and *Chapter 5, State Plan Types and Required Plan Components.*

9. State Measures Plans

A state measures plan is a plan that relies wholly or partially on state-only enforceable measures to achieve the Subpart UUUU emission goals for affected EGUs. A state measures plan must be mass-based; it must demonstrate compliance with either the statewide (or multi-state) mass emission goals for affected EGUs under Table 3 of Subpart UUUU, the mass emission goals for affected EGUs plus new source complement under Table 4, or EPA-approved revised emission goals. The state is not required to adopt emission standards applicable to affected EGUs under a state measures plan; however, any emission standards the state does adopt that are applicable to affected EGUs must be federally enforceable.[372] All CO_2 reduction strategies that are not emission standards for affected EGUs may be retained outside the federally enforceable elements of the state measures plan. State measures may be implemented through state-enforceable mechanisms such as regulations or statutes, or other state-enforceable vehicles. In addition, the state may rely on the implementation of policies or voluntary, incentive-based programs, such as demand-side EE programs. Each state measures plan must include a federally enforceable backstop, comprising federally enforceable emission standards applicable to affected EGUs. Implementation of the backstop would only be triggered in the event the state measures plan misses the step 1 or step 2 interim goals by 10% or more, or fails to achieve the applicable mass-based interim or final CPP performance goals during any performance period. In addition, because a state measures plan is a mass-based plan, each plan must include provisions to mitigate leakage or a demonstration that leakage is unlikely to occur.

One type of state measures plan EPA explicitly addresses in the final emission guidelines is a mass-based allowance trading program with broader source coverage (i.e., beyond affected EGUs plus new sources subject to Subpart TTTT) and/or with other flexibility provisions that could expand the emissions cap.[373] However, a state measures plan need not be an allowance trading program; it may be a compilation of other requirements, policies or programs designed to achieve the applicable emission goals. This chapter focuses primarily on state measures plans that do not involve a trading program, but comprise multiple other state measures that collectively are projected to achieve the statewide emission goals. Sample regulatory language is provided for several types of state measures a state may elect to include in the state measures plan. In general, state measures plans may rely on any strategy that will assist in achieving the required CO_2 emission reductions. For example, states can pursue any of the technologies, programs and policies described in NACAA's May 2015 publication, *Implementing EPA's Clean Power Plan: A Menu of Options.*[374]

9.1 State Measures Plans Available Pathways

A state can design a state measures plan in a variety of ways to satisfy the state's specific environmental and economic policy goals and reflect its particular circumstances and affected EGU inventory. As with a mass-based emission standards plan, mass-based state measures plans can be categorized under two major pathways: (1) the state can rely upon the Subpart UUUU Table 3 statewide emission goals (or alternative EPA-approved Table 3 statewide emission goals) as the plan performance metric for all affected EGUs collectively, or (2) the state can rely on the Subpart UUUU Table 4 statewide emission goals (or alternative EPA-approved Table 4 statewide emission goals) as the plan performance metric for affected EGUs plus new sources.[375] Under each of these primary pathways, a state

372 80 Fed. Reg. at 64,836. Note that 40 C.F.R. § 60.21(f) defines "emission standard" to include "establishing an allowance system," and EPA has clarified that allowance systems are emission standards under the CPP.

373 *See, e.g.,* 80 Fed. Reg. at 64,891.

374 Available at http://www.4cleanair.org/NACAA_Menu_of_Options.

375 A state relying on the statewide goal approach can, under certain circumstances as defined in Subpart UUUU, revise the state's Table 3 or Table 4 interim and/or final statewide emission goals.

measures plan can rely exclusively on state-only measures, or it can combine federally enforceable emission standards on affected EGUs with state-only measures to achieve the applicable emission goals. Figure 9.1 depicts the available pathways for a state measures plan.

9.2 When Would a State Consider a State Measures Plan?

The CPP makes the state measures plan pathway available to any state; thus, any state, under any set of circumstances, could elect to adopt and implement a state measures plan. However, the state measures plan type requires a significant level of plan demonstration and documentation for plan approval, requires more frequent reporting and performance evaluations during the interim period than other types of state plans, and must include a federally enforceable backstop measure comprising emission standards on affected EGUs that would automatically apply if the plan fails to meet all performance goals. In adopting the state measures option, EPA noted that some states may wish to adopt a plan that does not place the full obligation of emission reductions directly on owners and operators of affected EGUs. To this end, EPA stated that the agency's intent is to provide states with additional latitude in accommodating existing or planned programs that involve measures implemented by the state or entities other than affected EGUs that reduce emissions at affected EGUs.[376]

Considering the increased level of plan demonstration requirements up front, together with increased scrutiny during implementation with the potential for state measures to be supplanted by federal emission standards, there may be a limited set of circumstances under which a state is likely to elect, a state measures approach. This section describes some situations that may warrant adoption of a state measures approach.

9.2.1 States with Existing Cap-and-Trade Programs

One group of states EPA had explicitly in mind in establishing the state measures pathway is states with existing market-based trading programs, including California and possibly the RGGI states.[377] These states are successfully reducing CO_2 emissions from existing power plants through established cap-and-trade programs that incorporate many of the required plan elements under the emission guidelines. However, the California and RGGI programs also apply to a broader set of affected sources than the CPP, and include certain flexibility provisions that could effectively expand the emissions cap established for a given performance period beyond the Table 3 or Table 4 goals. Elements that go beyond EPA's authority under CAA section 111(d), or that may not in all cases align with the CPP mass-based emission goals, could make the existing programs incompatible in some respects with the emission guideline requirements for emission standards plans if their combined effect is to allow emissions to exceed the Table 3 or Table 4 goals. However, the state measures approach could be used to accommodate these program elements by allowing them to remain outside the federally enforceable portion of the state plan and/or by relying upon an upfront demonstration and annual plan performance review to assure that the program will achieve the CPP mass emission goals.

9.2.2 States Wishing to Join an Existing Cap-and-Trade Program or Establish a New Program

A state may wish to join an existing cap-and-trade program such as RGGI, or a group of states may wish to establish a similar program that extends source coverage beyond Subpart UUUU affected EGUs. In these circumstances, the state measures approach could be implemented to meet CPP requirements as described above.

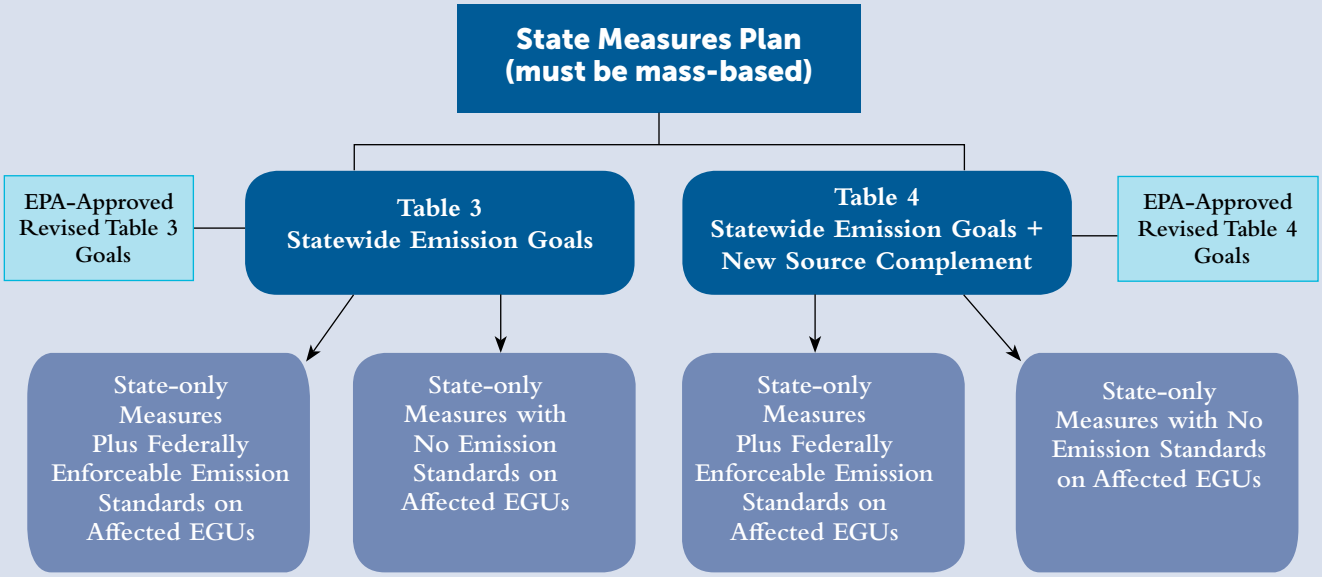
9.2.3 States with Existing Programs on Track to Achieve CPP Emission Goals

Most states have existing RE and/or EE programs, such as Renewable Portfolio Standards (RPS), Energy Efficiency Resource Standards (EERS), incentive programs or other measures. In states where these programs are mature and are successfully reducing CO_2 emissions from existing power plants such that the state is on target to achieve the CPP Table 3 emission goals, or where projections indicate moderate enhancements to existing programs would achieve the Table 3 emission goals, a state measures

376 80 Fed. Reg. at 64,835.

377 However, according to a document shared during a November 2015 RGGI public stakeholder meeting, the RGGI states anticipate using an emissions standards approach. *See* http://www.rggi.org/docs/ProgramReview/2016/11-17-15/Key_Discussion_Items_11_17_15.pdf. Subsequent RGGI stakeholder discussions have investigated ways to align the program, and in particular its Cost Containment Reserve mechanism, with the requirements of the emission standards approach. *See, e.g.,* http://www.rggi.org/docs/ProgramReview/2016/04-29-16/Burtraw_on_RGGI_CCR_April_29th.pdf.

Figure 9.1 **State Measures Plan Available Pathways**



plan could accommodate the continued implementation of these programs under state authority, without the imposition of new federally enforceable emission standards.

9.2.4 States that Want to "Share the Load" with Affected EGUs

As noted by EPA, some states may wish to adopt a plan that does not place all the obligations associated with achieving emission reductions on affected EGUs.[378] Such a state could design a plan that includes federally enforceable emission standards on affected EGUs that would not assure full compliance with the statewide emission goal while also implementing other state measures to reduce emissions, such that collectively, the plan elements would result in projected emissions at or below the applicable emission goal. State measures in a plan of this design could include state or third-party implemented incentive programs, mandated EE measures for state and municipal buildings and institutions, RE investments, or other state-enforceable measures applicable to affected EGUs such as heat rate improvement requirements.

9.2.5 States that Want to Minimize Federally Enforceable Requirements

Some states may prefer to rely on non-emission standard requirements to achieve the CPP emission goals, and in doing so retain implementation and enforcement authority under state law. For example, requirements that take the form of design, equipment, work practice or operational standards do not meet the definition of "standard of performance" under CAA section 111(d). Or, a state may wish to adopt and implement a carbon tax or fee in lieu of implementing emission standards or other standards. Requirements of these types that apply to affected EGUs could be included as state-only enforceable requirements under a state measures plan, and could be combined with state or third-party administered EE programs or other measures.

9.2.6 States with Emissions at or Near the Statewide Emission Goal

A number of states may determine that the collective aggregated emissions from their affected EGUs is currently at or near the level of the statewide emission goal, and that projected emissions are anticipated to meet the emission goals in the future, without the need for additional measures. If business-as-usual models and projections predict that current measures already in place, such as RPS, EERS, and Integrated Resource Planning (IRP) requirements, are sufficient to achieve and maintain the CPP emission goals, then the state may elect to package

378 80 Fed. Reg. at 64,835.

these existing programs as a state measures plan, together with the required projections and demonstrations. The state would also adopt the required federally enforceable emission standards to be implemented only contingent on failure of the existing measures.

9.3 Options for State Measures Reduction Strategies

A state can incorporate virtually any CO_2 reduction strategy as a component of a state measures plan, keeping in mind that any requirement that constitutes an emission standard applicable to affected EGUs must be included as a federally enforceable plan element. Excluding direct emission standards and trading programs, strategies that can be implemented as state-only enforceable measures generally fall into three categories. First, each of the three BSER building blocks can be relied upon as state-enforceable measures. Second, policies or regulations to deploy low- or zero-emitting electricity generation technologies that were not specifically included in the BSER determination can be relied upon as state measures. The third group of state measures comprises energy efficiency measures that result in saved or avoided generation. The following sections provide an overview of specific strategies in each of these three general categories, with several rule, statute or policy examples.

In developing a state measures plan, it is important to consider interactions between measures when projecting emission reductions. For example, as generation shifting to zero-emitting resources and energy efficiency measures will tend to reduce the need to operate affected EGUs, they will also tend to reduce the absolute amount of emission reductions that can be achieved through "inside the fenceline" reductions. States may also wish to consider whether they prefer to rely on measures that have been successfully implemented in other jurisdictions. For example, many states have successfully achieved CO_2 emission reductions through renewable portfolio standards. Furthermore, while this chapter is organized around the three BSER building blocks, states are under no obligation to approach planning under this framework or to achieve reductions using any particular building block.

Notably, each of the low- or zero-emitting generation strategies and energy efficiency measures discussed in this chapter could also be incorporated as ERC-eligible resources in a rate-based plan, or as setaside allowance-eligible resources in a mass-based emission standards plan.

9.4 Heat Rate Improvements

9.4.1 Overview of Heat Rate Improvements

Heat rate is a measure of the energy efficiency of a power plant or electric generating unit, expressed as the ratio of fuel energy input to the gross or net electric output. In the CPP, EPA expresses heat rate as the amount of heat input from fuel, on a high heating value (HHV) basis, per kilowatt hour (kWh) of net electric output (Btu(HHV)/kWh-net). Because CO_2 emissions are derived from the burning of fossil fuel, improvements in heat rate will generally translate directly to reductions in CO_2 emissions for a given amount of electricity produced. That is, by reducing the amount of fossil fuel required to generate electricity, less CO_2 is emitted.

Based on International Table standard units of conversion, 3,412 Btu of thermal energy is equivalent to 1 kWh of electric energy.[379] However, a substantial amount of energy is lost in converting the thermal energy (heat content) of fossil fuel to electricity. For existing coal-fired power plants, heat rates are typically in the range of 9,000 to 11,000 Btu/kWh-net.[380] The U.S. Energy Information Administration (EIA) reports an estimated U.S. 2014 coal steam generator EGU average of 10,080 Btu/kWh-net.[381] This performance is equivalent to an average overall coal plant efficiency of about 34%.

Improvements in heat rate can be gained through a variety of measures, including equipment upgrades and work practice changes. For example, equipment upgrades to overhaul the steam turbine could involve the replacement of blades, nozzles, rotors, seals and casings. Equipment upgrades to the boiler system or changes in the flue gas system, such as replacing the induced draft (ID) fan, might also garner heat rate improvements. Upgrades to ancillary operations such as coal-handling equipment, air heaters, water treatment systems, and emission control systems can also reduce heat rate by reducing the auxiliary load of energy required to operate the plant (i.e., improving the net:gross output ratio). Also, changes to operational control systems such as

379 American Physical Society, *Energy Units*, http://www.aps.org/policy/reports/popa-reports/energy/units.cfm.

380 Sam Korelis, *Coal-Fired Power Plant Heat Rate Improvement Options, Part 1,* POWER magazine, November 1, 2014, available at http://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-1/.

381 U.S. Energy Information Administration, *Table 8.2, Average Tested Heat Rates by Prime Mover and Energy Source, 2007-2014,* http://www.aps.org/policy/reports/popa-reports/energy/units.cfm.

upgrading to neural networks or digital control systems can improve operating efficiency, thereby reducing variability in heat rate and improving overall performance.[382] For more information on options for improving heat rate, see *Implementing EPA's Clean Power Plan: A Menu of Options, Chapter 1: Optimize Power Plant Operations.*[383]

Heat rate improvements at coal-fired steam EGUs comprise Building Block 1 of BSER. More specifically, EPA estimated the following heat rate improvement potential that affected coal steam unit EGUs can achieve on average, through best practices and equipment upgrades, for each of the three interconnect regions: 4.3% improvement in the Eastern Interconnection; 2.1% improvement in the Western Interconnection; and 2.3% improvement in the ERCOT Interconnection.[384] This reduction strategy is one approach to achieving CPP-required reductions that a state may elect to include in a state measures plan.

9.4.1.1 Potential Benefits of Heat Rate Improvement as a State Measure

Because a heat rate standard, or heat rate improvement requirement, does not constitute an emission standard for purposes of the CPP, a heat rate improvement standard can remain a state measure that is not federally enforceable. This aspect makes heat rate improvement a candidate for a state measures plan, particularly in cases where the state wishes to share the obligation to implement emission reduction strategies among affected EGUs, state entities and/or other entities. A heat rate improvement strategy can provide a mechanism to obtain a specific increment of the required CO_2 emission reductions from the affected EGUs, without invoking federal enforceability through an emission standard. A heat rate performance standard could be adopted as a state-enforceable measure in the form of a performance standard, or performance improvement requirement. Alternatively, some states may prefer to incorporate heat rate improvement programs through the IRP process or another mechanism, or to provide incentives rather than mandated performance standards for heat rate improvement.

Heat rate as an indicator of CO_2 emission performance has the advantage of providing a simple index that can be readily monitored. Power plants are already monitoring both the fuel input and electric output of EGUs; thus, measuring, recording and reporting heat rate should not impose a significant additional regulatory burden. Further, this one simple index inherently accounts for a wide variety of specific energy efficiency techniques, including numerous different equipment upgrades, a range of operational controls and many different work practice improvements. Thus, using a single standard with a simple form, the state plan can encompass a broad group of CO_2 reduction measures, affording a correspondingly high degree of compliance flexibility to the regulated facilities. The state can choose to establish a heat rate performance standard without prescribing specific work practices or equipment specifications, allowing the affected EGUs to devise the best way to achieve that standard for their particular circumstances.

Another benefit of including heat rate performance standards in a state measures plan is that, in general, improvements in heat rate performance are cost-effective and can be implemented on a relatively short timeframe as compared to measures such as expanding the use of renewable energy through capital investment in new construction of facilities and infrastructure. Because heat rate improvements offer a return on investment in the form of reduced fuel usage, costs attributable to implementing heat rate improvements are a net cost. EPA estimated that the cost of achieving the BSER heat rate improvements would be less than $23 per ton of CO_2 reduced.[385]

Heat rate performance standards also have the advantage of applying directly to the affected EGUs, as opposed to EE measures, for example, which occur across a widely dispersed area. Applicability of the standard directly to the affected EGUs provides a straight line of accountability, facilitating implementation and enforcement. Indeed, one significant advantage from a regulatory perspective is that the adoption of heat rate performance standards mirrors the traditional approach of regulating emissions under state environmental regulatory frameworks. The state environmental agency may have both the authority and mechanisms in place to establish, implement and enforce heat rate performance standards, which would apply "inside the fenceline" of the regulated stationary source and directly to the equipment that is subject to the standard. Further, because coal-fired EGUs are already subject to other well-established air quality programs and emission standards, the affected EGUs are already known to the air quality control agencies and included in the existing

382 Sargent and Lundy, LLC, *Coal Fired Power Plant Heat Rate Reductions,* January 22, 2009, https://www.epa.gov/sites/production/files/2015-08/documents/coalfired.pdf.

383 NACAA, May 2015, available at http://www.4cleanair.org/NACAA_Menu_of_Options.

384 80 Fed. Reg. at 64,789.

385 80 Fed. Reg. at 64,791.

permitting, surveillance and enforcement programs. Even where the affected EGUs may be owned and/or operated by non-utility entities, such as a merchant power plant, direct regulation of the coal-fired EGU by the state environmental agency is likely already occurring or could be readily achieved. Thus, many of the concerns regarding enforcement authority and regulatory infrastructure that may exist for other methods of CO_2 reduction are avoided with regard to heat rate improvements achieved at the power plant. However, as discussed below, some new capacities may be desirable, such as the ability to certify third-party heat rate auditors.

9.4.1.2 Potential Implementation Challenges for Heat Rate Improvements

One potential challenge related to heat rate performance standards is that EGU-specific data or evaluations are required to make a realistic determination of the actual heat rate reductions that can be achieved by each unit in the existing fleet. Also, because not all existing units can achieve the same heat rate performance level, setting a "one-size-fits-all" standard may not be feasible. Furthermore, if a flat improvement rate is required, owners and operators who have already invested in heat rate improvement projects could be placed at a competitive or compliance disadvantage. In addition, states will want to consider and address the potential for the imposition of heat rate performance standards to create a disincentive for properly operating pollution control equipment, particularly in programs that impose a percent improvement standard against a baseline.

A heat rate standard that encourages efficiency improvements at EGUs that use high-carbon fuels could also result in increased emissions if the efficiency improvements reduce per-MWh operating costs to the point where the EGUs are more economically competitive. If the heat rate standard is not combined with other measures, this rebound effect could reduce the emission reductions achieved from the heat rate standard.

The ***Heat Rate Improvement Rule Examples*** included at the end of this section provide options for addressing each of these challenges, including special provisions to incorporate compliance flexibility and to alleviate particular practical or policy concerns.

9.4.1.3 State Energy and Environmental Policy Considerations

If, as a matter of energy and environmental policy, the state wishes to ensure that existing EGUs optimize energy efficiency, a heat rate performance standard can help to achieve this goal. From a policy perspective, requiring owners and operators of coal-fired units to optimize the energy efficiency performance of those units is a commonsense approach to reducing CO_2 emissions without restricting the use of coal for generating electricity. At the same time, adoption of a state-enforceable heat rate performance requirement would help to ensure a certain increment of the state mass emission goal is achieved.

On the other hand, a mandate to achieve heat rate improvements at existing coal-fired plants will likely drive investment in those plants. Therefore, if the state energy and environmental policy goal is to disinvest in coal generation in favor of investments in low-carbon or zero-carbon energy sources, the state may choose not to adopt heat rate standards for existing coal units. Conversely, if the state policy goal is to prolong the life of existing coal units, investment in the energy efficiency of those units would tend to support that goal. Investment in existing facilities is also encouraged by adopting a flexible standard (i.e., one that allows for averaging across individual units), as opposed to an inflexible standard that requires compliance by each individual unit. Related research by Resources for the Future concludes that where the standard is flexible, substantially more investment to improve the operating efficiency of existing facilities occurs, whereas an inflexible standard leads to substantially greater retirement of existing facilities.[386]

9.4.2 Determining the Potential for Heat Rate Improvements

Understanding what degree of heat rate improvement and, ultimately, what heat rate performance level, can be achieved by individual coal-fired units is helpful for state planners to accurately predict how much this strategy can contribute toward meeting the state performance goal under the CPP. Assessing heat rate improvement potential and identifying which specific measures can achieve meaningful heat rate reductions in a cost-effective manner requires a site-specific evaluation for each affected source. Factors that must be examined include the existing equipment technology design, including thermodynamic cycle and size; the condition of the equipment (current and past operating and maintenance practices); current

386 Dallas Burtraw et al., *Retail Electricity Price Savings from Compliance Flexibility in GHG Standards for Stationary Sources,* Energy Policy 42:67-77, March 2012, available at http://www.sciencedirect.com/science/article/pii/S030142151100913X.

and future anticipated fuel usage (coal rank and quality); pollution control systems, cooling systems, and other parasitic load plant components; and geographic location.[387] Another significant factor impacting heat rate performance is operating mode. Shifts in utilization among base load, peak load, and load-following operations can create very different heat rate profiles, as can the frequency and duration of offline periods. Thus, historical and future operating modes and flexibility requirements must also be considered, including possible impacts of heat rate improvements on utilization.

Because of the source-specific nature of heat rate improvement potential, one key decision states will need to make in order to incorporate heat rate improvements as an element of the state plan is how and when source-specific heat rate improvement plans will be established. One approach would be for source-specific assessments to be conducted relatively early in the planning phase, as part of the state plan development, to establish a reasonable target for CO_2 reductions that would be achieved by heat rate reductions from the universe of affected sources. This approach would rely on some existing authority to require affected sources to develop and submit the information. In this case, the state plan could adopt specific heat rate improvement measures for particular affected sources, based on the results of the audits and considering technical feasibility and cost, as part of the state measures plan. This approach requires greater effort and time in the planning phase. However, this approach would afford greater certainty for affected sources and may also provide a stronger assurance in the effectiveness of the control strategy to provide the expected contributions toward the state goal.

Alternatively, the state could rely on existing studies and available data for purposes of developing source-specific heat rate standards.[388] Sources of information the state might consider include heat rate assessments already developed by affected sources as part of the utility resource planning process[389] or the statistical evaluations performed by EPA as part of the CPP rulemaking. Other useful publicly available data sources include the EPA National Electric Energy Database System (NEEDS), which includes unit-specific heat rate data developed from the Energy Information Administration's (EIA's) Annual Energy Outlook (AEO), and the Air Market Program Database (AMPD). Using this approach, the state could develop unit-specific heat rate baseline data and apply estimated achievable reductions to develop source-specific standards. To address the greater uncertainty inherent in this approach, given the variability in heat rate improvement potential from unit to unit, the state plan could include compliance flexibility options. For example, the plan could provide for the owner or operator of an affected source to conduct an assessment and develop a heat rate improvement plan. If the assessment concluded the adopted standard could not reasonably be met, the owner or operator would seek approval of an alternative standard, based on the assessment that was conducted for the facility. This type of approach could also include other compliance flexibility options, such as averaging across a group of EGUs within the owner's fleet. The incorporation of adequate compliance flexibility avoids the imposition of an unrealistic compliance risk if, for example, the performance standard established is not technically feasible and cost-effective for a given facility.

9.4.3 Administrative Authority Options for Heat Rate Improvements

To incorporate heat rate improvements as an element of a state measures plan, the state may choose to rely upon the state air quality agency, the state energy office, the Public Utility Commission (PUC), or some combination of administrative authorities.

9.4.3.1 State Air Quality Agency

Because heat rate improvement projects and heat rate standards directly affect individual EGUs, this CO_2 reduction strategy fits well under the traditional regulatory framework, and the state air quality agency can readily serve as the administrative authority to implement and enforce the applicable requirements of the program. Since the affected sources will typically already be regulated sources under the CAA and are subject to permitting requirements, as well as other emission limitations, emissions reporting and other applicable requirements, heat rate standards can be incorporated into the existing regulatory infrastructure.

Under this approach, the state air quality agency could adopt regulations that specify the heat rate performance standard, together with flexible compliance options, as well as compliance deadlines, monitoring, recordkeeping and reporting provisions adequate to measure progress toward

387 EPA Technical Support Document, *GHG Abatement Measures,* June 10, 2014, pp. 2-3 to 2-5, https://www.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

388 This approach is discussed further in Section 9.4.5.3, Source-specific Heat Rate Standards.

389 See discussion of Integrated Resource Planning in Chapter 2.

the state goal and to assure the standards are enforceable as a practical matter. The owner/operator of each affected source would bear the full compliance obligation and be subject to enforcement for noncompliance. The state air quality administrative authority would bear the obligation to adopt, implement and enforce the applicable requirements, without the need to involve any other affected entity or administrative body.

9.4.3.2 Public Utility Commission

Governmental agencies such as a state energy office, or other entities with regulatory oversight of electric utilities, such as the PUC or Public Service Commission (PSC) may already have a role in incentivizing or requiring and implementing heat rate improvements at utilities or other electric generating plants, or may be well suited to such a role. Recognizing this role, a state may choose to assign all or part of the administrative authority obligations for addressing heat rate improvements under the state plan to one of these entities.

For example, evaluation of specific measures to improve heat rate at individual power plants or EGUs could be established as a required element in the utility's Integrated Resource Plan (IRP),[390] overseen by the PUC. This strategy may include a requirement for each affected EGU to conduct a heat rate improvement audit and to develop a heat rate improvement plan based on technical feasibility, cost effectiveness and other specifications. Most states already have some level of integrated resource planning requirements in place, and in some cases the IRP process already includes a requirement to report heat rate and to assess improvements in efficient utilization of existing generating units as a resource available to meet future energy demand.[391]

While it may be desirable to rely upon the IRP process as an existing regulatory framework, the existing IRP process with PUC oversight, by itself, may not be sufficient to meet the requirements for CO_2 reduction strategies under the CPP. For example, IRP programs typically address long-term planning horizons of ten to twenty years, with plan updates required every two to five years. Thus, the timing of IRP development may not be compatible with the state planning and implementation requirements under the CPP, particularly for the initial plan development and early milestone dates. Also, in many cases, although utilities are required to conduct the IRP process, the resulting plan does not require review or approval by the PUC. In other cases, although the IRP is reviewed or approved by the PUC, it does not become an enforceable requirement to which the utility must adhere. Rather, the IRP may be used as a reference or guide for making decisions regarding resource development or as one factor considered in approving rate structures or carrying out other decision-making aspects of the PUC's role.[392]

Given these constraints, states may choose to create a separate enforceable requirement that builds upon the existing IRP process, to assure the implementation of cost-effective heat rate improvement projects and to track their effectiveness. Under this approach, the state air quality agency and the PUC may execute a Memorandum of Understanding or otherwise share a cooperative arrangement, whereby the PUC administers the heat rate improvement planning process by applying specific criteria through which heat rate improvement projects would be incorporated in the IRP, while the state air quality agency enforces implementation of the selected measures, together with monitoring, recordkeeping and reporting requirements as necessary for assuring compliance and tracking progress toward the state CPP goals. The affected utilities would bear the obligation to comply with the heat rate improvement requirements established through the IRP, which may be adopted through the operating permit or another enforceable mechanism. The PUC and state air quality agency would share the administrative authority obligations to establish, implement and enforce the specific applicable requirements for each affected source. If existing regulations are not sufficient to require and enforce HRI measures, the PUC and the state air agency would need to adopt changes to the IRP and operating permit regulations, respectively, in order to execute this approach.

390 Under section 111(d)(19) of the federal Energy Policy Act of 1992, "integrated resource planning" is defined, in part, as "a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost."

391 For example, see Kentucky's IRP regulations at 807 Ky. Admin. Regs. 5:058.

392 Rachel Wilson & Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans,* Regulatory Assistance Project & Synapse Energy Economics, Inc., June 2013, https://www.raponline.org/document/download/id/6608.

9.4.3.3 State Energy Office or Other Regulatory Entities

While the PUC typically has a well-established oversight role for electric generating facilities owned and operated by utilities, this may not be the case for merchant generators, cooperatives or other non-utility EGUs. For these facilities, a governmental agency other than the state environmental agency or air quality agency may already play a role in administering programs related to supply-side energy efficiency or IRP implementation. If so, the state may want to establish a shared administrative authority role with this governmental entity, in a similar fashion to that discussed above for the PUC. However, if non-utility EGUs currently fall outside of any administrative authority or oversight body that could readily support implementation of heat rate improvement plans under the state plan, the state may elect to broaden the scope of existing agency programs, such as the state energy office, or may elect to place the full administrative authority role under the state air quality agency, at least for non-utility affected sources. The adoption of state law would likely be needed to provide statutory authority for regulating energy efficiency at non-utility EGUs where it does not already exist.

9.4.4 Affected Sources and Affected Entities

9.4.4.1 Affected EGUs

With regard to heat rate performance, the affected sources are the EGUs to which the standards would apply. As discussed in the following paragraphs, a state might choose to apply the heat rate performance standards to:

1) Existing coal-fired EGUs subject to the CPP; or
2) Existing coal-fired EGUs plus other fossil fuel-fired combustion units subject to the state plan.

In the CPP, BSER takes into account heat rate improvements only from existing coal-fired EGUs.[393] In the examples of rule language provided here (Heat Rate Improvements Rule Examples 1, 2, 3 and 4), coal-fired steam generating units meeting the applicability criteria of Subpart UUUU are the affected sources. Specifically, these include any coal-fired steam EGU that: (1) commenced construction on or before January 8, 2014; (2) has a base load rating greater than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel); and (3) was constructed for the purpose of supplying one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility distribution system on an annual basis.[394]

A state could decide to broaden its approach to include oil-fired and/or natural gas-fired units as affected sources subject to heat rate performance standards, depending on their particular circumstances. For example, if a state identifies opportunities for significant CO_2 reductions through equipment or work-practice upgrades at EGUs other than coal-fired units, it may be reasonable to utilize those reductions for compliance with the state goals. Also, a state may determine that many of the best practices which would serve to achieve consistently strong heat rate performance and to reduce parasitic loads at coal-fired power plants apply equally well to other existing fossil-fuel fired power plants, are technically feasible and cost-effective and, as a matter of policy, should be implemented across all existing power plants. Another reason states may choose to include EGUs other than coal-fired units as affected sources under heat rate improvement programs could be to increase the usefulness of flexible compliance provisions such as performance averaging or heat rate credits, by allowing utilities to take advantage of heat rate improvement opportunities and strong heat rate performance at their non-coal units. Under a program that allows crediting or averaging of heat rate improvements at oil or gas-fired EGUs to offset heat rate improvements that would otherwise have been required at coal-fired EGUs, the state would need to include a mechanism or formula for adjusting the credits based on the relative CO_2 emission factors among the fuels. In evaluating a crediting or averaging program of this type, it would be important to consider the fact that, in addition to rewarding heat rate improvements, incentives created by the program would affect operating costs for EGUs, and therefore, dispatch decisions.

9.4.4.2 EGUs Excluded from the Heat Rate Performance Standard

States will want to consider which facilities to exclude from the Heat Rate Performance Standard. Some exclusions to consider include:

1) Oil and gas steam EGUs, IGCCs and NGCC EGUs;
2) EGUs subject to 40 C.F.R. Part 60, Subpart TTTT under CAA section 111(b);
3) Other EGUs excluded as affected sources under Subpart UUUU; and
4) EGUs that are being retired from service within a few years.

393 In the proposed rule, EPA found that the potential for CO_2 reductions through heat rate reduction is significantly greater for coal-fired steam EGUs than for other EGUs. 79 Fed. Reg. at 34,859.

394 40 C.F.R. § 60.5845.

Exclusion for Affected EGUs Other than Coal-fired Steam Units

As noted above, EPA's assessments concluded that heat rate improvements as an element of BSER are limited to coal-fired steam units. In the absence of specific state circumstances that would indicate applicability should be expanded beyond this category, states may choose to exclude all other affected EGUs. On the other hand, if states have oil- or gas-fired affected EGUs with significant potential to improve heat rates, excluding those EGUs could make them less competitive with coal-fired EGUs for dispatching, potentially foregoing emission reductions.

Exclusion for New, Modified and Reconstructed EGUs and Other Non-affected EGUs

States may choose to exclude from applicability of the heat rate standard any EGU that is not subject to Subpart UUUU. EGUs excluded under Subpart UUUU include: any EGU that is subject to 40 C.F.R. Part 60, Subpart TTTT; simple cycle combustion turbines; non fossil-fueled EGUs; stationary combustion turbines not connected to a natural gas pipeline; CHP units selling less than the applicable threshold; fossil-fueled EGUs serving a generator with capacity of 25 MW or less; and EGUs subject to Subpart Eb or Subpart CCCC of 40 C.F.R. Part 60.[395] The state regulations implementing the state plan may include an applicability section that clearly excludes these units. On the other hand, if a state measures plan adopts the Table 4 goals, the state may elect to include Subpart TTTT EGUs, as technology exists to construct EGUs that are subject to Subpart TTTT. Any regulations specifically addressing heat rate improvements for purposes of the state plan should either reference the exclusion in the general applicability section or repeat the exclusion for clarity. ***Heat Rate Improvements Rule Example 2*** includes an applicability section with these exclusions.

Exclusion for Retiring EGUs

States may elect to exclude from the heat rate performance requirements any coal-fired EGU with a firm retirement date that falls in a window occurring some time prior to the final state goal compliance date (2030), prior to a particular interim compliance date, or prior to the first compliance year (2022). Heat rate improvements will generally result in a return on investment through reduced fuel costs; however, the return may not be realized if the EGU will soon be retired. This exclusion also makes sense from the perspective of achieving the state goal. That is, if the EGU is retiring, the CO_2 emissions from that unit will go to zero. The retirement will contribute towards reaching the goal without the implementation of interim heat rate improvements. ***Heat Rate Improvements Rule Example 1*** includes an exclusion for retiring EGUs.

Retiring Unit Exclusion

Any coal-fired steam EGU with a certified retirement date on or before January 1, 2027, is not an affected source under this Section and is not subject to the requirements of this Section, provided the owner or operator has filed a certification with the Administrative Authority signed by the Responsible Official of the facility, identifying the EGU and the effective retirement date.

[From Heat Rate Improvements Rule Example 1]

9.4.4.3 Other Affected Entities

In addition to EGUs that are subject to the heat rate standards and associated monitoring, recordkeeping and reporting requirements of the state plan, the state may choose to include certain other parties with particular obligations as affected entities under the program. For example, if the state chooses to establish qualifications or performance criteria for third parties that provide related services to the affected EGUs, such as heat rate audits, identification and execution of heat rate improvement projects, or emissions monitoring and verification, those entities may be subject to registration, quality assurance plan implementation, or other obligations under the state plan. In the case of heat rate improvement standards, however, which are directly measureable and enforceable at the affected EGU, oversight and regulation of third-party service providers may not be necessary.

9.4.5 Mechanisms for Implementing Heat Rate Improvement Standards

The state may consider several different forms for the heat rate standard. Some options are discussed below. Regardless of the form of the standard selected, the state will need to estimate the level of CO_2 reductions available from improvements in heat rate and the timeline along which those reductions would contribute to achieving the state goal. As discussed above, estimating reductions would

395 40 C.F.R. § 60.5850.

require analysis of projected changes in utilization of the EGUs, as well as changes in per-MWh fuel usage.

9.4.5.1 Source-specific Heat Rate Standards (Btu/kWh-net)

One approach for adopting heat rate standards involves setting source-specific standards using a "RACT-type" framework, similar to the approach used by some states for implementing the Reasonably Available Control Technology (RACT) requirements for existing sources in nonattainment areas under Title I of the CAA. Under this approach, the state would rely on available data to set source-specific, reasonably achievable heat rate standards that would be adopted into the state regulation.[396] Each affected EGU would then have the option of either complying with the state-determined heat rate standard, or requesting approval of an alternative standard based on an assessment developed and submitted by the EGU operator. An example of this approach is provided in ***Heat Rate Improvements Rule Example 1.***

9.4.5.2 Flat Heat Rate Standard (Btu/kWh-net)

Another option would be to establish a single heat rate standard, expressed in Btu/kWh, applicable to every affected source, using a net basis for the form of the standard. For example, the state may adopt a regulation requiring every affected EGU to comply with an annual average heat rate of 9,800 Btu/kWh-net. To provide for compliance flexibility, the state could also adopt averaging provisions or credit programs, as discussed in Section 9.4.8.

To simplify the planning process under this approach, the state may choose to collect and rely upon existing available data to set the state heat rate standard. The availability and quality of existing source-specific data may vary from state to state, as well as for different EGUs. Readily available data can assist a state in determining the past performance of individual EGUs, but less information is available to make a determination with regard to the potential for heat rate improvement.[397] If the available dataset is not sufficiently robust, the state may need to rely upon more generalized data, such as engineering studies, literature, or data compiled by EPA as part of the CPP development, to assess what level of heat rate should be achievable for coal-fired EGUs in the state. Alternatively, the state could request or require data to be developed by the owners/operators of affected sources during the state plan development phase to obtain current data on a source-specific basis.

Once the level of the heat rate standard is established, this form of the standard affords a simple implementation approach, avoiding the need to include within the state rule a mechanism to establish and track baseline rates, compute individual EGU heat rate targets, or review, approve and track compliance with site-specific heat rate improvement plans. However, as discussed in Section 9.4.4, many factors impact the technical potential for an EGU to achieve a given heat rate performance. Therefore, establishing a single standard that all affected units can meet, while still assuring a meaningful reduction in CO_2 emissions, may be challenging. The range of achievable heat rate performance among the state fleet may make it necessary to adopt flexible compliance measures, such as averaging, or to establish various exemptions, which increases the complexity of implementation and compliance tracking. ***Heat Rate Improvements Rule Example 2*** provides model language for a flat heat rate standard, including flexible compliance options.

9.4.5.3 Percent Improvement Heat Rate Standard (%)

Another option would be to establish a standard that requires every affected source to improve heat rate performance by a specified percentage from a baseline period. This approach is consistent with the form of BSER Building Block 1. The model rule language in Heat Rate Improvements Rule Examples 3 and 4 follows this approach. As with the flat heat rate standard approach, a provision for averaging among EGUs under common control can provide flexible compliance options for affected sources, to account for differing levels of potential for heat rate improvement among EGUs.

Flat Heat Rate Standard

B. Heat Rate Performance Standard. Effective January 1, 2022, each affected source shall comply with an annual average heat rate performance standard of 9,800 Btu(HHV)/kWh-net. Compliance with the heat rate performance standard shall be demonstrated using one of the compliance options provided in Subsection 104.C of this Section.

[From Heat Rate Improvements Rule Example 2]

396 Some available data sources include the EPA NEEDS database, the Energy Information Administration's Annual Energy Outlook (AEO), utility or commission-developed IRPs, and EPA's CPP Technical Support Documents.

397 Data from EPA's NEEDS database may be used to determine unit-specific past or baseline heat rate performance.

Source-specific Heat Rate Standards

B. Heat Rate Performance Standards. Unless an alternative heat rate standard applies as provided in Paragraph 104.B.1, effective January 1, 2022, each affected source shall comply with the annual average heat rate performance standard specified in Table 1.

[From Heat Rate Improvements Rule Example 1]

Table 1 **Heat Rate Performance Standards for Existing Coal-fired Electric Generating Units**

Affected Source	Station	County	Heat Rate Standard, Annual Average (Btu(HHV)/kWh-net)
Cedar Creek 1	Cedar Creek	Washington	9,800
Cedar Creek 2	Cedar Creek	Washington	10,300
Candy Mountain	Candy Mountain	Hayes	10,100
Whiskey River 25	Candy Mountain	Hayes	9,700
Trojan 1	Odyssey	Homer	10,100
Trojan 2	Odyssey	Homer	9,900
Greek 1	Odyssey	Homer	10,400

9.4.5.4 Case-by-Case Heat Rate Standards (Btu/kWh-net)

Another variation would be a "case-by-case" approach, establishing source-specific heat rate standards for every affected EGU. Under this approach, the degree of improvement and ultimate heat rate performance standard applicable to each affected source would be determined on a case-by-case basis, considering site-specific factors and costs, based on a plan proposed by the owner/operator. This approach would require each affected EGU to undertake a site-specific heat rate audit to assess opportunities for equipment and work practice upgrades. The owner/operator would develop and submit a source-specific heat rate improvement plan based on the results of the audit, with projected aggregate heat rate improvements and associated CO_2 emission reductions. Specific equipment upgrades and work practice improvements considered would either be adopted or would be rejected based on technical feasibility, costs, or other considerations.

The case-by-case plans would require review and approval by an administrative authority, which may be the state air quality permitting authority, the public service commissioner or other entity with regulatory authority over the affected sources. This strategy may afford the greatest degree of flexibility to affected sources and discretion to the administrative authority, but may also involve a more complex regulatory and implementation framework and more time to execute. However, owners or operators of affected sources will ultimately need to conduct the site-specific planning process regardless of the form of the standard selected, and making the planning process an integral part of the program could add greater certainty to the level of CO_2 reductions available from heat rate improvements.

9.4.5.5 Equipment and Work Practice Heat Rate Standards

As a final option, the state planning process may want to consider adopting specific equipment and work practice standards that are designed to optimize heat rate. For example, the state may choose to require the installation and use of Neural Networks control systems for boiler systems, or to set a minimum frequency for control system tune-ups – best practices which EPA characterized as low cost.[398] Similarly, the state may limit the hours of low-load operation by a unit (thereby encouraging EGUs that were designed to be baseload units to operate as such).

One consideration with this approach is that the heat rate gain and cost effectiveness of any particular equipment upgrade or work practice standard is unit-specific. In addition, the compliance and operational flexibility for affected sources is diminished, removing the discretion to select among possible energy efficiency options based on individual source circumstances and needs. Thus, requiring any particular set of heat rate optimization measures

398 EPA TSD, GHG Abatement Measures, *supra* note 387, p. 2-16.

for all affected EGUs is not likely to optimize heat rate reductions or cost effectiveness across the fleet. Another potential concern with this approach is that the direct applicability of the heat rate measure as a simple metric and performance standard is lost, requiring the state to track compliance with and enforce the implementation of a set of individual equipment standards and work practice standards.

9.4.6 Flexible Compliance Options

As previously discussed, one of the potential challenges of reliance on heat rate improvements in the state plan is that the opportunities for heat rate improvement can vary widely from unit to unit and depend on site-specific factors, including the age and design of the EGU and ancillary equipment, the degree to which the owner/operator has made investments in equipment maintenance, upgrades and replacements over time, the sophistication of controls and work practice standards, and several other factors. Moreover, performance will often decline over time following an upgrade and must be monitored, with corrective action plans designed and implemented as needed. Given these concerns, a single standard that applies to all affected units could potentially impose significant compliance risk on some sources, compromise the reliability and availability of electricity, or impact cost of electricity to consumers. Inflexible standards have also been predicted to result in a greater retirement rate of existing units.[399] These potential issues can be avoided or mitigated, however, by providing flexible compliance options within the regulatory framework.

Several types of special provisions incorporating flexible compliance options for heat rate performance standards are included in the ***Heat Rate Improvement Rule Examples.*** Excerpts from the rule examples are presented in the sections below for illustrative purposes; however, the excerpts do not comprise the full provisions. Refer to the rule examples themselves to review the complete set of regulatory language for each provision. Each of the following provisions are discussed in this section:

1) An early action provision for EGUs that achieved significant heat rate improvement before 2012;
2) An excellent performer provision for EGUs that meet and will maintain a specified heat rate level;
3) An excellent performer provision for EGUs that meet and will maintain a specified CO_2 emission rate;
4) A pollution control equipment adjustment provision to avoid penalizing affected sources that install and operate pollution controls for criteria and hazardous air pollutants;
5) A co-firing adjustment provision to account for co-firing a coal unit with waste biomass and natural gas;
6) An extreme conditions provision to address temperature and operating load conditions beyond the control of the EGU operator that adversely affect heat rate; and
7) An EGU group averaging provision to allow heat rate averaging across affected EGUs under common control.

With regard to flexibility provisions that involve averaging and trading, owners and operators of affected EGUs may rely on shifting utilization among units as a compliance mechanism. Some states may wish to require that improvements in average heat rate performance across the affected fleet do not merely arise from shifts in utilization.

9.4.6.1 Accounting for Early Action to Improve Heat Rate

One consideration regarding reliance on improvements in heat rate as measured against a baseline period is that owners and operators of newer coal-fired units and of older units that have already made investments in optimizing heat rate performance are placed at a compliance and economic disadvantage in comparison to owners of older units at which few improvements have been made beyond basic maintenance. As a matter of policy, states will likely want to consider how and whether to recognize heat rate improvements from early action.

In a rule that uses a percent improvement form of the standard, an "early action" provision can address the concern that some owners and operators who acted prior to the CPP baseline to implement heat rate improvement projects would be unfairly penalized if required to obtain the same level of improvement as others who had not acted early. For example, the state may decide to exempt from obtaining further heat rate reductions any EGU that can demonstrate an improvement in heat rate performance over a certain time period and beyond a certain threshold. In this case, the state would need to determine an appropriate level of early action that would warrant exemption from further heat rate reductions. In addition, the state would need to be able to demonstrate attainment of the state CPP

399 Burtraw et al., *supra* note 386.

Early Action Provision

Any affected source for which the owner or operator demonstrates to the satisfaction of the Administrative Authority, no later than June 15, 2018, that the affected source has already achieved, for calendar year 2012 or before, an improvement in heat rate performance of greater than eight percent (8%) from a baseline period of 2004 or later, and that the reduced annual average heat rate of the unit used for the demonstration has been maintained for each year from 2012 forward, may be exempt from the requirement to achieve additional heat rate improvements under this Section, provided the EGU shall be subject to the 2012 annual average heat rate as the applicable annual average heat rate performance standard, as provided in Paragraph D.2 of this Section, in lieu of the standard established in Paragraph D.1 of this Section.

[From Heat Rate Improvements Rule Example 4]

goal without reliance on heat rate improvements from the exempt units. Finally, the state rule would likely require the exempt unit to demonstrate ongoing performance at the heat rate performance level demonstrated during the baseline year or other selected timeframe, to assure the heat rate reductions previously achieved remain intact. Model language for an early action provision is included in ***Heat Rate Improvements Rule Example 4.***

9.4.6.2 Provisions for Excellent Performance

EGUs that already meet an "excellent performance" heat rate level may also warrant certain compliance flexibility options in a state rule that incorporates a heat rate improvement standard (i.e., percentage improvement over a baseline performance). Even where an EGU has not demonstrated the required percent improvement level, if heat rate performance is already excellent and is consistently maintained, it may be unreasonable to require further reductions in heat rate. Again, the state would need to determine the appropriate heat rate level qualifying the source for the alternative standard and to demonstrate attainment of the state CPP goal without reliance on additional improvements from the qualifying EGUs. Model language for an excellent heat rate performance alternative standard is provided in ***Heat Rate Improvements Rule Example 4.***

The state plan may also choose to establish a specific

Alternative Standard for Excellent Performance

Any affected source for which the owner or operator demonstrates to the satisfaction of the Administrative Authority, no later than June 15, 2018, that the affected source has already achieved, for calendar year 2012 or before, an improvement in heat rate performance of greater than two percent (2%) but less than eight percent (8%) from a baseline period of 2004 or later, and that the reduced annual average heat rate of the unit used for the demonstration has been maintained for each year from 2012 forward, may elect to comply with the heat rate performance standard of Paragraph D.3 of this Section in lieu of the heat rate performance standard established in Paragraph D.1 of this Section.

[From Heat Rate Improvements Rule Example 4]

CO_2 lb/MWh-net emission rate as an alternative standard or compliance option available to affected EGUs in lieu of demonstrating compliance with the heat rate standard. Note, however, that any emissions performance rate standard applicable to affected EGUs must be incorporated as a federally enforceable emission standard in the state plan.

Alternative CO_2 Emission Rate Standard

D. Alternative CO_2 Emission Rate Standard. In lieu of complying with the heat rate performance standard of Subsection 104.C, an affected source under this Section may demonstrate compliance, on a calendar year basis, with the CO_2 emission rate standard under Paragraph 104.D.1 or D.2. For purposes of this Section 104, compliance with the CO_2 emission rate standard must be demonstrated based on actual CO_2 emissions and electric output generated by the affected EGU, without the use of any credits or allowances provided for under other Sections of this Chapter.

1. The CO_2 emission rate, expressed in lb CO_2/MWh-net, that is less than or equal to 94% of the CO_2 emission rate achieved during the baseline period; or,
2. 1,300 lb CO_2/MWh-net annual average over the calendar year.

[From Heat Rate Improvements Rule Example 3]

The state would need to determine the appropriate CO_2 emission rate qualifying for the alternative standard and would need to demonstrate that the state's CPP goal could be attained with the alternative standard in place. Model language for an alternative CO_2 emission rate standard is provided in ***Heat Rate Improvements Rule Example 3.***

9.4.6.3 Avoiding Disincentives for Operation of Pollution Control Equipment

Air pollution control equipment designed to reduce emissions of criteria or hazardous air pollutants typically has a negative impact on the net heat rate of power plants.[400] Equipment such as flue gas desulfurization (FGD) for the control of sulfur dioxide (SO_2), electrostatic precipitators (ESP) for the control of particulates, and selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X) all require power to operate. The required power comes from the gross electric output of the resident EGU, imposing a parasitic load on the net electric output that goes to the grid for distribution. Particularly when operating in a market-based compliance environment that provides for the sale and purchase of allowances to demonstrate compliance with SO_2 or NO_X emission limits, the operators of EGUs with pollution control equipment installed may have an economic incentive to shut down or reduce the operating level of control equipment in order to optimize net electric output for sale. That is, it may be more profitable to purchase allowances for criteria pollutant compliance or to operate control equipment just enough to achieve compliance, rather than to operate the pollution control equipment at its maximum control efficiency to outperform the required emission standard and to generate and sell allowances.

The imposition of a heat rate performance standard can potentially exacerbate such a disincentive for the operation of criteria pollutant control equipment, or create a new disincentive to install and operate pollution controls. In state plans that establish a heat rate improvement standard on a net basis (Btu/kWh-net) measured against performance during a baseline period, EGUs that did not have installed or did not fully operate control equipment during the baseline period could be effectively penalized for installing or operating control equipment in future compliance years. Similarly, if a state establishes a flat heat rate performance standard on a net basis, the standard is harder to achieve with pollution control equipment consuming gross electric output. One way to address this concern is to include a provision for adjusting the baseline or compliance year heat rate performance to account for the operation of new pollution controls or existing controls at higher control efficiencies than operated during the baseline period. Rule language to adjust heat rate

Heat Rate Adjustment for Pollution Control Equipment

C. Pollution Control Equipment Net Electric Output Adjustment.

1. If the compliance demonstration made in accordance with Subsection 104.C indicates an exceedance of the applicable heat rate performance standard solely due to auxiliary electric load used to power pollution control equipment, the owner or operator may demonstrate compliance by claiming an adjustment to the net electric output by an amount no greater than the amount of electricity consumed by pollution control equipment during the calendar year.
2. Any claim for net electric output adjustment shall be included in the annual compliance heat rate report. The claim must include:
   a. a calculation of heat rate without the pollution control equipment adjustment;
   b. a calculation of heat rate with the pollution control equipment adjustment;
   c. records of the amount of electricity consumed by the pollution control equipment; and,
   d. records demonstrating the pollution control equipment was being operated and maintained in accordance with good engineering practices.

[From Heat Rate Improvements Rule Example 2]

400 Some studies support this assumption on a unit-by-unit basis, but not as a general conclusion across a category of EGUs. A 2010 NETL study found no discernible difference in heat rate as a result of environmental equipment. A 2014 study by Staudt and Macedonia found the lowest heat rate units are scrubbed and suggested this may be because companies tend to add controls to their best units. This study also found that for individual units that added dry scrubbers, there was fairly consistently an increase in heat rate but not a consistent amount of heat rate increase. James E. Staudt & Jennifer Macedonia, *Evaluation of Heat Rates of Coal Fired Electric Power Boilers,* presented at Power Plant Pollution Control MEGA Symposium, August 19-21, 2014.

performance for operation of pollution control equipment is provided in ***Heat Rate Improvements Rule Example 2.***

9.4.6.4 Credit for Co-firing with Lower- or Zero-carbon Fuels

One method of reducing CO_2 emissions from coal-fired EGUs is to co-fire lower- or zero-carbon fuels, such as natural gas or waste biomass.[401] Although fuel co-firing reduces CO_2 emissions, this practice could lead to an increase in heat rate by reducing the overall efficiency of the steam boiler. Therefore, for state programs that wish to encourage co-firing of natural gas or waste biomass at coal-fired units, compliance flexibility provisions to allow for this approach should be incorporated in the heat rate performance standard.

To account for waste biomass co-firing at an affected EGU, the heat rate compliance demonstration could disregard the heat input associated with the biomass fuel while still counting the full net electric output of the unit. This method essentially treats the waste biomass as a zero-carbon fuel, contributing generation without contributing CO_2 emissions. Similarly, to account for natural gas co-firing at a coal-fired EGU, the heat input contribution from natural gas could be discounted by the natural-gas-to-coal ratio of CO_2 emission factors (kg CO_2/MMBtu) for the two fuels. While neither of these methods will ignore any loss in overall boiler efficiency resulting from co-firing, the adjustments will credit the unit with the reduction in CO_2 emissions per unit of heat input achieved by co-firing, which would partially offset or completely outweigh increases in heat rate due to efficiency losses.

Model language for incorporating this flexible compliance option is provided in ***Heat Rate Improvements Rule Example 2.*** For further discussion of the effects of crediting co-firing, particularly in the context of a market-based GHG reduction program, see research by Resources for the Future.[402]

Adjustment for Co-firing with Low Carbon Fuels

D. Heat Input Adjustment for Co-firing. In determining compliance with the applicable heat rate performance standard of this Section, the owner or operator may adjust the total fuel heat input of the affected EGU or EGU group in accordance with the following equation to account for co-firing of an EGU with natural gas or with qualified waste biomass, as defined in Subsection 104.H:

$$F_{adj} = F_{total} - F_{bio} - 0.555_{FNG}$$

[From Heat Rate Improvements Rule Example 2]

9.4.6.5 Temperature-load Category Standards (Btu/kWh-net or Btu/kWh-gross)

If the state elects to establish a flat heat rate performance standard or source-specific heat rate performance standards expressed in Btu/kWh, one issue that may warrant consideration is the significant effect of ambient temperature and load level on heat rate performance. In evaluating heat rate improvements as an element of BSER under the proposed CPP, EPA noted that a significant portion of observed heat rate variability is driven by ambient temperature and hourly load level (capacity factor).[403] Specifically, EPA's statistical analysis of the dataset for approximately 900 EGUs over a ten-year period revealed that hourly ambient temperature and capacity factor together explain 26% of the variability in observed heat rate. Further, EPA noted that for some EGUs, typically operating in a load-following mode, capacity factor can account for up to 50% of the heat rate variability. Also, for some EGUs, typically with once-through cooling water systems, ambient temperature may account for up to 30% of the change in heat rate, leading to up to a 10% increase in heat rate in summer months.[404] Based on these observations, EPA segregated heat rate performance data into 168 data subsets based on temperature-load categories to control for the temperature-load influence. EPA then evaluated each data subset to assess the potential for improvement in heat rate by reducing heat rate variability (reducing heat rate peaks) through factors that could be controlled through improved work practices.[405]

Thus, while EPA's modeled potential for *improvement* in heat rate is not dependent on temperature or load, it is clear that both of these factors can impact the absolute heat rate achievable by a given EGU. Therefore, the

401 Biomass must be qualified biomass, as required by 40 C.F.R. § 60.5800(d)(1). Restriction of credits for biomass co-firing to qualified waste biomass, as opposed to biomass from energy crops, avoids or minimizes questions related to carbon neutrality of biomass combustion and life-cycle carbon emissions typically associated with biomass from energy crops. In this discussion, all references to biomass are intended to reference qualified waste biomass.

402 Woerman, Matt et al., *The Role of Biomass and Natural Gas Cofiring in GHG Performance Standards,* Resources for the Future, May 7, 2012.

403 79 Fed. Reg. at 34,860.

404 EPA TSD, *GHG Abatement Measures, supra* note 387, p. 2-25.

405 *Ibid.*, pp. 2-30 to 2-31.

significant impact of ambient temperature and load level on heat rate performance may warrant the consideration of setting a different heat rate performance standard for periods exceeding certain temperature-load thresholds, or of including an exemption for periods when the unit is operating in extreme conditions. Establishing a separate, higher heat rate standard for high temperature-load conditions may result in an overall more effective performance standard than setting a single heat rate standard that must be achieved under all conditions, including extremely hot temperatures and high loads. Alternatively, an annual or even multi-year averaging period could take into account a certain amount of time operating under more extreme conditions.

9.4.6.6 Fleet-wide Averaging

One easily incorporated flexible compliance option is to allow for fleet-wide averaging of heat rate performance among affected EGUs owned or operated by the same party. Averaging can be allowed among any self-selected group within the owner's fleet in the geographic region (state or multi-state) where the plan applies. A fleet-wide averaging provision is simple to implement because there are no credits or allowances required. The owner/operator would only need to demonstrate in the annual compliance report that an aggregate heat rate, calculated as the total fuel input divided by the total net electric output across all units included in the average, meets the required performance standard. Model language for incorporating this flexible compliance option is provided in ***Heat Rate Improvements Rule Examples 1, 2, 3 and 4.***

As noted above in the discussion regarding affected sources, states may want to broaden the applicability of heat rate performance standards beyond EPA's application of Building Block 1 to coal-fired steam units. For example, states may choose to set heat rate performance standards for oil-fired units or for NGCC units. Broadening the applicability of this CO_2 reduction measure could help the state achieve the state emission goal while providing greater compliance flexibility to affected sources. If different types of EGUs and fuels are subject to heat rate requirements, fleet-wide averaging would need to address certain concerns. Specifically, both carbon intensity (i.e., CO_2 emissions impact) and heat content (e.g., Btu/scf) differ among fossil fuels; therefore, an equivalent reduction in fuel heat input does not yield an equivalent reduction in CO_2 emissions from one fuel to another. Similarly, EGU technology categories will have differing ranges of heat rate; therefore,

Heat Rate Averaging Provisions

1. **Heat Rate Averaging.** An owner or operator of an affected source may demonstrate compliance by averaging the heat rate performance in a given compliance period across an EGU group and meeting the heat rate performance standard for the EGU group.
   a. EGU groupings may be revised from year to year. An owner or operator may rely upon one or more EGU groups to meet the heat rate performance standard of this Section in any given calendar year.
   b. Each EGU group relied upon for purposes of heat rate averaging shall meet the following criteria:
      i. Each EGU in the EGU group is a coal-fired steam EGU that is an affected source under this Section 104.
      ii. The EGU group is composed of two or more affected sources located within the State and under common control of the same owner or operator. The owner or operator is not required to designate every affected source under his or her common control as part of an EGU group.
      iii. For each affected source included in an EGU group, the total fuel input and total net electric output for the EGU for the entire compliance period must be included in the compliance demonstration for the EGU group.
      iv. No affected source may belong to more than one EGU group in any calendar year.
   c. The EGU group average heat rate performance shall be calculated as a combined annual average heat rate performance for all EGUs in the group, using the following equation:

$$\mathbf{GHR_A = F/Enet}$$

Where:

GHR_A is the EGU Group Average Heat Rate for the calendar year,

F is the total fuel heat input to all EGUs belonging to the EGU group during the calendar year, adjusted in accordance with Subsection 104.D where applicable, expressed in Btu (HHV), and,

Enet is the total net electric output of the EGU group during the compliance period, in kWh.

[From Heat Rate Improvements Rule Example 1]

an equivalent reduction or percent improvement in heat rate will achieve differing CO_2 reduction levels from one EGU technology category to another. Also, different heat rate improvement standards may be established for different fuels or EGU categories. To address these concerns, while still allowing for averaging flexibility across EGU types and fuel types, state regulations could provide for weighted averaging. Alternatively, compliance flexibility with heat rate standards could be restricted to allow averaging only among EGUs subject to the same standard, or using the same fuel.

9.4.7 Heat Rate Improvements Rule Examples

Four examples of regulatory language for incorporating heat rate improvements as an element of the state measures plan are provided on the following pages. The rule examples encompass nearly all of the concepts discussed in this chapter, including several forms of the heat rate standard and most of the exclusions and special provisions presented for consideration. All examples are written in the framework of a state administrative code, with a single state administrative authority (e.g., the Air Administrator) serving as the entity that would implement and enforce the heat rate improvement requirements. It is important to note that the values of the specific standards used in the examples (i.e., six percent improvement, 1,000 lb CO_2/MWh-net), compliance timelines and other rule elements are intended to be examples only and do not represent an endorsement or recommendation of those specific standards.

Table 9.1 **Guide to Heat Rate Improvements Rule Examples**

Rule Example	Form of Heat Rate Performance Standard	Exclusions	Special Provisions	Flexible Compliance Demonstration Options
1	Source-specific Standards (Btu(HHV)/kWh-net)	• EGUs Subject to 40 C.F.R. Part 60, Subpart TTTT • Retiring EGUs	• Case-by-case Alternative Standard	• EGU Group Averaging for EGUs Under Common Control
2	Flat Heat Rate Standard (Btu(HHV)/kWh-net)	• Same as Rule Example 1	• Co-firing of Waste Biomass and Natural Gas • Operation of Pollution Control Equipment	• EGU Group Averaging for EGUs Under Common Control
3	Percent Improvement over Baseline Heat Rate Standard (Btu(HHV)/kWh-net)	• Same as Rule Example 1	• Alternative Baseline Period • CO_2 Emission Rate Alternative Standards	• EGU Group Averaging for EGUs Under Common Control • Heat Rate Credits Based on Excess Net Electric Output • Credit Adjustments for Carbon Neutrality
4	Percent Improvement over Baseline Heat Rate Standard (Btu(HHV)/kWh-net)	• Same as Rule Example 1	• Alternative Baseline Period • Excellent Heat Rate Performance • Early Achievement of > 8% Improvement • Early Achievement of >2% and ≤ 8% Improvement	• EGU Group Averaging for EGUs Under Common Control • Heat Rate Credits Based on Avoided Fuel Usage • Credit Adjustments for Carbon Neutrality

Heat Rate Improvements Rule Example 1
Source-specific Heat Rate Standards

Special Provisions for:

Case-by-Case Alternative Standard

Flexible Compliance Options:

EGU Group Averaging for EGUs Under Common Control

Heat Rate Improvements Rule Example 1
Source-specific Heat Rate Standards

Section 104. Heat Rate Performance Standards for Coal-fired Steam EGUs

A. Applicability.

1. Except as provided in Paragraphs 104.A.2 and 104.A.3 of this Section, an affected source under this Section is each coal-fired steam electric generating unit (EGU), as defined in Subsection 104.H, Definitions, that meets all of the following criteria:
   a. The EGU commenced construction on or before January 8, 2014;
   b. The EGU serves a generator or generators connected to a utility power distribution system with a name-plate capacity greater than 25 MW-net (i.e., capable of selling greater than 25 MW of electricity);
   c. The EGU has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and,
   d. The EGU is not subject to a federally enforceable permit limiting annual net-electric sales to a utility distribution system to one-third or less of its potential electric output or to 219,000 MWh or less.
2. Any coal-fired steam EGU that is subject to 40 CFR part 60 subpart TTTT, either as a result of commencing construction or reconstruction after the subpart TTTT applicability date or as a result of commencing modification or construction prior to becoming subject to this Chapter 1, CO_2 Standards for Existing Electric Utility Generating Units, is not an affected source under this Section and is not subject to the requirements of this Section.
3. Any coal-fired steam EGU with a certified retirement date on or before January 1, 2027, is not an affected source under this Section and is not subject to the requirements of this Section, provided the owner or operator has filed a certification with the Administrative Authority signed by the Responsible Official of the facility, identifying the EGU and the effective retirement date.

B. Heat Rate Performance Standards.

1. Unless an alternative heat rate standard applies as provided in Paragraph 104.B.1, effective January 1, 2020, each affected source shall comply with the annual average heat rate performance standard specified in Table 1.

Heat Rate Improvements Rule Example 1, *continued*
Source-specific Heat Rate Standards

Table 1. **Heat Rate Performance Standards for Coal-fired Existing Electric Generating Units**

Affected Source	Station	County	Heat Rate Standard, Annual Average (Btu(HHV)/kWh-net)
Cedar Creek 1	Cedar Creek	Washington	9,800
Cedar Creek 2	Cedar Creek	Washington	10,300
Candy Mountain	Candy Mountain	Hayes	10,100
Whiskey River 25	Candy Mountain	Hayes	9,700
Trojan 1	Odyssey	Homer	10,100
Trojan 2	Odyssey	Homer	9,900
Greek 1	Odyssey	Homer	10,400
Oak Bend 100	Oak Bend	Adams	9,800
SF Unit 1	Strawberry Fields	Jefferson	10,000
SF Unit 2	Strawberry Fields	Jefferson	9,600
Discovery	First Landing	Harrison	10,000
Constant	First Landing	Harrison	9,500

2. Upon the effective date of an alternative heat rate standard approved by the Administrative Authority for an affected source, the heat rate standard listed in Table 1 shall cease to apply. The heat rate performance standard listed in Table 1 shall continue to apply for the affected source pending review of any request for an alternative standard and until the effective date of an alternative heat rate standard. The Administrative Authority will revise Table 1 to reflect the alternative standard as part of the next rulemaking affecting this Chapter.

C. Alternative Heat Rate Standard. The owner or operator of an affected source may request approval of an alternative heat rate standard based on a demonstration that the affected source cannot reasonably achieve the applicable heat rate standard in Table 1. Requests and approvals of alternative heat rate standards shall be made in accordance with Paragraphs 104.C.1 through C.5.

1. A request for an alternative heat rate standard shall include:
   a. Identifying information for the affected EGU;
   b. A heat rate engineering audit report documenting:
      i. an evaluation of heat rate performance over the last five years;
      ii. an evaluation of maintenance and operating practices and activities for the affected source and ancillary equipment impacting net heat rate;
      iii. an evaluation of potentially available equipment upgrades and replacements, including the technical feasibility, projected level of heat rate improvement, cost, and any other considerations such as environmental and energy impacts;
      iv. an evaluation of improvements to work practices, including routine operations, limitation of part load operation, startup and shutdown procedures, and maintenance plans and schedules, and the potential for heat rate improvement.

Heat Rate Improvements Rule Example 1, *continued*
Source-specific Heat Rate Standards

c. A proposed heat rate improvement plan, specifying:
   i. the basis for rejecting any potentially available equipment upgrades, operational or work practice improvements considered in the audit report;
   ii. the equipment upgrades that will be made and work practices that will be adopted; and,
   iii. the proposed heat rate standard.

2. The Administrative Authority shall review the request and may require any additional information needed to fully evaluate the proposed heat rate improvement plan and proposed heat rate standard. The owner or operator shall respond to any requests for additional information in a reasonable time by a date specified by the Administrative Authority.
3. In reviewing the request for approval of an alternative heat rate standard, the Administrative Authority may require a demonstration that the affected EGU could not reasonably achieve compliance using the heat rate averaging provisions of Subsection 104.D.
4. A 30-day public notice and comment period shall be provided for any preliminary decision to approve an alternative heat rate standard. The request and any additional information provided by the applicant and the preliminary determination made by the Administrative Authority, including the proposed heat rate standard and a basis for decision, shall be made available to the public for review. The Administrative Authority shall consider any germane and timely comments received during the public comment period prior to issuance of a final determination.
5. Final action to approve an alternative heat rate standard shall specify the effective date of the alternative standard and, if the effective date is later than January 1, 2020, a compliance schedule with compliance milestones.

D. Heat Rate Performance Standard Compliance Demonstrations. The owner or operator shall demonstrate compliance with the heat rate performance standard of Subsection 104.B or Subsection 104.C for each affected source in accordance with Paragraph 104.D.1 through Paragraph 104.D.3.

1. Individual Unit Compliance. Demonstrate compliance for an individual affected source under the control of the owner/operator using the following equation:

$$HR_A = F/Enet$$

Where:

HR_A is the Annual Average Heat Rate for the calendar year, for the individual affected source;

F is the total fuel input to the EGU for all fuels used during the calendar year; adjusted in accordance with Subsection 104.D where applicable, expressed in Btu (HHV); and,

Enet is the total net electric output of the EGU during the calendar year, expressed in kWh.

2. Heat Rate Averaging. An owner or operator of an affected source may demonstrate compliance by averaging the heat rate performance in a given calendar year across an EGU group and meeting the heat rate performance standard for the EGU group.
   a. EGU groupings may be revised from year to year. An owner or operator may rely upon one or more EGU groups to meet the heat rate performance standard of this Section in any given calendar year.
   b. Each EGU group relied upon for purposes of heat rate averaging shall meet the following criteria:
      i. Each EGU in the EGU group is a coal-fired steam EGU that is an affected source under this Section 104.
      ii. The EGU group is composed of two or more affected sources located within the State and under common control of the same owner or operator. The owner or operator is not required to designate every affected source under his or her common control as part of an EGU group.

Heat Rate Improvements Rule Example 1, *continued*
Source-specific Heat Rate Standards

iii. For each affected source included in an EGU group, the total fuel input and total net electric output for the EGU for the entire year must be included in the compliance demonstration for the EGU group.

iv. No affected source may belong to more than one EGU group in any calendar year.

c. The EGU group average heat rate performance shall be calculated as a combined annual average heat rate performance for all EGUs in the group, using the following equation:

$$\mathbf{GHR_A = F/Enet}$$

Where:

GHR_A is the EGU Group Average Heat Rate for the calendar year,

F is the total fuel heat input to all EGUs belonging to the EGU group during the calendar year, adjusted in accordance with Subsection 104.D where applicable, expressed in Btu (HHV), and,

Enet is the total net electric output of the EGU group during the calendar year, expressed in kWh.

3. Where multiple affected EGUs are under common control of the same owner or operator, the owner or operator may elect to use the individual unit compliance option for one or more affected EGUs and the heat rate averaging compliance option for two or more other affected EGUs, provided compliance is demonstrated for each affected source.

E. Monitoring and Recordkeeping Requirements.

1. For each affected source under this Section 104, the owner/operator shall monitor and record the following information:
   a. Hourly heat input, in MMBtu/hr, for every hour or part of an hour any fuel is combusted, following the procedures in 40 CFR part 75, Appendix F;
   b. The type of fuel used by the EGU, including coal rank, on an hourly basis;
   c. Hourly gross electric output, in kWh;
   d. The amount of electricity used to operate the plant (i.e., auxiliary loads) on an hourly basis, including fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., point of sale);
   e. Where necessary, the allocation of auxiliary loads for the plant among individual affected sources at the plant; and,
   f. Hourly net electric output, in kWh-net.
2. Monitoring and recordkeeping in accordance with 40 CFR § 60.5860 and 40 CFR § 60.5865, as adopted under Section 102, General Requirements for Affected EGUs, of this Chapter, shall serve to meet the monitoring and recordkeeping requirement for the same parameters under this Section 104.

F. Annual Heat Rate Compliance Report. Beginning in calendar year 2023, no later than March 15 of each year, each owner/operator of an affected source under this Section 104 shall submit an annual compliance report demonstrating compliance for the preceding calendar year. The annual compliance report shall include the following information:

1. A list of all affected sources under this Section owned and/or operated by the owner/operator, with an explanation of any changes in the list of affected sources from the preceding calendar year.
2. For each affected source, the compliance option selected, and supporting data and calculations relied upon to demonstrate compliance, including:

Heat Rate Improvements Rule Example 1, *continued*
Source-specific Heat Rate Standards

a. Total fuel usage, with adjustments for co-firing qualified waste biomass and natural gas if applicable;
b. Total gross electric output;
c. Total auxiliary load electricity required to operate the plant, with allocations to individual affected sources if applicable;
d. Total net electric output;
e. Documentation of any EGU group(s), if applicable; and,
f. Annual average heat rate.

G. Definitions. For the purpose of this Section, all terms not defined herein shall have the meaning given to identical terms as provided in Section 101 of this Chapter.

1. ***Coal*** means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are included in this definition for the purposes of this Chapter.
2. ***Coal-fired steam electric generating unit*** means a steam electric generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount. For purposes of this Chapter, the term coal-fired steam generating unit includes pulverized coal combustion (PCC), fluidized bed combustion (FBC), cyclone furnace combustion, and stoker-fired coal combustion units.
3. ***Coal refuse*** means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g., culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.
4. ***Heat rate*** means the amount of fuel energy input utilized by an EGU to produce 1 kWh of net electric output. For purposes of this Chapter, heat rate is expressed in Btu(HHV)/kWh-net.
5. ***Net electric output*** means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbines, combustion turbines, and gas expanders), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale). For cogeneration EGUs, net electric output includes useful thermal energy equivalents.
6. ***Steam electric generating unit*** means any furnace, boiler, or other device used for combusting fuel and producing steam, other than nuclear steam generators, plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.
7. ***Qualified waste biomass*** means fuel derived from waste biological matter, including forest residue or slash, pulp and paper mill residue, wood chips, yard waste, agricultural waste and municipal waste, from a source approved by the Administrative Authority as provided under Section 100 of this Chapter. Waste biomass does not include fuel derived from crops grown for the production of energy.

Heat Rate Improvements Rule Example 2
Flat Heat Rate Standards

Special Provisions for:

Near-term Retiring EGUs

Co-firing of Qualified Waste Biomass and Natural Gas

Operation of Pollution Control Equipment

Flexible Compliance Options:

EGU Group Averaging for EGUs Under Common Control

Heat Rate Improvements Rule Example 2
Flat Heat Rate Standards

Section 104. Heat Rate Performance Standards for Coal-fired Steam EGUs

A. Applicability. *(See Heat Rate Improvements Rule Example 1)*

B. Heat Rate Performance Standard. Effective January 1, 2022, each affected source shall comply with an annual average heat rate performance standard of 9,800 Btu(HHV)/kWh-net. Compliance with the heat rate performance standard shall be demonstrated using one of the compliance options provided in Subsection 104.C of this Section.

C. Heat Rate Performance Standard Compliance Demonstrations. *(See Heat Rate Improvements Rule Example 1)*

D. Heat Input Adjustment for Co-firing. In determining compliance with the applicable heat rate performance standard of this Section, the owner or operator may adjust the total fuel heat input of the affected EGU or EGU group in accordance the following equation to account for co-firing of an EGU with natural gas or with qualified waste biomass, as defined in Subsection 104.H:

$$F_{adj} = F_{total} - F_{bio} - 0.555F_{NG}$$

Where:

F_{adj} is the adjusted total fuel heat input for the EGU (or EGU group, if applicable) during the calendar year, expressed in Btu (HHV);

F_{total} is the total fuel heat input to the EGU (or to all EGUs belonging to the EGU group, if applicable) during the calendar year, expressed in Btu (HHV);

F_{bio} is the total fuel heat input from qualified waste biomass to the EGU (or to all EGUs belonging to the EGU group, if applicable) during the calendar year, expressed in Btu (HHV);

0.555 is a constant representing the ratio of CO2 emissions derived from combusting natural gas to the CO2 emissions derived from combusting coal on a heat input basis; and,

F_{NG} is the total fuel heat input from natural gas to the EGU (or to all EGU belonging to the EGU group, if applicable) during the calendar year, expressed in Btu (HHV).

E. Pollution Control Equipment Net Electric Output Adjustment.

1. If the compliance demonstration made in accordance with Subsection 104.C indicates an exceedance of the applicable heat rate performance standard solely due to auxiliary electric load used to power pollution control equipment, the owner or operator may demonstrate compliance by claiming an adjustment to the net electric output by an amount no greater than the amount of electricity consumed by pollution control equipment during the calendar year.

Heat Rate Improvements Rule Example 2, *continued*
Flat Heat Rate Standards

2. Any claim for net electric output adjustment shall be included in the annual compliance heat rate report. The claim must include:
   a. a calculation of heat rate without the pollution control equipment adjustment;
   b. a calculation of heat rate with the pollution control equipment adjustment;
   c. records of the amount of electricity consumed by the pollution control equipment; and,
   d. records demonstrating the pollution control equipment was being operated and maintained in accordance with good engineering practices.
3. Any EGU for which compliance is demonstrated by claiming pollution control equipment net electric output adjustment cannot be included in an EGU group for heat rate averaging for that calendar year.

F. Monitoring and Recordkeeping Requirements. *(See Heat Rate Improvements Rule Example 1)*

G. Annual Heat Rate Compliance Report. Beginning in calendar year 2023, no later than March 15 of each year, each owner/operator of an affected source under this Section 104 shall submit an annual compliance report demonstrating compliance for the preceding calendar year. The annual compliance report shall include the following information:

1. A list of all affected sources under this Section owned and/or operated by the owner/operator, with an explanation of any changes in the list of affected sources from the preceding calendar year.
2. For each affected source, the compliance option selected, and supporting data and calculations relied upon to demonstrate compliance, including:
   a. Total fuel usage, with adjustments for co-firing qualified waste biomass and natural gas if applicable;
   b. Total gross electric output;
   c. Total auxiliary load electricity required to operate the plant, with allocations to individual affected sources if applicable;
   d. Total net electric output;
   e. Documentation of any EGU group(s), if applicable; and,
   f. Annual average heat rate.

H. Definitions. *(See Heat Rate Improvements Rule Example 1)*

Heat Rate Improvements Rule Example 3
Percent Improvement over Baseline Heat Rate Standard (1)

Special Provisions for:

Alternative Baseline Period

CO_2 Emission Rate Alternative Standards

Flexible Compliance Options:

EGU Group Averaging for EGUs Under Common Control

Heat Rate Credits Based on Excess Net Electric Output

Credit Adjustments for Carbon Neutrality

Heat Rate Improvements Rule Example 3
Percent Improvement over Baseline Heat Rate Standard (1)

Section 104. Heat Rate Performance Standards for Coal-fired Steam EGUs

A. Applicability. *(See Heat Rate Improvements Rule Example 1)*

B. Baseline heat rate determination.

1. No later than June 15, 2019, the owner or operator of each affected source shall determine the baseline heat rate of the affected source, in accordance with Paragraphs 104.B.2 through B.6 of this Section.
2. The baseline heat rate shall be the annual average heat rate, as defined in Subsection J of this Section, for the baseline period, expressed in Btu(HHV)/kWh-net.
3. The baseline period shall be calendar year 2012, unless a different consecutive twelve-month baseline period is approved for an affected source by the Administrative Authority. Requests for approval of a different baseline period must be submitted no later than January 31, 2018. In making a determination to approve a different baseline period, the owner or operator of the affected source shall demonstrate, and the Administrative Authority shall consider, whether the proposed baseline period is more representative of the normal operating conditions for the affected source, based on the following factors:
   a. Utilization pattern of the affected source;
   b. Fuel mix for the affected source; and,
   c. Conditions influencing parasitic loads affecting net electric output.
4. An annual average baseline heat rate performance value shall be calculated for each affected source using the following equation:

$$\mathbf{BHR_A = F/Enet}$$

Where:

BHR_A is the Average Baseline Heat Rate for the EGU for the baseline period;

F is the total fuel input to the EGU during the baseline period, expressed in Btu(HHV); and,

Enet is the total net electric output of the EGU during the baseline period, expressed in kWh.

C. Heat Rate Performance Standard. Effective January 1, 2022, each affected source shall achieve an annual average heat rate, on a calendar year basis, that is less than or equal to 94% of the annual average baseline heat rate for the affected source, unless compliance with the alternative emission rate standard of Subsection 104.D is demonstrated. Compliance with the heat rate performance standard of this Subsection 104.C shall be demonstrated using one of the compliance options provided in Subsection 104.E of this Section.

Heat Rate Improvements Rule Example 3, *continued*
Percent Improvement over Baseline Heat Rate Standard (1)

D. Alternative CO_2 Emission Rate Standard. In lieu of complying with the heat rate performance standard of Subsection 104.C, an affected source under this Section may demonstrate compliance, on a calendar year basis, with the CO_2 emission rate standard under Paragraph 104.D.1 or D.2. For purposes of this Section 104, compliance with the CO_2 emission rate standard must be demonstrated based on actual CO_2 emissions and electric output generated by the affected EGU, without the use of any credits or allowances provided for under other Sections of this Chapter.

1. The CO_2 emission rate, expressed in lb CO_2/MWh-net, that is less than or equal to 94% of the CO_2 emission rate achieved during the baseline period; or,
2. 1,300 lb CO_2/MWh-net annual average over the calendar year.

E. Heat Rate Performance Standard Compliance Demonstrations. The owner or operator shall demonstrate compliance with the heat rate performance standard of Subsection 104.C for each affected source in accordance with Paragraphs 104.E.1 through 104.E.4.

1. Individual Unit Compliance. Demonstrate compliance for an individual affected source using the following equation:

$$\mathbf{HR_A = F/Enet}$$

Where:

HR_A is the Annual Average Heat Rate for the calendar year, for the individual affected source;

F is the total fuel input to the EGU for all fuels used during the calendar year, adjusted in accordance with Subsection 104.D where applicable, expressed in Btu (HHV); and,

Enet is the total net electric output of the EGU during the calendar year, expressed in kWh.

2. Heat Rate Averaging. An owner or operator of an affected source may demonstrate compliance by averaging the heat rate performance in a given calendar year across an EGU group and meeting the EGU group heat rate performance standard.
   a. The EGU group annual average heat rate performance standard shall be the annual average heat rate, on a calendar year basis, that is equal to 94% of the generation-weighted average baseline heat rate for all EGUs in the EGU group.
   b. EGU groupings may be revised from year to year. An owner or operator may rely upon one or more EGU groups to meet the heat rate performance standards of this Section in any given calendar year.
   c. Each EGU group relied upon for purposes of heat rate averaging shall meet the following criteria:
      i. Each EGU in the group is a coal-fired steam EGU that is an affected source under this Section 104.
      ii. The EGU group is composed of two or more affected sources located within the State and under common control of the same owner or operator. The owner or operator is not required to designate every affected source under his or her common control as part of an EGU group.
      iii. For each affected source included in an EGU group, the total fuel input and total net electric output for the EGU for the entire year must be included in the compliance demonstration for the EGU group.
      iv. No affected source may belong to more than one EGU group in any calendar year.
      v. An affected source complying with alternative CO_2 emission rate standard of Paragraph 104.D shall not be included as part of an EGU group.

Heat Rate Improvements Rule Example 3, *continued*
Percent Improvement over Baseline Heat Rate Standard (1)

d. The EGU group average baseline heat rate and the EGU group average heat rate performance shall be calculated as a combined annual average heat rate performance for all EGU in the group, using the following equation:

$$GHR_A = F/Enet$$

Where:

GHR_A is the Average Group Heat Rate for the baseline period or calendar year, as applicable;

F is the total fuel input to all EGUs belonging to the EGU group during the baseline period or calendar year, as applicable, expressed in Btu(HHV); and,

Enet is the total net electric output of the EGU group during the baseline period or calendar year, as applicable, expressed in kWh.

3. Where multiple affected EGUs are under common control of the same owner or operator, the owner or operator may elect to use the individual unit compliance option for one or more affected EGUs and the heat rate averaging compliance option for two or more other affected EGUs, provided compliance is demonstrated for each affected source.
4. Heat Rate Credits. An owner or operator of an affected source may demonstrate compliance through the use of heat rate credits obtained from another owner or operator of an affected EGU located within the State, in accordance with Subsection 104.F. Heat rate credits, expressed as kWh, may be applied to an individual affected source or to an EGU group by adding the adjusted heat rate credit to the total net electric output of the source or group.

F. Generation of Heat Rate Credits.

1. The owner/operator of an affected source with a heat rate performance better than the required heat rate performance applicable to that affected source under Subsection 104.C may utilize the excess net electric output, expressed in kWh, as heat rate credits. Heat rate credits may be generated by an individual EGU or by an EGU group, except as provided in Paragraph 104.F.2.
2. Heat rate credits may not be generated by an affected source complying with an alternative CO_2 emission rate standard under Paragraph 104.D.
3. Heat rate credits are generated on a calendar year basis and are viable for the calendar year in which they are generated or for the following calendar year. Once used, heat rate credits are expired and cannot be reused.
4. The amount of heat rate credits available for transfer generated by an affected source shall be calculated as follows:
   a. Determine the minimum net electric output needed for the affected source or EGU group to meet the applicable annual average heat rate performance standard, using the following equation:

$$Enet_{MIN} = F/HR_A$$

Where:

$Enet_{MIN}$ is the minimum net electric output required during the calendar year to meet the annual average heat rate performance standard, expressed in kWh-net;

F is the total fuel input to the EGU or EGU group during the calendar year, expressed in Btu (HHV); and,

HR_A is the applicable Heat Rate performance standard for the individual EGU or the EGU group (i.e., equal to 94% of the annual average baseline heat rate performance value for an individual EGU, and equal to 94% of the generation-weighted annual average baseline heat rate for all EGUs in the EGU group).

Heat Rate Improvements Rule Example 3, *continued*
Percent Improvement over Baseline Heat Rate Standard (1)

b. Subtract the $Enet_{MIN}$ from the actual net electric output of the affected source or EGU group for the calendar year to determine the excess net electric output, $Enet_{Exc}$, available for use as heat rate credits.

5. Any excess net electric output utilized as heat rate credits under this Section 104 shall not be used, transferred or sold as credits or offsets of any type for any other purpose under this Chapter 1, CO_2 Reductions from Existing Electric Utility Generating Units in the State, or for the same or similar purposes under any other State plan adopted pursuant to 40 CFR part 60 subpart UUUU.
6. A certificate of heat rate credit transfer, signed by the Responsible Official of the affected source generating the heat rate credits, must be provided as part of the annual heat rate compliance report by the owner/operator relying upon the credits. The certificate must identify the EGU generating the credit, provide the amount of credits transferred together with supporting calculations demonstrating how the amount of available credits was determined, document the heat rate performance standard applicable to the EGU generating the credit, and identify the type of fuel (including coal rank) used by the generating EGU during the period in which the credits were generated.

G. Transfer and Use of Heat Rate Credits.

1. A certificate of heat rate credit generation and transfer, signed by the Responsible Official of the affected source generating the heat rate credits, must be provided as part of the annual heat rate compliance report by the owner or operator relying upon the credits. In addition, a copy of the certificate must be provided as part of the annual heat rate compliance report by the owner or operator generating and/or transferring the heat rate credits.
2. Heat rate credits shall be adjusted upon use to account for the type of fuel consumed by the affected source that generated the credits and the type of fuel consumed by the affected source relying on the credits for compliance. In addition, heat rate credits shall be adjusted upon use to account for the difference between the heat rate performance standard applicable to the affected source that generated the credits and the heat rate performance standard applicable to the affected source relying on the credits for compliance. The adjustments shall be made using the following equation:

$$\mathbf{Enet_{Exc\ Adj} = Enet_{Exc\ Tr}\ (HR_{Gen}/HR_{User})(EF_{User}\ /\ EF_{Gen})}$$

Where:

$Enet_{Exc\ Adj}$ is the adjusted heat rate credit available for use by the EGU relying on the credits, expressed in kWh-net;

$Enet_{Exc\ Tr}$ is the unadjusted heat rate credit as transferred from the EGU generating the credits, expressed in kWh-net;

HR_{Gen} is the heat rate performance standard applicable to the EGU generating the credits, expressed in Btu/kWh-net;

HR_{User} is the heat rate performance standard applicable to the EGU or EGU Group relying on the credits, expressed in Btu/kWh-net;

EF_{User} is the CO_2 emission factor for the fuel used by the EGU relying on the credit, during the calendar for which the credit is being applied, as obtained from 40 CFR part 98 subpart C, Table C.1. If multiple fuels were used, a generation-weighted average emission factor shall be used;

EF_{Gen} is the CO_2 emission factor for the fuel used by the EGU that generated the credit, during the calendar for which the credit is being applied, as obtained from 40 CFR part 98, subpart C Table C.1. If multiple fuels were used, a generation-weighted average emission factor shall be used.

Heat Rate Improvements Rule Example 3, *continued*
Percent Improvement over Baseline Heat Rate Standard (1)

3. If heat rate credits are utilized to demonstrate compliance for an EGU Group and multiple fuels were used by the group, then the credits shall be adjusted as provided in Paragraph 104.G.2, except that the term EF_{User} shall be the generation-weighted emission factor for all fuels used by any EGU in the group.

H. Monitoring and Recordkeeping Requirements. *(See Heat Rate Improvements Rule Example 1)*

I. Compliance Reporting.

1. Baseline report. No later than June 15, 2019, each owner/operator of an affected source under this Section shall submit a baseline report including the following information:
   a. A list of all affected sources under this Section under the control of the owner/operator.
   b. Documentation of the annual average baseline heat rate value for each affected source. Such documentation shall include the type of fuel, total fuel usage (Btu, HHV), total gross electric output (kWh), total parasitic load (kWh), the consumers of the parasitic load and amount used by each (kWh), and total net electric output.
   c. If the baseline year is not calendar year 2012 for any affected source, documentation of the approved baseline period and of prior approval by the Administrative Authority for the baseline period utilized.
   d. Supporting calculations for all baseline heat values reported, using the equations specified in Paragraph 104.B.4.
2. Annual Heat Rate Compliance Report. Beginning in calendar year 2023, no later than March 15 of each year, each owner/operator of an affected source under this Section 104 shall submit an annual compliance report demonstrating compliance for the preceding calendar year. The annual compliance report shall include the following information:
   a. A list of all affected sources under this Section owned and/or operated by the owner/operator, with an explanation of any changes in the list of affected sources from the preceding calendar year or, for calendar year 2020, from the baseline report.
   b. For each affected source complying with the heat rate performance standard of Paragraph 104.C, the applicable baseline heat rate, the applicable heat rate performance standard, the compliance option(s) selected, and supporting data and calculations relied upon to demonstrate compliance, including:
      i. Total fuel usage;
      ii. Total gross electric output;
      iii. Total electricity required to operate the plant, with allocations to individual affected sources if applicable;
      iv. Documentation of any EGU group(s), if applicable;
      v. Annual average heat rate or category heat rates, as applicable;
      vi. Records of any heat rate credits relied upon for the calendar year; and,
      vii. Documentation of any heat rate credits generated with supporting data and calculations and documentation of the transfer of any heat rate credits.
   c. For each affected source complying with the alternative CO_2 emission rate standard of Paragraph 104.D, the applicable baseline CO_2 emission rate, with supporting documentation, and supporting data and calculations relied upon to demonstrate compliance with the CO_2 emission rate standard of Paragraph 104.D.1 or D.2.

J. Definitions. *(See Heat Rate Improvements Rule Example 1)*

Heat Rate Improvements Rule Example 4
Percent Improvement over Baseline Heat Rate Standard (2)

Special Provisions for:

Alternative Baseline Period
Excellent Heat Rate Performance
Early Achievement of > 8% Improvement
Early Achievement of >2% and ≤ 8% Improvement

Flexible Compliance Options:

EGU Group Averaging for EGUs under Common Control
Heat Rate Credits Based on Excess Net Electric Output
Credit Adjustments for Carbon Neutrality

Heat Rate Improvements Rule Example 4
Percent Improvement over Baseline Heat Rate Standard (2)

Section 104. Heat Rate Performance Standards for Coal-fired Steam EGUs

A. Applicability. *(See Heat Rate Improvements Rule Example 1)*

B. Exemptions Subject to Alternative Standards.

1. Any affected source for which the owner or operator demonstrates to the satisfaction of the Administrative Authority, no later than June 15, 2018, that the annual average heat rate of the unit is less than or equal to 9,800 Btu/kWh-net for calendar year 2017 or earlier, may be exempt from the requirement to achieve additional heat rate improvements under this Section provided the EGU shall be subject to the heat rate performance standard of Paragraph D.2 of this Section in lieu of the heat rate performance standard established in Paragraph D.1 of this Section.
2. Any affected source for which the owner or operator demonstrates to the satisfaction of the Administrative Authority, no later than June 15, 2018, that the affected source has already achieved, for calendar year 2012 or before, an improvement in heat rate performance of greater than eight percent (8%) from a baseline period of 2004 or later, and that the reduced annual average heat rate of the unit used for the demonstration has been maintained for each year from 2012 forward, may be exempt from the requirement to achieve additional heat rate improvements under this Section, provided the EGU shall be subject to the 2012 annual average heat rate as the applicable annual average heat rate performance standard, as provided in Paragraph D.2 of this Section, in lieu of the standard established in Paragraph D.1 of this Section.
3. Any affected source for which the owner or operator demonstrates to the satisfaction of the Administrative Authority, no later than June 15, 2018, that the affected source has already achieved, for calendar year 2012 or before, an improvement in heat rate performance of greater than two percent (2%) but less than eight percent (8%) from a baseline period of 2004 or later, and that the reduced annual average heat rate of the unit used for the demonstration has been maintained for each year from 2012 forward, may elect to comply with the heat rate performance standard of Paragraph D.3 of this Section in lieu of the heat rate performance standard established in Paragraph D.1 of this Section.

C. Baseline Heat Rate Determination. *(See Heat Rate Improvements Rule Example 3)*

Heat Rate Improvements Rule Example 4, *continued*
Percent Improvement over Baseline Heat Rate Standard (2)

D. Heat Rate Performance Standards. Effective January 1, 2022, each affected source shall comply with the heat rate performance standard as specified in Paragraphs 104.D.1 through Paragraph 104.D.4.

1. Unless subject to an alternative heat rate performance standard under Paragraphs 104.B.1 through 104.B.3, each affected source shall achieve an annual average heat rate, on a calendar year basis, that is less than or equal to 94% of the annual average baseline heat rate performance for the affected source.
2. For any affected source that has been granted an exemption pursuant to Paragraph 104.B.1, based on a demonstrated heat rate performance less than or equal to 9,800 Btu/kWh-net, the applicable heat rate performance standard under this Section 104 shall be 9,800 Btu/kWh-net.
3. For any affected source that has been granted an exemption pursuant to Paragraph 104.B.2, based on demonstrated early action to achieve and maintain heat rate improvement of eight percent or greater, the 2012 annual average heat rate as approved by the Administrative Authority shall be the applicable annual average heat rate performance standard under this Section 104.
4. Each affected source that has demonstrated, to the satisfaction of the Administrative Authority, pursuant to Paragraph 104.B.3, early action to achieve and maintain a heat rate improvement of greater than two percent (2%) but less than eight percent (8%), shall achieve an annual average heat rate, on a calendar year basis, that is less than or equal to 97% of the annual average baseline heat rate performance for the affected source. For purposes of this paragraph, the baseline period is the early action baseline period as established pursuant to Paragraph 104.B.3.

E. Heat Rate Performance Standard Compliance Demonstrations. *(See Heat Rate Improvements Rule Example 3)*

F. Generation of Heat Rate Credits.

1. The owner/operator of an affected source with a heat rate performance better than the required heat rate performance applicable to that affected source under Subsection 104.C may utilize the avoided fuel usage, expressed in Btu, as heat rate credits. Heat rate credits may be generated by an individual EGU or by an EGU group, except as provided in Paragraph 104.F.2.
2. Heat rate credits may not be generated by an affected source complying with an alternative CO_2 emission rate standard under Paragraph 104.B.1 through B.3., or by an EGU group that includes such an EGU.
3. Heat rate credits are generated on a calendar year basis and are viable for the calendar year in which they are generated or for the following year. Once used, heat rate credits are expired and cannot be reused.
4. The amount of heat rate credits available for transfer generated by an affected source shall be calculated as follows:
   a. Determine the maximum fuel usage allowed for the affected source to meet the applicable annual average heat rate performance standard, using the following equation:

$$\mathbf{F_{Max} = HR_A / Enet_{Actual}}$$

Where:

$\mathbf{F_{Max}}$ is the maximum fuel input to the EGU during the calendar year that could have been consumed to meet the annual average heat rate performance standard, expressed in Btu (HHV);

$\mathbf{HR_A}$ is the applicable heat rate performance standard for the affected source; and,

$\mathbf{Enet_{Actual}}$ is the actual net electric output generated during the calendar year, expressed in kWh-net.

   b. Subtract the FMax from the actual fuel usage of the affected source for the calendar year to determine the avoided fuel, in Btu, available for use as heat rate credits.

Heat Rate Improvements Rule Example 4, *continued*
Percent Improvement over Baseline Heat Rate Standard (2)

5. Any fuel savings or energy efficiency gains utilized as heat rate credits under this Section 104 shall not be used, transferred, or sold as credits or offsets of any type for any other purpose under this Chapter 1, CO_2 Reductions from Existing Electric Utility Generating Units in the State, or for the same or similar purposes under any other State plan adopted pursuant to 40 CFR part 60 subpart UUUU.
6. A certificate of heat rate credit transfer, signed by the Responsible Official of the affected source generating the heat rate credits, must be provided to the owner/operator of the EGU relying on the credits for demonstrating compliance with the heat rate performance standards of this Section. The certificate must identify the EGU generating the credit, provide the amount of credits transferred together with supporting calculations demonstrating how the amount of available credits was determined, and identify the type of fuel used by the generating EGU during the period in which the credits were generated.

G. Transfer and Use of Heat Rate Credits.

1. A certificate of heat rate credit transfer, signed by the Responsible Official of the affected source generating the heat rate credits, must be provided as part of the annual heat rate compliance report by the owner/operator relying upon the credits.
2. Heat rate credits shall be adjusted upon use to account for the type of fuel consumed by the affected source that generated the credits and the type of fuel consumed by the affected source relying on the credits for compliance. The adjustment shall be made using the following equation:

$$F_{Adj} = F_{Tr} (EF_{User} / EF_{Gen})$$

Where:

F_{Adj} is the adjusted heat rate credit available for use by the EGU relying on the credits, expressed in Btu (HHV);

F_{Tr} is the unadjusted heat rate credit as transferred from the EGU generating the credits, expressed in Btu (HHV);

EF_{User} is the CO_2 emission factor for the fuel used by the EGU relying on the credits, during the calendar for which the credit is being applied, as obtained from 40 CFR part 98 subpart C, Table C.1. If multiple fuels were used, a generation-weighted average emission factor shall be used;

EF_{Gen} is the CO_2 emission factor for the fuel used by the EGU that generated the credit, during the calendar year for which the credit is being applied, as obtained from 40 CFR 98 subpart C, Table C.1. If multiple fuels were used, a generation-weighted average emission factor shall be used.

3. If heat rate credits are utilized to demonstrate compliance for an EGU group and multiple fuels were used by the group, then the credits shall be adjusted as provided in Paragraph 104.G.2, except that the term EFUser shall be the generation-weighted emission factor for all fuels used by the EGUs in the group.

H. Monitoring and Recordkeeping Requirements. *(See Heat Rate Improvements Rule Example 1)*

I. Compliance Reporting.

1. Baseline report. No later than March 15, 2017, each owner/operator of an affected source under this Section shall submit a baseline report including the following information:
   a. A list of all affected sources under this Section under the control of the owner/operator.
   b. Documentation of the annual average baseline heat rate, for each affected source. Such documentation shall include the type of fuel, total fuel usage (Btu, HHV), total gross electric output (kWh), total parasitic load (kWh), the consumers of the parasitic load and amount used by each (kWh), and total net electric output.

Heat Rate Improvements Rule Example 4, *continued*
Percent Improvement over Baseline Heat Rate Standard (2)

c. If the baseline year is not calendar year 2012 for any affected source, documentation of the approved baseline period and of prior approval by the Administrative Authority for the baseline period utilized.
d If the baseline year is an alternative early action baseline year as provided in Paragraph B.4 of this Section, documentation of the early heat rate improvements demonstrated and documentation of the heat rate achieved for each year from 2012 to 2016.
e. Supporting calculations for all baseline heat values reported, using the equations specified in Paragraphs 104.B.5 and 6.

2. Annual Heat Rate Compliance Report. Beginning in calendar year 2021, no later than March 15 of each year, each owner/operator of an affected source under this Section 104 shall submit an annual compliance report demonstrating compliance for the preceding calendar year. The annual compliance report shall include the following information:
   a. A list of all affected sources under this Section owned and/or operated by the owner/operator, with an explanation of any changes in the list of affected sources from the preceding calendar year or, for calendar year 2020, from the baseline report.
   b. For each affected source, the applicable baseline heat rate, the applicable heat rate performance standard, the compliance option(s) selected, and supporting data and calculations relied upon to demonstrate compliance, including:
      i. Total fuel usage;
      ii. Total gross electric output;
      iii. Total electricity required to operate the plant, with allocations to individual affected sources if applicable;
      iv. Documentation of any EGU group(s), if applicable;
      v. Annual average heat rate; and,
      vi. Records of any heat rate credits relied upon for the calendar year, including a copy of the certificate of transfer and documentation of credit adjustments as required pursuant to Paragraphs 104.F.2 and F.3.
   c. For each affected source, documentation of any heat rate credits generated with supporting data, including calculations and documentation of the transfer of any heat rate credits.

J. Definitions. *(See Heat Rate Improvements Rule Example 1)*

9.5 Generation Shift to Existing NGCC EGUs

9.5.1 Overview of Generation Shift

Generation shift, or dispatch changes, refers to shifting the level of utilization among the electric generating units in the fleet, while still achieving the total generation required to meet the electricity demand (often referred to as "load"). Generation shifting from higher CO_2-emitting fossil fuel-fired EGUs—in particular, from pulverized coal steam EGUs and oil and gas steam EGUs—to existing NGCC EGUs comprises Building Block 2 of BSER, and will likely be a key reduction strategy for many states. A clear trend in generation shift to existing NGCC units is apparent over the last several years, with NGCC generation increasing 83% from 2005 to 2012, and this trend will likely continue even without CPP requirements.[406] States that adopt a state measures plan will likely want to build on this trend by including generation shift provisions as a reduction strategy in the state plan, to assure that utilization of existing NGCC units occurs as envisioned under BSER and to the greatest extent feasible. Furthermore, because a state measures plan is a mass-based plan, the plan must address leakage.[407] Plan provisions assuring or incentivizing generation shift from coal and oil EGUs to existing NGCC units can therefore serve a dual purpose in a state measures plan, both by providing CO_2 emission reductions and by mitigating the deployment of new NGCC units preferentially over utilization of existing NGCC units.

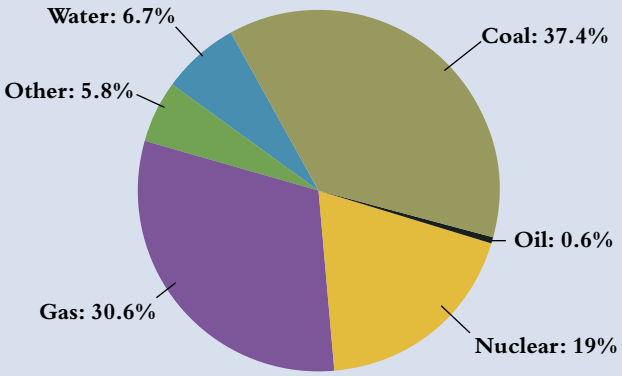
406 80 Fed. Reg. at 64,800.

407 *See* Section 5.4.1, Leakage to New Fossil Fuel EGUs and Section 8.3, Option for Addressing Leakage.

Table 9.2 **CO_2 Emission Factors by EGU Fuel Type**[408]

EGU Fuel Type	CO_2 Emissions (lb/MMBtu)	Average 2013 Heat Rate (Btu/kWh)	CO_2 Emissions (lb/kWh)
Bituminous coal	205.691	10,080	2.07
Subbituminous coal	212.289	10,080	2.16
Lignite coal	215.392	10,080	2.17
Natural gas	116.999	10,408	1.22
Distillate oil (No. 2)	161.290	10,156	1.64
Residual oil (No. 6)	173.702	10,156	1.76

Figure 9.2 **U.S. Electricity Generation by Energy Source, 2012**



Generation shifting to achieve CO_2 reductions can occur in a number of ways, including shifts outside the scope of Building Block 2. For example, displaced generation can shift to existing fossil fuel-fired EGUs with lower CO_2 emissions, to new fossil fuel-fired EGUs with lower CO_2 emissions, to new RE, nuclear power or other low-emitting technologies. A simple comparison of the typical CO_2 emission factors for different types of fossil fuels illustrates the potential for achieving CO_2 emission reductions through generation shifting. As long as the shift occurs from higher-emitting EGUs to lower- or zero-emitting EGUs, the directional goal of reducing CO_2 emissions can be met. However, generation shift to new NGCC EGUs can potentially cause a loss of emission reductions that would otherwise be realized by implementation of BSER; therefore, as noted above, all mass-based state plans must address leakage.

An important principle to bear in mind regarding generation shift is that the concept should be applied collectively to the power generation profile across a state or multi-state region, and not to individual electric generating units. For instance, a generation shift from coal- and oil-fired steam units to existing NGCC units conveys the idea that the portion (i.e., fraction or percent) of the load supplied by coal- and oil-fired steam units will decrease, while the portion of the load met by existing NGCC units will increase. Within the fleet, the capacity factor of some individual coal EGUs may increase, and the capacity factor of some individual NGCC units may decrease. The need to meet variable load shifts with reliable, continuous and affordable power makes flexibility in dispatching generation across the integrated power supply system a high priority. To maintain flexibility in dispatching individual EGUs while achieving a shift in the power generation profile, goals for generation shift should always be viewed in terms of long term (annual or multi-year) average utilization across a category or class of generation. In other words, flexibility should be a key tenet of the generation shift reduction strategy in a state plan.

Also, BSER under the CPP is designed to go beyond simply shifting generation among the existing fossil-fueled fleet. In fact, many states would not meet the applicable Table 2 statewide rate-based goal even if all coal- and oil-fired generation were eliminated and shifted to existing NGCC units that perform at or near the NSPS standards. In most cases, generation shift from higher- to lower-emitting existing EGUs is a compliance strategy that will be combined with strategies to further shift generation from fossil-fueled units to RE and/or nuclear generation, and strategies that reduce generation from affected EGUs through EE improvements.[409]

Figure 9.2 shows the relative proportions of electric generating capacity and electricity generation in the U.S. in 2012.[410] As shown in Table 9.2, the CO_2 emissions intensity of a typical natural gas-fired EGU is about half that of a typical coal-fired EGU. Historically, a large portion of U.S. power generation has been provided by coal. Although the power generation capacity of natural gas is greater

408 U.S. Energy Information Administration, https://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11, updated February 29, 2016.

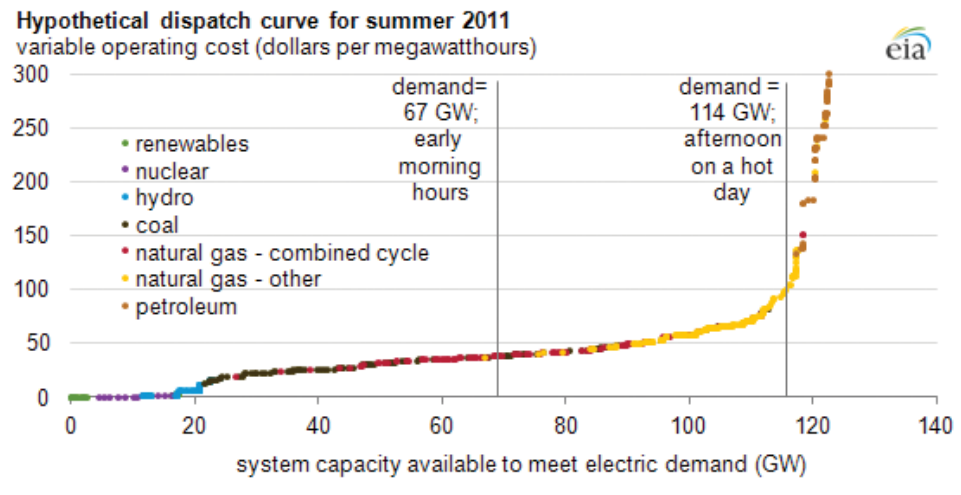
409 For a discussion of carbon capture and other reduction strategies that can be applied directly to existing EGUs as an alternative to generation shift, see NACAA, *Implementing EPA's Clean Power Plan: A Menu of Options,* May 2015, available at http://www.4cleanair.org/NACAA_Menu_of_Options.

410 American Public Power Association, *2014–2015 Annual Directory and Statistical Report,* data from Form EIA-923.

than all other energy sources, including coal, and has been increasing in recent years while coal capacity is declining, more electricity is still generated by coal than by any other energy source in the U.S.

Because the nation's EGUs are interconnected through the transmission grid system, EGU and grid operators have the ability to prioritize among available EGUs when selecting which units will be dispatched to serve the power demand of consumers. In regions with electric grids where EGU dispatch is managed by companies that generate and distribute electricity, algorithms factor the variable cost of generation and reliability and operational constraints into the dispatch decision-making process. In deregulated wholesale electricity markets where generation and dispatch are controlled by separate entities, generators can use these factors to determine bids that are used by grid operators to make dispatch decisions. In either case, the costs of complying with a wide range of environmental regulations, including the cost of compliance with CO_2 reduction strategies, can be factored into dispatch decisions, therefore shifting generation incrementally toward lower-emitting EGUs.

Figure 9.3 **Hypothetical Dispatch Curve, U.S. Energy Information Administration**



9.5.1.1 Dispatch Dynamics

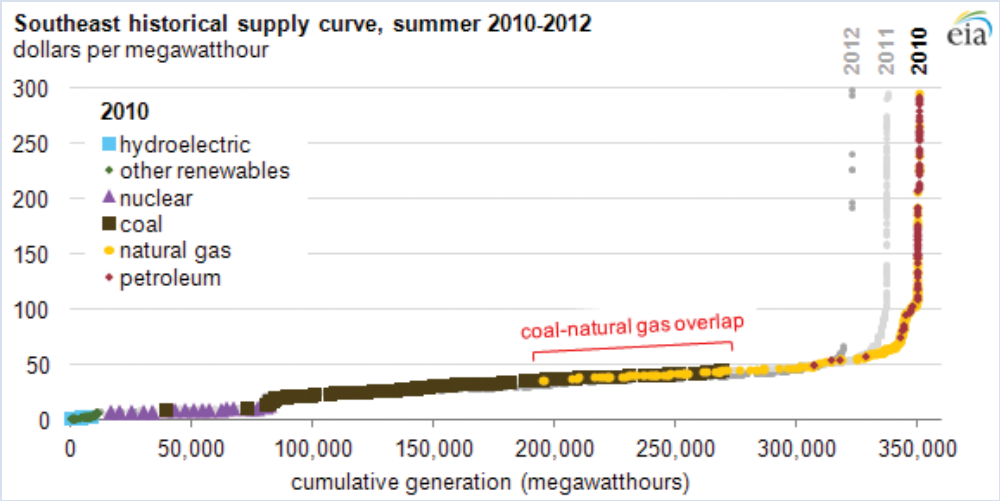
Variable cost is generally considered the key factor in deciding which EGUs are dispatched to meet real-time energy demand. Variable costs include the cost of maintenance, operation and other non-fixed costs, and for fossil fuel generation, they are largely influenced by fuel cost. Nuclear and renewable power generation units have relatively high fixed costs (i.e., construction costs) with relatively low variable costs, and are traditionally dispatched first. Due to their low variable costs, they are typically operated at maximum capacity whenever they are available. Many RE units are available for dispatch, however, only when the meteorological conditions are favorable (e.g., during favorable sun or wind conditions).[411] On the other hand, fossil-fueled EGUs tend to have flexible operational availability (i.e., they can be brought on and off line with relative ease), coupled with higher variable costs. Therefore, fossil-fueled generation is commonly favored by dispatchers to meet short-term variability in power demand, while long-term trends toward increasing load may be met by other resources, such as nuclear or RE.

This effect can be seen in Figure 9.3, which presents a hypothetical dispatch curve for a typical summer day. EGUs are dispatched from lowest to highest variable cost, with renewables and nuclear entering first, followed by coal, then natural gas combined cycle, other natural gas, and petroleum oil. On a short-term basis, the primary opportunity for generation shifting as a means of reducing CO_2 emissions is within the existing fossil-fueled fleet, from coal and/or oil-fired steam units to NGCC units. This is demonstrated by the utilization patterns of the existing generation fleet. On a short-scale timeframe fossil-fueled EGUs compete among themselves for dispatch selection, as opposed to competing with nuclear or renewable sources.

Traditionally, coal-fired EGUs have been dispatched preferentially over natural gas EGUs due to the lower cost of coal as compared to natural gas. Two developments in recent years have already begun to shift that trend. First, the development of much more efficient natural gas generation technologies has partially offset the traditionally higher cost of natural gas as a fuel relative to coal. This effect can be seen in Figure 9.3, as NGCC units are dispatched in advance of other, typically older natural gas steam and combustion turbine EGUs. The other factor that has shifted the typical dispatch curve is the low cost of

411 Of note, advances in power storage technology could radically shift these dynamics in dispatch of power generation sources.

Figure 9.4 **Hypothetical Dispatch Curve, U.S. Energy Information Administration**



natural gas in recent years. Figure 9.4 provides a comparison of the actual dispatch curves for 2010 and 2012 for the Southeast region of the United States. These figures illustrate a dramatic shift in the relative dispatch of coal and natural gas sources, with the dispatch curves virtually overlain in 2012.[412]

ISO and RTOs use a uniform clearing price auction system for setting wholesale electricity prices in the real-time market, in which power generators place bids for a particular time period that reflect their generation cost. The ISO/RTO then dispatches power to meet demand from the lowest to highest bidder, and each generator is paid at the single, highest price reached to meet the demand. In non-ISO/RTO markets, wholesale real-time auctions may be pay-as-bid, rather than uniform price, but dispatch is still driven by the lowest bid approach. Thus, in both restructured and traditional markets, the variable cost – and particularly fuel cost – is a key factor in determining dispatch.[413]

Based on these typical dispatch dynamics, significant CO_2 reductions can be achieved through generation shift within the existing fleet from higher- to lower-emitting fossil-fueled EGUs. The application of BSER to develop the Table 1 performance rates includes a gradual generation shift during the interim period away from coal- and oil-fired steam generating units to existing NGCC units, increasing the utilization rate of existing NGCC EGUs to 75% of the summer capacity, on average, across each of the three regional interconnects.[414] While no state is required to apply the BSER building blocks as CO_2 reduction strategies in designing and implementing a state plan, most states would conclude that reducing reliance on coal-fired EGUs is an important or even critical component of their plan to achieve the mass-based emission goals under a state measures plan.[415] Furthermore, while improved demand-side energy efficiency, increased deployment of renewable energy, improvements in transmission efficiency and other measures may play a significant role in reducing reliance on coal and oil in the longer term, an incremental shift to existing NGCC units can provide short-term progress in reducing CO_2 emissions toward CPP compliance. In addition, for many states, retirement of older coal units and a shift toward greater utilization of existing NGCC units is already underway, and so may prove to be a significant and cost-effective contribution to the overall CPP compliance strategy.

412 U.S. Energy Information Administration, *Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation,* August 17, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7590.

413 Electric Power Supply Association, *How Wholesale Electricity Prices Are Set, from Electricity Primer – The Basics of Power and Competitive Markets,* https://www.epsa.org/industry/primer/?fa=prices.

414 80 Fed. Reg. at 64,797-98. Note that the Table 1 performance rates reflect the least stringent regional emission performance for each year based on application of all three BSER building blocks; thus the Table 1 performance rates may not reflect the reductions available by the full shift for all regions and states.

415 For a discussion about carbon capture and other reduction strategies that can be applied directly to coal-fired units, see NACAA, *Implementing EPA's Clean Power Plan: A Menu of Options,* including Chapters 1, 4, 7, and 11, available at http://www.4cleanair.org/NACAA_Menu_of_Options.

Table 9.3 **Regional-level Available NGCC Generation Shift (MWh)**

Interconnection	NGCC at 75% Summer Capacity Potential MWh	2012 Adjusted Baseline NGCC MWH (% Summer Capacity)	Available Generation Shift MWh
Eastern	987,856,765	734,535,157 (56%)	253,321,608
Western	306,488,912	198,374,376 (49%)	108,114,536
ERCOT	203,650,232	137,182,895 (51%)	66,467,337

9.5.2 Determining the Potential for Generation Shift

To assess the potential contribution a generation shifting strategy can make toward complying with the statewide emission goals, three factors should be considered: (1) the magnitude of unused generation capacity available within the existing NGCC fleet; (2) any infrastructure limitations, including natural gas availability and transmission constraints, that may hamper access to the available generation capacity; and (3) the cost of shifting generation among existing units.

9.5.2.1 Identifying Unused NGCC Capacity

On a national scale, roughly 15% of existing NGCC units operated at or above 75% net summer capacity on an annual average in 2012; thus, taking 75% summer capacity[416] as the annual average goal, roughly 85% of existing NGCC units could contribute to the goal nationally.[417] If Building Block 2 were implemented nationally as conceived by EPA, NGCC generation from affected EGUs would increase from 1,070 TWh[418] to 1,498 TWh, an increase of 428 TWh, equivalent to 40% of the 2012 power generation from NGCC units.[419] This shift would represent approximately 25% of the 2012 U.S. generation from coal, oil and non-NGCC gas EGUs.[420] A state developing a single-state state measures plan will likely want to assess in greater detail, at the state and regional levels, the capacity for NGCC generation shift. A regional-level overview of the potential for generation shift to existing NGCC units is provided in Table 9.3.[421]

In Table 9.3 above, the 2012 baseline generation data are adjusted to add generation at a 55% summer capacity rate from affected NGCC EGUs that started operation in 2012 or that commenced construction by January 8, 2014. Table 9.4 below provides a summary state-by-state analysis of available generation shift capacity, developed using data from EPA.[422]

As seen in Table 9.4, the potential for generation shift to existing NGCC units ranges widely from state to state. For example, Idaho had no fossil steam in-state generation in 2012. All of the 2012 generation in Idaho was from NGCC EGUs, with a utilization rate at 72% summer capacity. At the state level, then, Idaho has no fossil steam generation available for shift to NGCC units, and the existing NGCC EGUs have very little capacity available to replace generation from coal or oil EGUs. Thus, even viewed from a regional perspective, a state with circumstances similar to Idaho's would be unlikely to benefit from implementing a gas shift strategy as a state measure.

Other states, however, appear to have significant opportunities for reducing CO2 emission rates through generation shifting to existing NGCC units. For example, in Wisconsin the 2012 affected EGU fossil-fuel power generation split was 76% fossil steam EGUs and 24% NGCC EGUs, and NGCC units were utilized at an annual average of 45% of the summer capacity rate.[423] For states with circumstances similar to these, where there is both a significant level of coal generation and a significant available

416 It should be noted that annual capacity of NGCCs is greater than "net summer capacity" and that much of the additional utilization of NGCCs could occur in colder seasons.

417 80 Fed. Reg. at 64,799.

418 A Terawatt-hour (TWh) is equal to 1 million MWh.

419 80 Fed. Reg. at 64,798, Table 7, BSER Maximum NGCC Generation by Region and Year (TWh).

420 Derived from American Public Power Association, *2014–2015 Annual Directory and Statistical Report,* US Power Generating Capacity and Generation by Fuel Type, data from Form EIA923.

421 EPA, *Data File: Goal Computation Appendix 1-5 (XLSX),* https://www.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx.

422 *Ibid.*, Appendix 3, State Level Data, https://www.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx.

423 See *ibid.*, Appendix 5 for state-level baseline generation mix.

Table 9.4 **State-level Available NGCC Generation Shift**

State/Tribe	Adjusted 2012 Electric Generation (MWh)	Adjusted 2012 as % Summer Capacity	Existing NGCC Summer Capacity (MW)	75% Summer Capacity (MWh)	Potential BB2 Annual Generation Shift (MWh)
AL	53,492,096	66%	9,278	61,120,829	7,628,733
AR	15,651,185	38%	4,661	30,703,374	15,052,189
AZ	26,783,421	33%	9,305	61,300,681	34,517,260
CA	93,068,612	57%	18,749	123,521,047	30,452,436
CO	11,131,370	42%	2,988	19,687,579	8,556,209
CT	15,299,704	72%	2,418	15,929,125	629,421
DE	6,672,111	53%	1,439	9,480,132	2,808,021
FL	147,327,444	63%	26,827	176,735,617	29,408,173
Fort Mojave	1,360,093	28%	550	3,623,400	2,263,307
GA	37,728,636	54%	7,898	52,032,024	14,303,388
IA	1,430,248	15%	1,092	7,192,120	5,761,872
ID	3,450,055	72%	547	3,601,660	151,604
IL	10,627,106	34%	3,544	23,344,578	12,717,472
IN	12,839,309	60%	2,452	16,153,117	3,313,808
KS	666,706	55%	138	909,144	242,438
KY	3,091,968	55%	640	4,216,320	1,124,352
LA	19,352,269	45%	4,894	32,241,672	12,889,403
MA	23,554,517	50%	5,409	35,631,198	12,076,681
MD	676,556	33%	230	1,515,240	838,684
ME	4,677,598	43%	1,250	8,235,000	3,557,402
MI	18,499,951	45%	4,668	30,750,808	12,250,857
MN	5,715,510	32%	2,017	13,284,702	7,569,192
MO	4,854,569	31%	1,807	11,904,516	7,049,947
MS	32,147,488	53%	6,944	45,746,413	13,598,925
MT - E	-	-	-	-	-
MT - W	-	-	-	-	-
Navajo	-	-	-	-	-
NC	25,519,802	62%	4,700	30,960,965	5,441,163
ND	-	-	-	-	-
NE	423,638	15%	321	2,112,113	1,688,475
NH	6,946,869	66%	1,203	7,925,364	978,495
NJ	33,664,782	51%	7,566	49,841,514	16,176,732
NM - E	2,987,812	64%	530	3,494,275	506,463
NM - W	2,743,145	36%	860	5,663,045	2,919,900
NV	23,783,256	53%	5,157	33,974,316	10,191,060
NY	44,035,434	59%	8,457	55,716,034	11,680,600
OH	23,687,009	69%	3,895	25,662,236	1,975,228
OK	29,943,376	49%	6,918	45,578,419	15,635,043
OR	13,486,830	54%	2,862	18,852,880	5,366,050
PA	57,420,455	67%	9,737	64,149,991	6,729,536
RI	8,140,017	54%	1,725	11,365,618	3,225,600
SC	11,209,394	56%	2,282	15,031,840	3,822,446

Table 9.4 **State-Level Available NGCC Generation Shift**, *continued*

State/Tribe	Adjusted 2012 Electric Generation (MWh)	Adjusted 2012 as % Summer Capacity	Existing NGCC Summer Capacity (MW)	75% Summer Capacity (MWh)	Potential BB2 Annual Generation Shift (MWh)
SD	1,401,048	55%	290	1,910,520	509,472
TN	7,333,244	60%	1,403	9,242,964	1,909,720
TX - E	20,981,139	59%	4,024	26,508,794	5,527,655
TX - ERCOT	137,182,895	51%	30,912	203,650,232	66,467,337
TX - W	1,870,134	42%	509	3,352,633	1,482,499
UTE	-	-	-	-	-
UT	8,486,187	53%	1,830	12,056,040	3,569,853
VA	36,291,895	62%	6,676	43,981,488	7,689,593
WA	11,728,154	44%	3,066	20,196,832	8,468,678
WI	10,244,273	45%	2,618	17,248,702	7,004,429
WV	-	-	-	-	-
WY	483,120	55%	100	658,800	175,680

unused capacity of NGCC units, a gas shift strategy could be a meaningful component of the state plan.

A state that has significant coal generation but little available existing NGCC capacity might still benefit from the implementation of a generation shift strategy at the regional level, consistent with EPA's application of BSER. For example, Nebraska's 2012 baseline affected EGU generation was 98% fossil steam and only 2% NGCC. Although the NGCC capacity factor for 2012 is very low, at 15% summer capacity, full implementation of Building Block 2 would yield a generation increase from existing NGCC units of only 1.688 million MWh, representing just under 7% of the fossil steam 2012 generation. However, Nebraska is located in the Eastern Interconnect, where significant availability of existing NGCC units could support further generation shift within the scope of BSER. Thus, a state measure that encourages generation shift and guards against leakage to new NGCC units could potentially be an important component of a state measures plan.

9.5.2.2 Infrastructure Considerations

For states that seek to achieve a generation shift from higher-emitting existing EGUs to existing NGCC units, consideration should also be given to the local and regional natural gas supply, as well as to the transmission infrastructure and its ability to support the increased demand for natural gas. On a national scale, EPA notes that the infrastructure system has demonstrated in practice the ability to deliver natural gas at high NGCC utilization levels both during peak hours when power demand is highest and for extended periods of a month or longer. In addition, EPA notes that the natural gas pipeline infrastructure has been expanded significantly in recent years and continues to undergo significant expansions.[424] Nonetheless, local circumstances may vary from the national scale, thus each state must consider whether the local and regional supply and delivery system will be adequate to support the level of potential increased NGCC utilization, taking into account the potential for expansion.

Toward that end, it may be informative to consider the modeling that EPA conducted using the Integrated Planning Model (IPM) to analyze the technical feasibility of generation shifting to existing NGCC units.[425] The IPM incorporates detailed information regarding the existing natural gas pipeline system and also projects expansion of the existing network to meet increased projected load. EPA's model runs included both individual state-level compliance, where generation shifting among existing EGUs was constrained by state boundaries, and regional (multi-state) compliance scenarios. The analyses examined scenarios that required NGCC average utilization rates of 65%, 70% and 75%, without including other CPP-driven compliance obligations. The modeling predicted that compliance could be achieved for either a single-state or regional scenario, although at higher average cost for the individual-state scenario.

424 79 Fed. Reg. at 34,863-64.

425 EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants,* Chapter 3, June 2014, EPA-452/R-14-002.

9.5.2.3 Cost Considerations

Cost is another important consideration related to adopting generation shift to existing NGCC units as a state measure compliance strategy. Using a regional compliance approach for each of the three regional interconnects, EPA's modeling predicted costs of $24/metric ton of CO_2 for the 75% net capacity NGCC utilization scenario. These are costs predicted by "dispatch-only" modeling scenarios, which considered generation shifting without taking into consideration any other CPP-driven reductions and without allowing for the multi-year phase-in reflected in the interim period emission goals. In addition, the modeling directed each region to achieve the 75% net summer capacity level, although the emission guidelines fall short of that level for the Western and ERCOT interconnections. To inform initial planning, states may find a closer evaluation of the IPM modeling conducted by EPA, including modeled compliance costs, to be informative. States may also want to undertake additional analyses using IPM or other models, customizing the model inputs to reflect their specific test scenarios, including geographic boundaries that may differ from those modeled by EPA.

States will also want to evaluate the cost of generation shift to existing NGCC units in relation to other compliance strategies. In particular, least-cost compliance modeling that considers the full suite of compliance opportunities and obligations the state is considering can be used as a planning tool to evaluate the role that shifting generation to existing NGCC units may play. Modeling that allows multiple strategies may result in a different prediction regarding the extent of generation shift among existing EGUs, and at a different cost, than would be observed when generation shift is modeled in isolation. If other compliance strategies, such as shifting generation to new RE EGUs, are favored by the model, this may lead the state to defer the adoption of requirements to force generation shift to existing NGCC units, in favor of adopting other strategies—for example, incentives for projects to construct new RE power plants. Also, to the extent investment in RE, EE or other measures will be the most cost-effective long-term compliance solution, states may want to consider advancing investment in these measures to the greatest extent possible as a preferred strategy to investment in generation shifts. Nonetheless, existing NGCC units can play a critical role in the interim compliance period as new RE EGUs are built and brought onto the grid, even if utilization is not increased to the 75% net summer capacity level. Accordingly, each state will want to develop data to best inform the policy choices and reduction strategies that are most suitable for its particular circumstances and preferences.

9.5.2.4 Projections of Least-cost Solutions

EPA's modeling suggests that generation shift to existing NGCC units at the levels assumed for BSER may not be the most cost-effective long-term solution to reducing CO_2 emissions to the level of the state emission goal. In the Regulatory Impact Analysis for the CPP, EPA presented modeling results for two illustrative scenarios of CPP emission guideline implementation. As compared to the base case, the future generation mix for the mass-based scenario predicted a significant decrease in coal generation (at -6%, -15% and -22% for years 2020, 2025 and 2030, respectively). Existing NGCC generation increased only modestly as compared to the base case (+2%, +2% and +5% for years 2020, 2025 and 2030, respectively). In fact, the model projections of capacity factors for coal and NGCC predicted existing NGCC capacity factors noticeably below the BSER Building Block 2 target of 75% net summer capacity. Speaking to this result, EPA noted, *"The utilization of existing natural gas combined cycle capacity is lower than the BSER level of 75 percent on an annual average basis in these illustrative plan approaches, reflecting the fact that, in practice, the most cost-effective CO_2 reduction strategies to meet each state's goal may not require that each building block be achieved in entirety."* With regard to leakage to new NGCC units, EPA's generation mix projections showed new NGCC capacity initially increasing significantly compared to the base case in 2020, but subsequently declining to well below the base case generation level (+111%, -8%, and -33% for 2020, 2025, and 2030, respectively).

Notably, the model did not impose any restrictions or parameters to limit leakage to new NGCC units, but did reflect state incentives for RE and investment in demand-side EE. Beyond the RE incentives (reflected by lowering the capital cost of RE development) and EE deployment, the model did not direct or require any specific reduction strategies, but simply directed all existing EGUs to achieve the state emission goal. Under these conditions for the mass-based case, across the 2020 to 2030 timeline, existing NGCC generation decreased from 1,132 thousand GWh to 1,090 thousand GWh, a decrease of 4%. At the same time, new NGCC generation increased three-fold, from 69,000 GWh to 207,000 GWh.[426]

426 EPA, *Regulatory Impact Analysis for the Clean Power Plan Final Rule,* Table 3-11, October 2015, https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

Table 9.5 **EPA Projected Capacity Factors of Existing Coal Steam and Natural Gas Combined Cycle Capacity for CPP Implementation Illustrative Cases**

	Existing Coal Steam			Existing Natural Gas Combined Cycle		
	2020	2025	2030	2020	2025	2030
Base Case	77%	76%	79%	54%	56%	51%
Rate-based	78%	75%	69%	56%	60%	61%
Mass-based	78%	75%	75%	56%	58%	54%

Table 9.5 presents the results of EPA's 2015 Integrated Planning Model (IPM) as presented in the RIA. EPA's modeling results are illustrative only, and do not reflect the reduction strategies of any particular state. Nonetheless, these results do suggest that a state should conduct an analysis to assess the value of adopting measures to require generation shift, given that other reduction measures may prove more cost-effective.

9.5.3 Administrative Authority Options for Implementing Generation Shift

To incorporate generation shift among existing EGUs as an element of the state plan, the state may choose to rely upon the state air quality agency, the Public Service Commission (PSC), or the state energy office, depending on the mechanism chosen to achieve the strategy. For direct regulation of entities, such as dispatch utilities, which traditionally have not been subject to CAA requirements or to PSC oversight, new statutory authority may need to be adopted through the state legislative process.

9.5.3.1 State Legislative Authority and Timing Considerations

While some regulatory strategies may be more firmly supported by existing authorities, such as establishing operating limits for higher-emitting EGUs, new statutory authorities may be needed for certain other approaches to implementing generation shift. For example, state regulations that require ISOs to maximize the capacity factor of NGCC units preferentially in dispatching units, or to incorporate CO_2 emissions intensity into the dispatch decision-making process, would likely require new administrative authority. State legislation may also be needed, for example, to adopt a fossil fuel energy portfolio standard, or to adopt new emission fees to incentivize generation shifts. The state legislative process is often a one-to-three-year endeavor, depending on the frequency of legislative sessions and the procedures involved. If implementing regulations are required, another process of perhaps six to eighteen months would follow. These efforts could extend the implementation timeframe for specific enforceable measures out to three to five years or more, calling for early planning in considering the preferred approach for achieving emission reductions from generation shift. States will want to examine the timeframes for adoption of necessary authorities and the timeframes for emission reductions to be gained from existing fleet generation shift under their particular circumstances. Accounting for these timing considerations will help to inform both the usefulness of pursuing this compliance strategy as well as the selection of particular regulatory mechanisms to achieve generation shifts to existing NGCC units.

9.5.3.2 State Air Quality Agency

For requirements directly applied to individual EGUs, the state air quality agency can readily serve as the administrative authority for implementation and enforcement. Since the affected sources are typically regulated sources under the CAA and are already subject to permitting requirements, including monitoring, recordkeeping and reporting requirements, specific conditions requiring or driving generation shift can be incorporated into the existing regulatory infrastructure and permitting process.

Examples of regulatory provisions and permit conditions that can be used to achieve generation shift among existing EGUs include: operating limitations on specific EGUs; requirements to balance utilization to meet specified ratios among different fuels; a requirement to pay an emission-based fee for emissions resulting from utilization over a specified baseline; or incorporation in the operating permit of direct mass emission limits derived from a target utilization rate. In addition, flexible compliance provisions, such as utilization averaging or emissions averaging, can be implemented by the state air quality agency through regulations and operating permits.

One apparent limitation to the permit limit approach is that, while permit limits could reduce utilization of coal-

and oil-fueled EGUs, it would not be feasible to incorporate a permit condition to require an existing NGCC unit to operate at or above a specified utilization rate. Section 9.5.5 discusses possible mechanisms to address this concern while preserving flexibility at the individual EGU level.

9.5.3.3 Public Service Commission

The Public Service Commission (PSC) may already have an indirect role in incentivizing and implementing generation shift, at least for Investor Owned Utilities (IOUs), through Integrated Resource Planning (IRP), approval of new EGU construction, and rate approvals. In light of this existing authority, a state may choose to build on existing PSC oversight procedures to implement a generation shift reduction strategy as a state measure under the CPP. For example, incorporating a plan to maximize the capacity factor at individual NGCC power plants or EGUs could be established as a required element in the utility's IRP.[427] This strategy may include a requirement for each affected utility to develop a utilization plan for fossil-fuel EGUs that takes into account CO_2 emissions intensity in conjunction with cost effectiveness and other specifications. In cases where the IOU also controls dispatch, this could be a direct mechanism for driving generation shift. In cases where an ISO or RTO controls dispatch through a market, CO_2 emissions intensity could be factored into the EGU availability assessment and variable cost determination.

While PSC existing authorities may help to support implementation of generation shift as a CPP compliance strategy, there are clear limitations to this approach. First, IRP programs typically address long-term planning horizons of ten to twenty years, with plan updates required every two to five years. Thus, the timing of IRP development may not serve to meet the state CPP compliance requirements. Also, in many cases, although utilities are required to develop an IRP, the PSC does not have the authority to approve or enforce the plan. Furthermore, the PSC typically does not have oversight authority for public power utilities, electric cooperatives, or independent power providers. In some states, these timing and scope of authority constraints could render existing PSC authorities largely ineffective in driving generation shift over the interim period plan performance timeline of 2022 to 2029. If, however, the state establishes new authorities to factor CO_2 emissions considerations into deciding which EGUs should be made available and selected for dispatch, the PSC may be better suited to the oversight role than the state air quality agency. PSCs have many years of experience in the oversight of the highly integrated power sector and may be more familiar with the dynamics of dispatch decision-making, including capacity market contracting, reliability, least-cost economics and variable cost considerations.

9.5.3.4 State Energy Office

Depending on the mechanism selected to achieve generation shift to existing NGCC, the State Energy Officer could be well suited to the administrative role. For example, in many states the state energy office is responsible for implementing incentive programs for RE or for oversight for the state RPS. If the state elects to expand the RPS in order to include requirements to balance generation among fossil fuels (i.e., create a renewable portfolio standard), then the state energy office could play a role in helping to track and implement this strategy. If so, the state air quality agency may want to establish a shared administrative authority role with the state energy office.

9.5.4 Affected Sources and Affected Entities

For a strategy that involves generation shift among existing EGUs, the primary affected sources are the existing EGUs to which the strategy is applied. States may make different choices about which types of existing sources to regulate or incentivize, based on the profile of their power fleet, their legal authorities, and their specific goals. At a minimum, it is likely that coal-powered EGUs would be affected sources, with a goal of reducing generation from coal steam EGUs. Oil and some natural gas EGUs may also be affected sources for reducing utilization. Specific requirements may also be targeted at existing NGCC units, and may include nuclear or RE generators if the state elects a more comprehensive generation shift approach. To address the potential for leakage to new NGCC units, some requirements may be adopted specifically applicable to proposed new NGCC EGUs.

In addition, to the extent the generation shift strategy involves making direct changes to dispatching procedures, the dispatch system operators may be the regulated affected

427 Under section 111(d)(19) of the federal Energy Policy Act of 1992, integrated resource planning (IRP) is defined in part as, "a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost."

entities.[428] Across much of the nation—including most of the west coast, northeast and central United States—the power sector is deregulated and power distribution is controlled by independent system operators (ISOs and RTOs).[429] In other areas, vertically integrated utilities have spun off dispatch utility companies to meet the FERC requirements for non-discriminatory access to transmission lines. As a result of this evolution in the power sector structure, the company that controls operation of the affected EGUs is usually not the same company directly controlling dispatch of generation to the distribution system. Owners and operators of affected EGUs, nonetheless, remain in control of making their units available for dispatch within the constraints of agreements with grid operators.

9.5.4.1 Coal, Oil and Gas Steam EGUs

Shifting generation from coal steam EGUs clearly has the greatest potential for reducing CO_2 emissions on a national scale; however, generation shift strategies can be applied to the fossil steam unit subcategory as a whole. On a national scale, coal provided more than 37% of power generation in 2012. On the state level, for the period January to May 2015, coal generated greater than 25% of the power produced in more than half of the states in the nation, with power generation in fourteen states at more than 50% from coal. By comparison, despite almost every state having the capacity to produce electricity from oil, oil-fueled generation produces less than 1% of the power generation nationally, with more than 30 states having no contribution from oil and only one state, Hawaii, using oil as the primary energy source.[430] Thus, most states will likely decide that regulatory or policy efforts aimed at oil are not worth pursuing.

9.5.4.2 Existing NGCC Units

Building Block 2 of BSER focuses specifically on generation shift to existing NGCC units, while Building Block 3 involves the deployment of new RE capacity. It would not be feasible, however, to incorporate a permit condition to require an existing NGCC unit to operate at or above a specified utilization rate. Thus, although existing NGCC units are the intended target to receive the displaced coal generation under this strategy, the NGCC units may not be directly regulated to achieve the goal. Some mechanisms could be designed to address existing NGCC units as regulated sources, however. For example, a fossil fuel energy portfolio standard may require a specified portion of fossil fuel generation to be derived from natural gas, or may specify goals specifically for the ratio of coal generation to generation from existing NGCC units.

9.5.4.3 RE, Nuclear, Biomass, Waste-to-Energy, and CHP

Some states may choose to combine an existing EGU generation shift strategy with an overall generation shift strategy that includes RE and other qualifying EGUs in the target group for receiving the shifted generation. One potential advantage of this approach is that a broader set of target units for receiving the generation shift away from coal creates greater flexibility, thereby supporting lower-cost compliance pathways while reducing reliability concerns.

9.5.4.4 New NGCC Units

A state may want to consider including new NGCC units as regulated sources in the strategy to implement generation shift to existing NGCC units. One possible mechanism for doing this would be to require any permit application to authorize construction of a new NGCC EGU to include a demonstration that the proposed new capacity is needed to meet demand that could not be met by increasing the utilization of existing NGCC units in the state.

9.5.4.5 Utilities, ISOs and RTOs

The key to generation shift lies equally with influencing power generators and distributors, and the two are highly interdependent. Also, interactions and business transactions between the power generators and the power distributors are dynamic and complex, involving long-term service contracts, capacity markets and short-term markets at regulated rates under a tariff system. It may be

428 Strategies that directly impact dispatch are often referred to using the phrase "environmental dispatch." For more information, see NACAA, *Implementing EPA's Clean Power Plan: A Menu of Options,* Chapter 21, available at http://www.4cleanair.org/NACAA_Menu_of_Options.

429 There are currently seven RTOs and ISOs operating in the U.S. In 2009, U.S. RTOs/ISOs managed 60% of the power supplied to customers. See Chapter 2, The U.S. Power Sector.

430 John Muyskens et al., *Mapping how the United States generates its electricity,* The Washington Post, July 31, 2015, https://www.washingtonpost.com/graphics/national/power-plants/ (data sourced from Energy Information Administration).

a challenge under existing state authorities to specifically regulate ISOs or RTOs, though dispatch utilities may come under existing PSC oversight or other state regulatory reach. Where feasible, however, implementation of changes to dispatch algorithms could be the simplest and most effective approach at driving the shift.

9.5.5 Mechanisms for Implementing Generation Shift

State measures plans can take advantage of a variety of CO_2 reduction strategies, including generation shift among existing EGUs, through requirements that are enforceable at the state level. Or, if the reduction strategy is implemented through imposition of an emission standard on affected EGUs, it must be incorporated into the plan as a federally enforceable requirement. Several options are presented in this section.

9.5.5.1 Adopting a Fossil Fuel Energy Portfolio Standard

One option states may consider to achieve a shift in generation away from existing coal and oil and toward existing natural gas would be to adopt an energy portfolio standard specifically for the portion of the power produced by fossil fuel energy sources. For example, each utility company or power retailer in the state could be required to provide a specified minimum percent of the fossil fuel generation from existing natural gas generation units, with the natural gas portion increasing incrementally over time. An example of regulatory language for this approach is provided in the ***Generation Shift Rule Example 1, Fossil Fuel Portfolio Standard***, located in Section 9.5.6, Generation Shift Rule Examples.

Alternatively, the standard could be set to limit the percentage of the total fossil fuel generation that is provided by coal and oil, with the percentage decreasing incrementally over time. Each state (or multi-state region) would need to analyze its current fossil fuel profile and goals to determine the appropriate levels for the standard.

A fossil fuel energy portfolio standard has several advantages as a mechanism to drive generation shift. First, energy portfolio standards have already been adopted by many states to achieve generation shift to renewable energy. These states have already established both administrative authority and procedures for adopting, implementing and enforcing energy portfolio standards, which could be relied upon or built upon for a fossil fuel standard.

Also, a fossil fuel energy portfolio standard has the advantage of applying directly at the fleet-wide level, thereby affording greater flexibility at the individual EGU level. In addition, a fossil fuel portfolio standard works both to shift generation away from coal and oil and to shift generation to natural gas—that is, it shifts the balance of the power mix within the fossil fuel generation portion of the total generation mix, regardless of what portion of the total power demand is supplied by fossil fuel. This approach can work in tandem with a renewable portfolio standard, allowing RE generation to grow and shifting the fossil fuel-generated portion of power supply toward natural gas concurrently.

Another advantage of the fossil fuel portfolio approach is that it readily accommodates fuel switching and co-firing at coal units, again providing greater flexibility for compliance.

A possible disadvantage of a fossil fuel portfolio standard is that it could conceivably result in higher total fossil-fuel EGU utilization than would otherwise have occurred, encouraging utilization of natural gas EGUs to reach the mandated percentages in relation to coal firing. However, this concern is avoided or minimized in cases where the state also has an RPS in place.

Another challenge with implementing a simple natural gas portfolio standard is that it may not, by itself, address

Fossil Fuel Portfolio Standard

C. Fossil Fuel Portfolio Standard for Natural Gas Generation.

1. For each affected entity, a minimum percentage of the total amount of electricity supplied by fossil fuel energy resources shall be generated by natural gas, as shown in Table 1, for each performance period.

[From Generation Shift Rule Example 1]

Table 1 **Retail Supplier Fossil Fuel Portfolio Standards for Natural Gas**

Performance Period	Electricity Generated by Natural Gas as a Percent (%) of Fossil Fuel Generation
Jan. 1, 2022–Dec. 31, 2024	45%
Jan. 1, 2025–Dec. 31, 2027	48%
Jan. 1, 2028–Dec. 31, 2029	50%
Jan. 1, 2030–Dec. 31, 2031 and each two-calendar year period thereafter	55%

leakage to new NGCC units. A state adopting this approach would need to either modify the fossil fuel portfolio standard to specify requirements for existing vs. new NGCC units, or adopt separate mechanisms to address leakage.

Based on the state's CPP compliance strategy and energy policy goals, the fossil fuel portfolio standard could be tailored to specify standards for existing NGCC units, or for new and existing NGCC units, as desired. Also, the standard can be tailored to apply to dispatch utilities, or to ISOs/RTOs operating in the region, as necessary.

9.5.5.2 Incorporating CO_2 Intensity into Dispatch Decisions

As noted, generation shift is already occurring from coal to natural gas due to the current low price of natural gas. One option states may consider to further this trend for purposes of CPP compliance would be to interject a CO_2 emissions intensity factor into the dispatch decision-making process. This could be accomplished in a number of ways. For example, a formula for adjusting the variable fuel cost to reflect CO_2 emissions could be utilized and reflected in the bids to wholesale auctions, thereby shifting the dispatch order of higher-emitting units.

Alternatively, CO_2 emissions intensity could be factored into the dispatch selection as a constraining factor, separate from the least-cost ranking, in the same way that constraints on the transmission system are considered. To accomplish this, a constraint could be placed on the average daily CO_2 lb/MWh of electricity distributed, for example on a rolling seasonal-average basis or a rolling 180-day basis. An excerpt of example regulatory language to implement this approach is provided in the ***Generation Shift Rule Example 2, CO_2 Dispatch Factors,*** provided in Section 9.5.6.

One advantage of this approach is that it can capture the emission reduction effects of generation shift among fossil fuel units together with the effects of zero- and low-emitting power sources, since the performance metric is applied directly to the grid. Thus, RE generation with zero emissions is added to the total generation. Similarly, new NGCC generation is effectively covered under the same carbon intensity standard, thereby addressing leakage effects. However, some adjustments would need to be made to the applicable CPP performance rates to account for existing RE in the baseline period.

The most effective means of implementing an approach to change the dispatch decision-making process would be through the system operators—e.g., the ISO/RTOs or dispatch utilities could consider CO_2 emissions in the variable cost component of dispatch algorithms. A challenge with implementing this approach in a single state is that dispatch typically occurs across a region. Implementation across a multi-state group collectively served by the dispatch system would be a more effective option.

CO_2 Dispatch Factors

C. CO_2 Emissions Intensity Dispatch Factor.

The generation-weighted average CO_2 emissions intensity of total electricity dispatched to the power grid by each affected entity shall not exceed the CO_2 emissions intensity standard shown in Table 1 for each compliance period.

Table 1 **CO_2 Emissions Intensity Standards**

Compliance Period	CO_2 Intensity, lb/MWh Dispatched, 180-day Rolling Average
Jan. 1, 2022–Dec. 31, 2024	1,468
Jan. 1, 2025–Dec. 31, 2027	1,325
Jan.1, 2028–Dec. 31, 2029	1,228
Jan. 1, 2030–Dec. 31, 2031 and each two-calendar year period thereafter	1,169

D. CO_2 Intensity Dispatch Procedures.

1. No later than January 1, 2020, each affected entity dispatch system operator shall adopt and implement dispatching procedures to assure that the standards of this Section are met.

[From Generation Shift Rule Example 1]

9.5.5.3 Setting Operational Limits on Existing Steam EGUs

The most direct method to assure generation shift from fossil steam units is to restrict the operation of those units to levels below the baseline. For some states, this approach may be the simplest compliance strategy, particularly if a portion of the coal fleet has already announced plans for retirement before or during the interim period. Operational limits could be in the form of limiting the capacity factor of generation from coal and oil, limiting the heat input from coal and oil, or limiting the total hours of operation. A degree of compliance flexibility can be provided by allowing for long averaging periods, e.g., consistent with the CPP interim step periods, and

by allowing for averaging across multiple EGUs located at the same power plant. However, while this approach could be used to force a generation shift away from the affected fossil steam EGUs, the shift would not necessarily be to existing NGCC units. Depending on the specific circumstances of the state and affected EGU inventory, this may not raise a concern regarding leakage, however. For example, if the state plan limits the operation of coal EGUs while placing no limits on existing NGCC units, it is logical to expect generation would be shifted to the existing NGCC units to the extent those units are available and represent the least-cost option. As discussed in Section 9.1, the typical utilization pattern would involve utilization of available RE or nuclear power prior to existing NGCC units. As for leakage to new NGCC units, this is less likely to occur within the plan design, given that existing NGCC units would not be limited in operation. Rule language to implement this approach is provided in ***Generation Shift Rule Example 3, Capacity Factor Standards for Coal-fired Affected EGUs,*** in Section 9.5.6.

For a state measures plan to achieve the full required level of emission reductions to meet the statewide mass emission limits, operational limits on existing steam EGUs would most likely need to be used in conjunction with other state measures, such as RE incentives or requirements to meet power demands, and EE deployment to reduce power load or limit load growth. For further discussion of RE and EE measures, see Sections 9.6 and 9.7.

Another approach to using operational limits, which is similar to the fossil fuel portfolio standard approach, is to establish a requisite level of operation of fossil steam units relative to NGCC units. In a state with a vertically integrated electric utility system, in which the same utility company (or companies) owns and operates both the power plants generating electricity as well as the power transmission and distribution systems, the plan may include enforceable obligations on the utility companies to meet a specific balance of coal- and natural gas-fired generation. This approach would work best for a state whose power providers have both coal and NGCC units under common control. Compliance flexibility could be provided by allowing EGU owner/operators to include power purchased from Independent Power Producers (IPPs) in their compliance demonstrations. For example, if a public power utility owns and operates only coal EGUs, power purchased from an IPP generated by NGCC could be used to meet the fuel balancing requirement. Alternatively, the plan may adopt provisions requiring the utility companies to consider CO_2 emissions intensity in the IRP process.

9.5.6 Generation Shift Rule Examples

Three examples of regulatory language for incorporating generation shift as an element of the state measures plan are provided on the following pages. The rule examples present different approaches to achieve generation shift within the existing fossil fuel fleet. All examples are written in the framework of a state administrative or legislative code, with a single state administrative authority (e.g., the Air Administrator or the PUC) serving as the entity that would implement and enforce the requirements. The example regulatory language is intended to provide an illustration of approaches a state could adopt in a state measures plan. In all cases, the regulatory provisions shown in the examples would need to be supplemented with additional regulatory provisions, such as detailed definitions or EM&V requirements, to meet CPP requirements. It is important to note that the values of the specific standards used in the examples are intended to be examples only and do not represent an endorsement or recommendation of those specific standards.

Table 9.6 **Guide to Generation Shift Rule Examples**

Rule Example	Form of Generation Shift Standard	Applicability	Rule Provisions	Flexible Compliance Demonstration Options
1	Fossil Fuel Portfolio Standard	Applies to suppliers of electricity to retail customers, using affected EGUs to generate power	• Establishes a minimum percentage of fossil fuel generation derived from natural gas for power supplied by affected EGUs	• Provides for three-year and two-year compliance periods, aligned with CPP plan performance periods
2	CO_2 Intensity Dispatch Standards	Applies to electricity system operators responsible for dispatch of EGUs	• Establishes standards for CO_2 emissions intensity (lb/MWh) for dispatched power for each plan performance period, on a 180-day rolling average • Requires system operator to develop dispatch procedures to take CO_2 intensity of EGUs into account	• Provides for three-year and two-year compliance periods, aligned with CPP plan performance periods • Provides for reliability emergency situations • Considers co-firing, RE, and low-emitting generation sources in determining CO_2 intensity
3	Capacity Factor Standards	Applies to affected coal-fired steam EGUs	• Establishes capacity factor operational limit standards for individual coal EGUs for each performance period • Accounts for retiring coal units and baseline utilization levels of coal units	• Provides for facility-wide weighted average compliance • Provides for owner/operator coal fleet weighted average compliance • Considers co-firing and fuel switching • Provides for revisions to capacity factor standards • Provides reliability safety valve

Generation Shift Rule Example 1
Fossil Fuel Portfolio Standards

Section 3010. Electric Power Fossil Fuel Portfolio Standards

A. Purpose. The fossil fuel portfolio standard of this Section is intended to provide CO_2 emission reductions for purposes of complying with the emission guidelines of 40 CFR part 60 subpart UUUU for existing fossil fuel-fired power plants.

B. Applicability.

1. An affected entity subject to the requirements of this Section is each public utility retail supplier of electricity for distribution within the State, including any investor-owned utility, municipal utility, rural electric cooperative, or other retail provider of electricity, which meets the criteria described in this Paragraph B.1.
   a. The entity serves a minimum of 3,000 retail customers;
   b. The entity owns and/or operates one or more affected EGUs located in the State, as defined under Section 1010 of Chapter 10, the State Plan for implementing 40 CFR part 60 subpart UUUU; and/or,
   c. The entity procures electricity that is generated by one or more affected EGUs located in the State, for distribution to retail customers.
2. The fossil fuel portfolio standard of this Section applies to the total amount of electricity generated by one or more affected EGUs and supplied to the grid by the affected entity during a performance period for the purpose of serving regional load in the Interconnect.

C. Fossil Fuel Portfolio Standard for Natural Gas Generation.

1. For each affected entity, a minimum percentage of the total amount of electricity supplied by fossil fuel energy resources shall be generated by natural gas, as shown in Table 1, for each performance period.

Table 1 **Retail Supplier Fossil Fuel Portfolio Standards for Natural Gas**

Performance Period	Electricity Generated by Natural Gas as a Percent (%) of Fossil Fuel Generation
Jan. 1, 2022–Dec. 31, 2024	45%
Jan. 1, 2025–Dec. 31, 2027	48%
Jan. 1, 2028–Dec. 31, 2029	50%
Jan. 1, 2030–Dec. 31, 2031 and each two-calendar year period thereafter	55%

2. The percentage of fossil fuel energy generated by affected EGUs using natural gas shall be determined using the following equation:

$$E_{NG\%} = E_{NG} / E_{FF} * 100$$

Where:

$E_{NG\%}$ is the percentage of the electricity supplied to the grid generated by an affected EGU using natural gas as fuel, expressed in percent (%) and rounded to the nearest whole number;

E_{NG} is the total amount of electricity supplied to the grid generated by an affected EGU using natural gas as fuel, during the performance period, expressed in MWh; and,

E_{FF} is the total amount of electricity supplied to the grid generated by an affected EGU using any fossil fuel, during the performance period, expressed in MWh.

Generation Shift Rule Example 1, *continued*
Fossil Fuel Portfolio Standards

D. Monitoring and Recordkeeping Requirements.

1. The responsible party for each affected entity under this Section 3010 shall monitor and record the following information. Where the required information pertains to affected EGUs not owned or operated by the affected entity, the affected entity shall obtain the information from the responsible party for the affected EGU and shall record the information for demonstrating compliance with this Section.
   a. Total hourly electricity supplied to the grid for distribution to retail customers, in MWh;
   b. For each affected EGU generating electricity supplied by the affected entity:
      i. The name and location of the affected EGU;
      ii. Total hourly electricity supplied to the affected entity for distribution to retail customers; and,
      iii. The type of fuel used by the EGU to generate the electricity supplied to the affected entity, on an hourly basis.
2. Monitoring and recordkeeping in accordance with 40 CFR § 60.5860 and 40 CFR § 60.5865, as adopted under Section 102, General Requirements for Affected EGUs, of this Chapter, shall serve to meet the monitoring and recordkeeping requirements for the same parameters under this Subsection 104.F.

E. Compliance Reporting. No later than March 15 of each year following the end of a performance period as listed in Table 1 of this Section, the responsible party for each affected entity under this Section 3010 shall submit a compliance report demonstrating compliance with the fossil fuel portfolio standard for the preceding performance period. The compliance report shall be submitted using the State Electronic Clean Power Portal.

F. Definitions. For the purpose of this Section, all terms not defined herein shall have the meaning given to identical terms as provided in Section 101 of this Chapter.

Generation Shift Rule Example 2
CO_2 Intensity Dispatch Standards

Section 3050. Electric Power CO_2 Intensity Dispatch Standard

A. Purpose. The CO_2 intensity dispatch standard of this Section is intended to provide CO_2 emission reductions for purposes of complying with the emission guidelines of 40 CFR part 60 subpart UUUU for existing fossil fuel-fired power plants.

B. Applicability.

1. An affected entity subject to the requirements of this Section is each electricity system operator providing for the dispatch of electric generating units and the transmission of electricity for distribution to retail customers within the State.
2. The CO_2 emissions intensity standards of this Section apply to the total amount of electricity dispatched to the grid by the affected entity during a given performance period, without adjustments for transmission and distribution losses.

C. CO_2 Emissions Intensity Dispatch Factor. The generation-weighted average CO_2 emissions intensity of total electricity dispatched to the power grid by each affected entity shall not exceed the CO_2 emissions intensity standard shown in Table 1 for each compliance period.

Table 1 **Emissions Intensity Standards**

Compliance Period	CO_2 Intensity, lb/MWh Dispatched, 180-day Rolling Average
January 1, 2022–December 31, 2024	1,468
January 1, 2025–December 31, 2027	1,325
January 1, 2028–December 31, 2029	1,228
January 1, 2030–December 31, 2031 and each two-calendar year period thereafter	1,169

D. CO_2 Intensity Dispatch Procedures.

1. No later than January 1, 2020, each affected entity dispatch system operator shall adopt and implement dispatching procedures to assure that the standards of this Section are met.
2. As part of the CO_2 intensity dispatching procedures, each affected entity dispatch system operator shall assign, for each electric generating unit (EGU) contracted to supply power, a CO_2 Intensity Factor for each calendar year, which shall be calculated based on data reported from the previous calendar year, using the following equation:

$$\mathbf{IF_{CO2}} = \mathbf{Em_{CO2}} \ / \ \mathbf{MWh\text{-}net}$$

Where:

IF_{CO2} is the CO_2 Intensity Factor of the EGU;

Em_{CO2} is the total CO_2 mass emissions from the EGU during the time period for which the CO_2 Intensity Factor is determined, expressed in pounds (lb), as provided in Paragraph D.4 of this Section; and,

MWh-net is the total amount of electricity supplied to the grid generated by the EGU, expressed in MWh and rounded to the nearest whole number.

Generation Shift Rule Example 2, *continued*
CO_2 Intensity Dispatch Standards

3. If warranted based on a review of historic operating data, technology design or other factors, the affected entity may assign seasonal CO_2 intensity factors for some or all contracted EGUs, in lieu of calendar year CO_2 Intensity Factors.
4. The following provisions shall apply for purposes of determining CO_2 emissions to assign the CO_2 Intensity Factor for an EGU:
   a. For affected EGUs subject to emissions monitoring, recordkeeping and reporting requirements in accordance with 40 CFR § 60.5860 and 40 CFR § 60.5865, as adopted under Section 102, General Requirements for Affected EGUs, of State Administrative Code Title X Chapter 10, emissions shall be as monitored and reported under those provisions.
   b. For zero-emitting renewable energy resources, including wind, solar, geothermal, hydro, wave and tidal generating units, and for nuclear energy, emissions shall be zero.
   c. For EGUs using qualified biomass or municipal waste as fuel, emissions shall be adjusted such that the portion of CO_2 emissions resulting from qualified biogenic fuel sources is not included in the CO_2 Intensity Factor determination.
   d. For generation derived solely from recovered heat using bottoming cycle Combined Heat and Power or Waste Heat Power technologies, emissions shall be zero.
   e. For EGUs subject to 40 CFR part 60 subpart TTTT, emissions shall be as monitored and reported in accordance with that subpart.
5. CO_2 Intensity Factors shall be accounted for, together with other factors, in making dispatch decisions in order to assure compliance with the generation-weighted average CO_2 emissions intensity standards of this Section.

E. CO_2 Intensity Dispatch Procedures Review Process.

1. No later than June 1, 2020, each affected entity dispatch system operator shall submit draft CO_2 Intensity Dispatch Procedures to the Commission for review.
2. The PUC shall review the draft procedures and provide comment to the affected entity no later than August 1, 2020.
3. The Commission shall provide an opportunity for public review and comment on all draft procedures, including the comments of the PUC.
4. The affected entity shall take into consideration all comments received during the review and comment period, whether by the PUC or others, in finalizing the CO_2 Intensity Dispatch Procedures.

F. Reliability Emergency Situations.

1. The CO_2 Intensity Dispatch Procedures adopted pursuant to this Section may provide that, in the event of an unforeseen, emergency situation that threatens reliability, the affected entity may dispatch power to address the reliability concern even though a short-term exceedance of the CO_2 Emission Intensity Standard would occur.
2. Notification must be made to the PUC within 32 hours of any emergency situation that results in dispatching power in exceedance of the CO_2 Emission Intensity Standard. A second notification to the PUC must be made within five days of the first notification.
3. Exceedances of the applicable CO_2 Emission Intensity Standard under this Paragraph 3050.F shall be no more than 90 days in duration.
4. In the event the reliability issue is not resolved within the 90-day timeframe, the affected entity shall provide

Generation Shift Rule Example 2, *continued*
CO_2 Intensity Dispatch Standards

a draft modification to the dispatch procedures to address the reliability concerns in a manner that will achieve the applicable CO_2 Emission Intensity Standards for future performance periods.

G. Compliance Reporting. No later than March 15 of each year following the end of a performance period as listed in Table 1 of this Section, the responsible party for each affected entity under this Section 3050 shall submit an annual compliance report demonstrating compliance with the CO_2 Emission Intensity Standard for the preceding performance period. The compliance report shall be submitted using the State Electronic Clean Power Portal.

H. Definitions. For the purpose of this Section, all terms not defined herein shall have the meaning given to identical terms as provided in Section 101 of this Chapter.

Generation Shift Rule Example 3
Capacity Factor Standards for Coal-fired Affected EGUs

Section 3040. Capacity Factor Standards for Coal-fired Steam EGUs

A. Applicability.

1. An affected source under this Section is each coal-fired steam electric generating unit (EGU), as defined in Subsection 3040.H. Definitions, that meets all of the following criteria:
   a. The EGU commenced construction on or before January 8, 2014;
   b. The EGU serves a generator or generators connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (i.e., capable of selling greater than 25 MW of electricity);
   c. The EGU has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and,
   d. The EGU is not subject to a federally enforceable permit limiting annual net-electric sales to a utility distribution system to one-third or less of its potential electric output or to 219,000 MWh or less.

B. Capacity Factor Standards. Except as provided in Paragraph 3040.D of this Section, each affected source shall comply with the applicable capacity factor standard as specified in Table 1 for each compliance period, for power generated by coal.

Table 1. **Coal Capacity Factor Standards for Affected Sources by Compliance Period**

Affected Source	Station	Nameplate Annual Capacity (MWh)	Period 1 2022–2024 3-year Average	Period 2 2025–2027 3-year Average	Period 3 2028–2029 2-year Average	Final Periods (2-year blocks starting with 2030-2031) 2-year Average
Pleiades ST1	Copper Canyon	995,136	25%	0	0	0
Orion ST2	Copper Canyon	3,027,456	45%	35%	30%	30%
Big Rock CST	Candy Mountain	438,000	18%	0	0	0
Whiskey River	Candy Mountain	438,000	25%	25%	25%	25%
Coal Fleet Aggregate	4,898,592	37%	24%	21%	21%	

C. Compliance Demonstration.

1. The owner or operator of an affected source shall demonstrate compliance with the applicable standards of Paragraph B of this Section using the following equation:

$$\mathbf{CF_{Coal} = MWh\text{-}net_{Coal} \,/\, (MWh_{NP} * Y)}$$

Where:

CF_{Coal} is the Coal Capacity Factor for the affected source for the performance period, expressed as a percent (%) of the nameplate capacity of the affected source;

MWh_{Coal} is the total electrical output generated by coal during the performance period;

MWh_{NP} is the nameplate annual capacity for the affected source, expressed in MWh, as provided in Table 1 of this Section; and,

Y is the number of years in the performance period.

Generation Shift Rule Example 3, *continued*
Capacity Factor Standards for Coal-fired Affected EGUs

2. For purposes of determining the electrical output generated by coal, if coal is co-fired with another fuel at an affected source, then the portion of electrical output attributed to generation by coal for each hour shall be determined by multiplying the ratio of the heat input (HI) provided by coal to the total heat input provided by all fuel to the affected source times the total electrical output for each hour, as follows:

$$MWh_{Coal} = HI_{Coal} / HI_{Total} * MWh_{Total}$$

3. Facility-wide Aggregation. The owner or operator of multiple affected EGUs located at the same facility may elect to demonstrate compliance with the applicable capacity factor standards of Paragraph B of this Section by demonstrating that the total output weighted capacity factor for all affected sources at the facility is equal to or less than the output weighted average of the capacity factor standards for the affected sources during the compliance period.
4. Owner/Operator Fleet-wide Aggregation. The owner or operator of multiple affected sources under common control located in the State may elect to demonstrate compliance with applicable capacity factor standards of Paragraph B of this Section by demonstrating that the total output weighted capacity factor for all affected sources in the owner/operator's fleet is equal to or less than the output weighted average of the capacity factor standards for the affected sources during the compliance period.

D. Revisions to Emission Standards.

1. Capacity factor standards for individual affected sources may be revised by the Administrative Authority, provided that the revised capacity factor standard(s) result in the coal fleet aggregate capacity factor for each performance period remaining at or below the coal fleet aggregate capacity factor specified in Table 1 Paragraph B of this Section.
2. Any revision to a capacity factor standard approved by the Administrative Authority shall be made no later than twelve months before the ending date of the compliance period for which the revised standard would apply.
3. The owner or operator of an affected source may request a revision to an applicable standard under this Section by submitting an application for a significant modification to revise the facility's Title V Operating Permit, pursuant to Chapter 9, Operating Permits for Major Sources.
4. The Administrative Authority may initiate a revision to an applicable standard for an affected source under this Section by issuing a notice to reopen the facility's Title V Operating Permit, pursuant to Chapter 9, Operating Permits for Major Sources.

E. Reliability Safety Valve.

1. An affected source may be exempt from the applicable capacity factor standard under this Section for a period of up to 90 days during a performance period, in the event of an unforeseen, emergency situation that threatens reliability, if dispatch of the affected source at a level that would result in an exceedance of the applicable capacity factor for the performance period is critical to address the reliability concern.
2. Notification must be made to the Administrative Authority within 32 hours of any emergency situation that results in dispatching power from an affected source to address a reliability concern, where such dispatch may result in exceedance of the applicable capacity factor for the performance period. A second notification, providing a status of the emergency situation and utilization of the affected source, must be made within five days of the first notification.
3. The Administrative Authority may grant an exemption of up to 90 days based on the information provided in the first and second notice under this Paragraph 3040.E.

9.6 Replacement Generation Measures

The development and deployment of renewable energy and other low- or zero-emitting energy sources[431] is likely to be a key strategy for achieving CPP emission goals under any plan, and will likely be a key element of any state measures plan. In particular, for any state measures plan that seeks to rely primarily upon state-enforceable measures, state RE and EE programs will most likely serve as the foundation for demonstrating the plan will succeed.

This section addresses a number of low- and zero-emitting generation technologies in the context of a state measures plan, and provides examples of rule language a state may consider as a starting point to incorporate RE into the state measures plan. The energy sources addressed in this section include each of those incorporated by EPA as an element of BSER or approved by EPA as an ERC-qualifying resource for purposes of implementing a rate-based plan to comply with the CPP. However, other low- or zero-emitting technologies could be approved by EPA for inclusion in a state plan.[432] Also, while this chapter focuses on inclusion of renewable and other low-emitting technologies as part of a state measures plan, much of the discussion is equally relevant to emission standards plans. For example, a state adopting a rate-based plan that authorizes the use of waste-to-energy power generation as an ERC-qualifying resource may find the discussion and example rule language for waste-to-energy useful for those purposes.

9.6.1 Overview of Renewable, Low- and Zero-emitting Generation

The RE technologies incorporated by EPA as an element of BSER Building Block 3 include:

- Onshore wind;
- Utility-scale solar PV;
- Concentrating solar power (CSP);
- Geothermal; and
- Hydropower.

Only utility-scale RE is included under BSER, with no contribution from distributed energy program deployment. Additional RE and low-emitting energy sources are listed as qualifying resources for ERC issuance in Subpart UUUU, including:

- Wave and Tidal energy;
- Qualified biomass;
- Waste-to-energy (biogenic portion only);
- Nuclear; and
- Combined heat and power (CHP) applications that are not affected EGUs.

A brief description of each of these technologies is provided below. Additional information is available in *Implementing EPA's Clean Power Plan: A Menu of Options.*[433] Further discussion related to inclusion of particular technologies in a state measures plan is provided in the following sections.

9.6.1.1 Onshore Wind

Onshore wind accounts for 31% of new electricity capacity added to the U.S. grid between 2008 and 2014. The cost of wind power generation has dropped steadily and dramatically since 1980, by approximately 80%, as shown in Figure 9.5, below. Twenty-three states have at least 500 MW of wind power installed, and wind power exceeds 10% of in-state power generation in nine states. As of 2014, there were 65,000 MW of land-based wind power on the grid, providing 4.4% of total U.S. generation. An additional 13,600 MW were under construction as of the first quarter 2015. Technology advances continue to move wind power into the mainstream, with design improvements such as longer turbine blades and taller towers increasing the potential of wind power output by 67% above turbines currently deployed.[434] According to DOE, near-future technology will expand the technical feasibility of wind power geographically across much of the southeast U.S., where currently deployed technology would not meet technical feasibility thresholds.[435]

431 For simplicity, the term "renewable energy" or "RE" may sometimes be used in this chapter to refer to all zero- or low-emitting energy sources as a group. CPP-qualifying generation resources are also referred to herein as "replacement generation."

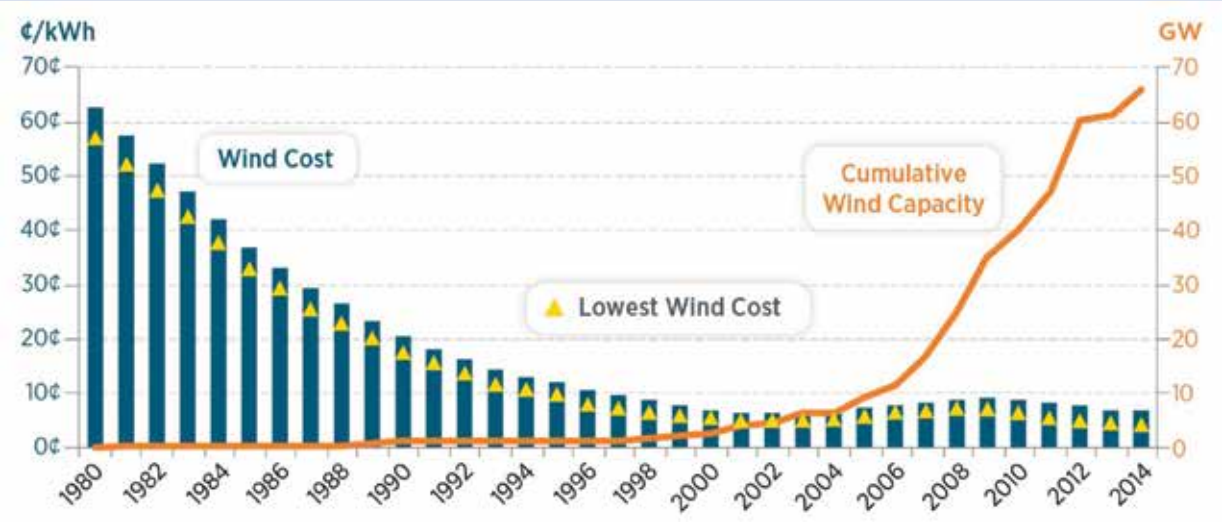
432 40 C.F.R. § 60.5800(a)(4)(vii).

433 NACAA, May 2015, available at http://www.4cleanair.org/NACAA_Menu_of_Options. See in particular *Chapter 6: Increase Generation from Low-Emission Resources and Chapter 2: Implement Combined Heat and Power in the Electric Sector.*

434 DOE, *Revolution…Now, The Future Arrives for Five Clean Energy Technologies – 2015 Update,* November 2015, http://www.energy.gov/sites/prod/files/2015/11/f27/Revolution-Now-11132015.pdf.

435 U.S. Department of Energy, *Enabling Wind Power Nationwide,* May 2015.

Figure 9.5 **Trends in Onshore Wind Power Cost and Capacity**[436]



Notes: 1 gigawatt (GW) = 1,000 megawatts (MW). All costs shown are inflation adjusted to dollar year 2014 and exclude the production tax credit (PTC). Wind capacity as reported by market reports. "Wind Cost" represents estimated levelized cost of energy from a representative wind site, and "Lowest Wind Cost" represents costs derived from power purchase agreements from good to excellent wind resource sites in the interior of the country.

9.6.1.2 Utility-scale Solar PV

Utility-scale solar photovoltaic (PV) facilities are grid-connected, enter into long-term power purchase agreements (PPAs) with one or more power companies for the sale of electricity, and are typically stand-alone installations. By contrast, a net-metering solar PV facility is one that is typically installed on the rooftop of the primary power consumer, such as a home or business, with excess power going to the grid for sale. No standardized size threshold defining utility-scale installations has been adopted; various references range from less than 5 MW to greater than 50 MW. State-specific legislation generally establishes a maximum size threshold eligible for net metering to the grid.[437] Deployment of utility-scale solar PV is experiencing a rapid increase. In 2014, the total capacity of utility-scale solar PV reached 9.7 GW. Over 99% of that capacity was installed after 2008, with utility-scale solar PV accounting for 15% of all new electric capacity brought online from January to September 2015. The cost of a utility-scale solar PV system declined 59% between 2008 and 2014 from $5.70/watt to about $2.74/W.[438]

9.6.1.3 Concentrating Solar Power (CSP)

Concentrating solar power (CSP) systems produce electricity by focusing sunlight to heat a fluid, which then creates steam for powering a conventional steam turbine. CSP plants consist of three major subsystems: one that collects solar energy and converts it to thermal energy; one that stores thermal energy and sends it to the power block; and the power block, which converts the thermal energy to electricity.[439] The CSP market is another RE technology market that is expanding rapidly. The first utility-scale CSP plant commenced operation in the 1980s in the California Mojave Dessert. As of 2012, there were 503 MW of utility-scale CSP facilities operating in the U.S., located in only three states: California (364 MW); Florida (75 MW); and Nevada (64 MW). Yet, more than 4,000 MW of capacity were under development in 2012, representing an almost ten-fold increase.[440]

9.6.1.4 Geothermal

Geothermal energy technology uses heat from beneath the earth's surface to generate electricity. Existing geothermal plants operate throughout the Western U.S., relying on subsurface reservoirs of steam or hot water

436 Figure taken from DOE, *supra* note 434.

437 Patrick Donnelly-Shores, *What Does 'Utility-scale' Solar Really Mean?,* Greentech Media, July 30, 2013.

438 DOE, *supra* note 434.

439 Michael Mendelsohn et al., *Utility-Scale Concentrating Solar Power and Photovoltaics Projects: A Technology and Market Overview,* National Renewal Energy Laboratory, DOE, April 2012.

440 *Ibid.*

as the energy source, generating electricity with a steam turbine. Geothermal energy production has increased slowly but steadily over the last decade, with net generation increasing from 14.57 billion kWh in 2006 to 15.67 billion kWh in 2010, accounting for approximately 3.7% of all renewable energy generation.[441] This RE technology is also advancing. DOE's National Renewable Energy Laboratory (NREL) predicts that advanced engineering will capture the intense heat deep below the earth's surface for electricity generation across the country in the foreseeable future.[442]

9.6.1.5 Hydropower

Hydropower generates almost 90% of all renewable energy globally, and accounted for about 60% (257 billion kWh) of U.S. renewable net electricity production in 2010.[443] Hydroelectric power plants come in all sizes, the largest ones having a production capacity of more than 10 GW. Most hydropower comes from the kinetic energy of dammed water driving a water turbine and generator. The major advantage of hydropower is that the fuel is readily available at no cost. In addition, hydroelectric power plants have a long economic life and require limited staff resources for their operation. Like conventional hydropower, wave and tidal power also harness the kinetic energy of water.

9.6.1.6 Wave Energy

Wave energy technology has not been deployed; it is a new technology currently under development. Harnessing the kinetic energy of waves promises significant potential as a source of electricity generation; the total energy potential of waves off the coasts of the United States is 252 billion kWh a year, equivalent to about 6% of U.S. electricity generation in 2014. In particular, the west coast of the United States has good-potential wave energy sites. Wave energy could be harnessed by directing waves into a narrow channel, increasing their power and size, and using the energy to spin turbines that generate electricity. Other potential methods include placing devices on or just below the surface of the water, and anchoring the devices to the ocean floor.[444]

9.6.1.7 Tidal Energy

Tidal energy technology aims to utilize the subsurface flux of tides. Tide energy is distinct from wave energy, which relies on the surface movement of water. Because tides are caused by the gravitational pull of the moon and sun traversing predictable orbits and rotational cycles, tides are more predictable than wind. Tides can create water rises of up to 40 feet, providing a naturally occurring opportunity to unleash kinetic energy. A tide height of at least 10 feet is required to make tidal energy viable. Three types of tidal power technology are currently in use or under development: tidal fences; tidal turbines; and tidal barrages. A tidal fence forces water moving through a land-formed channel to move through vertically mounted turbines. No tidal fence projects have been completed; one is planned for the San Bernardino Strait in the Philippines. Tidal turbines use the same basic design as wind turbines, but must be constructed to withstand the density of water, which is about 800 times denser than air. Only two tidal turbines are operating globally, each with a 1.5 MW capacity; they are located in Scotland and South Korea.[445] Tidal barrages, located across an inlet of an ocean bay or lagoon that forms a tidal basin, use sluice gates to control water levels and flow rates of both the incoming and outgoing tides. Only six tidal barrages are in use worldwide. Two are approximately 250 MW capacity and are located in South Korea (254 MW) and France (240 MW). The other four are smaller units ranging from 1 to 20 MW, located in Canada, China, Russia and South Korea. According to DOE, only a few sites in the U.S. could produce tidal power economically.

9.6.1.8 Qualified Biomass

In 2010, the combustion of biomass accounted for 11.5 billion kWh of U.S. electricity generation, or 0.33% of the total U.S. generation. Of that, 10.1 billion kWh was from dedicated biomass firing, and 1.4 billion kWh was from co-firing of biomass with fossil fuel.[446] The CPP emission guidelines acknowledge that certain waste-derived biomass feedstocks and certain forest-derived industrial byproducts, such as those without alternative markets, are likely to have minimal or no net atmospheric contribu-

441 DOE, *Renewable Energy Consumption and Electricity Preliminary Statistics 2010,* Data Table 3, available at http://www.eia.gov/renewable/annual/preliminary/.

442 National Renewable Energy Laboratory, *Geothermal Technologies,* http://www.nrel.gov/geothermal/.

443 *Ibid*.

444 U.S. Energy Information Administration, Hydropower Explained: Wave Power, http://www.eia.gov/Energyexplained/index.cfm?page=hydropower_wave.

445 U.S. Energy Information Administration, Hydropower Explained: Tidal Power, http://www.eia.gov/Energyexplained/index.cfm?page=hydropower_tidal.

446 Joe Marriot & Booz Allen Hamilton, *Contribution of Biomass to the LCI of Cofiring Power,* NETL, DOE, September 2012.

tions of biogenic CO_2 emissions, and may reduce biogenic CO_2 impacts when compared to alternative means of disposal.[447] However, not all forms of biomass are expected to be approvable as a qualified biomass for use in a state plan. "Qualified Biomass" is defined in Subpart UUUU to mean "a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere."[448] Each state plan that proposes to recognize qualified biomass as a replacement generation strategy must provide qualifying criteria and EM&V procedures for EPA review and approval in the state plan. Further discussion of demonstrations and requirements for state plans that seek approval for biomass feedstocks as a qualified CO_2 emission reduction strategy is provided in Section 9.6.3.1.

9.6.1.9 Waste-to-Energy (WTE)

Waste-to-Energy (WTE) is defined in Subpart UUUU to mean "a process or unit (e.g., solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat."[449] Municipal solid waste (MSW) WTE facilities typically recover heat from the incineration or combustion of waste at high temperatures. Recovered heat is used to generate steam, which drives a steam turbine for the generation of electricity. Many MSW WTE facilities process the combustion ash to extract and recover metal for recycling. In 2011, WTE plants operated in 20 states and generated approximately 14 million MWh of electricity from MSW, or about 0.3% of total U.S. generation, roughly the same as geothermal electricity generation in the United States. In 2010, WTE plants converted about 12% of total domestic MSW to energy.[450] EIA data indicate that in 2014, the U.S. MSW generation capacity was distributed among 94 EGUs at 71 plants, with a total nameplate capacity of 2,688 MW.[451] Subpart UUUU establishes state plan requirements for the use of WTE as a CO_2 reduction measure. Further discussion of these requirements is provided in Section 9.6.3.2.

9.6.1.10 Nuclear Energy

Nuclear energy provided 16% of total U.S. electricity generation in 2013, the third largest fuel source following coal (39%) and natural gas (27%), and is the largest source of zero-emitting generation. In the CPP emission guidelines, EPA recognizes five nuclear facilities under construction as of 2014, and notes that these units are expected to play a role in replacing generation from fossil-fueled EGUs. Accordingly, EPA has recognized nuclear as a zero-emitting generation resource, and states may rely on new or expanded nuclear as a state measure to reduce CO_2 emissions in the context of a state measures plan.[452]

9.6.1.11 Combined Heat and Power (CHP) and Waste Heat Power (WHP)

Combined Heat and Power (CHP) units produce both electricity and thermal energy or mechanical power. CHP is typically fueled by fossil fuel and so is not a renewable energy resource; however, CHP can produce power with zero incremental CO_2 emissions, or can provide an energy-efficient means of producing thermal energy that minimizes or avoids the use of electricity, thereby reducing CO_2 emissions from affected EGUs. CHP can be configured in a "topping cycle" or a "bottoming cycle" mode. Topping cycle CHP uses fuel to generate electricity, and then recovers the exothermic heat from the electricity generation cycle to produce thermal or mechanical energy. Conversely, a bottoming cycle CHP configuration uses fuel to first generate thermal energy (e.g., for an industrial process), and then recovers the "waste" or excess heat to drive a steam turbine for generating electricity.[453] Bottoming cycle CHP is a type of waste heat power (WHP). Another type of WHP is an EGU configuration where fuel is first used to generate electricity (as opposed to thermal or mechanical energy), and then the heat from the initial fuel combustion is recovered to generate additional power.[454] A rate-based plan can qualify non-affected EGU CHP resources for ERC issuance.[455] Similarly, a state measures plan can rely on qualified CHP as a CO_2 reduction strategy, provided all other qualifying criteria are met.

447 80 Fed. Reg. at 64,885.

448 40 C.F.R. § 60.5880.

449 *Ibid*.

450 U.S. Energy Information Administration, Municipal solid waste plants convert garbage to electricity, September 17, 2012, https://www.eia.gov/todayinenergy/detail.cfm?id=7990.

451 U.S. Energy Information Administration, Annual Electric Generator Data, 2014, available at http://www.eia.gov/electricity/data/eia860/index.html.

452 80 Fed. Reg. at 64,757.

453 80 Fed. Reg. at 64,902 n.965.

454 80 Fed. Reg. at 64,903.

455 40 C.F.R. § 60.5800(a)(4)(v); 80 Fed. Reg. at 64,757.

Subpart UUUU establishes state plan requirements for the use of CHP as a CO_2 reduction measure. Further discussion of these requirements is provided in Section 9.6.3.3.

9.6.2 State Measures Plan Requirements for Replacement Generation Strategies

Each state measure relied upon to achieve the CPP emission goals in a state measures plan must be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity.[456] These are the same criteria that must be demonstrated for any federally enforceable emission standard included in a state plan. Accordingly, it is likely that EPA will expect states to adopt an equivalent level of monitoring, recordkeeping, reporting, and associated integrity assurance provisions for low- and zero-emitting EGUs included under a state measures plan as for the same or similar replacement generation EGUs included under an emission standards state plan. Notably, EPA's TSD for incorporating RE and EE measures in a state plan specifies that state plan performance projections of impacts from state RPS programs must be adjusted to disregard any generation from technologies that are ineligible under the final CPP emission guidelines.[457]

9.6.2.1 Quantifiable and Verifiable (EM&V)

The criteria of quantifiable and verifiable are met if the relevant elements of the strategy (e.g., emissions or electricity generated) can be reliably measured in a manner that is replicable, and if adequate monitoring, recordkeeping and reporting requirements are imposed to provide the necessary data and to allow the administrative authority to independently verify compliance.

For zero-emitting EGUs, such as nuclear, wind or solar, the relevant information that must be measured is the net generation provided to the grid. One approach to address these resources is to require any RE or nuclear EGU relied upon for replacement generation to install and operate a revenue-quality electricity meter. For EGUs with a small capacity, an alternative approach may be appropriate.

For other low-emitting replacement generation with special requirements, such as qualified biomass, CHP and WTE, additional information will also need to be monitored and reported. Both biomass and WTE EGUs will likely also be subject GHG emissions measurement and reporting under 40 C.F.R. Part 98. Table 9.7 provides a summary of the monitoring provisions in EPA's proposed

Table 9.7 **Summary of EPA Proposed Monitoring for Low- and Zero-emitting EGUs**

ERC Resource Type	Approach	EM&V
RE and Nuclear >10 kW	Measure generation continuously, electronic data collection	A revenue-quality meter or EPA-approved alternative
RE ≤ 10 kW	Measure generation at least monthly	Use software or algorithms based on the unit's capacity, estimated capacity factors, and an assessment of the local conditions that affect generation
Qualified Biomass Feedstocks	Measure generation as for RE, and meet requirements specific for the feedstock	The monitoring and reporting requirements for biogenic CO_2 emissions in 40 C.F.R. Part 98 (40 C.F.R. §§ 98.3(c), 98.36(b)-(d), 98.43(b) & 98.46) are presumptively approvable[458]
Waste-to-Energy	Measure generation as for RE, and determine the portion of energy from biogenic waste	
Combined Heat & Power (CHP) >25 k	Measure generation continuously, electronic data collection	Meet monitoring requirements for affected EGUs
CHP ≤25 kW	Measure generation per Part 75	Meet the low mass unit monitoring requirements of Part 75
CHP ≤1 kW	Monthly records of thermal output and record of baseline thermal efficiency per manufacturer data	Keep monthly cumulative records of useful thermal output and fossil fuel input

456 40 C.F.R. § 60.5780.

457 EPA Technical Support Document, Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations, July 31, 2015, https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-incorporating-re-ee.pdf, p. 17.

458 80 Fed. Reg. at 65,005.

rate-based model state rule for low- and zero-emitting EGUs seeking eligibility for ERC issuance.

9.6.2.2 Permanent and Enforceable

To be considered permanent, an applicable action or measure must be required for the entirety of the relevant compliance period or plan performance period, unless and until it is subsequently removed or replaced through an EPA-approved state plan revision.[459] Accordingly, the state measures plan demonstration will need to document the relevant time period for which each applicable replacement generation strategy is relied upon, and establish that the duration of the requirement is adequate to achieve and maintain the statewide emission goals. For example, if the state is relying upon an RPS, the plan demonstration should project the level of the RE performance standard required over the course of each interim step period and into the final performance period to demonstrate that the necessary emission reductions are achieved. In addition, the instrument through which the RPS is administered and enforced (e.g., state regulations) must be in effect for the duration of each compliance period for which the resulting emission reductions are claimed.

Each state measure must be enforceable, therefore RE and other replacement generation projects that are completely voluntary in nature, with no mechanism for state enforceability, cannot be included in the plan performance projections.[460] To be considered enforceable, the requirement must be clearly defined in a technically accurate manner, including any appropriate averaging period, with adequate monitoring, reporting and recordkeeping requirements to render the requirement enforceable as a practical matter. In addition, the affected entity must be clearly identified and the state must demonstrate adequate legal authority to enforce the requirements.

9.6.2.3 Non-duplicative

Low- and zero-emitting generation relied upon in a state measures plan is considered non-duplicative provided it is not also incorporated as a reduction strategy in another state plan or state plan supporting material, except if it is included as part of a multi-state plan and only states that are part of the multistate group are claiming the measure. In general, because a state measures plan is mass-based, the effect of the state measure is reflected at the stack, in the form of lower reported emissions. Additionally, the plan performance metric is the mass emission goal, and collective emissions from affected EGUs are directly compared to the mass-based goal to assess plan performance. Therefore, EPA has determined that, as a practical matter, no double-counting of emission reductions associated with measures located in a mass-based state can take place.[461] Accordingly, any potential concerns regarding double-counting of RE or other replacement generation arises not in the context of measuring plan performance during implementation for the state measures plan, but with regard to two other possible concerns. First, during plan development and approval, and in developing the plan performance projections, the state will need to consider the extent to which RE and other replacement generation sources located within the state or region will likely serve to reduce generation and emissions from the state's affected EGUs (as opposed to replacing generation from other affected EGUs in the regional interconnect). This concern would be largely mitigated or eliminated if the state measures plan is a multi-state plan or a plan involving a regional mass trading program. The second circumstance for which double-counting may need to be addressed involves interactions of the state measures plan with rate-based states—and, in particular, assessing the potential impacts of interactions between state RPS Renewable Energy Credits (RECs) issued under the state measure and ERCs issued by rate-based states. These considerations are addressed in the following paragraphs, with further discussion provided in *Section 9.9, State Measures Plan Performance Demonstrations.*

Avoiding Double-Counting of Replacement Generation from In-State EGUs

The potential for double-counting of in-state replacement generation resources could be a concern for a state measures plan only during plan development and in making demonstrations projecting plan performance as part of the plan submittal. That is, if the level of generation projected from incremental RE and low-emitting EGUs that will replace generation from affected EGUs within the state is overestimated, then actual plan performance could be less than predicted. Again, during plan implementation and reporting, there is no concern that the effects of the low- or zero-emitting EGUs on reducing emissions of in-state EGUs could be double-counted by the state, because stack emissions are used to assess plan

459 40 C.F.R. § 60.5780(a)(4).

460 40 C.F.R. § 60.5780; see also EPA TSD, *Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations, supra* note 457, at 16.

461 80 Fed. Reg. at 64,913.

RPS for In-State Power Generation

C. Renewable Portfolio Standards.

1. Except as provided in Paragraph C.2, the renewable portfolio standards of this Section apply to the total amount of electricity generated within the State and supplied to the grid by the affected entity during a performance period for the purpose of serving regional load in the Interconnect.

2. For purposes of demonstrating compliance with the renewable portfolio standards, qualified renewable energy generated outside of the State may be counted in determining the total amount of electricity supplied (i.e., included in the denominator in Equation 1) and credited toward meeting the renewable portfolio standard (i.e., included in the numerator in Equation 1), provided it meets the criteria of Paragraph D.

3. For each affected entity, a minimum percentage of the total amount of electricity supplied during each performance period shall be generated by qualified renewable energy resources as follows:

Table 1. **Renewable Energy Portfolio Standards**

Performance Period	Minimum Required Electricity Generated by Renewable Energy Resources, as a Percent (%) of Total Electricity Supplied*	Maximum Allowable Renewable Resources Provided by Out-of-State Generation, as a Percent (%) of Total Electricity Supplied*	Minimum Required Incremental Renewable Energy, as a Percent (%) of Total Electricity Supplied*
Jan. 1, 2022–Dec. 31, 2024	20%	10%	5%
Jan. 1, 2025–Dec. 31, 2027	22%	10%	8%
Jan. 1, 2028–Dec.31, 2029	25%	10%	12%
Jan. 1, 2030–Dec. 31, 2031 and each two-calendar year period thereafter	30%	10%	15%

**Total electricity supplied by the affected entity includes all electricity generated in-state plus any renewable energy generated out-of-state that is used to meet the portfolio standard.*

[From Replacement Generation Rule Example 1]

performance. Regarding the potential for these reduction strategies to be double-counted by another state, only a rate-based state could potentially double-count the reductions, through the issuance of ERCs for the same MWh's of replacement generation. Also, generation from nuclear, qualified biomass, WTE or qualified CHP EGUs located in a mass-based state cannot qualify for ERC issuance under a rate-based program; therefore, no double-counting of the impact from these resources could occur. Furthermore, the CPP eligibility provisions regarding geographic location of RE resources guard against double-counting of generation for RE located in mass-based states, by requiring the EGU owner/operator to demonstrate the generation is intended to service load in a rate-based state in order to qualify for ERC issuance.[462] Therefore, no double-counting of replacement generation from EGUs located in-state could occur by other states during plan implementation, provided the other state plans meet the CPP guidelines.

While there is little risk of double-counting during plan implementation, a state developing a state measures plan that relies on low- and zero-emitting replacement generation should assure that double-counting of reductions is avoided in plan performance projections. Specifically, the state measures plan projections should appropriately address any anticipated RE generation located in the state that would be intended to serve load in another state, including any rate-based state. Taking into account any in-state RE or low-emitting EGUs that have power purchase agreements or power delivery contracts to serve other states will help to assure the plan projections are reasonably predictive of emission reductions that will be achieved by the state measures plan. Plan projections to incorporate the impacts of RE and EE state measures are discussed further in Section 9.9.

Another option a state measures plan could adopt to assure the integrity of the plan performance projection would be to design the RPS to specifically target a level

462 40 C.F.R. § 60.5800(a)(3)(ii).

of incremental replacement generation for power generated within the state, as opposed to power sold within the state. Model language for implementing this approach is included in ***Replacement Generation Rule Example 1, RPS for In-State Power Generation,*** located in Section 9.6.7, Replacement Generation Rule Examples.

Avoiding Double-Counting of Replacement Generation Located in Other States

A separate consideration regarding double-counting involves how the state plan performance projections treat RE or low-emitting generation located in other states. For example, many state RPS provisions allow for the use of RECs from qualifying resources located in other states. However, if the state's plan projections rely on replacement generation from RE resources in another state, and that other state plan is also relying on the same MWh's of replacement generation to achieve compliance, either through issuance of ERCs or directly through mass emission reductions, then the state's RPS measure could be duplicative of measures or emission standards incorporated in another state plan. This concern can be addressed in a number of ways in the plan provisions and/or performance projections. For example, regional modeling conducted jointly with other states in the interconnection, which appropriately accounts for the proposed state measures, would not allow any given MWh of generation to serve the load in multiple states. If regional modeling that accurately accounts for the overlap between the state plans nonetheless predicts generation and mass emission levels from affected EGUs that achieve the statewide mass emission goals, adequacy of the RPS measures would be demonstrated.

The state could also include provisions in the state RPS policy that expressly prohibit a resource from receiving RECs under the state program if it is also receiving ERCs under another state plan for CPP compliance purposes. With such an explicit implementation provision in place, no discounting of the RPS requirement to address potential double-counting should be needed in modeled projections of plan performance. Illustrative language for prohibiting duplicative use of replacement generation is included in ***Replacement Generation Rule Example 2, Provisions to Avoid Duplicative Replacement Generation Credits.***

> A REC does not qualify for use in meeting the Renewable Portfolio Standards of this Section if any party in another State or Territory has relied upon the same MWh of electricity for issuance of an Emission Rate Credit (ERC) or otherwise for purposes of demonstrating compliance with a state plan under 40 CFR part 60 subpart UUUU, or with a federal plan under 40 CFR part 62 subpart NNN administered by the U.S. EPA Administrator or the Administrator's agent.
>
> *[From Replacement Generation Rule Example 2]*

9.6.3 Special Considerations for Replacement Generation Strategies

Some categories of replacement generation require special consideration if incorporated in a state plan. Specifically, power generation from biomass, waste-to-energy, and combined heat and power EGUs must meet particular criteria set forth in the emission guidelines. Each of these replacement generation categories is discussed below.

9.6.3.1 Qualified Biomass

Subpart UUUU imposes specific requirements for qualified biomass resources to qualify for the issuance of ERCs under a rate-based plan, or to qualify for set-aside allowances under a mass-based trading program.[463] Further, the TSD guidelines for incorporating RE in state plan demonstrations indicate that only eligible resources can be taken into account in plan projections. Therefore, it is likely that EPA will rely on the same considerations to review and approve a state measures plan that proposes to rely on qualified biomass as a replacement generation strategy as would apply under a rate-based plan or mass-based trading program. Specifically, a state plan that relies on replacement generation from qualified biomass must include the categories of proposed qualified biomass feedstocks and a description of why those feedstocks should qualify as a reduction strategy; the proposed valuation of biogenic CO_2 emissions from those feedstocks; and methods for monitoring and verifying emissions from biomass combustion as part of the plan, including appropriate EM&V procedures, together with any relevant supporting documentation, for EPA review and approval.[464] For a state measures plan that does not include a mass-based trading program, reliance on qualified biomass would likely be in the form of an RPS or similar mechanism. In this case, it is likely that EPA would require that only qualified biomass generation, subject to EM&V provisions, be included in the plan performance projections. In addition, it is likely that EPA

463 40 C.F.R. §§ 60.5800(d)(1) & 60.5815(c).

464 80 Fed. Reg. at 64,885-87.

approval would extend to consideration of state-enforceable RECs derived from biomass generation only to the extent the biomass feedstock meets the criteria for qualified biomass under the CPP guidelines.

In some instances, an EGU may be a dedicated qualified biomass unit. In other instances, affected EGUs may co-fire qualified biomass as a means to reduce fossil-fuel generation and associated CO_2 emissions directly at the affected EGU. Affected EGUs that will co-fire qualified biomass with fossil fuels must have an approved method in place to determine the proportion of CO_2 emissions that would not be counted toward the CPP emission goal, and must monitor and report both total CO_2 emissions and biogenic CO_2 emissions. In these situations, under a state measures plan, it may not be necessary to determine the amount of generation attributable to qualified biomass, provided the associated biogenic emissions can be measured. 40 C.F.R. Part 98 provides EPA-approved and required methods for determining the amount of CO_2 emissions attributable to biomass from a source that co-fires both fossil fuels and biomass.[465]

EPA has proposed presumptively approvable state plan language for EM&V provisions for qualified biomass in the proposed federal plan and model state rules. See Table 9.7 for a summary of those provisions.

9.6.3.2 Waste-to-Energy (WTE)

One type of qualified biomass that may be included as a resource for replacement generation is the biogenic portion of MSW combusted in a WTE facility. Subpart UUUU imposes specific requirements for WTE resources to qualify for the issuance of ERCs under a rate-based plan, or to qualify for set-aside allowances under a mass-based trading program.[466] As for other qualified biomass resources, it is likely that EPA will rely on the same considerations to review and approve a state measures plan that proposes to rely on WTE as a replacement generation strategy as would apply under a rate-based plan or mass-based trading program. Two specific demonstrations are required in a state plan regarding WTE.

First, the plan must assess the capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. Since the eligible WTE resource would be either an expanded capacity or new facility, the state would likely want to focus this assessment on the area from which the WTE facility would receive the waste feed stream. Capacity for strengthening or expanding waste reduction, reuse, recycling and composting programs would be dependent on several factors, including but not limited to the availability of funding mechanisms and the available market for recycled or composted materials. Measures to minimize any potential impacts of WTE facilities on waste reduction, recycling and compositing programs may include, for example, requiring that municipal waste be routed to the WTE facility only after processing by available recycling and compositing facilities. A comprehensive state plan including illustrative language for a WTE demonstration is provided in *Section III, Model State Plans.*

The second required plan element for WTE resources is the inclusion of the method to be used for determining the proportion of the total MWh of generation that is eligible as replacement generation under the CPP emission guidelines. The emission guidelines do not prescribe a particular method; rather, EPA will review the state's proposed method during plan review and approval.[467] EPA directs states to consider the revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources and the EPA Decision Support Tool for EPA's Waste Reduction Model (WARM) for assistance in assessing biogenic feedstocks used in WTE facilities.[468]

With regard to CO_2 emissions measurement and verification, WTE facilities are subject to GHG emissions monitoring and reporting requirements under 40 C.F.R. Part 98, and EPA has noted that these requirements are presumptively approvable for purposes of the Subpart UUUU.[469] Under Part 98, WTE facilities must sample stack exhaust gas quarterly for radiocarbon analysis to determine the fraction of CO_2 emissions that is biogenic in origin.[470] Thus, the proportion of biogenic to non-biogenic CO_2 emissions can be obtained directly from Part 98

465 *See, e.g.,* 40 C.F.R. § 98.34.

466 40 C.F.R. §§ 60.5800(d)(2) & 60.5815(c).

467 80 Fed. Reg. at 64,900.

468 80 Fed. Reg. at 64,900; *see also* EPA, *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources,* November 2014, http://www3.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.

469 80 Fed. Reg. at 65,005.

470 40 C.F.R. §§ 98.33(e) & 98.34(d), referencing using ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis and ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

monitoring, testing and reporting. The fraction of biogenic carbon emissions could be used as a surrogate for the fraction of biogenic waste fuel for the facility. Alternatively, the state could propose a different method for determining the proportion of biogenic waste in the total waste feed stream.

Total generation (MWh) will also be monitored and reported for metering purposes and in accordance with 40 C.F.R. Part 75 as required. To determine the proportion of total generation that is derived from biogenic materials, additional information is required, because different biogenic and non-biogenic materials have differing heating values.[471] Accordingly, a state plan proposing to rely on WTE as a CO_2 reduction strategy will need to either specify a particular method to be used, or include a requirement that each new or expanded-capacity WTE facility propose a method for prior approval. Note that EPA's proposed federal plan and model state rules do not specify a particular method for determining the relative heating values of biogenic to fossil-derived waste, or for otherwise determining the biogenic proportion of total generation based on the Part 98 stack gas sampling and analysis. Instead, the proposed federal plan and model state rules would require each WTE facility to include a proposed method in the proposed EM&V plan.[472]

The following equation provides one potential option for determining the MWh of biogenic-derived generation, based on the relative heating values of the biogenic waste and total waste stream, the fraction of biogenic carbon as derived from Part 98 sampling and analysis, and the total metered generation. It is important to note that this equation does not account for any difference in the combustion efficiency of the WTE system for biogenic waste as compared to fossil-derived wastes. Sample rule language incorporating this equation as a pre-approved method is included in ***Replacement Generation Rule Example 3, Accounting Provisions for Waste-to-Energy Generation.***

$$MWh_{Bio} = MWh_T \star F_{Bio} \star \left(\frac{HHV_{Bio}}{HHV_{MSW}} \right)$$

Where:

MWh_{Bio} is the calculated net WTE electricity generation from biogenic materials (MWh);

MWh_T is the total net electricity output to grid as measured and reported per the state plan requirements (MWh);

F_{Bio} is the fraction of total CO_2 emissions from biogenic material as measured and reported pursuant to 40 C.F.R. § 98.34(d), used as a surrogate for the fraction of biogenic waste in the total waste feed stream;

HHV_{Bio} is the annual average high heating value for biogenic waste received by the WTE facility; and

HHV_{MSW} is the annual average high heating value for total municipal solid waste received by the WTE facility.

9.6.3.3 Combined Heat and Power (CHP) and Waste Heat Power (WHP)

Special provisions apply to the use of CHP as a CPP reduction strategy. As previously noted, some CHP EGUs are affected EGUs under Subpart UUUU, or may be new sources subject to Subpart TTTT. These units must meet their applicable requirements under a state plan, including reducing emissions and/or providing for avoided or replacement generation. Under a rate-based plan, if CHP is applied to an affected EGU in a topping cycle mode (using recovered heat to generate thermal or mechanical energy), the additional useful energy output is treated as net energy output (MWh) to determine the emission performance rate of the EGU (lb/MWh) under Subpart UUUU.[473] Thus, under a rate-based plan, *topping cycle* CHP installations at affected EGUs will support compliance with the applicable performance rate. Moreover, in some applications, the installation of CHP may serve as a heat rate improvement measure for an affected EGU—for example, where the thermal or mechanical output is used to drive auxiliary equipment. In this situation, the overall fuel usage of the affected EGU may be reduced to achieve the same net electrical output to the grid. However, in many instances, the application of CHP at an affected EGU would not reduce fuel consumption or mass CO_2 emissions from the EGU, and thus would not be directly credited toward meeting a mass-based emission goal or emission limit for which compliance is measured by stack emissions. Nonetheless, because CHP improves the overall efficiency of the power system, its application would be expected to result in avoided MWh that would otherwise have been required to provide the useful thermal or mechanical energy.

For *bottoming cycle* non-affected EGU CHP units that use waste heat from an industrial process or other combustion source to generate electricity, Subpart UUUU allows a state plan to rely on the generated power as a CO_2 replacement generation strategy. In this type of CHP

471 80 Fed. Reg. at 64,900.

472 80 Fed. Reg. at 65,071 (proposed to be codified at 40 C.F.R. § 62.16260(c)(4)).

473 40 C.F.R. § 60.5880 (definition of "net energy output"); 40 C.F.R. § 60.5860(a)(5).

application, where the electricity is produced without any incremental consumption of fossil fuel, the MWh are essentially zero-emissions power. This power may qualify for ERC issuance under a rate-based plan, provided all other qualifying criteria (i.e., dates of CHP installation and power generation and geographic location criteria) are met.[474] In the same manner, qualifying zero-emissions power produced from non-affected EGU units or WHP units may be treated as a replacement generation strategy under a state measures plan.

Topping cycle CHP installations at non-affected EGUs provide a source of low-emitting power generation that can be credited toward CPP compliance.[475] Although these units do burn fossil fuel, the CO_2 emissions are lower than would occur for the same MWh of generation at an affected EGU. The relatively low CO_2 emissions from this type of CHP application result from the fact that CHP units are typically very thermally efficient, and the fact that a portion of the CO_2 emissions would have occurred at another source in the absence of the CHP unit (e.g., from an industrial boiler to meet the thermal load provided by the CHP). Subpart UUUU allows a state plan to rely on, as avoided or replacement generation, the MWh from the non-affected CHP unit that replaces generation that would have occurred from affected EGUs. Recognizing that this replacement generation is not a zero-emitting energy source, the state plan must include an EM&V method that accounts for the "incremental CO_2 emissions" of the CHP unit in relation to the applicable performance rate. EPA has proposed an accounting method for topping cycle non-affected EGU CHP applications in its proposed rate-based model rule.[476]

A state measures plan could incorporate CHP as a compliance strategy, with the approach depending on the type of CHP or WHP application as well as the design of the state measures. First, bottom cycling CHP installations could qualify as replacement generation, and could be recognized as a means of meeting an RPS requirement or EERS requirement, with the full MWh or generation from the bottoming cycle credited as zero-emitting energy (provided, of course, the waste heat is not supplemented with additional fossil fuel). Also, topping cycle CHP installations at non-affected EGUs, with the appropriate EM&V accounting methods in place, could be recognized as a means to meet an applicable EERS.

9.6.4 Administrative Authority Options for Implementing Replacement Generation Strategies

To incorporate replacement generation strategies for affected EGUs as an element of the state plan, options for selecting the administrative authority that will implement and enforce the state measure may be very similar to those for a generation shift strategy, depending on the mechanism chosen. Specifically, the state may choose to rely upon the state air quality agency, the Public Service Commission (PSC), or the State Energy Office. If the state will directly regulate entities, such as dispatch utilities, which traditionally have not been subject to CAA requirements or to PSC oversight, new statutory authority may need to be adopted through the state legislative process. States should understand that any attempt to regulate dispatch utilities will be scrutinized carefully for any potential impact on reliability or costs, and will also need to address the need for such regulation, given experience with RPS programs that address replacement generation without regulating dispatch utilities.

9.6.4.1 State Legislative Authority and Timing Considerations

As may be the case for strategies to maximize utilization of existing NGCC units, a requirement for dispatch utilities to maximize the capacity factor of low- and zero-emitting units preferentially in making dispatching decisions, or to incorporate CO_2 emissions intensity into the dispatch decision-making process, could require new administrative authority. State legislation may also be needed, for example, to adopt a new RPS or to expand or revise an existing RPS. States will want to examine the timeframes for adoption of necessary authorities and subsequent implementation of the RE strategy, and take these timing considerations into account in plan performance projections.

9.6.4.2 State Air Quality Agency

For requirements directly applied to individual EGUs, the state air quality agency can readily serve as the administrative authority for implementation and enforcement. In some cases, the affected EGUs could be directly regulated for a replacement generation strategy. For example, provisions for co-firing of qualified biomass or for re-fueling to qualified biomass would be applied directly to the affected

474 80 Fed. Reg. at 64,757 & 64,902-03.

475 80 Fed. Reg. at 64,902.

476 *Ibid.*

EGU. These requirements can be incorporated directly into the facility operating permit as specific conditions. If the state chooses to adopt state-enforceable requirements applicable to affected EGUs to achieve a shift of generation to low- or zero-emitting EGUs, those goals could potentially be achieved in combination with strategies to shift generation to NGCC units.

For example, operating limitations on specific EGUs; requirements to balance utilization to meet specified ratios among different fuels; a requirement to pay an emission-based fee for emissions resulting from utilization over a specified baseline; or incorporation in the operating permit of direct mass emission limits derived from a target utilization rate could all serve to achieve both a generation shift from coal or oil to NGCC units, and a shift to replacement generation from RE resources. These approaches all lend themselves to inclusion in an operating permit, with the state air quality agency as the implementing authority. However, prior to including requirements in operating permits, it would be necessary to consider existing and expected agreements with dispatch authorities, as such agreements may require that EGUs be available to operate under certain circumstances.

9.6.4.3 Public Service Commission

The Public Service Commission (PSC) may already have an indirect role in incentivizing and implementing new and expanded-capacity RE resource deployment, at least for Investor Owned Utilities (IOUs), through Integrated Resource Planning (IRP), approval of new EGU construction, and rate approvals. In light of this existing authority, a state may choose to build on existing PSC oversight procedures to implement state measures under the CPP. This strategy may include a requirement for each affected utility to develop a utilization plan for fossil-fuel EGUs that takes into account CO_2 emissions intensity in conjunction with cost-effectiveness and other specifications. In cases where the IOU also controls dispatch, this could be a direct mechanism for driving generation away from fossil-fueled EGUs and to RE resources. In cases where an ISO or RTO controls dispatch through a market, CO_2 emissions intensity could be factored into the EGU availability assessment and variable cost determination.

The same limitations to relying on the PSC as the administrative authority will apply as for generation shift. That is, IRP programs typically address long-term planning horizons of ten to twenty years, with plan updates required every two to five years. Thus, the timing of IRP development may not serve to meet the state CPP compliance requirements. Also, in many cases, the PSC does not have the authority to approve or enforce the IRP plan but instead can only require that one be developed for PSC review. Furthermore, the PSC typically does not have oversight authority for public power utilities, electric cooperatives, or independent power providers. In some states, these timing and scope-of-authority constraints could render existing PSC authorities largely ineffective in expanding RE resources over the interim period plan performance timeframe.

9.6.4.4 State Energy Office

In many states, the state energy office is responsible for implementing incentive programs for RE or for oversight of the state RPS. If the state elects to add or modify an RPS in order to increase the use of low- and zero-emitting resources, then the state energy office could play a role in helping to track and implement this strategy. If so, the state air quality agency may want to establish a shared administrative authority role with the state energy office.

9.6.5 Affected Sources and Affected Entities

For a replacement generation strategy, the two general categories of sources impacted by the state requirements are the affected EGUs from which generation would be lowered and the new or expanded qualifying EGU resources that would provide the replacement generation. Under a state measures plan that incorporates replacement generation strategies as a state-enforceable mechanism such as an RPS, the requirement may apply at the company level, as opposed to individual EGUs.

To the extent the generation replacement strategy involves making direct changes to dispatching procedures, the dispatch system operators may be the regulated affected entities. This is another opportunity a state may consider to combine mechanisms for generation shift to existing NGCC units with generation shift to expanded and new RE resources. A combined approach provides a broader set of target units for receiving the generation shift away from affected EGUs (or meeting increased load with new RE capacity), creating greater flexibility and supporting lower-cost compliance pathways. As discussed in Section 9.5.4, across much of the nation the power sector is deregulated and power distribution is controlled by independent system operators (ISOs and RTOs).[477] In other areas, vertically integrated utilities have spun off dispatch utility

477 There are currently seven RTOs and ISOs operating in the U.S. In 2009, U.S. RTOs/ISOs managed 60% of the power supplied to customers. See *Chapter 2, The U.S. Power Sector.*

companies to meet the FERC requirements for non-discriminatory access to transmission lines. As a result of this evolution in the power sector structure, the company that controls operation of the affected EGUs is usually not the same company directly controlling dispatch of generation to the distribution system. Owners and operators of EGUs remain in control of making their units available for dispatch, though for nuclear and renewable energy, there are substantial limits on dispatch flexibility.

As previously stated, the key to generation shift lies equally with influencing power generators and distributors, and the two are highly interdependent. Business transactions between the power generators and the power distributors are dynamic and complex, involving long-term service contracts, capacity markets and short-term markets at regulated rates under a tariff system. It may be a challenge under existing state authorities to specifically regulate ISOs or RTOs, though dispatch utilities may come under existing PSC oversight or other state regulatory reach. Where feasible, however, implementation of changes to dispatch algorithms could be the simplest and most effective approach at driving the shift.

9.6.6 Mechanisms for Implementing Replacement Generation Strategies

One overarching consideration for choosing a state-enforceable mechanism to increase the deployment of RE generation is the overlap and interaction between RE and NGCC generation shift strategies. For each of the mechanisms discussed below, the state may wish to explore opportunities to streamline the state plan, guard against leakage to new NGCC units, and create compliance flexibilities where feasible by combining RE and natural gas strategies.

9.6.6.1 State Renewable Portfolio Standards (RPS) and Clean Power Portfolio Standards (CPPS)

Most states have existing Renewable Portfolio Standards (RPS) that are already influencing a shift from fossil-fuel generation at affected EGUs to low- and zero-emitting resources. In the context of CPP compliance via a state measures plan that does not incorporate a mass-based trading program, the RPS may be the most likely mechanism for achieving replacement generation goals. Most RPS are established by legislative authority and implemented by the Public Utility Commissioner ((PUC), or Public Service Commissioner (PSC)). A comprehensive listing of existing state RPS standards and voluntary targets, with links to the corresponding statutory or regulatory code, is available on the National Conference of State Legislatures website.[478] These existing statutes and regulations provide an excellent source of model language for a state that does not have a RPS in place.

Existing state RPS should be incorporated into the base case modeling as an "on the books" strategy for the state plan performance demonstration, and may contribute to future CO_2 emission reductions reflected in the base case. To contribute further emission reductions toward achieving the state's CPP mass-based emission goals, a state may elect to revise or enhance the existing RPS. New or enhanced RPS provisions relied upon to achieve compliance should be incorporated into the plan performance demonstration. For further discussion of plan performance demonstrations, see Section 9.8.

Several considerations may affect the revision or expansion of the existing state RPS, including the following:

- Only RE resources (new or expanded capacity) installed after 2012 are considered eligible for purposes of CPP compliance;
- Certain restrictions apply for particular types of generation resources under the CPP, such as qualified biomass, that may differ from the existing RPS;
- Some existing RPS include qualifying resources that are not eligible resources under the CPP;
- The scope of applicability delineating affected EGUs under the CPP may not align well with the scope of the existing state RPS, for example with regard to rural co-operatives, municipal utilities, or other entities; and
- The standards established in the existing RPS may be insufficient to meet CPP emission goals.

Given these considerations, the state may find it necessary to establish new or revised RPS provisions that provide coverage of all or most CPP affected EGUs, and that are aligned with the performance periods and emission goals of the CPP. These provisions could be adopted in combination with a fossil fuel portfolio standard, as described in Section 9.5.5, to create a comprehensive energy portfolio standard. A sample of regulatory language for this combined approach is provided in ***Replacement Generation Rule Example 4, Clean Power Portfolio Standard (CPPS)***, in Section 9.6.7.

478 *State Renewable Portfolio Standards and Goals,* March 23, 2016, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

The use of a RPS or CPPS as a state measure has a number of advantages, particularly when combined with a fossil-fuel energy portfolio standard. First, the state can rely upon or build upon existing authorities and administrative procedures previously established for the existing RPS. In addition, the combined standards can provide for compliance flexibility at the fleet-wide level, across all EGU resources under common control. Also, the fossil-fuel standard can shift the balance of fossil generation while at the same time, the RPS assures the expansion of RE generation. Another advantage of the fossil fuel portfolio approach is that it readily accommodates fuel switching and co-firing at coal units, again providing greater flexibility for compliance. In addition, the standard can be tailored to apply to dispatch utilities, or to ISOs/RTOs operating in the region, as necessary.

9.6.6.2 Incorporating CO_2 Intensity into Dispatch Decisions

A requirement to include a CO_2 emissions intensity factor into the dispatch decision-making process is another mechanism that could serve to some extent to support both a shift to existing NGCC and an increased deployment of RE resources. For example, CO_2 emissions intensity could be factored into the dispatch selection as a constraining factor, separate from the least cost ranking, in the same way that constraints on the transmission system are considered. To accomplish this, a constraint could be placed on the average daily CO_2 lb/MWh of electricity distributed, either on a rolling seasonal average basis or a rolling 180-day basis, for example. An example of regulatory language to implement this approach is provided in ***Generation Shift Rule Example 2,*** in Section 9.5.6. Under these provisions, zero-emitting RE resources would be assigned a CO_2 emissions intensity of zero, thereby encouraging dispatch of RE. An advantage of this approach is that it can capture the emission reduction effects of generation shift among fossil fuel units together with the effects of zero- and low-emitting power sources, since the performance metric is applied directly to the grid. Thus, RE generation with zero emissions is added to the total generation in determining compliance. Similarly, new NGCC generation is effectively covered under the same carbon intensity standard, thereby addressing leakage effects. That is, there is no advantage to utilization of new NGCC generation in comparison to existing NGCC.

One potential mechanism of incorporating CO_2 emissions intensity into dispatch decisions is the adoption of a formula for adjusting an EGU's variable fuel cost to reflect CO_2 emissions; however, this approach would not effectively capture the benefits of RE. While this mechanism could be effective for accomplishing a shift to natural gas, a variable fuel cost adjustment would not be relevant for most RE units. This is because RE units typically have very low fuel costs (e.g., solar or wind), and therefore are typically dispatched whenever they are available in advance of dispatching coal or natural gas EGUs.

9.6.6.3 Setting Operational Limits on Existing Steam EGUs

Operational limits on affected steam EGUs can also be relied upon to drive increased deployment of RE resources. For a discussion of this approach, see the discussion in Section 9.5.5. Rule language to implement this approach through the application of capacity factor standards on affected coal-fired EGUs is provided in Generation Shift Rule Example 3 in Section 9.5.6.

9.6.7 Replacement Generation Rule Examples

Four examples of regulatory language for incorporating replacement generation resources as an element of the state measures plan are provided on the following pages. The rule examples present different provisions addressing different aspects of replacement generation strategies. The example regulatory language is intended to provide an illustration of approaches a state could adopt in a state measures plan.

In all cases, the regulatory provisions shown in the examples would need to be supplemented with additional regulatory provisions, such as detailed definitions and/or EM&V requirements, to meet CPP requirements. It is important to note that the values of the specific standards used in the examples are intended to be examples only and do not represent an endorsement or recommendation of those specific standards.

Table 9.8 provides an overview of the Replacement Generation rule examples.

Table 9.8 **Guide to Replacement Generation Rule Examples**

Rule Example	Form of Generation Shift Standard	Applicability	Rule Provisions	Flexible Compliance Demonstration Options
1	RPS for In-State Power Generation	Applies to suppliers of electricity to retail customers, using affected EGUs to generate power	• Establishes a minimum percentage of fossil fuel generation derived from natural gas for power supplied by affected EGUs	• Provides for 3-year and 2-year compliance periods, aligned with CPP plan performance periods
2	Provisions to Avoid Duplicative Replacement Generation Credits	Applies to registered renewable energy resources and applications for issuance of renewable energy credits	• Establishes that each REC must represent a single and unique MWh • Prohibits use as a REC for any MWh otherwise used to demonstrate compliance with the CPP, including in any other state • Provides for revocation of invalid RECs or RECs used improperly	• Provides for use of unused RECs issued for prior performance periods • Recognizes CHP, WTE, WHP
3	Accounting Provisions for Waste-to-Energy Generation	Applies to waste-to-energy facilities applying for registration or registered as a qualified renewable energy resource	• Establishes the method for determining the portion of electric output attributable to biogenic waste • Establishes that EM&V protocol will specify method for determining relative HHV of biogenic and total waste streams	• Relies on 40 C.F.R. Part 98-required EM&V methods to determine emissions • Provides for using the portion of biogenic emissions as surrogate for portion of biogenic waste
4	Clean Power Portfolio Standard (CPPS)	Applies to suppliers of electricity to retail customers, using affected EGUs to generate power	• Combines fossil fuel portfolio standard (portion of fossil fuel generation to be provided by natural gas) and renewable fuel portfolio standard • Provides for incremental RE to meet CPP eligibility criteria	• Provides for 3-year and 2-year compliance periods, aligned with CPP plan performance periods • Allows renewable energy to be used to meet natural gas portfolio standard

Replacement Generation Rule Example 1
RPS for In-State Power Generation

Section 6050. Renewable Portfolio Standards.

A. Purpose. The renewable portfolio standard of this Section is intended to provide CO_2 emission reductions for purposes of complying with the emission guidelines of 40 CFR part 60 subpart UUUU for existing fossil fuel-fired power plants, by achieving specified levels of incremental replacement generation from renewable resources for fossil fuel-fired power generated within the state.

B. Applicability. An affected entity subject to the requirements of this Section is each public utility retail supplier of electricity for distribution within the State, including any investor-owned utility, municipal utility, rural electric cooperative, or other retail provider of electricity, which serves a minimum of 5,000 retail customers, that meets the following criteria:

1. The entity owns and/or operates one or more affected EGUs located in the State, as defined under Section 1010 of Chapter 10, the State Plan for implementing 40 CFR part 60 subpart UUUU; and/or,
2. The entity procures electricity that is generated by one or more affected EGUs located in the State, for distribution to retail customers.

C. Renewable Portfolio Standards.

1. Except as provided in Paragraph C.2, the renewable portfolio standards of this Section apply to the total amount of electricity generated within the State and supplied to the grid by the affected entity during a performance period for the purpose of serving regional load in the Interconnect.
2. For purposes of demonstrating compliance with the renewable portfolio standards, qualified renewable energy generated outside of the State may be counted in determining the total amount of electricity supplied (i.e., included in the denominator in Equation 1) and credited toward meeting the renewable portfolio standard (i.e., included in the numerator in Equation 1), provided it meets the criteria of Paragraph D.
3. For each affected entity, a minimum percentage of the total amount of electricity supplied during each performance period shall be generated by qualified renewable energy resources as follows:

Table 1. **Renewable Energy Portfolio Standards**

Performance Period	Minimum Required Electricity Generated by Renewable Energy Resources, as a Percent (%) of Total Electricity Supplied*	Maximum Allowable Renewable Resources Provided by Out-of-State Generation, as a Percent (%) of Total Electricity Supplied*	Minimum Required Incremental Renewable Energy, as a Percent (%) of Total Electricity Supplied*
Jan. 1, 2022–Dec. 31, 2024	20%	10%	5%
Jan. 1, 2025–Dec. 31, 2027	22%	10%	8%
Jan. 1, 2028–Dec.31, 2029	25%	10%	12%
Jan. 1, 2030–Dec. 31, 2031 and each two-calendar year period thereafter	30%	10%	15%

**Total electricity supplied by the affected entity includes all electricity generated in-state plus any renewable energy generated out-of-state that is used to meet the portfolio standard.*

Replacement Generation Rule Example 1, *continued*
RPS for In-State Power Generation

4. The percentage of electricity generated by qualified renewable energy resources shall be determined using Equation 1, below:

$$E_{RE\%} = E_{RE} / E_T * 100$$

Where:

$E_{RE\%}$ is the percentage of the electricity supplied to the grid by the affected entity during the performance period that is generated by a qualified renewable energy resource, expressed in percent (%) and rounded to the nearest one-tenth of one percent;

E_{RE} is the total amount of electricity, expressed in MWh, that is supplied to the grid by the affected entity during the performance period and that is generated by a qualified renewable energy resource;

E_T is the total amount of electricity, expressed in MWh, that is supplied to the grid by the affected entity during the performance period and that is either:

a. generated by an electric generating unit located in the State; or,
b. generated by a qualified renewable energy resource outside of the State and being credited by the affected entity toward meeting the renewable portfolio standard.

D. Qualified Renewable Energy Resources.

1. Resources qualifying as renewable energy resources include the following categories of technologies and fuels:
   a. Renewable electric generating technologies using wind, solar, geothermal, hydro, wave or tidal energy;
   b. Electricity generated from qualified biomass, including the portion of electricity generated from biogenic municipal solid waste at a waste-to-energy facility;
   c. Nuclear power;
   d. Combined heat and power units, including waste heat power generating units, that are not affected electric generating units under 40 CFR part 60 subpart UUUU.
2. Resources qualifying as Incremental Renewable Energy Resources, in addition to belonging to a category listed in Paragraph D.1, must meet the following criteria:
   a. The renewable resource generating unit capacity was installed on or after January 1, 2013;
   b. If the generating unit capacity is an uprate to a pre-existing generating unit installed on or after January 1, 2013, then only electricity generated at levels above the pre-uprated capacity are eligible as qualifying renewable energy;
   c. The renewable resource is located in a state within the Interconnect service area and delivers energy to the grid serving the Interconnect service area.
3. Electricity generated by a qualified renewable energy resource used to satisfy the renewable energy portfolio standards of this Section shall not also be used by the same entity or any other entity in this State or another State or Territory for purposes of demonstrating compliance with any requirement of a state plan under 40 CFR part 60 subpart UUUU, or with a federal plan under 40 CFR part 62 subpart NNN administered by the U.S. EPA Administrator or the Administrator's agent.

Replacement Generation Rule Example 2
Provisions to Avoid Duplicative Replacement Generation Energy Credits

E. Renewable Energy Credits (RECs) may be issued, in accordance with procedures established and adopted by the Public Utility Commissioner, for electricity generated by qualifying renewable energy resources for use in the compliance demonstration specified in Paragraph C.4 of this Section, provided that the following criteria are met:

1. Each REC has a unique serial number.
2. Each REC represents one MWh of actual energy generated with zero associated CO_2 emissions, and no duplicate REC representing the same MWh of actual energy generated or saved has been issued by this State or by any other entity.
   a. For electric generating units using qualified biomass, only that portion of electricity generated using the qualified biomass is eligible for issuance of RECs, which shall be determined in accordance with Paragraph H of this Section;
   b. For electric generating units using CHP, WHP, or WTE technology, the amount of qualifying actual energy generated shall be determined in accordance with Paragraph I of this Section.
3. Each REC can be used only once for purpose of compliance with the Renewable Energy Portfolio Standards of this Section.
4. Each REC is issued for the year in which the actual energy generation occurred, and can be used to demonstrate compliance only for the compliance period that includes the year for which the REC is issued, or for a year in a prior compliance period. A REC does not qualify for use in meeting the Renewable Portfolio Standards of this Section if it represents a MWh of energy generated in a future compliance period.
5. A REC does not qualify for use in meeting the Renewable Portfolio Standards of this Section if any party in another State or Territory has relied upon the same MWh of electricity for issuance of an Emission Rate Credit (ERC) or otherwise for purposes of demonstrating compliance with a state plan under 40 CFR part 60 subpart UUUU, or with a federal plan under 40 CFR part 62 subpart NNN administered by the U.S. EPA Administrator or the Administrator's agent.
6. Any REC determined to have been improperly issued or improperly used shall be revoked by this State or its designated Agent. Any affected entity who has relied upon a REC that is subsequently revoked shall be subject to potential enforcement action in accordance with Chapter 10 of this Administrative Code.

F. Registration of Renewable Energy Resources....

G. Monitoring, Recordkeeping and Reporting Requirements....

H. Compliance Reporting. No later than March 15 of each year following the end of a performance period as listed in Table 1 of this Section, the responsible party for each affected entity shall submit a compliance report demonstrating compliance with the Renewable Energy Portfolio Standard for the preceding performance period. The compliance report shall be submitted using the State Electronic Clean Power Portal.

I. Definitions....

Replacement Generation Rule Example 3
Accounting Provisions for Waste-to-Energy Generation

A. Waste-to-Energy.

1. For qualified renewable resources that are municipal waste-to-energy facilities, only that portion of net electricity output derived from qualified biogenic waste shall be eligible for the issuance of RECs under this Section.
2. The following equation shall be used to determine the portion of net electricity output derived from biogenic waste materials:

$$\mathbf{MWh_{Bio}} = \mathbf{MWh_T} \star \mathbf{F_{Bio}} \star \left(\frac{\mathbf{HHV_{Bio}}}{\mathbf{HHV_{MSW}}} \right)$$

Where:

MWh_{Bio} is the calculated net WTE electricity generation from biogenic materials (MWh);

MWh_T is the total net electricity output to grid as measured and reported per the state plan requirements (MWh);

F_{Bio} is the fraction of total CO_2 emissions from biogenic material as measured and reported pursuant to 40 CFR § 98.34(d), used as a surrogate for the fraction of biogenic waste in the total waste feed stream;

HHV_{Bio} is the annual average high heating value for biogenic waste received by the WTE facility; and,

HHV_{MSW} is the annual average high heating value for total municipal solid waste received by the WTE facility.

3. Each applicant for registration of a waste-to-energy facility as a qualified renewable energy resource shall monitor and report emissions in accordance with 40 CFR part 98 subpart C, §§ 98.3(c) & 98.36(b)–(d), and subpart D, §§ 98.43(b) & 98.46.
4. Each applicant for registration of a waste-to-energy facility as a qualified renewable energy resource shall include, as part of the EM&V protocol, a specific method for determining the ratio of HHV_{Bio}/HHV_{MSW}. The method for determining high heating values for biogenic and total waste may be derived by periodic sampling and analysis of waste streams received at the facility, or the applicant may propose to rely upon representative values from U.S. government studies or studies published in peer-reviewed scientific or trade journals.

Replacement Generation Rule Example 4
Clean Power Portfolio Standard (CPPS)

Section 7060. Clean Power Portfolio Standards.

A. Purpose. The clean power portfolio standards of this Section are intended to provide CO_2 emission reductions for purposes of complying with the emission guidelines of 40 CFR part 60 subpart UUUU for existing fossil fuel-fired power plants, by increasing the proportion of power generated from lower-emitting fossil fuels relative to higher-emitting fossil fuels, and by achieving specified levels of incremental replacement generation from renewable resources for fossil-fuel power generated within the state.

B. Applicability. An affected entity subject to the requirements of this Section is each public utility retail supplier of electricity for distribution within the State, including any investor-owned utility, municipal utility, rural electric cooperative, or other retail provider of electricity, which serves a minimum of 5,000 retail customers, that meets the following criteria:

1. The entity owns and/or operates one or more affected EGUs located in the State, as defined under Section 1010 of Chapter 10, the State Plan for implementing 40 CFR part 60 subpart UUUU; and/or,
2. The entity procures electricity that is generated by one or more affected EGUs located in the State, for distribution to retail customers.

C. Renewable Portfolio Standards.

1. Except as provided in Paragraph C.2, the clean power portfolio standards of this Section apply to the total amount of electricity generated within the State and supplied to the grid by the affected entity during a performance period for the purpose of serving regional load in the Interconnect.
2. For purposes of demonstrating compliance with the renewable portfolio standards, qualified renewable energy generated outside of the State may be counted in determining the total amount of electricity supplied (i.e., included in the denominator in Equation 1) and credited toward meeting the renewable portfolio standard (i.e., included in the numerator in Equation 1), provided it meets the criteria of Paragraph D.

Table 1. **Clean Power Portfolio Standards**

Performance Period	Electricity Generated by Natural Gas as a Percent (%) of Fossil Fuel Generation1	Minimum Required Electricity Generated by Renewable Energy Resources, as a Percent (%) of Total Electricity Supplied*	Maximum Allowable Renewable Resources Provided by Out-of-State Generation, as a Percent (%) of Total Electricity Supplied*	Minimum Required Incremental Renewable Energy, as a Percent (%) of Total Electricity Supplied*
January 1, 2022–December 31, 2024	45%	20%	10%	5%
January 1, 2025–December 31, 2027	48%	22%	10%	8%
January 1, 2028–December 31, 2029	50%	25%	10%	12%
January 1, 2030–December 31, 2031 and each two-calendar year period thereafter	55%	30%	10%	15%

1. Fossil fuel generation includes all electricity supplied by the affected entity generated in-state using fossil fuel, plus any renewable energy generated in- or out-of-state that is used to the meet the natural gas portfolio standard.
2. Total electricity supplied by the affected entity includes all electricity generated in-state plus any renewable energy generated out-of-state that is used to meet the portfolio standard.

Replacement Generation Rule Example 4, *continued*
Clean Power Portfolio Standard (CPPS)

3. For each affected entity, a minimum percentage of the total amount of electricity supplied during each performance period shall be generated by qualified renewable energy resources as provided in Table 1.
4. For each affected entity, a minimum percentage of the total amount of electricity supplied during each performance period that is generated by fossil fuel shall be generated by natural gas, as provided in Table 1. Qualified renewable energy may be used to meet the natural gas generation requirements of this paragraph, subject to the requirement that each MWh of renewable energy may be used only once to demonstrate compliance with any Clean Power Portfolio Standard under this Section.
5. The percentage of electricity generated by qualified renewable energy resources shall be determined using Equation 1, below:

$$E_{RE\%} = E_{RE} / E_T * 100$$

Where:

$E_{RE\%}$ is the percentage of the electricity supplied to the grid by the affected entity during the performance period that is generated by a qualified renewable energy resource, expressed in percent (%) and rounded to the nearest one-tenth of one percent;

E_{RE} is the total amount of electricity, expressed in MWh, that is supplied to the grid by the affected entity during the performance period and that is generated by a qualified renewable energy resource;

E_T is the total amount of electricity, expressed in MWh, that is supplied to the grid by the affected entity during the performance period and that is either:

a. generated by an electric generating unit located in the State; or,
b. generated by a qualified renewable energy resource outside of the State and being credited by the affected entity toward meeting the renewable portfolio standard.

6. The percentage of fossil fuel energy generated by affected EGUs using natural gas shall be determined using Equation 2, below:

$$E_{NG\%} = E_{NG} / E_{FF} * 100$$

Where:

$E_{NG\%}$ is the percentage of the electricity supplied to the grid generated by an affected EGU using natural gas as fuel, expressed in percent (%) and rounded to the nearest whole number;

E_{NG} is the total amount of electricity supplied to the grid generated by an affected EGU using natural gas as fuel (or by a qualified renewable energy resource, if renewable energy is used to demonstrate compliance), during the performance period, expressed in MWh; and,

E_{FF} is the total amount of electricity supplied to the grid by the affected entity during the performance period, expressed in MWh, and that is generated by an affected EGU using any fossil fuel, provided that EFF shall also include the amount of any qualified renewable energy being used by the affected entity to demonstrate compliance with the natural gas portfolio standard.

D. Qualified Renewable Energy Resources.

1. Resources qualifying as renewable energy resources include the following categories of technologies and fuels:
   a. Renewable electric generating technologies using wind, solar, geothermal, hydro, wave or tidal energy;
   b. Electricity generated from qualified biomass, including the portion of electricity generated from biogenic municipal solid waste at a waste-to-energy facility;
   c. Nuclear power;
   d. Combined heat and power units, including waste heat power generating units, that are not affected electric generating units under 40 CFR part 60 subpart UUUU.

Replacement Generation Rule Example 4, *continued*
Clean Power Portfolio Standard (CPPS)

2. Resources qualifying as Incremental Renewable Energy Resources, in addition to belonging to a category listed in Paragraph D.1, must meet the following criteria:
   a. The renewable resource generating unit capacity was installed on or after January 1, 2013;
   b. If the generating unit capacity is an uprate to a pre-existing generating unit installed on or after January 1, 2013, then only electricity generated at levels above the pre-uprated capacity are eligible as qualifying renewable energy;
   c. The renewable resource is located in a state within the Interconnect service area and delivers energy to the grid serving the Interconnect service area.
3. Electricity generated by a qualified renewable energy resource used to satisfy the renewable energy portfolio standards of this Section shall not also be used by the same entity or any other entity in this State or another State or Territory for purposes of demonstrating compliance with any requirement of a state plan under 40 CFR part 60 subpart UUUU, or with a federal plan under 40 CFR part 62 subpart NNN administered by the U.S. EPA Administrator or the Administrator's agent.

9.7 Energy Efficiency Measures

Programs and policies to require or incentivize demand-side energy efficiency improvements are an important component in achieving CO_2 emission reductions through reduced use of electricity, accounting for roughly 35 to 70 percent of expected reductions of states' power sector emissions.[479] While EE measures were not included as a BSER building block, EE measures could serve as a key element of any state measures plan.

One excellent resource for example state legislation, policies and regulations related to energy efficiency programs is the American Council for an Energy Efficient Economy (ACEEE) database of state energy efficiency policies, State Energy Efficiency Policy Database, located at http://aceee.org/sector/state-policy. In addition, the SEE Action Network's energy efficiency "pathways" guide is now available at http://seeaction.energy.gov/EEpathways.

9.7.1 Overview of Energy Efficiency Measures

In 2014 alone, state legislatures in at least 37 states and Washington, D.C. enacted more than 100 bills related to energy efficiency, including building energy codes; energy use in publicly owned or operated buildings; efficient building initiatives for new construction or retrofits; state energy efficiency policies; financing energy efficiency; and education and outreach.[480]

This section addresses a number of EE strategies in the context of a state measures plan, and provides examples of rule language a state may consider as a starting point to incorporate EE into the state measures plan. As with the discussions of RE, while this chapter focuses on inclusion of EE programs as part of a state measures plan, much of the discussion is equally relevant for states that adopt emission standards plans. Five specific energy efficiency strategies that states may consider including in a state measures plan are discussed:

- Energy Efficiency Resource Standards (EERS);
- Energy Savings Performance Contracting;
- Building Energy Codes;
- Above-code Building Certifications; and
- Industrial Energy Efficiency.

Additional information about each of these measures is available from NASEO, *Energy Efficiency Strategies for Clean Power Plan Compliance: Approaches and Selected Case Studies.*[481]

9.7.1.1 Energy Efficiency Resource Standards (EERS)

One mechanism many states have relied upon to reduce demand for electricity is implementation of Energy Efficiency Resource Standards (EERS). An EERS is a demand-side EE corollary to an RPS, establishing a standard requiring that retail electricity providers meet a certain portion of their projected future electricity demand by load reductions achieved through energy efficiency. EERS are typically adopted by a state legislature, and implemented through regulation, order or policy guidelines, most often by the Public Service Commission or Public Utility Commission. EERS usually set a standard for energy savings based on retail electricity sales over a multi-year compliance period.[482]

As of March 2015, 27 states have adopted EERS, as shown in Figure 9.5 below, reflecting a substantial increase from only five states in 2005.

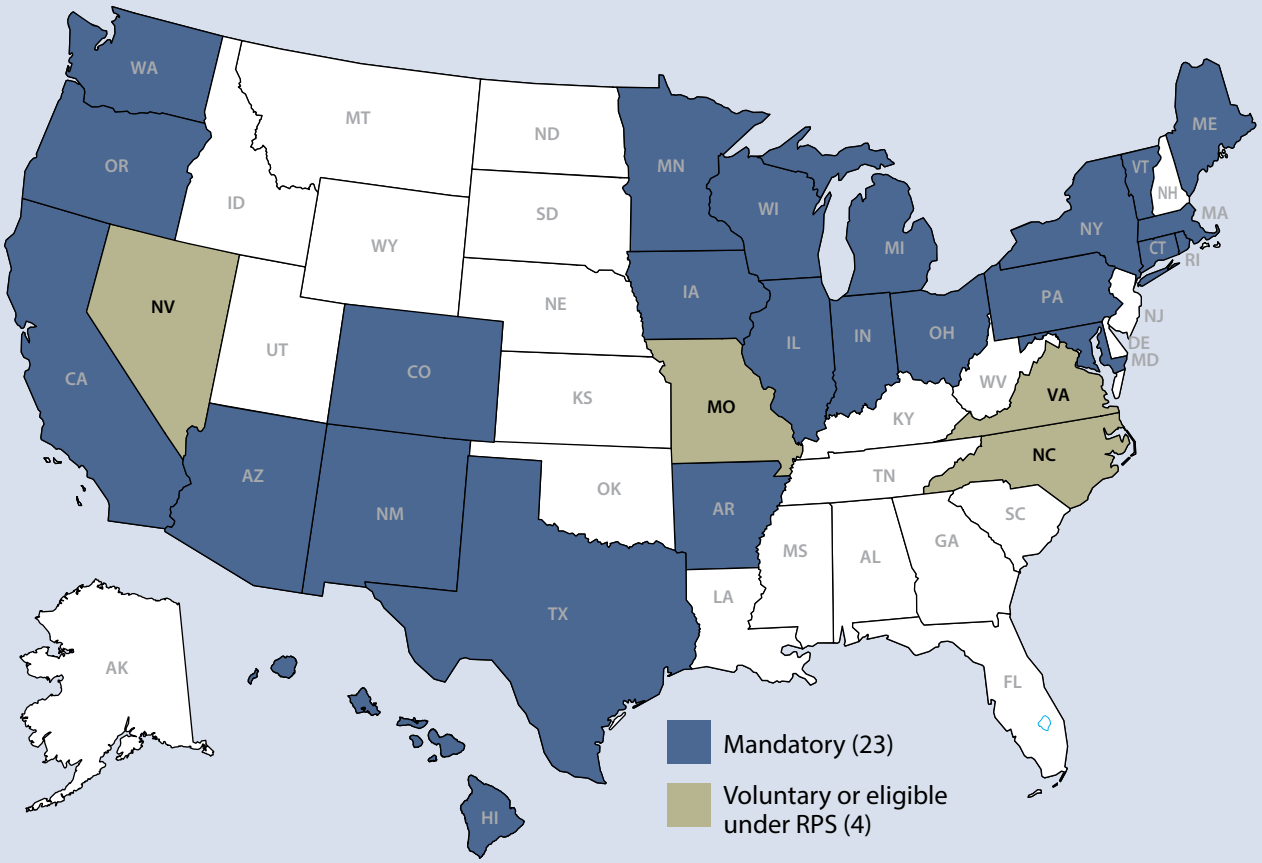
479 EPA Technical Support Document, *Survey of Existing State Policies and Programs that Reduce Power Sector CO_2 Emissions,* June 2014, http://www.epa.gov/sites/production/files/2014-06/documents/existing-state-actions-that-reduce-power-sector-co2-emissions-june-2-2014_0.pdf. These reduction target ranges are based on EPA's review of state GHG reduction laws in California, Connecticut, Hawaii, Maine, Maryland, Massachusetts, Minnesota, New Jersey, Oregon, and Washington.

480 National Conference of State Legislatures, Energy Efficiency, http://www.ncsl.org/research/energy/energy-efficiency.aspx.

481 NASEO, August 2015, http://111d.naseo.org/Data/Sites/5/media/documents/naseo-ee-for-cpp-2015-aug-20.pdf.

482 EPA TSD, *Survey of Existing State Policies and Programs that Reduce Power Sector CO_2 Emissions, supra* note 479.

Figure 9.6 **States with EERS as of March 2015**[483]



Many EERS include targets for both natural gas and electricity. With regard to electricity, a common form for a state EERS is to require a set percentage of energy savings (kWh or MWh) relative to baseline average sales. Often, EERS set a modest target for the first performance period that is gradually increased over time. Some states, including Texas and Illinois, express their targets in terms of load growth.[484] For example, if the state projects an average load growth of 1.5% per year and the EERS establishes a standard of 10% of load growth, the average annual energy savings required would be 0.15% of prior-year load. Other states, like California and Vermont, express goals in terms of absolute kWh savings.[485]

Energy savings to comply with EERS targets can be met through a variety of programs, including building energy codes, appliance exchange rebate programs, residential home improvement programs, and many others. For example, the Ohio EERS regulation specifies that eligible energy efficiency programs may include combined heat and power and waste energy recovery programs put into service after an applicable baseline date.[486] IOUs and other retail distributors subject to EERS often rely upon state-approved EERS program administrators to identify and track eligible EE programs and the energy savings achieved.

Adoption of an EERS can provide an effective mechanism for a state to establish an overarching EE target, which can contribute to achieving the CPP emission goals. An EERS can readily be designed to align with CPP plan performance periods and interim period emission goals, and can provide broad flexibility to the affected entities with regard to the specific EE projects selected for achieving the EERS target. The EERS overarching target can also provide a streamlined way for a state to model plan performance in the state plan demonstrations, by allowing

483 Figure taken from EPA, *Energy and Environment Guide to Action*, 2015 edition, available at https://www.epa.gov/statelocalclimate/energy-and-environment-guide-action.

484 DOE, *State Energy Efficiency Resource Standards Analysis*, July 2010, http://www1.eere.energy.gov/manufacturing/states/pdfs/eers_web_final.pdf.

485 *Ibid*.

486 http://codes.ohio.gov/orc/4928.66.

a "top-down" projection that reflects implementation of the EERS level over time (possibly with some degree of "rule effectiveness" applied) rather than requiring a "bottom-up" approach that sums energy savings from the individual project or activity level.

A mandatory EERS that applies directly to utilities and other power retailers or distributors is typically established through state legislation and implemented through regulation or policy, for example under the authority of the PSC. EERS are usually ratepayer (customer)-funded at least in part. Some states also direct other funds toward funding EE measures, including measures that are implemented by retail electricity providers to meet EERS requirements. For example, California uses a combination of a ratepayer surcharge, called a Public Goods Charge, and utilities' resource procurement budgets, which are funds redirected from power plant investments.[487]

EERS set state-enforceable EE standards. Frequently, EERS include incentive payments for retailers that meet the EE goals, and most include specified penalties for failure to meet the standard. Many state EERS establish a two-tiered penalty system, including both a direct Alternative Compliance Payment and civil enforcement penalty liability. DOE reports that most states establish a minimum automatic Alternative Compliance Payment of $50/MWh of energy savings deficit. Many EERS require the retailer to absorb the full cost of penalties, without recovering any portion from the customer through rate increases or other charges.[488]

While an EERS can allow for a wide variety of EE resources to be deployed and credited toward achieving the standard, an administrative mechanism is still required to assure the energy savings are qualified and creditable. The EE resource application, certification and verification system is often operated by a third-party contractor on behalf of the PSC, funded through fees paid by the electricity retailers.

9.7.1.2 Energy Savings Performance Contracting

Energy Savings Performance Contracting (ESPC), also known as Energy Performance Contracting (EPC), Performance Contracting (PC), or Guaranteed Energy Savings Contracting (ESC), is an energy efficiency funding mechanism and project implementation approach that enables building or facility owners to use savings from avoided energy consumption to pay for new energy-efficient equipment and energy efficiency services, without reliance on expenditures of capital funds.

Under an ESPC, a facility owner enters into a guaranteed energy savings contract with an Energy Service Company (ESCO), which serves as a prime contractor for a suite of energy efficiency measures to be implemented at the site. The ESCO first conducts a comprehensive energy audit of the building owners' facility or facilities and identifies potential Energy Conservation Measures (ECMs) geared toward achieving maximum cost-effective energy savings. Some examples of ECMs that may be implemented as part of an ESPC project include:

- Lighting improvements;
- Building management systems;
- HVAC controls;
- High-efficiency boilers or cooling systems;
- Electric motors and drives;
- Building envelope improvements (e.g., windows & insulation); and
- Water conservation measures.

Traditionally, ESPC focused on energy savings through the installation of new energy efficient equipment or implementation of energy efficient administrative, building-management or work and maintenance practices. However, incorporation of renewable energy and other energy-producing measures is a growing trend, with increasing implementation of onsite distributed energy such as rooftop or ground-mounted solar panels, or geothermal pumps.[489] Other thermal and electric energy generation measures that may be implemented under an ESPC include CHP, WTE, and biomass fuel.

An ESPC project will typically bundle multiple ECMs into an agreed-upon contract. Under the contract terms, the ESCO guarantees that the ECMs will collectively generate sufficient energy cost savings to pay for the project over the term of the contract. Using a portion of the energy cost savings, the facility then pays the ESCO in accordance with the contract terms for the duration of the contract. After the ESPC terminates, all future energy cost savings accrue to the building owner. Figure 9.7 illustrates the EE funding and implementation process for ESPC.

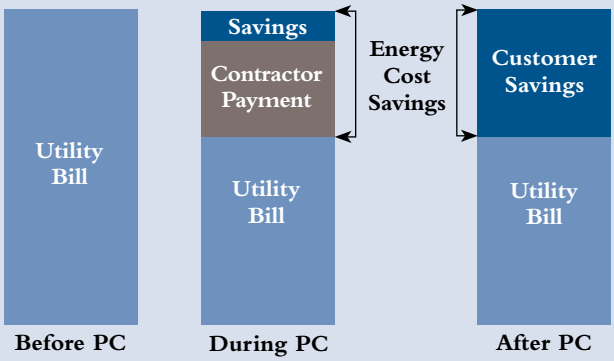
ESPC is a well-established, proven mechanism for achieving energy savings and reducing load to the grid, with a 30 year history of implementation by government

487 DOE, *State Energy Efficiency Resource Standards Analysis, supra* note 484.

488 *Ibid.*, p. 9.

489 AJW, Inc., *Greenhouse Gas Reductions Through Performance Contracting Under EPA's Clean Power Plan,* November 26, 2014, available at http://ajw-inc.com/pc/.

Figure 9.7 **The ESPC Mechanism for Funding EE Measures**[490]



agencies. The U.S. Congress initially authorized the use of ESPC by federal agencies in 1986. In addition, every state has adopted either the authority for state agencies to enter into ESPC service agreements or an ESPC program incentivizing or requiring the use of ESPC.[491] Most ESPCs have been executed for government or institutional buildings—i.e., in the municipal, university, state and hospital (MUSH) buildings sector. Federal agencies use a standardized process and contract overseen by the U.S. Department of Energy's Federal Energy Management Program (FEMP) as a standardized process and template contract for federal agency ESPC execution. Most states also have a designated state agency to oversee ESPC services, with a standardized contract. For detailed information about individual state performance contracting programs, including links to state implementation websites, legislation, policies and example contracts, see NCSL, Oak Ridge National Laboratory, *Performance Contracting by State, and ACEEE, Energy Savings Performance Contracting.*[492]

The National Association of Energy Service Companies (NAESCO) reports that since 1990, ESPC projects have resulted in a reduction of 470 million tons of CO_2.[493] According to NAESCO, ESCOs have executed $45 billion in projects, including $35 billion in infrastructure improvements, producing $50 billion in guaranteed and verified energy savings. A 2013 DOE Lawrence Berkeley National Laboratory report estimates that the national ESCO investment market in energy efficiency accounted for about $5 billion a year, and projected that ESCO industry annual revenues would grow to between $10.6 and $15.3 billion by 2020.[494]

Under a state measures plan, ESPC offers a potential mechanism for a state to achieve CO_2 emission reductions through demand-side energy efficiency, as well as non-utility scale renewable energy. While states are already using ESPC to varying degrees in the MUSH sector, use of performance contracting in this sector could be enhanced or extended in many areas. Beyond the MUSH sector, a state could administer state funding of EE projects through ESPC. For example, a state incentive program that provides matching funds to property owners of low-income rental properties could rely on state-backed ESPC contracts as a mechanism to reduce energy bills in low-income neighborhoods while achieving CO_2 emission reductions.

9.7.1.3 Building Energy Codes

Building energy codes establish energy performance standards for key building components in newly constructed and renovated buildings, covering building elements such as insulation, refrigeration, windows, lighting, heating and cooling systems. The U.S. Department of Energy (DOE) estimates that in 2012, building energy codes saved about 40 billion kWh of electricity while avoiding 36 million metric tons of CO_2 emissions.[495]

Currently, there are no mandatory building energy standards or codes at the national level; building codes are adopted and implemented at the state or local government level. However, building energy codes need not be developed by the state; in fact, states generally adopt by reference building energy codes developed and published by non-governmental organizations. One code commonly adopted by states is the American Society of

490 Figure taken from AJW, Inc., *Greenhouse Gas Reductions Through Performance Contracting Under EPA's Clean Power Plan*, *supra* note 489.

491 *Ibid*.

492 Oak Ridge National Laboratory, Performance Contracting by State, http://web.ornl.gov/info/esco/legislation/newesco.shtml; American Council for an Energy-Efficient Economy, *Energy Savings Performance Contracting,* http://database.aceee.org/state/energy-savings-performance.

493 National Association of Energy Service Companies, *What is an ESCO?*, http://www.naesco.org/what-is-an-esco.

494 Elizabeth Stuart et al., *Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry,* Lawrence Berkeley National Laboratory, National Association of Energy Service Companies, prepared for the U.S. Department of Energy, September 2013, http://emp.lbl.gov/sites/all/files/lbnl-6300e_0.pdf.

495 DOE, *Achieving Energy Savings and Emission Reductions from Building Energy Codes: A Primer for State Planning,* April 2015, https://www.energycodes.gov/sites/default/files/documents/Codes_Energy_Savings_State_Primer.pdf.

Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) Standard 90.1, *Energy Standard for Buildings Except Low-rise Residential Buildings,* most recently updated in 2013.[496] Another commonly adopted code is the International Energy Conservation Code (IECC), most recently updated in 2015.[497] IECC 2015 contains separate provisions for commercial buildings and for low-rise residential buildings three stories or less in height above grade, and includes a new optional residential compliance pathway, the Energy Rating Index (ERI). Both ASHRAE Standard 90.1 and IECC are updated every three years. For residential buildings, another common code is the International Resident Code (IRC) published by the International Code Council (ICC). The ICC's International Building Code (IBC) is also utilized by several states, territories and Washington, D.C. The ICC has published 2015 versions for both the IRC and IBC.[498] Some states, such as California, have developed their own building energy code instead of adopting a model building energy code.[499]

Substantial avoided electricity demand and avoided CO_2 emissions can be achieved through implementation of building energy codes, because buildings account for 70% of U.S. electricity consumption.[500] The most cost effective way to incorporate energy efficiency into buildings is at the time of construction, expansion or renovation, as opposed to retrofitting existing energy components after construction. Furthermore, as building energy codes are updated every few years to reflect the most current technologies and building materials, considerably greater energy efficiency is achieved by compliance with the most current standard. Thus, the most cost-effective approach for states to adopt energy codes is to require compliance with the version of the code that is in effect at the time of construction or renovation of a building. A common and substantial loss of energy efficiency occurs when a state adopts a specific version of a referenced building code (e.g., 2009), which remains in place for many years despite significant improvements in available energy-efficient building components as reflected in updated building codes. For example, the U.S. DOE found that annual energy costs for residential buildings decreased by 32 percent for buildings that meet the 2012 IECC energy code, as compared to the 2006 IECC.

In situations where the state has already adopted a building energy code and the adopted code specifies a particular year (e.g., 2009), the state may consider updating the requirement to gain additional emission reductions. In this case, the electricity demand forecast reflecting the "on-the-books" version of the code may be accounted for in the base case version of the plan performance demonstration, with the incremental impacts of the new standard accounted for in the plan projections. For additional discussion of plan performance demonstrations, see Section 9.9.

9.7.1.4 Above-code Building Certifications

Above-code building certification programs expand upon minimum building code requirements by requiring or incentivizing achievement of electricity savings beyond what would be achieved through compliance with the applicable building code. To demonstrate that the above-code criteria are met, third-party assessment and verification is required for the certification of a building, or portfolio of buildings. Above-code certification programs typically require a rigorous demonstration that savings at a specified level (e.g., 20%) above the applicable code are met, with certifications available for various building components.

One example of above-code building certification is EPA's ENERGY STAR program for commercial and industrial buildings. The ENERGY STAR certification is incorporated into a number of green building programs, including the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) program. Other programs relying on the ENERGY STAR system include the Green Building Initiative's Green Globes system, the U.S. Guiding Principles for High Performance and Sustainable Buildings, and Honest Buildings.[501]

The process for earning the EPA ENERGY STAR for buildings starts by entering building information into an EPA online tool, Portfolio Manager for commercial buildings and Energy Performance Indicators for industrial facilities. These tools measure and track energy and

496 Available at https://www.ashrae.org/standards-research--technology/standards--guidelines.

497 Available at http://www.iccsafe.org/codes-tech-support/codes/2015-i-codes/iecc/.

498 Available at http://www.iccsafe.org/codes-tech-support/codes/2015-i-codes/irc/ and http://www.iccsafe.org/codes-tech-support/codes/2015-i-codes/ibc/.

499 National Conference of State Legislatures, *Efficient Buildings Update 2013,* November 19, 2013, http://www.ncsl.org/research/energy/a-kilowatt-saved-is-a-kilowatt-earned-efficient-buildings-update-2013.aspx.

500 DOE, *Achieving Energy Savings and Emission Reductions from Building Energy Codes: A Primer for State Planning, supra* note 495.

501 EPA, *Green Buildings and ENERGY STAR,* https://www.energystar.gov/buildings/about-us/how-can-we-help-you/energy-star-action/green-buildings-and-energy-star.

water use and GHG emissions. Both tools calculate an ENERGY STAR building score on a scale of 1 to 100. Facilities that score a 75 or higher are eligible to apply for ENERGY STAR certification. For each application, a professional engineer or registered architect must verify that the information contained within the certification application is accurate.[502]

A state measures plan that does not involve a mass-based trading program could incorporate an above-code building certification strategy to reduce CO_2 emissions from affected EGUs through a number of mechanisms. One option would be to adopt state legislation requiring the construction of any new building owned by the state or occupied by a state agency to be certified as meeting a specified above-code building program, such as LEED. A second option would be to require affected utilities to invest in programs to incentivize certification of new or existing commercial buildings built by third parties. In addition, above-code certification could be incorporated as an eligible resource to meet an EERS requirement.

9.7.1.5 Industrial Energy Efficiency, ISO 50001 and SEP

Industrial sector electricity use accounts for approximately 35% of delivered electric power in the United States.[503] As one of the significant consumers of electric power, the industrial sector presents a significant opportunity for CO_2 reductions from affected EGUs through increased energy efficiency. A 2009 study estimated that energy savings of up to 18% could be gained through EE at industrial sites, providing CO_2 reductions while increasing U.S. industrial competitiveness on a global scale.[504]

Most states have existing programs in place that support industrial energy efficiency. For example, more than 35 states administer voluntary energy programs through the state energy office targeting manufacturers and the industrial sector through mechanisms such as loans, grants, technical assistance, and energy audits. In addition, in many states, industrial EE projects can obtain funding through utility ratepayer-funded EERP or RFP programs, administered by utilities or third-party program administrators. In a study of electric IEE program spending in 2010, 84% of the funding was from ratepayer-funded utility program budgets; the remainder of the funding came from state or federal budgets, universities, nonprofit organizations, and other groups.[505]

Many industrial EE projects have traditionally focused on replacements or upgrades of energy-consuming equipment or processes, and much work in this area can still be advanced. Industrial customer participation in ratepayer-based utility EE programs could be enhanced to increase the benefits of these traditional EE projects. The State and Local Energy Efficiency Action Network (SEE Action) has recently published a case study resource with specific tips on how to expand EE efforts.[506]

Another approach to industrial EE advancement is the implementation of an Energy Management System (EnMS). An EnMS promotes operational, organizational, and behavioral changes for continual improvements in energy efficiency, by establishing a framework and management process for assessing and managing energy use and implementing efficiency improvements. Adoption of EnMS provides a corollary to the environmental, safety and quality management systems many industrial facilities and manufacturing companies have already instituted, with a specific focus on energy. The International Organization for Standardization has published an EnMS standard, ISO 50001:2011, based on the continual improvement model also used for other well-known standards, such as ISO 9001 or ISO 14001. ISO 50001:2011 provides a framework of requirements for organizations to:

- Develop a policy for more efficient use of energy;
- Fix targets and objectives to meet the policy;
- Use data to better understand and make decisions about energy use;
- Measure the results;
- Review how well the policy works; and
- Continually improve energy management.[507]

502 EPA, *ENERGY STAR certification,* https://www.energystar.gov/buildings/about-us/energy-star-certification.

503 U.S. Energy Information Administration, *Annual Energy Outlook 2015,* available at http://www.eia.gov/forecasts/aeo/.

504 McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy,* July 2009, referenced in AJW, Inc., *Securing Greenhouse Gas Reductions Through Private-Sector Delivered Industrial Energy Efficiency Under EPA's Clean Power Plan,* infra note 505.

505 AJW, Inc., *Securing Greenhouse Gas Reductions Through Private-Sector Delivered Industrial Energy Efficiency Under EPA's Clean Power Plan,* December 1, 2014, available at www.ajw-inc.com/IEE/, citing Chittum & Nowak 2012.

506 SEE Action, *Sustained Energy Savings Achieved through Successful Industrial Customer Interaction with Ratepayer Programs: Case Studies,* October 2015, available at https://www4.eere.energy.gov/seeaction/publication/sustained-energy-savings-achieved-through-successful-industrial-customer-interaction.

507 International Standards Organization, *ISO 50001 – Energy management,* http://www.iso.org/iso/home/standards/management-standards/iso50001.htm.

On a global scale, more than 7,300 sites achieved ISO 50001 certification between March 2013 and May 2014, increasing the number of certified sites by 234% in just over a year. Further, DOE reports that the growth of ISO 50001 is expected to continue to accelerate, even beyond this rapid pace.[508] As with other ISO standards, industries that elect to implement the ISO 50001 standard can obtain third-party certification to verify the EnMS is appropriately established and followed.

A state adopting a state measures plan could take advantage of these projected energy savings by incorporating mechanisms to encourage and recognize ISO 50001-certified industrial facilities, and the CO_2 emission reductions that ISO 50001 will achieve.

Another program that builds upon ISO 50001 to advance continual gains in industrial EE is the U.S. DOE Superior Energy Performance (SEP) program. SEP provides guidance, tools, and protocols to increase sustained energy savings from ISO 50001-certified facilities. To become certified, facilities must meet the ISO 50001 standard and demonstrate improved energy performance. Under the SEP Performance Pathways, an independent third party audits each facility to verify achievements and qualify it at the Silver (5%), Gold (10%), or Platinum (15%) level, based on energy performance improvement over two to three years, relative to a baseline that is calculated using the SEP Energy Performance Indicator (EnPI) tool. This certification emphasizes measureable savings through a transparent process. SEP provides a robust measurement protocol and third-party verification. To certify facilities, SEP uses only Verification Bodies accredited by the American National Standards Institute (ANSI) and the ANSI-ASQ National Accreditation Board (ANAB).[509]

In addition to the Performance Pathway described above, SEP offers a Mature Pathway for plants that have achieved significant energy savings over a long period of time (e.g., 10 years) prior to implementing SEP and for which achieving the improvements under the Performance Pathway are not realistic or cost-effective. The Mature Energy Pathway requires a minimum 15% energy performance improvement, retrospectively, over a 5- to 10-year period and can credit up to 40% improvement over the 10 years prior to the year in which the baseline was established. According to DOE, facilities in SEP under the Performance Pathway and Mature Pathway have met the ISO 50001 standard and have improved their energy performance up to 25% over three years or up to 40% over 10 years.[510]

Coupled with ISO 50001, SEP-certified industries have the potential to provide significant EE savings under a state measures plan. In addition to the significant energy savings potential, these systems incorporate U.S. DOE-adopted and ANSI-certified verification systems, providing states with a CPP-ready EM&V protocols.

9.7.2 State Measures Plan Requirements for Energy Efficiency Strategies

Any EE strategy relied upon to demonstrate a state measures plan will achieve the CPP emission goals must be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity.[511] Just as with RE strategies, it is likely that EPA will expect states to adopt an equivalent level of monitoring and verification provisions for EE programs included under a state measures plan as would be required for the same or similar EE measures included under an emission standards state plan. The key difference under a state measures plan is that EE programs and associated EM&V procedures would not be federally enforceable elements of the state plan.

9.7.2.1 Quantifiable and Verifiable (EM&V)

The criteria of quantifiable and verifiable are met if the relevant elements of the strategy can be reliably measured in a manner that is replicable, and if adequate monitoring, recordkeeping and reporting requirements are imposed to provide the necessary data and to allow the administrative authority to independently verify compliance. For EE strategies, the relevant information that must ultimately be measured is the net electric generation avoided by implementation of the various EE resources.[512] Accordingly, state-enforceable EE strategies included in a state measures plan will likely be expected to incorporate EM&V plans with the same level of rigor as EE resources qualifying for ERCs under a rate-based plan. For purposes of the CPP, EM&V is defined in the proposed federal plan as the set

508 DOE, Office of Energy Efficiency & Renewable Energy, *ISO 50001 Energy Management Standard,* http://energy.gov/eere/amo/iso-50001-energy-management-standard.

509 DOE, Office of Energy Efficiency & Renewable Energy, *About SEP,* http://energy.gov/eere/amo/about-sep.

510 AJW, Inc., *Securing Greenhouse Gas Reductions Through Private-Sector Delivered Industrial Energy Efficiency Under EPA's Clean Power Plan, supra* note 505.

511 40 C.F.R. § 60.5780.

512 Note that several of the state measures discussed in this section also reduce emissions from on-site fuel combustion, particularly industrial efficiency and building codes. Only impacts on electricity consumption would be relevant for a state measures plan.

Table 9.9 **Summary of CPP Requirements for Demand-side EE EM&V Plans (40 C.F.R. § 60.5830)**

1. Quantify and verify electricity savings on a retrospective (ex-post) basis.
2. Use industry best-practice EM&V protocols and methods that yield accurate and reliable measurements of electricity savings.
3. Include an assessment of independent factors that influence energy savings.
4. Include the expected life of the savings (in years) and a baseline of expected electricity use without the EE measure.
5. Include a demonstration of how the industry best-practices protocol and methods apply to the specific activity, project, measure or program for the purposes of quantifying and verifying MWh savings.
6. Explain why these protocols and methods were selected.
7. Submit ex-post reports of savings values, demonstrating how the EM&V plan was followed.

of procedures, methods, and analytic approaches used to quantify the MWh from RE, demand-side EE, and other eligible measures to ensure that the resulting savings and generation are quantifiable and verifiable.[513] The final emission guidelines include general requirements for demand-side EE resource EM&V procedures, summarized in Table 9.9.

In addition, the emission guidelines require that EM&V plans and M&V reports be certified by an independent verifier. Independent verification entities should be accredited by the state or a program administrator as having the technical knowledge and skills required to review EM&V plans and reports, and should have a system in place to identify potential conflicts of interest and avoid providing services where conflicts of interest would occur. For example, the verification entity and individual verifiers should not have any financial or business interest in the EE resource, or any personal relationship that would compromise their ability to act as an independent third party.[514]

EPA proposed more detailed EM&V procedures for RE measures as part of the proposed federal plan and model state rules, but did not propose detailed EM&V protocols for demand-side EE measures. However, EPA has provided detailed EM&V guidance for demand-side EE measures in a draft guidance document, *Evaluation Measurement and Verification (EM&V) Guidance for Demand-Side Energy Efficiency (EE)*.[515] EM&V protocols that meet the requirements in the emission guidelines (40 C.F.R. § 60.5830) and follow the demand-side EE EM&V guidance as set forth in the final guidance document would be presumptively approvable as part of an emission standards plan and therefore should also be presumptively approvable as part of a state measures plan.

9.7.2.2 Permanent and Enforceable

To be considered permanent, the applicable action or measure must be required for the entirety of the relevant compliance period or plan performance period, unless and until it is subsequently removed or replaced through an EPA-approved state plan revision.[516] Accordingly, the state measures plan demonstration will need to document the relevant time period for which the applicable EE strategy is relied upon, and establish that the duration of the requirement is adequate to achieve and maintain the statewide emission goals. For example, if the state is relying upon an EERS, the plan demonstration should project the level of the EE performance standard required over the course of each interim step period and into the final performance period to demonstrate that the necessary emission reductions are achieved. In addition, the instrument through which the EERS is administered and enforced (e.g., state legislation or PUC policies or rules) must be in effect for the time periods for which the resulting emission reductions are claimed. States will also likely need to demonstrate that the EE program has adequate funding to achieve the projected level of EE deployment.

To be considered enforceable, any element of an EE strategy that imposes a requirement on an affected entity must be clearly defined in a technically accurate manner, including any appropriate averaging period, with adequate monitoring, reporting and recordkeeping requirements to render the requirement enforceable as a practical matter. In addition, the affected entity must be clearly identified and the state must demonstrate adequate legal authority to enforce the requirements.

513 80 Fed. Reg. at 65,002 n.77.

514 80 Fed. Reg. at 65000-01.

515 EPA, August 3, 2015, available at http://www.epa.gov/cleanpowerplantoolbox/draft-evaluation-measurement-and-verification-guidance-demand-side-energy.

516 40 C.F.R. § 60.5780(a)(4).

9.7.2.3 Non-duplicative

An EE measure in a state measures plan is non-duplicative provided it is not also incorporated as a reduction strategy in another state plan or state plan supporting material, except that a measure may be included for multiple states that are part of the multi-state group under a multi-state plan. As previously discussed, because a state measures plan is mass-based and collective emissions from affected EGUs are directly compared to the mass-based goal to assess plan performance, EPA has determined that, as a practical matter, no double-counting of emission reductions can take place in the plan compliance demonstrations.[517] Accordingly, any potential concerns regarding double-counting of RE or other replacement generation arises not in the context of measuring plan performance during the implementation phase, but with regard to plan performance demonstrations during plan development and approval. In developing the plan performance projections, the state will need to consider the extent to which EE programs and projects used to meet state EE requirements will likely serve to reduce generation and emissions from the state's affected EGUs, as opposed to replacing generation from other affected EGUs in the regional interconnect. This concern would be largely mitigated or eliminated if the state measures plan is a multi-state plan or a plan involving a regional mass trading program. For a single-state plan, modeling of the regional grid could be used to support a demonstration of where affected EGU emission reductions are most likely to occur. Further discussion of avoiding double-counting for EE strategies in plan performance projections is provided in Section 9.9, State Measures Plan Performance Demonstrations.

9.7.3 Administrative Authority Options for Implementing EE Strategies

The selection of the administrative authority that will implement and enforce the state's EE strategy will to a large extent be determined by the selection of the sector that will have responsibility for achieving the EE goals. For example, if the state makes utilities responsible for achieving all or some of the EE deployment targets (e.g., by adopting an EERS), the PSC may be the most appropriate administrative authority. If the EE strategy involves consumer incentive or rebate programs to be implemented by the state energy office through a contracted program administrator, then the state energy office would be the administrative authority. If the EE strategy involves, for example, a requirement that all new construction for state buildings meet updated building codes, the state agency with oversight over approving state building plans, such as the Division of Administration, may be the administrative authority.

For a state measures plan, annual reporting to EPA is required during the CPP interim period regarding the status of plan implementation in relation to all programmatic milestones. It is likely that the state air quality agency will be the agency compiling and submitting reports to EPA, whereas one or more other state agencies (e.g., the PSC or the SEO) will have a role in administering EE programs. Accordingly, interagency agreements establishing protocols for data collection, compilations and reporting will likely be needed.

New authority through state legislation may be needed, for example, to adopt a new or expanded EERS, to establish new funding mechanisms if necessary, or to establish new incentive or grant programs to encourage EE investment. States will want to examine the timeframes for adoption of necessary authorities and subsequent implementation of the EE strategy, and take these timing considerations into account in plan performance projections.

9.7.4 Affected Sources and Affected Entities

In general, individual affected EGUs are not directly subject to EE requirements. It is common, however, for IOUs to be subject to EERS requirements or other forms of EE targets. Other electricity producers and retailers are also often subject to EERS, including munis, co-ops, or distribution utilities. Under a state measures plan that relies upon EE reductions to be achieved by power producers or distributors, these affected entities must be subject to state-enforceable requirements to assure the EE requirements are met.

The EE resources providing the energy savings are also affected entities to the extent they must comply with registration requirements, performance specifications or EM&V requirements. Companies or individuals providing services as independent verifiers will also be affected entities, to the extent they are subject to application, registration or training requirements and to the extent they must develop reports and provide certification statements in accordance with applicable state policies and regulations. These requirements should also be enforceable under state law.

517 80 Fed. Reg. at 64,913.

9.7.5 Mechanisms for Implementing EE Strategies

A well-established and successful mechanism for implementing EE programs is the use of an EERS, as discussed in Section 9.7.1. A state adopting a state measures plan could readily rely on an already established EERS, by extending or enhancing the compliance periods and EE standards to assure they are aligned with the state's CPP compliance requirements. For purposes of plan demonstrations through modeling, any energy demand impacts associated with existing EE requirements could be incorporated into the base case projections, while incremental energy savings from newly adopted measures would be modeled in the plan projections. A state without an existing EERS may elect to adopt an EERS, which may be combined with an RPS, to support achieving the state's Table 3 or Table 4 mass emission goals (or EPA-approved alternative goals).

For states that do not have an EERS or EE program administrative and funding mechanism in place, an excellent resource for example state legislation, policies and regulations related to EERS and energy efficiency programs is the American Council for an Energy Efficient Economy (ACEEE) database of state energy efficiency policies, *State Energy Efficiency Policy Database,* located at http://aceee.org/sector/state-policy. Another publicly available repository with links to existing state legislation and regulations is the National Council of State Legislatures (NCSL) Energy Efficiency webpage at http://www.ncsl.org/research/energy/energy-efficiency.aspx, which includes a primer on and examples of state financing mechanisms for funding EE projects.

Ratepayer-based funding through electricity bill surcharges is commonly used to fund EERS compliance. As discussed in Section 9.7.1, the ESPC is a well-proven mechanism for funding EE projects in the MUSH sector, and could be used to a greater extent in the industrial and commercial sectors.

9.8 Determining the Potential for Reductions from RE and EE

Several studies and tools are available to assist states in determining the RE and EE potential in their state, as well as the related impacts on the electric grid and associated CO_2 reductions.

9.8.1.1 Online Calculator Tools

EPA has established a repository of resources called *Estimating Potential Energy Efficiency and Renewable Energy (EE/RE) Impacts.*[518] One of the resources provided in the EPA toolbox is the AVoided Emissions & geneRation Tool (AVERT).[519] AVERT is a free online tool designed for use by state air quality planners or others, including non-experts, to evaluate county, state and regional-level avoided emissions from power plants achieved by EE and RE state programs. AVERT uses publicly available data and can be used to evaluate NO_X and SO_2 emissions impacts in addition to CO_2 emissions benefits. EPA characterizes AVERT as a useful screening tool to compare different RE or EE strategies (e.g., wind vs. solar) and their influence during high-demand scenarios. AVERT has the functionality to present location-specific emissions benefits in tabular and map formats to facilitate interpretation and communication. Importantly, EPA notes that AVERT should not be used to examine the emission impacts of major fleet adjustments or changes extending further than five years from the baseline year.

Another online calculator tool, provided by ACEEE, is the State and Utility Pollution Reduction Calculator, Version 2 (SUPR2).[520] SUPR2 is designed to assist states in assessing the costs and emissions benefits of different CPP compliance options. Using SUPR2, state planners can model the emissions impacts of 19 different EE policies and RE technologies to compare different compliance scenarios. SUPR2 predicts how much each scenario will cost and what reductions will be achieved. SUPR2 is an update to the original SUPR calculator, and reflects the final Clean Power Plan rule.

While these tools may be helpful in determining whether to include EE in state plans, additional analysis would be necessary to support the projections required for approval of a state measures plan.

9.8.1.2 Guidance and Studies

Another resource available on the EPA Clean Power Plan Toolbox webpage is the guidance document, *Assessing the Multiple Benefits of Clean Energy: A Resource for States.*[521]

518 Available on EPA's *Clean Power Plan Toolbox for States* webpage, http://www.epa.gov/cleanpowerplantoolbox.

519 Available at https://www.epa.gov/statelocalclimate/avoided-emissions-and-generation-tool-avert.

520 Available at http://aceee.org/research-report/e1601; *see also* Cassandra Kubes et al., *User Guide for the State and Utility Pollution Reduction Calculator Version 2 (SUPR 2), Compliance Tool for Clean Power Plan Final Rule,* January 2016.

521 EPA, February 2010, available at https://www.epa.gov/statelocalclimate/assessing-multiple-benefits-clean-energy-resource-states.

This EPA technical guidance document is intended to help states identify and quantify the energy, environmental, and economic benefits of EE and RE policies and programs. The guidance specifically addresses replaced or avoided generation in Chapter 3, Assessing the Electric System Benefits of Clean Energy. CO_2 and other air emissions impacts are addressed in Chapter 4.

Several other recent studies have estimated the national potential for reductions in electricity consumption based on implementation of a variety of EE measures in various sectors, including new commercial buildings, residential buildings, MUSH buildings, and industrial plants. For example, in relation to ESCO implementation of ESPC projects, a 2013 DOE Lawrence Berkeley National Lab report noted that ESCOs have delivered retrofit projects for a total of 4.9 billion square feet of space in the MUSH, federal, commercial and industrial and public housing market segments from 2003-2012, and estimated an additional 17 billion square feet are immediately available in "ESCO-addressable" buildings, indicating a significant near-term untapped market potential for EE in these sectors.[522]

Many studies are also available at the state level. In a 2008 study, ACEEE surveyed energy efficiency potential studies and methodologies, and provided insights into the various protocols and assumptions used to estimate EE potential and the implications those protocols and assumptions could have on the outcome and usefulness of the study.[523] In addition, ACEEE has developed a series of state-specific EE and RE potential analyses under the State Clean Energy Resource Project. Each study estimates the overall potential for energy efficiency and renewable resources in a state and addresses specific recommended energy efficiency policies and renewable resources for states to pursue. The ACEEE process relies on extensive stakeholder engagement, comprehensive analysis, and focused expert technical assistance, with the goal of serving as an independent and unbiased resource to support the development and implementation of EE and RE policies at a state level. Funding for the State Clean Energy Resource Project is provided by DOE, the Energy Foundation, EPA, and additional state foundations and agencies.[524]

9.9 State Measures Plan Performance Demonstrations

Each state measures plan must include a plan performance projection demonstrating that the state measures included in the plan, in conjunction with federally enforceable emission standards, if any are included in the plan, will achieve the applicable statewide CO_2 emission goals for the interim step periods, interim period and final performance period. EPA has provided specific guidance on the development of plan performance demonstrations, including the treatment of RE and EE resources in plan projections. Subpart UUUU requires each state measures plan demonstration to include a two-tiered demonstration, which is further described in a TSD that accompanied the final CPP, *Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations.* The two-step plan projection process includes:

Step 1: Select or Develop a Base Case Demand and Supply Forecast;

Step 2: Adjust the Base Case Forecast to Reflect the State Plan RE and EE Measures.

9.9.1 Base Case Forecast

Each state measures plan demonstration must include a base case forecast of energy demand and supply, including the energy generation profile, which would be expected to occur in the absence of the proposed state plan. To meet this requirement, the state may choose to utilize a base case forecast developed by any of the following sources:

- U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook (AEO);
- North American Electric Reliability Corporation (NERC);
- Regional transmission organizations (RTOs)/independent system operators (ISOs) (e.g., PJM Interconnection, ISO-New England, NYISO);
- Vertically integrated utilities (e.g., a large power company that operates the electricity system for a specific region), in combination with another publicly available source;
- State energy agencies (e.g., state energy office or Public Utility Commission (PUC)); or
- Regional councils that coordinate energy planning (e.g., Northwest Power and Conservation Council).

522 Elizabeth Stuart et al., *Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry,* Lawrence Berkeley National Laboratory & National Association of Energy Service Companies, prepared for the U.S. Department of Energy, September 2013, available at http://emp.lbl.gov/sites/all/files/lbnl-6300e_0.pdf.

523 Maggie Eldridge et al., *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned,* American Council for an Energy-Efficient Economy, 2008, http://aceee.org/files/proceedings/2008/data/papers/8_468.pdf#page=1.

524 http://aceee.org/state-clean-energy-resource-project.

525 40 C.F.R. § 60.5745(a)(6); EPA TSD, *Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations, supra* note 457.

Alternatively, the state may develop its own forecast, which may rely on data from one of the sources listed above, or may rely on another resource. A state-developed forecast or a forecast developed by a different source than those listed above must be approved by EPA on a case-by-case basis.

The plan demonstration must document any RE and EE programs that are already in place ("on-the-books" programs), and document whether and how those programs are incorporated in the base case forecast. In some cases, existing programs may be explicitly identified and incorporated into the base case. In other cases, the programs may be fully or partially reflected through underlying assumptions in the economic models or algorithms relied upon in the model. For each program, the state plan demonstration must document:

1) Policy or program name;
2) Whether the policy is codified in state or local rule;
3) Year enacted; and
4) When the policy requirements sunset.

Note that the base case forecast model will likely be conducted using data and inputs that are more current than the 2012 BSER baseline year. Accordingly, state measures that meet the CPP eligibility criteria for qualifying RE or EE resources may be included as "on-the-books" programs. If an "on-the-books" program is a CPP-qualifying program and the state will rely on it to meet the statewide emission goal, the following information must also be documented:

5) Program requirements (e.g., targets in megawatt hours (MWh) or percentage);
6) Annual energy savings or generation in the base year (MWh);
7) Annual and cumulative energy savings or generation in the future interim and final periods (MWh); and
8) Estimated useful lives for programs.

Each base case forecast demonstration will be assessed by EPA to determine whether the demand and supply forecast is reasonable, and this assessment will include a review of the assumptions made with regard to "on-the-books" programs. In addition, a full understanding of how "on-the-books" measures are included in the base case is necessary to assure that impacts from those same measures are not double-counted by duplicative inclusion in the plan projection scenarios.

As previously discussed, one situation in which a state may conclude a state measures plan is the preferred CPP plan pathway is where the collective emissions from affected EGUs already meet or are on target to meet the statewide emission goals due to actions already taken or programs already in place. If this is the case, the base case projections may demonstrate that the emission goals are achieved with no further state measures applied in Step 2. A state with existing programs, and particularly with programs that were in place prior to 2012, that are projected to achieve the CPP emission goals without additional state measures may find it useful to consult with the EPA Regional Office on the appropriate documentation and representation of those programs in the state plan performance projections.

9.9.2 Plan Performance Projection Demonstrations

State measures plans that rely on replacement generation or EE programs to reduce emissions from affected EGUs will need to project the expected incremental impacts of those measures in the plan performance demonstration. Incremental impacts are those impacts that are not reflected in the base case forecast. As previously noted, some "on-the-books" CPP-qualifying resources may already be incorporated in the base case, and the impacts from those resources cannot be double-counted by inclusion in the plan projection case. The state plan performance projection can be a model scenario that incorporates RE and EE impacts as model inputs, or it can be developed by adjusting, or "post-processing," the base case forecast to reflect the impacts of the state RE and EE measures. In accordance with the EPA guidance, impacts can be projected using a "bottom-up" approach, starting with project-specific or EGU-specific estimates and summing those contributions to determine the statewide impact. Alternatively, the impact assessment can be a "top-down" approach, based on applying the design and requirements of the state program over the plan performance period. For example, EERS or RPS programmatic levels of avoided energy consumption or replacement generation could be applied in a "top-down" fashion. On the other hand, incremental impacts resulting from a state law requiring all state buildings to enter into ESPC energy savings contracts within a ten-year period may be better assessed using a "bottom-up" approach.

The TSD *Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations* provides general equations for states to use to quantify projected RE and EE impacts during the interim and final plan performance periods.[526] The following sections summarize the approaches illustrated in the TSD.

526 *Ibid.*

9.9.2.1 Emission Reduction Impacts from RE and Other Replacement Generation

While the TSD specifically addresses incorporation of RE impacts, with a focus on state Renewable Portfolio Standards (RPS), the same concepts could be extended to any replacement generation measures relied upon in the state plan, including nuclear, qualified biomass, waste-to-energy, or CHP. If the replacement generation is a non zero-emitting resource, such as qualified biomass or CHP, appropriate adjustments to emissions projections will need to be made to the CO_2 emissions projections.

For programs that specify annual targets in terms of a percent of retail electricity sales, the following equation would be used to provide a top-down impact assessment:

$$\mathbf{MWh_{Impact}}(t) = \mathbf{r}(t) \star \mathbf{Z}(t) - \mathbf{MWh_{Ineligible}}(t)$$

Where:

MWh_{Impact} is the qualifying replacement generation, in MWh, provided in a future year, ***t***;

r is the annual RPS percent RE target for the year ***t***;

Z is the forecasted electricity sales projected to fall under the RPS policy; and

$MWh_{Ineligible}$ is any MWh of replacement generation from CPP ineligible technologies.

Ineligible resources would include, for example, the non-biogenic portion of WTE generation or RE generation located in a rate-based state that would qualify for ERC issuance under the rate-based program. Also, purely voluntary RE goals are not eligible for use in the plan projection.

For state plans that include both EE and RE measures, the plan projections should first adjust the base case forecast to account for the EE-based energy savings, and then apply the RPS percent requirement to the adjusted sales forecast. Otherwise, a portion of the RPS projections would be duplicative of the applied EE savings projections.

Some RPS are capacity-based, with requirements for particular technologies to provide a specified portion of absolute capacity. For this type of RPS, the TSD provides the following equation for calculating RE impacts based on the incremental capacity of RE generation:

$$\mathbf{MWh_{Impact}} = \mathbf{MW_{Capacity}} \star \mathbf{CF} \star \mathbf{H}$$

Where:

MWh_{Impact} is the replacement generation, in MWh, provided by the specific technology;

$MW_{Capacity}$ is the installed (or projected) incremental capacity for the qualified resource;

CF is the location-specific and technology-specific capacity factor representative of projected dispatch during the plan performance period; and

H is the number of hours in the year (8760, except 8784 in leap years).

The equation should be applied for each technology, based on the location- and technology-specific target capacity and projected capacity factor, and the results should be summed to estimate the total RPS impact on generation for each year. The use of a location-specific and technology-specific capacity factor is important when converting capacity to generation impact, because different technologies, geographies and meteorological conditions can result in widely varying availability for utilization. Generation replaced by other eligible resources, such as WTE or CHP, can be estimated in the same manner. However, the impacts should be adjusted as appropriate for the technology. For instance, for WTE resources, only the portion of the generation attributable to biogenic waste should be included.

The above equation can also be used for RPS programs that set capacity-based targets without including specific targets for particular technologies. In this case, however, the state will need to estimate a weighted-average, or aggregate, RE CF based on the types of technologies and their anticipated locations most likely to be deployed for the state or region. EPA notes that the plan demonstration should document the assumed location and type of projected RE generation and the source of the associated CFs in cases where an aggregate CF is used.

9.9.2.2 Fossil Generation Reduction Impacts from EE Measures

The TSD provides that, in general, the procedure for estimating incremental EE impacts on fossil-fueled generation during the plan performance periods requires summing the incremental first-year impacts of EE savings plus the cumulative EE savings from prior years, over the effective useful life for the EE measures deployed. That is, the plan projections should reflect the annual impacts that occur due to new EE projects deployed in a given year plus the impacts of EE projects deployed in previous years that are still generating savings. First-year impacts will reflect the specific requirements of the EERS, and the expected life of the cumulative savings will reflect the useful life of the particular types of EE measures anticipated to be deployed. This general equation should be applied to the state's specific EERS program requirements. For example, in some programs, savings are based on a percent of sales,

and in other states, an absolute level of EE savings is required. Note that where a portion of the EE savings are embedded in the base case forecast, the embedded savings should not be included in the plan projections as incremental energy savings.

Where a state adopts an EERS that can be met through a number of mechanisms, the state plan should assure that no double-counting of energy savings is reflected in the plan projections. As an example, assume a state adopts an EERS requiring energy savings equivalent to 2% of retail electricity sales, and also adopts a building energy code requiring newly constructed and renovated buildings to meet the ASHRAE 90.1-2015 model code. The EERS allows energy savings from buildings meeting the ASHRAE 90.1-2015 code to be counted toward the 2% EE target. In this example, the state plan projections should not reflect discrete energy savings from new buildings in addition to the required 10% energy savings. Another circumstance in which the state should take care to avoid double-counting is where an EERS and RPS requirement overlaps. For example, in two states (Nevada and North Carolina, depicted in green in Figure 9.6), the state's existing RPS/EERS provisions set a combined EE and RE target, or allow an affected entity to utilize EE energy savings toward compliance with the RPS target. In any state for which the EE and RE savings provisions are combined in this manner, care should be taken to assure that the energy savings are not double-counted in the plan projections by incorporating both the full RPS and EERS targets. Note that, for EE measures adopted as part of a state measures plan, there is no concern about double counting energy savings through the issuance of ERCs under a rate-based plan, because ERCs cannot be issued for EE resources deployed in a mass-based state.

9.10 The Federally Enforceable Backstop

Each state measures plan must include a federally enforceable backstop. This is a required plan component regardless of whether the state plan is composed entirely of state-only enforceable measures or also includes federally enforceable emission standards on affected EGUs as an element of the plan. The federally enforceable backstop is distinct from and in lieu of the corrective action measures triggers required under other state plans that are not "streamlined" (i.e., plans that do not by design mathematically assure compliance with the CPP performance standards or emission goals).[527]

The backstop must include federally enforceable "emission standards for affected EGUs."[528] As discussed in Section 5.5.3, certain types of enforceable requirements are not considered emission standards under Subpart UUUU and thus would not meet the backstop requirement. For example, limits on operating hours, heat input, or energy output are not emission standards, even though these requirements would have the effect of limiting CO_2 emissions.[529] Additionally, demand-side energy efficiency standards, renewable or fossil fuel portfolio standards, heat rate performance standards, and enforceable EGU retirement deadlines are not emission standards.

The federally enforceable backstop is triggered by a failure to meet the Step 1 or Step 2 interim performance goals by ≥10%, a failure to meet the cumulative interim performance goal for the performance period 2022–2029, or a failure to meet the final performance goal for any two-year performance period. In addition to these triggers, the federally enforceable backstop is triggered if the state measures plan fails to meet any programmatic milestone for state measures relied upon under the plan. For example, if the state is relying upon a particular level of demand-side EE deployment under a state program by a particular milestone date in order to reach the interim performance goal, and that milestone is not met, then the federally enforceable backstop measures would be triggered. Table 9.10 below summarizes the federally enforceable backstop triggers.

Because any failure to meet a programmatic milestone would trigger implementation of the federally enforceable backstop, it is critically important for the state plan to define the programmatic milestones and establish a schedule for achieving the milestones in a manner that is realistic and achievable.

Another important distinction of the federally enforceable backstop, as compared to corrective action measures, is that the backstop provisions—including emission standards for affected EGUs—must be adopted and incorporated into the final plan upon submittal. A triggering event activates a timeline for implementation of the enforceable backstop emission limits and associated compliance obligations, as opposed to triggering the beginning of a rulemaking period to adopt compliance requirements.[530] The backstop emission standards must be sufficiently

527 40 C.F.R. § 60.5740(a)(2)(iii).

528 *Ibid.*

529 80 Fed. Reg. at 64,834.

530 40 C.F.R. § 60.5740(a)(3).

Table 9.10 **Required Triggers for Federally Enforceable Backstop Provisions Under a State Measures Plan**
40 C.F.R. § 60.5740(a)(3)

No.	Corrective Action Triggers	Description
A	Any failure to meet a Programmatic Milestone	The state measures plan must define programmatic milestones designed to achieve the mass-based performance goals for each performance period.
B	Interim Step 1 Performance Goal (2022–2024) or Interim Step 2 Performance Goal (2025–2027), ≥10% exceedance	The cumulative sum of mass emissions from all affected EGUs is compared to each interim step goal. Adjustments for net exports/imports must be made if the plan includes a trading program that covers non-EGU sources.
C	Interim Period Performance Goal (2022–2029), any level of exceedance	There is no separate Interim Step 3 trigger required. Any-level exceedance of the eight-year cumulative Interim Performance Goal triggers the backstop. Adjustments for net exports/imports must be made if the state measures plan incorporates a mass trading program with applicability to non-EGU sources or with provisions that could expand the budget.
D	Final Period Performance Goal (2030–2031; 2032–2033; etc.), any level of exceedance for any performance period	The backstop emission limits are triggered for any level of exceedance for any two-year block performance period. Adjustments for net exports/imports must be made if the state measures plan incorporates a mass trading program with applicability to non-EGU sources or with provisions that could expand the budget.

stringent to assure compliance with the interim and final performance standards or statewide emission goals, and in addition, must make up for any prior emissions shortfall that would have been achieved had the relevant interim step, interim period, or final period performance goals been met.

Table 9.11 summarizes the required elements of the federally enforceable backstop.

Table 9.11 **Required Elements for Federally Enforceable Backstop Provisions Under a State Measures Plan**
40 C.F.R. §§ 60.5740(a)(3) & 60.5785(d)

No.	Corrective Action Triggers	Description
A	Federally enforceable emission standards for affected EGUs	The state measures plan must adopt federally enforceable emission standards that would become applicable to affected EGUs upon a triggering event. The emission standards must be effective within 18 months of the triggering event.
B	Emission standards must be able to meet either the Table 1 performance rates, or the Table 2, Table 3 or Table 4 performance goals for the state	The standards or emission goals must be met for both the interim and final plan performance periods.
C	Provisions to make up emissions performance shortfalls "as expeditiously as practicable"	The final plan must either include: • Enforceable provisions establishing a mechanism to adjust the adopted emission standards as necessary to make up for performance shortfalls, *or* • Revised emission standards can be submitted as a plan revision after the triggering event occurs, provided that the shortfall must be made up as expeditiously as practicable.

For a state measures plan that does not involve an interstate trading program, one relatively simple approach to meet the federally enforceable backstop requirement would be to incorporate by reference the final federal plan language or final EPA model state rule to implement a trading-ready allowance trading program using the statewide Table 3 emission goals as the state cap, or using the Table 1 rate-based performance standards as the applicable standards in conjunction with an ERC trading program.[531] Under this scenario, in the event that the state measures failed to meet any applicable performance goal, the affected EGUs in the state would become subject to a "pre-approved" trading program within eighteen months of the triggering event.

To make up any shortfall in emissions performance that occurs during the state measures plan implementation, a state using a mass-based trading program as a backstop could adopt a provision for adjusting the statewide cap and associated allowances in the initial plan performance period(s). Note that, if a rate-based performance standard approach is used as a backstop, such as under a rate-based trading program, it would be somewhat more complicated to demonstrate that the mass-based shortfall would be made up in future periods. The state could potentially include an adjustment provision to require additional ERCs during the initial performance period(s), together with a demonstration of mass emissions equivalence based on the affected EGU inventory and projected generation rates. Or, the state could potentially include other adjustments or regulatory mechanisms to demonstrate the mass emissions shortfall was met.

One alternative to adopting a trading program as the federally enforceable backstop would be to establish direct mass emission limits on affected EGUs that mathematically assure compliance with the statewide emission goals for future plan performance periods, less any mass emissions shortfall. This approach may be the simplest and most effective approach in a situation where the specific state measures adopted in the state plan failed to meet a programmatic milestone, but the mass emissions from affected EGUs are nonetheless at or near the Table 3 emission goal. For any EGUs that have retired or are scheduled to retire, an EPA-approvable approach is to establish an enforceable mechanism with a 0 tpy or 0 lb/MWh emission standard.[532]

9.11 Treatment of Leakage Under a State Measures Plan

Because any state measures plan is a mass-based plan, the emission guidelines require that the plan address the potential for mass emissions leakage from affected EGUs to new EGUs subject to the new source performance standards under 40 C.F.R. Part 60, Subpart TTTT.

As summarized in Section 5.4, the emission guidelines set forth three options a state can rely on to make the leakage demonstration:

1) The state can elect to regulate new non-affected EGUs, through state-only enforceable requirements, under the mass-based program. For example, if new fossil fuel-fired EGUs are subject to mass-based limits or allowance provisions in the same manner as existing EGUs, the incentive for leakage is minimized or avoided.
2) Under a mass-based trading program that does not regulate new sources, the state can include an allocation scheme that avoids or minimizes incentives for leakage to new sources.
3) The state could develop its own new source complement budget or an approvable equivalent method for addressing new sources under the state program, or could include a demonstration and justification that leakage to new fossil fuel-fired EGUs is not anticipated under the state plan.

9.11.1 Leakage Under a State Measures Plan with an Expanded Trading Program

One type of state plan that falls under the state measures plan pathway is a plan involving a mass-based trading program with applicability beyond affected EGUs and new EGUs subject to Subpart TTTT, or that includes special provisions such as cost containment triggers that could have the effect of expanding the mass-based emissions cap beyond the Table 3 or Table 4 emission goals. For a state measures plan that fits this description, it is very likely that new affected EGUs would be covered under the trading program, thereby addressing leakage concerns in accordance with Option 1 listed above.

531 Note that neither EPA's proposed federal plan nor its proposed model rules have been finalized as of May, 2016.

532 80 Fed. Reg. at 64,834.

9.11.2 Leakage Under a State Measures Plan with Federally Enforceable Emission Standards

A state may adopt a state measures plan that combines federally enforceable direct mass emission limits on affected EGUs (without an interstate allowance trading program) with state-enforceable non emission-limit measures to achieve the mass-based statewide emission goals. This type of plan, depending on its design and the full suite of plan provisions, could potentially incentivize leakage of emissions from affected EGUs to new fossil-fuel fired EGUs. Because this type of plan does not include trading, Option 2—designing an allocation schedule for allowances that minimizes leakage concerns—is not applicable.

To address leakage concerns, the state would likely need to evaluate the affected EGU inventory and incentives for leakage, and establish customized plan provisions designed to counter those incentives. The potential for leakage incentive under this type of plan would be dependent on the particular state circumstances, and could be influenced by a number of factors, including but not limited to:

- The affected EGU inventory mix, including any plans for retirement of affected EGUs;
- The level of the federally enforceable emission limits on affected NGCC EGUs, particularly in relation to the targeted capacity factor to assure BSER reductions are achieved;
- The level of affected EGU emissions in relation to the statewide emission goals;
- The design and scope of the state-enforceable measures, including RPS and EERS requirements or fossil-fuel portfolio standards; and
- Provisions for proposed new EGUs, including IRP reviews, PSC reviews, and air permitting procedures.

In a few cases, the likelihood of leakage may be minimal due to the particular EGU inventory in relation to the statewide emission goal. For example, if mass emission limits for affected EGUs can be set such that: (1) emissions from coal-fired affected EGUs reflect planned retirements, with a decrease in emissions over the interim period; and (2) existing NGCC EGUs are authorized to emit at the BSER-anticipated level (i.e., equivalent to 75% summer capacity factor), then the incentive for generation shift to new NGCC units is greatly diminished. For an example of setting mass emission limits under this scenario, see Section 8.1.1, ***Mass-based Rule Example 1, Direct Emission Limits on Affected EGUs, with Flexibility Provisions.***

Another factor that could avoid or minimize leakage under this plan type is the impact of state-only measures such as EERS and RPS requirements. To the extent these requirements drive investment in energy efficiency to reduce demand, and in renewable energy generation to meet demand, the cost efficiency and incentive for construction of new fossil-fueled EGUs is reduced.

The state could also adopt procedures specifically aimed at avoiding leakage. For example, the PSC review process to authorize rate adjustments for the construction and deployment of new EGUs could include a leakage evaluation. Or, the state air quality preconstruction process could require such an evaluation. One approach the state could consider in performing a preconstruction new-source leakage evaluation would be to assess the total allowable CO_2 emission rates for affected plus new EGUs, including the proposed new EGUs, in comparison to the Table 4 statewide emission goals or to an approved alternative goal.

9.11.3 Leakage Under a State Measures Plan that Includes only State Measures

For a state measures plan that does not include any emission standards directly applicable to affected EGUs, the options for addressing leakage could potentially fall under Option 1 or Option 3. This type of plan relies solely on state measures that are not emission standards, such as RE and EE programs.

First, because the affected EGUs are not subject to a mass emission limit, the plan is unlikely to create an incentive for shifting emissions to new fossil fuel-fired EGUs in the same way a mass-based trading program could. Also, if the state measures include EERS and RPS requirements that apply to electricity retailers, both affected EGUs and new EGUs are collectively impacted in the same manner. Furthermore, any new EGUs would be subject to rate-based performance standards under Subpart TTTT, which could serve as a disincentive to construct new fossil fuel-fired EGUs in lieu of deploying RE units or EE projects that could serve to comply with the applicable state measures. Compliance with EERS and RPS minimum requirements would favor energy efficiency gains and generation shift to renewable energy over the deployment of new NGCC or fossil-fueled units, thereby providing a counter-balance to leakage incentives. Accordingly, a state measures plan of this type inherently minimizes or avoids an incentive for leakage to new units.

SECTION III:

Comprehensive Model State Plan Submittals

Model State Plan Initial Submittal

Requesting Extension of
Final Plan Submittal Deadline

and

Model Final State Plan Submittal

Mass-based Allowance Trading Plan
with New Source Complement
Interstate Trading-Ready

10. Introduction to NACAA's Comprehensive Models

10.1 Overview

Section III presents two models for state plan submittals. The first is a model Initial Submittal, fulfilling all requirements of Subpart UUUU, § 60.5765 to obtain a two-year extension for the final plan submittal until September 6, 2018.[533] The second is a comprehensive model for a final state plan submittal, including example legislation; a complete, mass-based, trading-ready rule for existing affected EGUs and new sources subject to 40 C.F.R. Part 60, Subpart TTTT; and an accompanying state documentation report addressing each required plan component, including all required descriptions and demonstrations.

These comprehensive models are intended to complement EPA's published materials and to provide states with additional, alternative examples of state plan components to consider. With regard to NACAA's model Initial Submittal, the format and content closely track the EPA guidance memo, *Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act* (referred to herein as the Initial Submittal Guidance Memo).[534] Expanding on the guidance EPA provided in the memo, the model Initial Submittal provides a complete response to each of the three required initial submittal elements, including a thorough description of an example process for identifying vulnerable communities that goes beyond use of EPA's *EJ Screening Report for the Clean Power Plan*.[535]

Similarly, NACAA's model Final State Plan offers an example of a plan design and several key plan provisions not covered by either of EPA's proposed model state plans or the proposed federal plan, while remaining consistent with certain required plan provisions such as affected EGU monitoring and recordkeeping requirements. For example, NACAA's model Final Plan regulates new sources, uses a direct allocation scheme without the inclusion of set-asides, provides procedures for state auctions and sales of allowances, and includes enforcement provisions, none of which are included in EPA's proposed model rules.

Each model includes some detailed descriptions of state-specific circumstances and preferences, although the models are not intended to represent actual states. Also, to allow for a more varied presentation of examples, the Initial Submittal and the Final Plan Submittal are not written to represent the same hypothetical state. For example, the Initial Submittal is written from the perspective of a hypothetical state in the PJM service area, with both coal-mining communities and coastal areas. The Final Plan Submittal is written from the perspective of a hypothetical state in the MISO service area, with no coal-mining activity. However, some examples and concepts are carried over from the Initial Submittal to the Final Plan to provide a complete illustration. The Initial Submittal, for instance, suggests the state is leaning toward adoption of a mass-based trading program that may include regulation of new sources, and the Final Plan reflects that choice. Also, the Initial Submittal introduces the concept of a state-designed "allowance rewards" program to incentivize investment in the deployment of demand-side energy efficiency (EE) programs in vulnerable communities, and the Final Plan incorporates regulatory language to implement such a provision.

533 As discussed in the Preface to this document, all dates and deadlines established under the Clean Power Plan are potentially subject to change due to the Supreme Court-ordered stay on the rule's implementation pending judicial review. No state submittals will be required while the stay remains in effect.

534 Stephen D. Page, *Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act,* October 22, 2015, https://www3.epa.gov/airquality/cpptoolbox/cpp-initial-subm-memo.pdf (hereafter, "Initial Submittal Guidance Memo").

535 EPA, *EJ Screening Report for the Clean Power Plan,* July 30, 2015, https://www3.epa.gov/airquality/cppcommunity/ejscreencpp.pdf.

10.2 Introduction to Comprehensive Model Initial Submittal

The Initial Submittal Guidance Memo notes the agency's "intent to place only modest requirements on states seeking extensions" and describes the request and extension as a "simple" process that "requires only that the state demonstrate it has taken certain preliminary and readily achievable steps toward the development of its plan."[536] In keeping with that intent, the model Initial Submittal is brief, straightforward and self-explanatory.

Each of the three required initial submittal elements as set forth at 40 C.F.R. § 60.5765 are addressed in order. In addition, the model provides a non-binding statement of intent to participate in the Clean Energy Incentive Program (CEIP), as required for a state that may wish to do so. Section 2 of the Initial Submittal includes a timeline for milestones in the development of the State Plan and adoption of regulations, demonstrating the need for an extension to September 6, 2018. Section 3 includes a table summarizing the benchmark indicators the State is using to identify vulnerable communities, in accordance with the Initial Submittal Guidance Memo.

The Model Initial Submittal goes a bit beyond the minimum requirements of § 60.5765 as described in the Guidance Memo by describing concerns raised by representatives of vulnerable communities during the public outreach and engagement. This discussion affords an opportunity to introduce the concept of a state-designed provision for incentivizing and rewarding the deployment of EE programs in vulnerable communities, as described in the Model Initial Submittal and incorporated in the Model State Plan.

Finally, the Model Initial Submittal is organized to include a template for three appendices:

A. State Authorizing Legislation
B. Documentation of Public Participation and Outreach
C. Identification and Engagement of Vulnerable Communities

A cover page is provided for each appendix, listing the specific materials that would be included. For Appendix A, model legislation is not included; however, three pieces of model state legislation are included with the Model State Plan. For the remaining two appendices, example materials are not included with the model. This is because the materials are straightforward documentation that each state will have readily available to include with its submittal, and each state's information will comprise a unique set of materials.

10.3 Introduction to Comprehensive Model State Plan Submittal

Presented in this section is a comprehensive model state plan submittal, combining all of the major required plan components into an illustrative example to support states in the plan development process. This introduction provides a brief overview of the plan components, highlights some of the regulatory provisions and plan sections that differ from EPA's models or that may be most useful or interesting for states to consider, and discusses a few of the significant policy considerations addressed in the model.

10.3.1 Overview of Model Plan Design

The comprehensive model state plan is a streamlined, trading-ready, mass-based trading program that adopts the Subpart UUUU Table 4 statewide mass-based emission goals for affected EGUs plus new source complements as the plan performance goals and as the mass allowance budgets for existing and new EGUs. This plan type was selected for the comprehensive model for several reasons. First, the mass-based, interstate trading program design seems to be a popular emerging preference among states. Many utilities, RTOs, states, and experts seem to concur that a regional or interstate plan design is preferable. Some of the primary reasons for this preference are that regional approaches optimize flexibility, support grid reliability, and reduce compliance costs as compared to a state-by-state compliance approach. Many also seem inclined toward the mass-based approach, in part because under a mass-based program the number of allowances is budgeted and known in advance, whereas under a rate-based program the number of Emission Rate Credits (ERCs) that will be created for a given compliance period is unknown.

Furthermore, EPA has published a proposed model state plan for a mass-based trading program based on the Table 3 statewide emission goals for existing affected EGUs. However, it is not anticipated that EPA will publish a model rule to include new sources under a mass-based trading program, particularly given that EPA does not have the authority to regulate new sources under section 111(d) of the Clean Air Act. Thus, this model provides example regulatory language for a plan design contemplated as an approvable pathway under Subpart UUUU but for which EPA has not and likely will not provide a model.

536 Initial Submittal Guidance Memo, *supra* note 534.

10.3.2 Primary Plan Components

The model plan comprises three main components: (1) a complete model state regulation; (2) model state legislation, consisting of three separate acts to authorize and fund the program and to provide for the auction, sale, and allocation of allowances; and (3) a model plan documentation report including checklists and addressing the required plan demonstration and documentation.

To avoid redundancy, this introductory section will not provide a detailed discussion of each plan element. A few of the more significant policy considerations incorporated into the plan are highlighted below, with suggestions for how a state could adapt or modify the model to accommodate differing policy goals.

10.3.3 Allowance Distribution and Allocation Scheme

The model plan adopts a four-part allowance distribution scheme that lends itself to use by states in whole or in part. In brief, the segments of allowance distribution under the model include:

1) The State, which reserves from 15% to 50% of the budget for auction or sale;
2) Qualified energy efficiency resources (EERs), which are allocated allowances (i.e., not via set-asides) based on verified and certified energy savings in the three- or two-year period immediately prior to the year in which allocations are made;
3) New affected electric generating units (EGUs), which are allocated allowances based on generation (using a projected prorated generation for the first compliance period of operation), with total new EGU allocations capped at the level of the new source complement;
4) Existing affected EGUs and qualified renewable energy (RE) and low-emitting EGUs, which are allocated allowances based on their relative proportion of generation in the three- or two-year period immediately prior to the year when allocations are made.

This multi-component approach could serve as an example to balance competing goals and interests with regard to the distribution of allowances, and has the advantage of presenting regulatory language for a number of options, such that a state could choose to adopt one or more pieces and omit others.

10.3.3.1 The State's Portion

The model plan retains a portion of the allowances from the budget for each compliance period for the state to auction or sell. The model also incorporates example statutory language to authorize the state to conduct auctions and sales, and regulatory language to establish procedures for auctions and sales of allowances. One fundamental reason for the state to auction or sell allowances under a mass-based trading plan is to fund the cost of implementing and enforcing the program. Toward this end, the model sets a minimum of 15% of the allowances to be auctioned or sold by the state and provides that proceeds from allowance sales will be used to fund the program costs, with any proceeds in excess of program costs to be appropriated to other funds. A 15% portion would likely be adequate to fund the program, based on recent RGGI program costs estimated at approximately 7% of allowance revenues.

The model also sets a ceiling of 50% of the allowance budget to be reserved by the state for auction or sale. The ceiling accommodates an allowance distribution framework that apportions the budget to multiple stakeholder recipients. However, a state could choose to raise or lower the ceiling or to omit the ceiling, based on the preferences and circumstances of the state.

The model illustrates an approach of establishing flexibility within the legislative and regulatory framework of the program to adjust the state's share of allowances over time, within specified boundaries, with additional flexibility to direct proceeds toward different funds over time. This approach could facilitate stakeholder consensus and adoption of a state auction or sale provision, by avoiding the need to make a "once and forever" decision about how much of the monetary value of allowances the state should retain and how the revenues should be disbursed.

10.3.3.2 Allocations to Energy Efficiency Resources and Incentivizing EE in Vulnerable Communities

The second tier of the model plan allocation scheme provides allowances directly to qualifying EERs based on the verified energy savings certified for the three- or two-year period immediately preceding the year when the allocations are made. These allocations are not intended to address leakage to new sources (which is accomplished by regulating new sources under the cap). Rather, these allocations monetize the energy savings provided by EE

537 Jonathan L. Ramseur, *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Policy Makers,* Congressional Research Service, November 14, 2014.

measures and recognize the direct contribution of energy savings to the balance of power supply and demand and reduction of CO_2 emissions. Direct allocation of allowances based on certified energy savings that have already occurred provides a simple way to recognize the value of EE measures and avoids much of the "guesswork" of set-aside schemes. The model establishes a cap on the total amount of allowances that could be directly allocated to qualified EERs, at 15% of the budget remaining after the state portion, except that the enhanced portion of an allocation issued from energy savings in a vulnerable community is not counted toward the 15% cap, as explained below. This cap could be lowered, raised or removed. The cap is established in the model as a mechanism to provide for a broad distribution of allocations among multiple groups.

In addition, the model plan incorporates an allowance reward scheme for the deployment of EE programs in vulnerable communities. This is accomplished by adding a multiplier of 1.5 times the allocations that would otherwise be awarded for the same amount of verified energy savings in any area that is not considered a vulnerable community. The allowance "bonus" is not counted toward the 15% cap on EE allowances, thus effectively increasing the cap to up to 22.5% of the remaining budget (after deduction of the state's portion) if all EE deployment were to occur in vulnerable communities. For purposes of the EE allowance reward provision, a vulnerable community is defined in a manner consistent with the benchmarks as laid out in the Model Initial Submittal. Specifically, a vulnerable community includes any census block that has a minority population greater than 70%, or that has greater than 50% low-income households. For purposes of the EE allowance reward provision, a community need not be located within a 3-mile radius of an affected source to qualify as a vulnerable community. Also, the model rule does not include communities within 25 miles of the coast line or those identified as a coal-mining community for purposes of the EE allowance reward provision; however, a State could readily expand the definition of vulnerable community as appropriate to meet the State's particular circumstances. Notably, the EE allowance reward provision is not an early action incentive provision and does not include a sunset clause.

With regard to the eligibility criteria for EE resources and programs, it is worth noting that the model does not adopt criteria identical to the Subpart UUUU qualifications for ERC-eligible resources. Adoption of the ERC-eligible criteria is not required for the model plan, since the EERs are qualifying in the context of an allocation scheme only, and states have broad discretion to allocate allowances to a wide range of entities. Furthermore, the eligibility criteria adopted under the model are not to qualify EERs to receive set-asides under the CEIP, to address leakage, or to receive ERCs. Accordingly, the allocations are not intended to be restricted to energy savings that are beyond the base case forecast, nor is it necessary to restrict the allocations in this regard, because the provision of allocations to EERs is not a measure that is relied upon to achieve the emission goals of the program. So long as the EER uses a qualifying EE measure to save energy from an in-state consumer, provides the required evaluation, measurement and verification (EM&V) and meets other qualifying criteria, energy savings from both "on the books" and new EE programs can be eligible for allocations. The allocation scheme recognizes energy savings based on the year in which the savings occurred regardless of the year in which the EER was installed, just as affected EGUs are allocated allowances based on the generation that occurred in a given period regardless of when the EGU was installed.

10.3.3.3 Allocations to Renewable Energy and Low-emitting Generation Resources

The model plan recognizes nuclear, RE and low-emitting generation in much the same way as EE resources, by providing allocations based on their contribution to the grid for a given allocation period. For nuclear, wind, solar, geothermal, hydropower, wave or tidal energy, each megawatt-hour (MWh) of generation qualifies for allocations based on the proportion of the EGU's generation to the total generation of affected EGUs and qualified EGUs.

For low-emitting EGUs that require additional adjustments to determine the eligible portion of generation, such as combined heat and power (CHP), waste heat to power (WHP), biomass and waste to energy (WTE), the model rule provides specific provisions and formulas. Specific regulatory language to identify qualified biomass is included, together with detailed provisions for determining the biogenic portion of MWh eligible for allocations.

10.3.3.4 Allocations to Affected EGUs

Affected EGUs receive allocations under the model plan in direct proportion to their generation during the years immediately prior to when the allocations are made. Coal, oil and gas steam units are treated equally to NGCC units, on a MWh basis. Fossil fuel-fired units are treated equally to RE units, on a MWh basis. This approach inherently rewards low emitters and incentivizes a shift to less

carbon-intensive generation, in comparison to an emissions-based allocation scheme.

10.3.4 Enforcement Provisions

Equity in enforcement penalties is an important program integrity and policy consideration for an interstate mass-based trading program, particularly given the interconnectedness of affected EGUs across the region and the wide-ranging access to emission reduction measures. Accordingly, the enforcement provisions of the plan bear careful consideration in plan development. The model plan incorporates several enforcement-related provisions in the state regulation, Chapter 10, § 1027. These provisions include a specific designation of entities liable for violations, to assure all parties responsible for the affected EGU and facility are accountable. A severability clause is also provided, to protect the integrity of the plan. The model also adopts an automatic initial remedy requiring the surrender of "two-for-one" allowances in the event of excess emissions in violation of the allowance-holding standard. This provision closely mirrors similar provisions under EPA's proposed model plan. Importantly, the model regulation adopts nondiscretionary stipulated penalties for violations of the emission standard. The model language sets two stipulated penalties. First, a penalty is assessed at an amount equal to three times the most recent allowance market price from a state sale or auction for each ton of excess emissions. Second, in the event that the owner or operator fails to surrender the two-for-one allowances required in a timely manner under the initial remedy provisions, an additional stipulated penalty is assessed in an amount equal to two times the most recent allowance market price from a state sale or auction for each allowance due that is not timely surrendered.

10.3.5 Highlights of Regulatory Language

The comprehensive model plan includes several additional examples of regulatory language that are not included in Section II and that may be particularly useful for states to examine. Examples include:

10.3.5.1 Provisions to Regulate New Sources

Language is provided to regulate new sources solely under state law, while conferring federal enforceability to existing affected EGUs. Also, language for the incorporation of plan provisions into the affected EGU's air permit is provided, with distinct requirements for new vs. existing sources.

10.3.5.2 Provisions to Exempt EGUs that Permanently Retire

The model rule distinguishes among three different time periods when the retirements occur. First, any EGU that has not operated at any time on or after January 1, 2012 is not an affected EGU (i.e., EGUs that retired before the baseline period). Second, any affected EGU that is permanently retired after the baseline date, but before the first period for which generation is eligible for allowance allocations, need only submit a notification and retain records to document the retirement. Third, any affected EGU retiring after the first year for which allocations are assigned is exempt effective on the first day of the compliance period following the permanent retirement date.

10.3.5.3 Provisions to Adopt a Reliability Safety Valve

The model rule provides detailed regulatory language to adopt the reliability safety valve, putting the responsibility on the designated representative of the affected EGU to provide information in a timely manner and to justify the need for the requested temporary modified emission standard, including providing an explanation of why allowances cannot be obtained. The rule language clarifies that any emissions that would reasonably have been anticipated to occur absent the power emergency must still be matched with allowances.

10.3.5.4 Provisions to Align EM&V Schedules with the Allocation Schedules

Rule language is provided to require that, to the greatest extent practicable, time intervals for quantifying energy savings from qualified EERs should be scheduled to coincide with the time periods for determining the allocation of allowances. A specific schedule is provided to assure energy savings are aligned with the plan schedule.

10.3.5.5 Procedures for State Auctions and Sales of Allowances

Section 1029 of the model rule provides detailed administrative procedures for the conducting of auctions and sales, including requirements for participating bidders and buyers, such as the provision of financial security in advance of the auction or sale event.

10.3.6 Plan Documentation

The State Plan Documentation component of the comprehensive model plan submittal provides an example and template for addressing each required plan compo-

nent in an organized fashion. The document includes three tables that serve as a checklist identifying the location in the plan submittal of each required plan element. These tables include, from Subpart UUUU, the list of five required federally enforceable plan components; the list of thirteen required plan information items and demonstrations; and, the list of five requirements for a mass-based trading program.

Finally, the model is organized to provide four appendices:

A. State Authorizing Legislation
B. State Regulations
C. Documentation of State Rulemaking Procedures
D. Documentation of Stakeholder and Public Participation, Including Vulnerable Communities

For the first two appendices, legislative authority and state regulations, the full content of the appendix is provided (i.e., complete model legislation and a complete model regulation). For the two remaining appendices, the model provides an organized list of the items that should be included, such as transcripts of public hearings, proof of publication of public notices, documentation of public meetings, and other information documenting public participation in the planning process.

Model State Plan Initial Submittal

State Clean Power Plan
to Comply with 40 C.F.R. Part 60, Subpart UUUU

Initial Submittal Requesting Extension
for Submittal of Final State Plan

State Request
and Required Information

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State Plan Initial Submittal Overview

This submittal includes all required information for requesting an extension to the final state plan submittal deadline under the U.S. EPA Clean Power Plan (CPP), as adopted at 40 C.F.R. Part 60, Subpart UUUU, October 23, 2015 at 80 Fed. Reg. 64,662 (referred to herein as Subpart UUUU). The regulations of Subpart UUUU and the corresponding preamble establish emission guidelines (EGs) that each state must follow in developing a state plan to reduce CO_2 emissions from existing fossil fuel-fired electric generating units (EGUs).

Under Subpart UUUU § 60.5760, each state must submit, by September 6, 2016, either a final state plan or an initial submittal seeking a two-year extension of the final plan submittal deadline. Subpart UUUU § 60.5765 provides that, if a state makes an initial submittal, an extension for a final plan submittal is considered granted and the final plan is due no later than September 6, 2018, unless the state is notified within 90 days of EPA's receipt of the initial submittal that the submittal does not meet the requirements of § 60.5765.

This State Clean Power Plan (State Plan or Plan) Initial Submittal is being submitted on or before the September 6, 2016 deadline, and includes all required information and supporting documentation. The submittal is made according to the electronic reporting requirements of Subpart UUUU § 60.5875.

The required elements of the Initial Submittal are set forth at § 60.5765 and are described in detail in an EPA guidance memo, *Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act.*[1] The required information includes:

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

2. An explanation of why the state requires additional time to submit a final plan; and

3. A demonstration or description of the opportunity for public comment the state has provided on the initial submittal and opportunities for meaningful engagement with stakeholders, including vulnerable communities, during preparation of the initial submittal, and plans for public engagement during development of the final plan.

In addition, Subpart UUUU § 60.5737 requires that, if a state is making an initial submittal and wishes to participate in the Clean Energy Incentive Program (CEIP), the initial submittal must include a non-binding statement of intent to participate in the program.

Each of the required elements of the initial plan submittal is addressed in the following three sections.

1 Stephen D. Page, *Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act,* October 22, 2015.

1. Identification of Plan Approaches Under Consideration and Progress Made to Date

1.1 Plan Approaches Under Consideration

At this stage in the State Plan development, the State is intentionally keeping all options for plan type and design "on the table" in order to ensure a comprehensive analysis of the strengths and potential weaknesses of each plan type, and to afford full consideration of all stakeholder input as the plan development proceeds. While a particular plan type has not been selected, the status of our selection of key aspects of plan design at the time of this submittal is summarized below. This summary represents the State Department of Environmental Quality's (SDEQ's) assessment, based on evaluation of our existing state programs, the requirements for different plan types, stakeholder input to date, and briefings with numerous state officials.

Emission Standards vs. State Measures Plan. It is likely that the State will elect to adopt an emissions standards plan, assuring compliance with the Subpart UUUU requirements while retaining existing state-only programs outside of the federally enforceable State Plan. We believe this approach will afford greater flexibility and autonomy to the State to implement or revise existing programs for energy efficiency and/or renewable energy, or to develop new state programs, without triggering the need to revise the State Plan under Subpart UUUU and without being bound to specific federal guidance or constraints.

Mass-based vs. Rate-based, and Performance Rates vs. Statewide Goals. At this stage in plan development, a firm decision regarding mass- vs. rate-based plan design has not been made and no consensus has been reached by the stakeholder planning group. However, the most recent poll shows less support and greater opposition to a rate-based plan as compared to a mass-based plan. The State tentatively agrees that a mass-based plan would be preferable. In the event a mass-based plan is adopted, the plan will be designed to achieve the statewide mass-based CO_2 emission goals of Table 3 of Subpart UUUU, or may be designed to meet the Table 4 statewide mass-based goals plus new source emission complement, or may propose state-developed new source complements. The legislative authority adopted by the State does not mandate adoption of a mass-based plan, but does provide explicit authority to regulate new sources in addition to existing sources, and to administer an allowance-based trading program; each of these authorities relates to aspects unique to a mass-based plan under Subpart UUUU.

Single-state vs. Multi-state, and Trading. The State is not considering submittal of a multi-state plan at this time. However, we continue to communicate and share information with other states in our region, within our Eastern Interconnect, and across the country to stay apprised of the decisions other states are making and to evaluate our plan design in relation to activities in other states. Most stakeholders firmly support an interstate trading platform, and at this stage, it is anticipated the State Plan will be a "trading-ready" plan that allows trading of compliance instruments across state lines.

Clean Energy Incentive Program (CEIP) Participation. In accordance with Subpart UUUU § 60.5737(d), the State hereby makes a non-binding expression of intent to participate in the CEIP. The State recognizes that the State Plan can incorporate opportunities to assist vulnerable communities in lowering energy costs and becoming more resilient to climate change. Toward this end, the State is interested in working with EPA as the details of the CEIP program are developed. Nonetheless, the stakeholder group has raised some concerns regarding CEIP implementation. Section 3 provides further discussion related to CEIP participation and engagement with vulnerable communities.

1.2 Progress Made to Date on Final Plan Components

Commencing with the proposal of the federal CPP in 2014, the State has engaged in an evaluation and planning process. Activities and progress made to date include the following.

Evaluation of the Proposed CPP, Public and Stakeholder Engagement, and Development of Comments. During the public comment period for the proposed CPP, the State convened stakeholder meetings with the owners and operators of affected EGUs, including investor owned utilities and municipal cooperatives, as well as the PJM Interconnection, the Public Service Commission (PSC), and the State Energy Office (SEO). Also during the CPP proposal period, the Department conducted three public input and listening sessions and conducted meetings with stakeholder groups, including energy efficiency service providers, several non-governmental associations, citizen groups, public housing program representatives, and others. The State developed comments on the proposed rule based on our evaluation of the proposal and input from these groups.

Outreach and Education. The SDEQ and the PSC have worked collaboratively to provide training materials and training sessions to educate staff, the regulated community, interested citizens, and state officials about the goals and requirements of the CPP. Four public workshops were held across the state, and briefings were provided to the State House of Representatives Environment and Energy Committees, as well as the State Senate Natural Resource Conservation and Public Utilities Committees. Public outreach and engagement is ongoing, as described in Section 3.

Adoption of State Legislation. During the 2015 General Session of the State Legislature, and following the release of the final CPP, the State enacted three new pieces of legislation to authorize, fund and direct the State Plan development and implementation: Act 1040, State Clean Power Plan; Act 654, Creation and Sale of Carbon Allowances; and, Act 175, Interagency Coordination for CO_2 Reductions. Adoption of these laws represented a major milestone in the State's compliance with Subpart UUUU. As is the case in all states, the Legislature's deliberative process involved multiple opportunities for the public and other interested parties to provide input. Even prior to the introduction of bills before their committees, the State House of Representatives and State Senate environmental committees held a joint hearing on the CPP to hear from constituents regarding the State's actions to comply with the final CPP. In addition, each of the three bills came first before a House committee, and later before a Senate committee, where stakeholders had an opportunity to speak for or against the bill or to provide information. A copy of the legislation, as enacted, is included in Appendix A of this document.

Base Case Projections, Gap Analysis and Compliance Projections – Consultation with PJM and Other States. In order to plan successfully, it is critical to understand the State's current energy demand load and supply, including generation, transmission and distribution. The State has consulted with the Regional Transmission Organization (RTO), PJM, to evaluate various state plan approaches in the context of existing conditions. During the CPP proposal phase, PJM conducted modeling across the operating system to compare various compliance strategies and evaluate the potential impacts to grid reliability, energy mix and cost. The State has worked with PJM and other states to analyze modeling results and to design additional studies to inform plan development. The State is closely following the work of PJM, which is undertaking significant additional modeling exercises at the request of the Organization of PJM States, Inc. (OPSI), an inter-governmental organization of state PSCs covering the entire PJM service area. To date, PJM has developed an updated, thorough base case profile, including business-as-usual (BAU) projections (without implementation of state plans) of energy demand and fuel mix over the Subpart UUUU interim period, to the final compliance date of 2030 and beyond. The BAU projections have been developed to account for state-specific projected load increases, existing state energy efficiency (EE) and renewable portfolio standard (RPS) programs, projections of fuel costs and renewable energy costs, infrastructure expansions, and announced retirements and new builds. The BAU projections are informing the planning process by identifying the gap between BAU and compliance with the Subpart UUUU emission goals; depicting any predicted trends the State may wish to encourage, discourage or bolster through the plan design; and helping the State to avoid the creation of overly burdensome, redundant or duplicative provisions in the State Plan. Based on the reference modeling, PJM has also developed updated modeled projections of various CPP compliance alternatives and has

produced a Compliance Assessment Report, which the State is considering as planning moves forward. Importantly, this collaborative regional work is ongoing, and has recently entered a phase of inter-RTO coordination, with PJM and MISO developing a coordinated analysis across most of the Eastern Interconnect.

Evaluation of Existing State Programs in Relation to the State Plan. An important aspect of plan development is the evaluation of existing state energy and environmental programs. In concert with the grid modeling work being performed by the RTOs (at the direction of the PSCs), the SDEQ, in partnership with the PSC, SEO and other interested stakeholders, has undertaken a comprehensive review of existing state programs to assess how these may be built upon to achieve the Subpart UUUU emission reduction goals; how the State Plan could enhance or potentially interfere with the goals and implementation of these programs; or whether any of the existing state programs should be subsumed or replaced by any elements of the State Plan. This work is ongoing.

State Plan Stakeholder Group. The State has convened a small group of stakeholders with broad representation, dedicated to regular monthly working sessions. The stakeholder group has adopted a charter and a set of guiding principles to provide direction in the planning process. Regular monthly meetings allow for in-depth discussion and information-sharing regarding specific concerns and particular plan components. The work of the Stakeholder Group is ongoing.

2. Explanation of the Need for Additional Time to Submit Final Plan

Section 1 describes many of the activities the State has undertaken and is continuing to undertake toward development of the final State Plan. Although much has been accomplished, including the adoption of state legislation for authorization and funding, a substantial amount of work remains to be done. Additional time is needed to make decisions about the plan design, and to develop and adopt the final plan. Activities requiring additional time include the following:

1. Further evaluate and finalize decisions regarding the overall plan approach and design, such as:
   - Whether to adopt a mass- vs. rate-based plan;
   - Whether to rely upon performance-based standards, direct mass emission limits, or a rate- or mass-based trading program; and
   - Whether to regulate new sources under the plan.

2. Select and design specific plan elements that are best suited to the State's particular needs and circumstances, such as:
   - Whether and how to link the State Plan to existing state programs for EE, RE, housing, electricity consumer assistance subsidies, and other related initiatives;
   - How to incorporate and incentivize EE and RE deployment;
   - Whether and how to incorporate provisions for vulnerable communities, including the CEIP;
   - How to distribute allowances, should a mass-based trading program be selected;
   - How to assure grid reliability, including whether to incorporate a Reliability Safety Valve; and
   - How to assure effective and equitable enforcement of plan requirements.

3. Select, design and develop program infrastructure, as needed, based on plan design, such as:
   - Auction, sale or fee systems;
   - Allowance distribution scheme;
   - Allowance or ERC tracking system;
   - Qualifying EE and RE criteria;
   - EM&V requirements and guidelines; and
   - Certification programs for independent auditors.

In making these important decisions, the State will also require additional time in order to evaluate and consider the specific provisions of the EPA federal plan and model state plan, once these rulemakings are finalized, as well as models, templates or draft rules developed by others.

Culmination of the State Plan adoption will be achieved through the development of draft regulations and adoption of final regulations through the formal state rulemaking procedures, in accordance with Subpart UUUU and 40 CFR § 60.23. A timeline of milestones for completion and adoption of the final State Plan is provided in Table 1. Note that many planning activities will likely overlap and occur in parallel. All dates listed are tentative and for planning purposes only, with the exception of assuring compliance with the final plan submittal deadline of September 6, 2018.

Table 1 **State Plan Development Timeline**

State Plan Development Milestone	Target Date for Completion
Ongoing stakeholder meetings (monthly) and public listening sessions (quarterly) on particular elements of plan design	As appropriate throughout timeline
Final PJM/MISO Coordinated Analysis Report	January 2017
Finalize decisions regarding overall plan approach for purposes of drafting regulations for public comment	March 2017
Implement agency and/or stakeholder workgroups to develop specific draft plan approaches for elements such as: allowance distribution schemes; qualifying EE and RE criteria; ERC or allowance tracking systems; EM&V requirements; integration of existing state programs; vulnerable community support; and grid reliability	March 2017 through December 2017
Develop draft regulations, as well as any necessary interagency memorandums of agreement	March 2017 through December 2017
Plan for and develop necessary program infrastructure, such as ERC or allowance tracking systems, independent auditor certification programs, EM&V guidelines, auction, sale or fee programs, and enforcement procedures	December 2017 through June 2018
Public notice and opportunity for public comment on proposed state plan and proposed regulations	January 2018
Public hearings on proposed state plan and proposed regulations	February 2018
Review and respond to public comment on proposed regulations; revise proposed regulations as appropriate	March–May 2018
Legislative briefings and Committee oversight	June 2018
Adopt final implementing regulations	July 2018
Develop State Plan submittal document and submit Final State Plan	September 6, 2018

3. Opportunities for Public Comment and Meaningful Stakeholder Engagement, Including Vulnerable Communities

3.1 Public Outreach and Engagement Leading up to the Initial Submittal

A summary description of some of the public outreach and stakeholder engagement the State has undertaken leading up to this Initial Submittal is included in Sections 1 and 2. Appendix B includes supporting documentation of public participation, including records of stakeholder meetings, public listening sessions and numerous meetings with various interest groups. In addition, the Department has maintained a Clean Power Plan public website for the State Plan development, www.sdeq.gov/cpp/stateplan/publicparticipation, which includes schedules and agendas of meetings, lists of attendees and presenters, copies of meeting handouts and presentations, and many other records related to the Plan development.

3.2 Public Outreach and Engagement on the Initial Submittal

Public notice and a 30-day opportunity for comment was provided on the draft Initial Submittal. Notice was provided through publication in the State Journal, by e-mail distribution to the State Clean Power Plan "listserv," and by publication on the State Clean Power Plan webpage as well as the SDEQ Public Notice website. The draft Initial Submittal was presented by SDEQ staff at the most recent public listening session, held at the SDEQ main offices on Friday, July 15, 2016, with WebEx accommodations. A copy of the presentation was made available on the State CPP website. Comments were requested to be submitted by Monday, August 15, 2016. The State has not responded to comments; however, the State will take comments into consideration as the planning process moves forward. Appendix B includes proof of publication of the public notice and staff presentation.

3.3 Plans for Public Outreach and Engagement on the Final State Plan Submittal

The State intends to continue to inform and engage the public throughout the State Plan development process. As indicated in the plan development schedule in Table 1, the State anticipates small group stakeholder meetings to be held approximately monthly, with public listening sessions to be held quarterly. Engagement of vulnerable communities will continue using the approaches described in Section 3.4. The State intends to provide a public comment period of approximately 45 to 60 days on the draft final State Plan, with at least one public hearing to be held during the public comment period. The State will prepare a summary Response to Comments document as part of the rulemaking process.

3.4 Identification and Engagement of Vulnerable Communities

The State combined multiple approaches to identify vulnerable communities, and has discussed our methods and results with the EPA Regional Office at multiple stages as our work has progressed. First, the State consulted EPA's 2015 EJ Screening Report for the Clean Power Plan[2] and associated proximity studies and maps to assist in identifying potential target communities based on demographic and environmental indicators. However, this study did not include a tabulation of data from the National Air Toxics Assessment (NATA), such as the NATA cancer risk or respiratory hazard index (HI) indicators, which were considered the most relevant for purposes of outreach regarding the State Plan. Therefore, the State separately reviewed the most recent NATA results (2011 NATA, released in December 2015).[3] With regard to these demographic and environmental indicators, the State is considering communities within three miles of a power plant where an affected EGU is located and with a 2011 NATA cancer risk or 2011 NATA respiratory HI at or above the 80th percentile, or with demographic indicators for percent low-income or percent minority at or above the 80th percentile, as a preliminary indicator of a vulnerable community.[4]

2 EPA, *2015 EJ Screening Report for the Clean Power Plan,* July 30, 2015.

3 EPA, *2011 National Air Toxics Assessment,* December 2015, https://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment.

4 "Low income" is defined as 2 x the federal poverty level. The percent of population benchmarks shown in Table 2 for low-income and minority communities are approximately equivalent to the 80th percentile level on a national scale.

In addition, the State considers citizens in coal mining towns to be vulnerable to the potential impacts of the CPP, to the extent a shift away from coal as a primary energy source could impact the livelihood of those employed by or providing services to coal mining operations and of those in jobs within the community indirectly tied to the coal mining operations, such as grocery stores, restaurants, clothing stores, and others. Finally, the State identified communities in coastal areas (within 25 miles of an ocean, bay or sound) where fishing, tourism or other coastal-related industries are a key source of income to residents as being highly vulnerable to the impacts of climate change, including such impacts as rising sea levels and increased incidence of severe weather events such as hurricanes, tornadoes and associated flooding.

Table 2 summarizes the indicators the State is using to identify potentially vulnerable communities for purposes of the State Plan development.[5]

Table 2 **Indicators Used to Identify Potentially Vulnerable Communities**

Communities located within three miles of an affected EGU and with: • 2011 NATA cancer risk or respiratory HI indicators ≥ 80th percentile; or • Percent low-income population ≥ 50%; or • Percent minority population ≥ 70%
Communities identified as coal-mining towns
Communities located within 25 miles of an ocean, bay or sound and where fishing, tourism or other coastal-related industries are a key source of income to residents

The State has developed a web-based GIS map with layers identifying these three categories of potentially vulnerable communities, which can be found on the State CPP webpage. The EPA Regional Office has provided informal concurrence through conference calls and face-to-face meetings on the indicators presented in Table 2, and has noted that the GIS map is a good tool for regulators, stakeholders, and the public alike to gain a visual understanding of the demographics and locations of vulnerable communities in relation to CPP affected facilities and the impacts of climate change.

In a targeted engagement effort, the State has enlisted the support and involvement of environmental group local representatives (e.g., the Foothills Conservation Group and Coastal Environmental Advocates) and of citizen advocacy groups (e.g., the Municipal Housing Alliance and the Advocates for Affordable Power) to provide outreach to members of vulnerable communities within their memberships and constituencies. In addition, the State has included the county council governments where these communities are located on its email distribution list of meeting notices, and has requested that the county governments post notices of meetings and listening sessions on their webpages. Finally, where appropriate contacts could be identified, the State has reached out to community faith leaders requesting that notices of public meetings be posted at houses of worship. As a result of these efforts, these three categories of potentially vulnerable communities have been represented at public meetings and listening sessions, and some are represented on the stakeholder planning group. The State intends to continue similar avenues of outreach to keep vulnerable communities informed and engaged in the planning process.

3.5 Concerns of Vulnerable Communities Related to the CPP and State Plan

Potential adverse impacts related to the CPP and State Plan, as communicated by the vulnerable community residents and leaders, include loss of jobs resulting from the retirement of coal-fired power plants; increased electricity prices impacting low-income, fixed-income, or out-of-work households; displacement of pollution reduction to other states or communities under an interstate trading program; and grid reliability impacts leading to power failures in low-income and

5 The population levels and distances presented in the Table 2 indicators are not intended to be "bright lines" or to constitute a precise definition of "vulnerable community." The State's planning process is inclusive and aimed at addressing the needs of all citizens.

minority communities, where the infrastructure and technology of transmission facilities is older and more congested than in newer suburbs and higher-income communities. Based on input to date, a high-priority concern among all three types of vulnerable communities is the cost of energy. Whether the community is near an affected power plant, near the coast, or near a coal mine, many are already burdened with high energy costs. It is not surprising under these circumstances that the potential for increased utility bills or temporary loss of income is one of the highest-priority concerns expressed by vulnerable communities.

Furthermore, citizen advocacy groups stress that in most of these communities, a primary contributor to high electric and heating fuel bills is aged and poorly maintained housing structures and appliances that are not energy-efficient. Accordingly, one way that the State could provide support to vulnerable communities is to encourage the deployment of demand-side EE programs in residential buildings, including single-family dwellings and multi-family apartments, in these areas. In fact, these communities expressed excitement about the potential for deployment of expanded demand-side EE programs at reduced cost to the residents or building owners that would abate increases in or potentially reduce electric bills. Workers in coal mining towns and at coal-fired power plants also voiced interest in the potential for new job opportunities in energy efficiency and green energy job markets, in the event job attrition occurs through the retirement of coal-fired EGUs. Accordingly, the State is committed to actively promoting the advancement of EE programs in the three types of vulnerable communities we have identified.

4. The CEIP and Alternative EE Incentives in the State Plan

As noted in Section 1, the State expresses its non-binding intent to participate in the CEIP. Indeed, the CEIP is designed to prioritize the deployment of EE and RE in vulnerable communities, which directly aligns with a goal of the State. Nonetheless, the State has some concerns about the constraints of the CEIP as well as the level of uncertainty about how the program will be administered. Accordingly, we are also exploring state-designed options to achieve the goal of EE deployment in vulnerable communities.

With regard to concerns about the CEIP, we note that the CEIP is a developing program. The specific program requirements, benefits, and procedures cannot readily be predicted, nor can the final design of the CEIP be controlled or substantially influenced by the State. For example, the level of "reward" in the form of allowances or ERCs that would be provided to energy savings in our State is unknown at this time. In addition, the CEIP as it is currently envisioned under a mass-based program relies on the establishment of set-asides, and the State is seeking the flexibility to develop and implement a mass-based program that does not involve set-asides. Perhaps most importantly, the CEIP incentivizes investment in vulnerable communities only for a short time period (i.e., for energy savings that occur during 2020 and 2021 only), while the State is seeking options to incorporate a plan element that would provide ongoing incentives and rewards for investment in vulnerable communities.

Given these potential concerns, while the State intends to participate in the CEIP if the final design of the program is compatible with other elements of the State Plan, we are at the same time developing the framework of a state-designed plan provision that would promote the deployment of energy efficiency programs in vulnerable communities. For example, the State is considering provisions for direct allocation of allowances under a mass-based program at an enhanced reward rate (i.e., 1.5-to-1) for energy savings in vulnerable communities as compared to energy savings demonstrated elsewhere in the State. Allowances would come from the mass allowance budget for each compliance period. The State-designed rewards program would not be for the encouragement of early reductions, per se, and thus would not sunset in 2022, but instead would continue into the final performance periods. Similarly, we are exploring options to create an ongoing rewards program for EE savings in vulnerable communities under a rate-based program.

Appendix A

State Legislative Authority

Act 1040, State Clean Power Plan
Act 654, Creation and Sale of Carbon Allowances
Act 175, Interagency Coordination for CO_2 Reductions

Appendix B

Documentation of Public Participation and Outreach

Schedule of Stakeholder Meetings and Public Listening Sessions
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Appendix C

Identification and Engagement of Vulnerable Communities

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Model Final State Plan Submittal

State Clean Power Plan
to Comply with 40 C.F.R. Part 60, Subpart UUUU

Mass-based Allowance Trading Plan
with New Source Complement
Interstate Trading-Ready

Model State Plan Documentation

State Clean Power Plan
to Comply with 40 C.F.R. Part 60, Subpart UUUU

Mass-based Allowance Trading Plan
with New Source Complement
Interstate Trading-Ready

State Required Plan Components
and Supporting Documentation

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1. State Plan Submittal Overview

This submittal includes all required state plan components to meet the State's obligations for compliance with the U.S. EPA Clean Power Plan, as adopted at 40 C.F.R. Part 60, Subpart UUUU, October 23, 2015 at 80 Fed. Reg. 64,662 (referred to herein as Subpart UUUU). The regulations of Subpart UUUU and the corresponding preamble establish emission guidelines (EGs) that each state must follow in developing a state plan to reduce CO_2 emissions from existing fossil fuel-fired electric generating units (EGUs). Under Subpart UUUU, the State received a two-year extension for submittal of the complete and final state plan, to September 6, 2018. This State Clean Power Plan (State Plan or Plan) is being submitted on or before the September 6, 2018 deadline, includes all required state plan components, with supporting documentation as needed, and meets all requirements of the EGs.

The State has adopted a streamlined, mass-based trading program relying on the EPA-specified statewide emission goals for existing affected EGUs, regulated under state and federal law, plus the EPA-specified new source complements for new EGUs subject to 40 C.F.R. Part 60, Subpart TTTT (subject to the trading program under state law). Specifically, the Plan adopts the Subpart UUUU Table 4 goals as the allowance budget for the interim and final performance periods, and establishes compliance periods identical to the interim step and final plan performance periods of Subpart UUUU.

1.1 Components of the State Plan Submittal

The Plan is composed of three major components that collectively meet all EG requirements and comprise all of the required state plan elements. First, the State Legislature has enacted legislation to provide the legal authority and funding for adopting, implementing and enforcing the Plan. Second, the State Department of Environmental Quality has promulgated implementing regulations that establish the specific Plan requirements, including emission standards for affected EGUs and the procedures and requirements of the State CO_2 Trading Program for EGUs. Third, this State Plan Documentation report provides all additional required information, descriptions and demonstrations, with appendices including supporting documentation as necessary. Section 2 of this document provides a Plan description, with a summary of the state legislation and regulations that are part of the Plan. The remaining sections of the Plan Documentation address other required plan documentation and demonstrations.

1.2 Checklists of Required State Plan Components

The following tables, Tables 1, 2 and 3, provide checklists identifying the location in the Plan submittal of each required plan element.

Table 1 lists requirements from 40 C.F.R. § 60.5740, *What must I include in my federally enforceable State or multi-State plan?*

Table 2 lists requirements from 40 C.F.R. § 60.5745, *What must I include in my final plan submittal?*

Table 3 lists requirements from 40 C.F.R. § 60.5790(b), specifying requirements for a mass-based emissions trading program.

Table 1 **Checklist of Required Federally Enforceable State Plan Components as listed at 40 C.F.R. § 60.5740**

No.	Required Plan Component	Description of Required Component	Location in State Plan Submittal
(a)(1)	Identification of Affected EGUs	Identify each affected EGU and provide the CO_2 emissions inventory from the most recent calendar year available.	Section 3, Table 4 of the Plan Documentation Chapter 10, § 1003 identifies what sources are subject to the Plan.
(a)(2)	Emission Standards	Identify all emission standards for affected EGUs and the compliance periods for each standard. Demonstrate that the emission standards are quantifiable, verifiable, non-duplicative, permanent and enforceable, as specified in § 60.5775. Document the compliance periods are no longer than each interim step period or final performance period, and are imposed for the entirety of each plan performance period, according to § 60.5770. Demonstrate that the emission standards collectively will achieve the state performance goal. Include all required triggers for corrective measures, if applicable.	Section 4 of the Plan Documentation summarizes the emission standards. Section 5 of the Plan Documentation provides the required demonstrations. Chapter 10, § 1005 incorporates the emission standards and compliance periods for affected EGUs.
(a)(3)	State measures backstop	If a state measures plan is submitted, include required backstop emission standards for affected EGUs.	Section 5.2 of the Plan Documentation documents that a backstop is not required.
(a)(4)	Monitoring, recordkeeping and reporting requirements	Include all required monitoring, record-keeping and reporting requirements for affected EGUs, consistent with or no less stringent than the requirements of § 60.5860.	Sections 2 and 5.3 of Plan Documentation Chapter 10, § 1025 (for emissions and generation information) Chapter 10, §§ 1009 and 1011 (for allowance tracking information)
(a)(5)	State Reporting	Describe the process, contents and schedule for state reporting to EPA as required under § 60.5870.	Sections 7 and 8 of Plan Documentation Chapter 10, §§ 1001.A and 1005.F

Table 2 **Checklist of Required Plan Submittal Information, Federal Enforceability Not Required, as listed at 40 C.F.R. § 60.5745**

No.	Required Plan Component	Description of Required Component	Location in State Plan Submittal
(a)(1)	Plan description	Describe the plan type and pathway, including whether the plan is single- or multi-state and the geographic boundaries of the plan.	Sections 1 and 2 of Plan Documentation
(a)(2)	CO_2 performance rates or statewide CO_2 emission goals	Identify which performance rates or goals the plan is designed to achieve (e.g., Subpart UUUU Table 1, 2, 3 or 4). Include interim step, interim period, and final period performance goals, per §§ 60.5750 and 60.5855.	Sections 1, 2 and 4 of Plan Documentation Chapter 10, § 1001, Table 1
(a)(3)	Demonstration projecting affected EGUs will achieve the emission goals	The plan must include a demonstration that the affected EGUs are projected to achieve the selected CO_2 performance rates or emission goals. The level of demonstration is dependent on plan type.	Sections 5.1 and 5.2 of Plan Documentation Chapter 10, § 1005, Table 2 *(No further demonstration required)*
(a)(4)	Demonstration for each emission standard	Demonstrate each standard is quantifiable, non-duplicative, permanent, verifiable and enforceable. Specific criteria are provided at § 60.5775.	Section 5.3 of Plan Documentation
(a)(5)	Emission Standards Plan information	For mass-based plans that apply emission standards that mathematically assure compliance with the Table 3 or 4 emission goals, no additional demonstration is needed. For all other emission standards plans, a detailed demonstration that the plan will assure compliance is required, as specified at § 60.5745.	Sections 5.1 and 5.2 of Plan Documentation Chapter 10, § 1005, Table 2 *(No further demonstration required)*
(a)(6)	State Measures Plan information	Required information includes, but is not limited to, a description of state measures' projected impacts, applicable state laws and regulations, identification of implementing entities, schedules and milestones for implementation, EM&V measures, and plan performance projections.	Section 5.2 of Plan Documentation *(No further demonstration required)*
(a)(7)	Consideration of Electrical Grid Reliability	Document consultation with ISOs, RTOs, the state energy officer, or other means of assessing and considering the plan's potential impact on grid reliability.	Section 7 of Plan Documentation Appendices C and D of Plan Documentation Chapter 10, § 1005.F
(a)(8)	Milestone Schedule leading to January 1, 2022	A plan implementation timeline from submittal to January 1, 2022 is required for all plans.	Section 8 of Plan Documentation
(a)(9)	Demonstration of adequate legal authority and funding	Documentation of adequate legal authority, through legislation or regulations, and funding to implement and enforce the plan must be included.	Section 2 of Plan Documentation Appendices A and B of Plan Documentation

Table 2 **Checklist of Required Plan Submittal Information, Federal Enforceability Not Required, as listed at 40 C.F.R. § 60.5745**, *continued*

No.	Required Plan Component	Description of Required Component	Location in State Plan Submittal
(a)(10)	Demonstration of projected compliance with interim step goals	Include a demonstration that interim step goals will be met and the process, tools and methodology used to make the projection.	Sections 5.2 and 5.3 of Plan Documentation *(No further demonstration required)*
(a)(11)	Certification and documentation of public hearing on state plan	Documentation must include a list of witnesses and their affiliations, and a summary of comments received.	Section 9 of Plan Documentation Appendix C of Plan Documentation
(a)(12)	Documentation of community outreach and involvement	Document community outreach conducted during plan development, including outreach to vulnerable communities.	Section 9 of Plan Documentation Appendix D of Plan Documentation
(a)(13)	Supporting materials	Any other supporting materials needed to evaluate the plan.	Appendices A, B, C and D of Plan Documentation

Table 3 **Checklist of Required Mass-based Trading Program Plan Components, as listed at 40 C.F.R. § 60.5790(b)**

No.	Required Plan Component	Description of Required Component	Location in State Plan Submittal
(b)(1)	CO_2 emissions monitoring, reporting, and recordkeeping requirements for affected EGUs	Requirements must be no less stringent than those in § 60.5860(a).	Section 6 of Plan Documentation Chapter 10, § 1025
(b)(2)	Requirements for State allocation of allowances	Requirements must be consistent with § 60.5815.	Section 6 of Plan Documentation Chapter 10, §§ 1007, 1015, 1017, 1019, 1021, 1023 and 1025
(b)(3)	Requirements for tracking of allowances	Allowances must be tracked from issuance through submission of compliance, consistent with § 60.5820.	Section 6 of Plan Documentation Chapter 10, §§ 1007, 1011 and 1013
(b)(4)	Process for affected EGUs to demonstrate compliance	Process must be consistent with § 60.5825.	Section 6 of Plan Documentation Chapter 10, § 1011
(b)(5)	Requirements to address leakage to new sources	The State may elect option (a)(5)(i), (ii) or (iii)	Section 6 of Plan Documentation Chapter 10, §§ 1003 and 1005

2. Description of Plan Approach

The State Plan is a mass-based trading program regulating both new and existing EGUs, relying on the Allowance Tracking and Compliance System (ATCS) to provide an interstate platform for trading of allowances with other EPA-approved or EPA-administered mass-based trading programs under 40 C.F.R. Part 60, Subpart UUUU. Under the state regulations (Chapter 10), an existing affected EGU is any EGU meeting the applicability criteria for an affected EGU under Subpart UUUU, and a new affected EGU is any EGU meeting the applicability criteria of 40 C.F.R. Part 60, Subpart TTTT for new fossil fuel-fired EGUs. Consistent with Subpart UUUU, all plan requirements as they apply to existing affected EGUs are designed to be enforceable under both state and federal law, with federal enforceability conferring upon EPA approval and adoption of the Plan. Also consistent with EPA guidance under the EGs, all plan requirements as they apply to new affected EGUs are designed to be state-enforceable only. Regulatory provisions and other documentation or submittal elements pertaining to new sources are included in this submittal for informational purposes only, to allow EPA to understand the Plan in the full context of state law and to assess how state-enforceable provisions regulating new sources will affect and support the reduction of CO_2 emissions from existing sources.

The State Plan is a single-state plan covering the entire geographic area of the State. This submittal is not on behalf of, and is not intended to meet the EG requirements for, any other state; therefore no multi-state plan participants are identified. The Plan is a streamlined plan under the EGs, relying on the Subpart UUUU Table 4 Statewide Mass-based CO_2 Goals plus New Source CO_2 Emission Complements as the statewide trading program mass emission budgets for the interim and final compliance periods. The Plan is a trading-ready plan that supports interstate trading with any other state plan or tribal plan that is also designed as a trading-ready plan, that is EPA-approved or EPA-administered under Subpart UUUU, and that uses the same ATCS allowance tracking system or an EPA-approved interconnected tracking system.

2.1 Legislative Authority

The State enacted three laws in the 2015 legislative session to support, authorize and direct the Plan development. A copy of the legislation, as enacted, is included in Appendix A of this document.

Act 1029 of 2015 amended the State Environmental Quality Act by adding new sections State Revised Statute (SRS) § 60:3685 and § 60:3686. These sections provide specific authorization for the State Department of Environmental Quality (SDEQ) to adopt and implement regulations to comply with 40 C.F.R. Part 60, Subpart UUUU, including authorization to adopt and implement a CO_2 mass emissions cap-and-trade program for new and existing fossil fuel-fired electric generating units, which may provide for interstate trading of allowances. This legislation mandates that the Director of SDEQ consult and coordinate with the State Energy Office (SEO), Public Service Commissioner (PSC), and Regional Transmission Operator (RTO), as appropriate, to identify the likely least-cost options for compliance and to assess, and avoid to the greatest degree practicable, any potentially adverse impacts to the reliability of the delivery of electricity to consumers in the State.

Act 1340 of 2015 amended the State Fiscal Procedures Act by adding a new section SRS § 15:6790. This section establishes the authority for the State to determine, direct, and perform necessary and appropriate actions related to CO_2 emission allowances under the State CO_2 Trading Program for EGUs, including administrative actions to create and distribute allowances in accordance with the statewide emission budget, to conduct auctions or sales of allowances in amounts authorized by the State Legislature to generate state revenues, and to allocate and issue at no charge allowances to qualified entities in accordance with governing regulations. The state legislation provides that funding for the SDEQ to implement and enforce the State Clean Power Plan, including the State CO_2 Trading Program for EGUs, will be provided by revenues generated from the auction or sale of allowances.

Act 1751 of 2015 amended the State Energy Act by adding SRS § 35:2860. This new law provides that, as part of the Integrated Resource Planning (IRP) process, the State Public Service Commissioner (PSC) will oversee and review plans for existing affected EGUs to reduce emissions of CO_2 through a "comprehensive and balanced" effort that seeks the least-cost option while maintaining grid reliability and safety. Under this legislation, IRPs developed by utility companies must take CO_2 emissions and achievement of the statewide CO_2 emission goals under the State Clean Power Plan into consideration when planning for retirement of existing EGUs, construction of new EGUs, and availability of generation resources owned by independent power producers (IPPs) or others. Utilities must also specifically consider options for improving energy efficiency of existing EGUs, and options for reducing emissions including co-firing of natural gas or other fuels at coal-fired units. In addition, this legislation provides that the PSC and SDEQ will coordinate and share information and data as necessary to support the goals of the State Clean Power Plan.

2.2 State Regulations

The State has adopted a final regulation, State Administrative Code (SAC) 55 Regulation VII, Chapter 10, State Clean Power Plan, (referred to herein as Chapter 10) to implement the State CO_2 Trading Program for EGUs. Appendix B includes a copy of the regulation. Appendix C provides supporting documentation demonstrating public participation during the rulemaking process and compliance with the state rulemaking procedures of the State Administrative Procedure Act. A section-by-section summary of Chapter 10 is provided below. The summary is intended to be descriptive only; please refer to the actual regulation for detailed requirements and provisions.

Section 1001. Purpose and Authority. The rule adopts the Subpart UUUU Table 4 statewide CO_2 emission goals for existing affected EGUs plus the new source complements for new EGUs, as developed by EPA, for all plan performance periods including the interim 1, 2 and 3 step periods and the final period. This section also incorporates by reference the Subpart UUUU requirements for state reporting to EPA. In addition, this section provides that all requirements as applicable to existing affected EGUs are enforceable under both state and federal law, whereas all requirements as they apply to new affected EGUs are enforceable solely under state law.

Section 1003. Applicability. The rule applies to "affected EGUs" which is defined to include both existing affected EGUs and new affected EGUs. Existing affected EGUs are all EGUs that operated at any time on or after January 1, 2012, and that meet the applicability criteria set forth in Subpart UUUU. New affected EGUs are all EGUs that are subject to 40 C.F.R. Part 60, Subpart TTTT. All exclusions to applicability included in Subpart UUUU are also adopted in the State Plan. Any EGU with a permanent retirement date on or before December 31, 2017, is exempt from all requirements except for notification and recordkeeping. Any EGU with a permanent retirement date on or after January 1, 2018, is exempt beginning on the first day of the compliance period following permanent retirement.

Section 1005. Emission Standards and Permit Requirements for Affected EGUs. The rule establishes an allowance holding and surrender emission standard applicable to all affected EGUs. Compliance periods are identical to the interim step periods and final periods for plan performance established under Subpart UUUU. Allowance budgets for each compliance period are set equal to the statewide existing plus new source emission goals. The transfer, or "true-up," deadline is May 1 of the year following the end of each compliance period.

This section also incorporates provisions to authorize interstate trading, consistent with the EGs, and provides that allowances in excess of those required for compliance in a compliance period may be used for demonstrating compliance in a future compliance period. Borrowing of allowances from future compliance periods is prohibited.

In addition, this section establishes procedures and timing requirements for incorporation of applicable requirements into air permits, and establishes a reliability safety valve and associated notification and approval procedures, consistent with the EGs.

Section 1007. Distribution of Allowances by Auction, Sale and Allocation. This section establishes the allowance distribution and allocation scheme and incorporates provisions for the Administrative Authority to make corrections to errors in allocations. The allowance distribution and allocation scheme follows a four-step process as follows.

1. The State retains a portion of the allowances for each compliance period "off the top" to be distributed by sale or auction. The State Legislature will adopt the specific percentage to be reserved for the state, with a minimum of 15% and a maximum of 50%, as part of the State budget process. Proceeds from the auction or sale of allowances will be used to fund the program, and revenues in excess of program costs may be used for other purposes as directed by the Legislature.

2. Up to 15% of the remaining budget is allocated directly to qualified Energy Efficiency Resources (EERs), with the specific allocation based on verified savings during the prior allocation basis period and the value of each MWh of savings assigned at the adjusted emission rate of the statewide affected EGU fleet (fleet-wide lb/MWh, including MWh from qualified zero- and low-emitting EGUs). Enhanced allocations are provided for certified energy savings in a vulnerable community, at a rate of 1.5 times the number of allowances that would be awarded for the same energy savings had they occurred in a location not identified as a vulnerable community. The enhanced portion of an allowance allocation for energy savings in a vulnerable community (i.e., one-third of the total allocation) does not count toward the 15% cap on allocations to qualified EERs. Eligibility criteria for qualified EERs are established in Section 1015. Qualified EERs must open a general account in the ATCS, submit an evaluation, measurement and verification (EM&V) plan, and submit annual monitoring and verification (M&V) reports. Certification of verified energy savings must be provided to receive allocations. If the total amount of eligible energy savings from qualified EERs would result in allocations of greater than 15% of the budget remaining after deducting the State portion, then allocation calculations must be adjusted proportionately among qualified EERs such that total allocations to qualified EERs, excluding the enhanced portion of allocations for vulnerable community energy savings, do not exceed 15% of the remaining budget.

3. New affected EGUs are allocated allowances based on the startup date of the unit. If initial startup is on or before January 1, 2018 (the start of the first allocation basis period), allocations for all compliance periods are based on generation during the respective allocation basis periods. When operation will commence after January 1, 2018, such that the first period of operation is for only a partial allocation basis period, allocations for the EGU's first compliance period are based on the projected number of days of operation and a projected utilization rate of 55% capacity, times the New Source Performance Standard (NSPS) emission rate applicable to new NGCC units under 40 C.F.R. Part 60, Subpart TTTT. Adjustments to the first period allocations are made in the second compliance period in the event startup occurred later than projected. For future compliance periods, new affected EGUs are treated the same as existing EGUs, with allocations for each compliance period based on generation during the prior compliance period, except that total allocations to new sources cannot exceed the new source complement portion of the budget. If the calculated allocations to new sources would exceed the new source budget, allocations must be adjusted downward proportionately among new affected EGUs, and the allocations subtracted to make this adjustment remain in the allowance budget for further allocations.

4. After deducting the State's portion and determining allocations to qualified EERs and new affected EGUs, all of the remaining budget is allocated to existing affected EGUs and to qualified RE and low-emitting EGUs, in proportion to their actual generation during the prior allocation basis period. Eligibility criteria for qualified EGUs are provided in Section 1017. For CHP, WHP, biomass and WTE qualified EGUs, only the qualified portion of generation is eligible to receive allocations.

Section 1009. Requirements for Designated Representatives of Affected EGUs. The rule requires that a designated representative be established for each facility at which one or more affected EGUs are located. The rules are consistent with the requirements of Subpart UUUU, and require that all submittals under Chapter 10 be made and certified by the designated representative or by the alternate designated representative.

Section 1011. Allowance Tracking and Compliance System (ATCS) Procedures. This section requires that all accounting of CO_2 allowances be made by the Administrative Authority or his or her designee through the ATCS. This section establishes reciprocity and interstate recognition of allowances issued by another state or by EPA under a mass-based program approved or administered by EPA under 40 C.F.R. Part 60, Subpart UUUU or 40 C.F.R. Part 62, Subpart MMM, provided the allowance tracking system is the same ATCS or an interconnected system designated as authorized for trading. This section also establishes the eligible account holders and types of accounts, as well as procedures for recording, transferring, surrendering and retiring allowances for compliance with the Chapter 10 emission standards. The Administrative Authority has the authority to make deductions of allowances from a facility compliance account or general account to remedy noncompliance with the allowance surrender requirements.

Section 1013. ATCS General Accounts and Authorized Account Representatives. Section 1013 requires that submittals pertaining to a general account be made and certified by the authorized account representative or alternate authorized account representative, and it sets forth the requirements for establishing an authorized account representative and alternate authorized account representative. In addition, this section establishes the procedures for applying to open an ATCS general account, and provides the rules and procedures for maintaining the general account. The Administrative Authority has the authority to freeze a general account for cause.

Section 1015. Qualifying Criteria and Registration Requirements for Qualified Energy Efficiency Resources (EERs). The Plan does not create set-asides for EE measures, and does not rely on set-asides to address leakage (leakage is addressed by regulation under state law of new affected EGUs). Nonetheless, the Plan invests directly in EE resources by allocating allowances for each compliance period to verified energy savings from qualified EERs that occurred during the prior allocation basis period. To designate those EERs and EE measures that are eligible to receive allocations, the State has elected to use qualifying criteria that are generally consistent with, though not exactly the same as, the criteria established by EPA under Subpart UUUU for entities to receive ERCs under a rate-based state plan. Because qualified EER status under the Plan is used only as a mechanism for allocation of allowances, and not to create ERCs or to assign set-aside allowances, it is not necessary to exactly align the qualification criteria with those required under a rate-based program. Given that the State could elect to allocate allowances to a wide variety of entities, it is well within the State's discretion to establish qualifying criteria for the allocation of allowances to EERs.

All qualified EERs must have an ATCS general account and must be registered with the National Energy Efficiency Registry or another registry approved by the Administrative Authority for purposes of certifying energy savings. Additional minimum qualifying criteria include:

a. The EER was or will be installed or implemented on or after January 1, 2013 and produces verifiable energy savings on or after January 1, 2018;
b. The EER strategy must be connected to and must produce energy savings from the electric grid in the contiguous United States; and
c. The EER must implement energy savings strategies in one or more of the following categories:
    i. Residential or commercial EE programs (including distributed energy net-metering solar power) implemented in the State commencing on or after January 1, 2013;
    ii. Energy Savings Performance Contracting, excluding contracts implemented at State-owned buildings or facilities, implemented at buildings or facilities within the State on or after January 1, 2013;
    iii. Above-Code Building Certification programs implemented at buildings that commenced construction in the State on or after January 1, 2013; or
    iv. Industrial Energy Efficiency achieved through an ISO 50001:2011 or better certified Energy Management System, or a U.S. Department of Energy (DOE) Superior Energy Performance certification program.

Section 1017. Qualifying Criteria and Registration Requirements for Qualified EGUs. The Plan does not create set-asides for RE or other replacement generation measures, nor does the Plan rely on set-asides to address leakage (leakage is addressed by regulation under state law of new affected EGUs). Nonetheless, the Plan invests directly in zero- and low-emitting generation resources by allocating allowances for each compliance period to eligible generation from qualified

EGUs that was provided to the grid during the prior allocation basis period. As noted above, the State has broad discretion to establish criteria for the allocation of allowances to a wide variety of entities. All qualified EGUs must have an ATCS general account and must be registered with the Administrative Authority. Additional minimum qualifying criteria include:

a. The EGU produces electricity using one or more of the following categories of technologies and fuels:
   i. Renewable electric generating technologies using wind, utility-scale solar, geothermal, hydropower, wave or tidal energy;
   ii. Nuclear power;
   iii. Combined heat and power units, including waste heat power generating units, that are not affected EGUs under this Chapter;
   iv. Electric generation using qualified biomass, including biogenic municipal solid waste at a waste-to-energy facility, provided that for such qualified EGUs, only the portion of electricity generated from the qualified biomass shall be eligible for allocation of allowances.

b. The EGU must meet the following design, location and operating criteria:
   i. Have a nameplate capacity equal to or greater than 10 MW;
   ii. Be located within the State;
   iii. Be connected to and provide electricity to the electric grid for the Regional Interconnect; and
   iv. Have installed and operate a revenue-quality meter for measuring generation on a continuous basis.

Section 1019. Evaluation, Measurement and Verification Plan Requirements for Qualified EERs and Certain Qualified EGUs. Any EER applying to be a qualified EER and any EGU applying to be a qualified EGU that is a CHP (including any WHP unit) or that fires biomass (including any WTE facility) must develop and submit an EM&V plan as part of the application for eligibility. Requirements for the content of EM&V plans are consistent with Subpart UUUU and include a requirement to be verified and certified by an independent verifier.

Section 1021. Monitoring and Verification (M&V) Reporting Requirements for Qualified EERs and Qualified EGUs. Annual M&V reports are required to document the energy generation or energy savings eligible to receive allocations. This section establishes the requirements for the content and timeliness of M&V reporting.

Section 1023. Requirements for Independent Verifiers and Verification Reports. This section establishes requirements for accreditation of independent verifiers, including provisions for conflict of interest avoidance and for revocation of accredited status for cause by the Administrative Authority. This section also provides requirements for the content of verification reports.

Section 1025. Emissions and Electricity Generation Monitoring, Reporting and Recordkeeping for Qualified EGUs and Affected EGUs. Section 1025 establishes specific, detailed requirements for qualified EGUs to monitor, record and report electricity generation. This section also adopts emissions and generation monitoring requirements for affected EGUs consistent with 40 C.F.R. Part 75 and with Subpart UUUU.

Section 1027. Enforcement Liabilities and Penalties. Section 1027 clarifies the entities potentially subject to enforcement for violations of the provisions of Chapter 10. Violations of the emission standards trigger an initial remedy requiring the surrender of two allowances for each ton of excess emissions that occurred, which must be surrendered no later than December 31 of the year following the close of the compliance period in which the excess emissions occurred. This section also establishes nondiscretionary stipulated penalties that apply for each ton of excess emissions, and an additional stipulated penalty that applies for each ton of excess emissions for which the initial remedy is not timely met. In addition, owners and operators who incur violations of Chapter 10 requirements are, in addition to the prescribed initial remedies and stipulated penalties, subject to injunctive remedies, fines, penalties or any other remedy pursuant to the State Environmental Quality Act and, for existing affected EGUs, under the federal Clean Air Act.

Section 1031. Definitions. Definitions are provided consistent with 40 C.F.R. Part 60, Subpart UUUU.

3. Affected EGUs and CO_2 Emissions Inventory

The State has identified 54 EGUs that meet the applicability criteria as existing affected EGUs under Subpart UUUU, at 40 C.F.R. § 60.5845. No new affected EGUs have commenced construction after the new source applicability date of January 8, 2014. A listing of all existing affected EGUs is shown in Table 4. Of these EGUs, five have permanently retired and their Title V air permits have been rescinded. These five EGUs are therefore exempt from the state CO_2 trading program requirements.

The remaining 49 existing affected EGUs include seven (7) coal steam units; eight (8) natural gas steam units; and thirty-four (34) NGCC units. Of the seven coal steam units, one (1) is operated by an independent power provider (IPP) and the remainder are electric-utility operated. All of the eight natural gas steam units are electric-utility operated. Of the thirty-four NGCC units, two (2) are IPP-operated combined heat and power (CHP) units, twelve (12) are IPP non-CHP units, and the remainder (20) are electric-utility operated non-CHP units.

Table 4 also presents both the 2012 CPP baseline CO_2 emissions inventory and the 2016 CO_2 emissions inventory for the existing affected EGU fleet. The inventory shows a slight decrease in emissions from 2012 to 2016 of approximately 2%, with an increase in net energy output of 4% during the same time period, resulting in an overall reduction in the CO_2 emission rate of approximately 6%. In general, the trend within the existing affected EGU fleet in fuel and prime mover utilization indicates a shift away from coal and natural gas steam units toward natural gas combined cycle turbines.

Table 4 **State Existing Affected EGUs with 2012 and 2016 CO_2 Emissions Inventories**

Plant Name	ORIS Code	Generator ID	Fuel type	Prime mover type	Nameplate Capacity (MW)	Summer Capacity (MW)	Heat Input Capacity (mm Btu/hr)	Source Category	2012 Emissions (tons CO_2)	2016 Emissions (tons CO_2)
Camellia	116	2 (retired)	NG	ST	69	60	0	Utility	0	0
Camellia	116	3	NG	ST	156	110	1,505	Utility	3,235	0
Havier Mathias	167	1 (retired)	NG	ST	69	67	0	Utility	0	0
Havier Mathias	167	2 (retired)	NG	ST	69	67	0	Utility	0	0
Henry Carter	1699	2	NG	ST	156	123	0	Utility	0	0
Curvy Lane	52175	1 (retired)	NG	ST	40	47	0	Utility	62	0
Curvy Lane	52175	2	NG	ST	40	45	725	Utility	170	0
Curvy Lane	52175	3	NG	ST	120	96	1,292	Utility	2,253	22,028
Curvy Lane	52175	4	NG	ST	553	525	7,606	Utility	436,567	436,567
Freedom Flag	157	1 (retired)	NG	ST	359	300	0	Utility	0	0
Freedom Flag	157	2	NG	ST	545	544	0	Utility	0	0
Thistle Weed	2501	1	NG	CC	59	62	1,750	Utility	20,672	175,604
Thistle Weed	2501	2	NG	CC	126	103	1,750	Utility	44,146	359,731
Carolina Blue	2502	1	NG	ST	120	122	1,436	Utility	35,551	31,996
Misty Morning	2503	1	NG	ST	136	134	1,436	Utility	144,437	129,994
Grey Plains	56018	1	SUB	ST	900	815	9,700	Utility	5,314,862	3,986,146
Grey Plains	56018	2	SUB	ST	900	844	10,016	Utility	5,897,951	4,423,463
Bear Mountain	65176	1	SUB	ST	558	528	6,324	Utility	4,150,944	3,113,208

Table 4 **State Existing Affected EGUs with 2012 and 2016 CO_2 Emissions Inventories**, *continued*

Plant Name	ORIS Code	Generator ID	Fuel type	Prime mover type	Nameplate Capacity (MW)	Summer Capacity (MW)	Heat Input Capacity (mm Btu/hr)	Source Category	2012 Emissions (tons CO_2)	2016 Emissions (tons CO_2)
Stag Cove	56682	1	SUB	ST	900	836	9,525	Utility	5,804,743	4,353,557
Stag Cove	56682	2	SUB	ST	900	842	10,480	Utility	5,996,078	4,497,059
Indy Power Center	65514	CT01	NG	CC	180	145	2,406	IPP CHP	642,744	655,877
Indy Power Center	65514	ST01	NG	CC	56	47	2,406	IPP CHP	199,965	205,968
Magdalena Arnold	45544	G1	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G2	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G3	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G4	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G5	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G6	NG	CC	51	47	567	Utility	15,348	24,557
Magdalena Arnold	45544	G7	NG	CC	84	76	1,260	Utility	25,129	40,206
Magdalena Arnold	45544	G8	NG	CC	105	95	567	Utility	31,599	50,558
Magdalena Arnold	45544	G9	NG	CC	105	95	567	Utility	31,599	50,558
Rae Me Energy	65542	CTG1	NG	CC	199	142	3,646	Utility	93,122	148,995
Rae Me Energy	65542	CTG2	NG	CC	199	142	3,092	Utility	93,122	148,995
Rae Me Energy	65542	STG	NG	CC	281	180	3,646	Utility	131,062	209,699
Southern Power	65599	CTG1	NG	CC	176	145	2,319	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG2	NG	CC	176	145	2,319	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG3	NG	CC	176	145	2,319	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG4	NG	CC	176	145	2,319	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG5	NG	CC	176	145	2,127	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG6	NG	CC	176	145	2,125	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG7	NG	CC	176	145	2,319	IPP Non-CHP	311,844	498,950
Southern Power	65599	CTG8	NG	CC	176	145	2,321	IPP Non-CHP	311,844	498,950
Southern Power	65599	STG1	NG	CC	255	215	2,319	IPP Non-CHP	451,819	722,910
Southern Power	65599	STG2	NG	CC	255	215	2,319	IPP Non-CHP	451,819	722,910
Southern Power	65599	STG3	NG	CC	255	215	2,127	IPP Non-CHP	451,819	722,910
Southern Power	65599	STG4	NG	CC	255	215	2,319	IPP Non-CHP	451,819	722,910
Mary Stanton	53123	CT1	NG	CC	199	170	2,650	Utility	62,930	100,688
Mary Stanton	53123	CT2	NG	CC	199	170	2,650	Utility	62,930	100,688
Mary Stanton	53123	ST1	NG	CC	317	290	2,650	Utility	100,295	160,472
Mayberry Power	53456	GT1	NG	CC	242	208	2,800	Utility	351,046	561,674
Mayberry Power	53456	GT2	NG	CC	242	208	2,800	Utility	351,046	561,674
Mayberry Power	53456	ST1	NG	CC	262	225	2,800	Utility	380,058	608,093
Wild Elk Station	75666	STG1	SUB	ST	720	670	7,564	IPP Non-CHP	4,944,118	3,708,089
Eagle Nest Station	65465	1	SUB	ST	609	609	6,000	Utility	188,786	3,169,907

4. CO_2 Emission Goals and Emission Standards

This section summarizes the CO_2 emission goals that the Plan is designed to achieve, and the CO_2 emission standards applicable to affected EGUs.

4.1 Emission Goals

The State has adopted the EPA-specified statewide mass-based CO_2 emission goals for existing affected EGUs plus the new source complement as included at 40 C.F.R. Part 60, Subpart UUUU Table 4 for the interim period and final period. The interim period is divided into three interim step periods, as required under Subpart UUUU. The State has adopted the three interim step period mass-based emission goals that are equal to the existing affected EGU interim step goals published in Table 13 of the preamble to the final Subpart UUUU, plus the EPA-specified State-level new source complement for each interim step period published in the *Technical Support Document: New Source Complements to Mass Goals.*[1] Table 5 documents how the emission goals were calculated, by summing the two EPA-specified components (for existing and new sources) for each interim step period, interim period and final performance period.

Table 5 **Computation of Statewide Emission Goals for New and Existing Fossil Fuel-fired EGUs (Short Tons of CO_2)**

	Interim 1 2022–2024	Interim 2 2025–2027	Interim 3 2028–2029	Interim Period 2022–2029	Final 2030–2031
Existing EGU Goals	108,098,013	98,860,563	62,507,488	269,466,064	60,645,264
New Source Complement	506,358	1,708,206	1,075,956	3,290,520	725,794
Existing Plus New Source Goals	108,604,371	100,568,769	63,583,444	272,756,576	61,371,058

From a 2012 baseline emission level of 39,746,539 tons, the final goal to be achieved by 2030–2031 represents a decrease in emissions of 9,061,010 tons annually, a 23% reduction. Table 6 below presents the emission goals the Plan is designed to achieve, as adopted by the State at Chapter 10, § 1001, Table 1.

Table 6 **Statewide Emission Goals and Plan Performance Periods for New and Existing Fossil Fuel-fired EGUs (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons, 3-yr period)	Interim 2 2025–2027 (total tons, 3-yr period)	Interim 3 2028–2029 (total tons, 2-yr period)	Interim Period 2022–2029 (total tons, 8-yr period)	Final 2030–2031 and After (tons per 2-yr period)	Final Period Annual Average Emissions
108,604,371	100,568,769	63,583,444	272,756,576	61,371,058	30,685,529

1 Final CPP preamble, Table 13, at 80 Fed. Reg. 64,825 and EPA, *Technical Support Document: New Source Complements to Mass Goals, Data File: New Source Complements Appendix (XLSX),* at https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents

4.2 Emission Standards

The Plan establishes emission standards, at Chapter 10, § 1005.A, for new and existing affected EGUs in the form of an allowance system, as explicitly authorized by EPA under Subpart UUUU, § 60.5740(a)(2). Both new and existing affected EGUs are required to hold CO_2 allowances, as of the transfer deadline for each compliance period, in an amount not less than the total tons of CO_2 emissions from the affected EGU during the compliance period, and to surrender such allowances for retirement to demonstrate compliance with the emission standard. The emission standards as applicable to new sources are enforceable under state law and are not intended to be incorporated as federally enforceable requirements of the Plan. The Plan establishes compliance periods and an allowance budget for each compliance period that are identical to the Plan emission goals for the Interim 1, Interim 2, Interim 3, and Final plan performance periods. Table 7 below presents the mass allowance budget for each compliance period as adopted at Chapter 10, § 1005.C under the Plan.

Table 7 **Mass Allowance Budgets and Compliance Periods for New and Existing Affected EGUs (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons, 3-yr period)	Interim 2 2025–2027 (total tons, 3-yr period)	Interim 3 2028–2029 (total tons, 2-yr period)	Final 2030–2031 and After (tons per 2-yr period)
108,604,371	100,568,769	63,583,444	61,371,058

In addition to the allowance system emission standards which apply for each compliance period to all affected EGUs, the Plan allows for a temporary modified emission standard to be granted to an affected EGU in the event of a power system emergency or catastrophic event, incorporating the provisions for the "reliability safety valve" as adopted by EPA under Subpart UUUU. The reliability safety valve provisions, at Chapter 10, § 1005.F, could be used to authorize one or more critical EGUs operating in response to the emergency to emit CO_2 for which an allowance match is not required, for a period not to exceed 90 days. Further discussion on the reliability safety valve provision is included in Section 7.

5. Required Demonstrations for Emission Standards

This section addresses the following required demonstrations:

1. A demonstration that the emission standards, when taken together, will achieve the applicable CO_2 emission goals (§ 60.5740(a)(2));
2. A demonstration that corrective measures are not required (§ 60.5740(a)(2)(i));
3. A demonstration that projections of plan performance are not required (§ 60.5745(a)(5));
4. A demonstration that the emission standards are quantifiable, verifiable, non-duplicative, permanent, and enforceable (§ 60.5775); and
5. A demonstration that the emission standards are imposed for the entirety of each plan performance period (§60.5770(c)(1) and (a)(2)).

5.1 The Emission Standards Mathematically Assure Compliance with the Emission Goals

The design of the Plan assures that the allowance holding emission standards applicable to new and existing affected EGUs will collectively achieve the state performance goals. This is accomplished by setting the allowance budget and compliance period equal to the state emission goal for each interim step period and final performance period. Specifically, the allowance budget for each compliance period is identical to the state emission goal for the corresponding performance period. Table 7, above, presents the allowance budget for each compliance period, as adopted at Chapter 10, § 1005.C, Table 2.

In addition, the compliance periods are identical to the interim step periods and final performance periods established by EPA and adopted by the State for the statewide emission goals. Compliance periods are specified in § 1005.B of the state regulation as follows:

Interim 1: The 3-year period from January 1, 2022 through December 31, 2024;
Interim 2: The 3-year period from January 1, 2025 through December 31, 2027;
Interim 3: The 2-year period from January 1, 2028 through December 31, 2029;
Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year.

To provide further assurance, Chapter 10, § 1005.A explicitly provides that the allowance budget for each compliance period constitutes the full complement of new allowances available for issuance by the Administrative Authority, including any allowances auctioned or sold by the State as well as any allowances allocated to affected EGUs and to any other qualified entities.

5.2 Corrective Measures Triggers, a Federally Enforceable Backstop, and Plan Performance Projections Are Not Required

As demonstrated above, assuming compliance with the applicable emission standards by existing affected EGUs under state and federal law, and by new affected EGUs under state law, the plan mathematically assures the State will achieve the applicable emission goal for each plan performance period. Therefore, the Plan is a streamlined plan for which no corrective measures are required in accordance with § 60.5740(a)(2)(i)(C).

In addition, the Plan does not rely on state measures applicable to existing affected EGUs in order to achieve the Plan performance goals. All affected EGUs required to be regulated under Subpart UUUU are subject to federally enforceable emission standards under the Plan. Furthermore, the mass-based trading program is not an expanded program with broader source coverage (that is, coverage beyond affected EGUs plus new sources subject to Subpart TTTT), and does not include flexibility features such as cost containment or offset provisions. Accordingly, the Plan is not a state measures plan type that requires provisions for a federally enforceable backstop.[2]

Also, no further demonstration or projection of plan performance is required because the Plan establishes mass-based emission standards for affected EGUs that cumulatively do not exceed the EPA-specified mass CO_2 emission goal plus new source complement, in accordance with § 60.5745(a)(5)(iii) and § 60.5790(b)(5)(i).

As specified by EPA in the EGs, if a state chooses to adopt a mass-based trading program that regulates existing affected EGUs plus, as a matter of state law, new fossil fuel-fired EGUs that meet the applicability standards for EGUs subject to Subpart TTTT, and the trading program adopts the EPA-provided mass budgets for existing affected EGUs plus the EPA-provided new source complements as the mass allowance budgets, then plan performance will be evaluated based on whether the existing affected EGUs (regulated under the federally enforceable provisions) and the new sources (regulated under state law) together meet the total mass budget.[3]

2 80 Fed. Reg. at 64,890-91.

3 80 Fed. Reg. at 64,888.

5.3 The Emission Standards Are Quantifiable, Verifiable, Non-duplicative, Permanent, and Enforceable, and Are Imposed for the Entirety of Each Plan Performance Period

Subpart UUUU, §60.5775, requires that the Plan include a demonstration that each emission standard for affected EGUs is quantifiable, verifiable, non-duplicative, permanent, and enforceable. Each of these emission standard requirements is addressed below.

Quantifiable and Verifiable. Compliance with the allowance holding emission standard is demonstrated based on two components: the amount of CO_2 that the affected EGU emitted during the compliance period, and the number of allowances held. First, the CO_2 emissions of each affected EGU for each compliance period must be reliably measured, in a manner that can be replicated, to determine the number of allowances required to meet the emission standard. The Plan establishes quantifiable and verifiable methods for determining CO_2 emissions through the monitoring, recordkeeping and reporting requirements of Chapter 10, § 1025. These requirements are consistent with the monitoring, recordkeeping and reporting requirements adopted by EPA in Subpart UUUU, which in turn are consistent with the CO_2 emissions monitoring, recordkeeping and reporting requirements of 40 C.F.R. Part 75.

With regard to assuring that the allowances used to demonstrate compliance are quantifiable and verifiable, the Plan adopts the ATCS system for tracking and compliance purposes. This system establishes a consistent denomination for quantifying allowances (each allowance is equal to one whole short ton of CO_2) and establishes robust procedures for tracking allowances from initial issuance and recordation through each transfer over the life of the allowance until it is retired for compliance purposes. The ATCS, together with the emissions monitoring, recordkeeping and reporting requirements of the Plan, assures that the allowance holding emission standard is quantifiable and verifiable.

In addition to the allowance holding emission standards, the Plan provides that the Administrative Authority may grant a temporary modified emission standard to an affected EGU to respond to a power system emergency. Any temporary modified emission standard would also be quantifiable and verifiable, because the form of the emission standard would be a not-to-exceed mass emission limit for a specified number of days. Accordingly, the continuous emissions monitoring system and associated recordkeeping and reporting requirements will provide a quantifiable and verifiable measure of compliance.

Non-duplicative. The emission standards incorporated in Chapter 10 for affected EGUs are derived from the State-specific emission goals, unique to the State, and are not incorporated in another state plan. The CO_2 reductions used for compliance under the Plan cannot be "double-counted" by applying the same reductions for compliance with another state plan. Specific provisions are incorporated in the Plan to guard against double-counting. For example, each CO_2 allowance used to demonstrate compliance under the Plan must be surrendered and permanently retired (Chapter 10, § 1011). Also, the Plan requires that any EE savings from a qualified EER or energy generated by a qualified EGU that receives allowances under Chapter 10 shall not also receive ERCs or allowances for the same energy savings or generation under another state plan (Chapter 10, § 1015.A.5 and § 1017.A.6). These provisions collectively assure that the emission standards under the plan are non-duplicative.

Any temporary modified emission standard that may be established under the Plan would also be non-duplicative, as these emission standards are customized to the specific affected EGU and specific emergency circumstances and, as such, are not incorporated into another state plan.

Permanent and Imposed for the Entirety of the Performance Period. The emission standards for affected EGUs are permanent, in that the standards apply for the entirety of each compliance period. Specifically, the allowance holding emission standard of § 1005.A of Chapter 10 applies at all times to each affected EGU, unless the emission standard is temporarily modified in response to a power system emergency under the provisions of § 1005.F of Chapter 10.

In the event that the emission standard for an affected EGU is modified in accordance with § 1005.F, the Plan nonetheless imposes the modified emission standard such that there is no interruption in the regulation of emissions from the affected EGU. Furthermore, the temporary modified emission standard itself incorporates the underlying permanent emission standard, by requiring that allowances be provided for any emissions occurring during the period of the modified standard that reasonably would have been anticipated to occur in the absence of the emergency.

This demonstration that the emission standards under the Plan are permanent also demonstrates that the emission standards under the plan are imposed for the entirety of the each performance period, consistent with Subpart UUUU § 60.5770(a)(1) and § 60.5775(e).

Enforceable. Subpart UUUU, § 60.5775(f), establishes a five-part test for demonstration of whether the emission standards for affected EGUs are enforceable. Each of the five criteria are addressed below.

1. The standard itself must be clearly specified in a technically accurate form, with regard to the numeric limit, the units of measure and the associated averaging period or applicable time period.
   - Units of measure (total tons of CO_2) and applicable time periods (compliance periods) are clearly prescribed under Chapter 10, § 1005.
2. The compliance requirements must be clearly defined.
   - Compliance requirements are clearly defined by Chapter 10, including but not limited to §§ 1005, 1009, 1011, 1025, and 1027.
3. The parties responsible for compliance must be clearly specified.
   - Responsible parties are clearly specified in Chapter 10, including but not limited to §§ 1003, 1005, 1009, 1011, 1025, and 1027. In particular, § 1027.A clarifies enforcement liabilities and specifies that requirements for each affected EGU apply to each owner and operator and designated representative of the affected EGU and facility at which the EGU is located.
4. The standard and compliance requirements must be enforceable as a practical matter.
   - The emission standards are enforceable as a practical matter through the form of the standards taken together with the monitoring, recordkeeping and reporting requirements for CO_2 emissions from affected EGUs and through the ATCS. See the discussion above related to "quantifiable and verifiable."
5. The state, EPA and third parties have the ability to enforce the standard and secure appropriate corrective measures.
   - Chapter 10 explicitly provides that the emission standards, as they apply to existing affected EGUs, are enforceable under the federal Clean Air Act at § 1001.B and § 1027.A. This assures the ability of the State, EPA and third parties to enforce the standards and secure corrective measures. In addition, § 1027 prescribes nondiscretionary corrective measures and stipulated penalties that apply to any violation of the allowance holding emission standard.

6. Required Mass-based Trading Program Plan Components

Subpart UUUU, § 60.5790(b), lists five plan elements that must be included in each plan incorporating a mass-based emissions trading program. Each of those items is addressed below.

6.1 CO_2 Emissions Monitoring, Reporting, and Recordkeeping Requirements for Affected EGUs

Chapter 10, § 1025, establishes specific, detailed requirements for affected EGUs to monitor, record and report electricity generation and emissions. The monitoring requirements for affected EGUs are consistent with 40 C.F.R. Part 75 provisions to which most, if not all, affected EGUs are already subject. The requirements are consistent with and drawn from those incorporated in Subpart UUUU at § 60.5860(a) and the proposed federal model rule for mass-based emissions trading programs.

6.2 Requirements for State Allocation of Allowances

Subpart UUUU provides minimum requirements for the allocation of allowances at § 60.5815(b) through (f). Chapter 10, § 1007, sets forth the allowance sale, auction and allocation scheme for the State CO_2 Trading Program for EGUs.

First, the Plan must provide for allocation of allowances for a given compliance period prior to the beginning of the compliance period. Chapter 10 meets this requirement. The Administrative Authority will determine and publish a notice of allocations of allowances no later than December 1 of the year prior to the beginning of each compliance period.

Second, if the plan relies on set-aside allowances (i.e., as an incentive to EE or RE resources), the plan must include eligibility requirements, application and verification provisions equivalent to those for ERC-eligible resources under a rate-based plan. The State Plan does not incorporate or rely on set-aside allowances. As noted below, leakage is addressed through the regulation of new EGUs subject to Subpart TTTT under the trading program. Nonetheless, the Plan does provide for the direct allocation (not set-asides) to qualified EE resources and to qualified non-affected EGUs, and incorporates associated EM&V and M&V requirements.

Third, each plan must provide for adjusting allocations if allowances are incorrectly allocated. The State Plan includes provisions for adjusting allocations to correct errors. These provisions are incorporated at Chapter 10, § 1007.G.

Fourth, each plan must include provisions that either restrict or allow the banking of allowances between compliance periods. The State Plan allows for the banking of excess allowances that were not relied upon to demonstrate compliance, to be transferred or used to demonstrate compliance for a future compliance period. These provisions are found at in Chapter 10, § 1005.C.2.

Finally, each plan must include provisions prohibiting any borrowing of allowances from future compliance periods by affected EGUs. This provision is found at § 1005.C.1. It should be noted that, consistent with the EPA proposed model rule for mass-based trading programs, the Plan requires, in the case of a violation of the emission standard, that the owners and operators of the affected EGU provide an initial remedy in the form of two allowances for each ton of excess emissions. The initial remedy may be met by allowances from a prior compliance period, the compliance period during which the excess emissions occurred, or the compliance period immediately following the period in which the excess emissions occurred (Chapter 10, §1027.F). This requirement does not constitute "borrowing" from a future compliance period, as the allowances are for the purpose of providing an enforcement remedy for a violation and not for the purpose of demonstrating compliance.

6.3 Requirements for Tracking of Allowances

Chapter 10, § 1011, establishes requirements for allowances to be recorded upon initial issuance in the Allowance Tracking and Compliance System (ATCS), provides specific procedures for establishing and maintaining accounts, and provides specific procedures for the transferring, surrendering and retiring of allowances. The procedures are consistent with Subpart UUUU, § 60.5820(a) and (b). Specifically, the Plan regulations specify that the ATCS is an electronic tracking system that will record the issuance, transfer, surrender and retirement of allowances. The ATCS will provide internet-based public access to information regarding the allocation of allowances, including the ability to generate reports. The Plan does not rely on or include set-aside allowances, therefore the provisions of § 60.5820(a) pertaining to set-aside allocations are not applicable. Chapter 10, § 1011 also provides for transfers of allowances to or from accounts in another allowance tracking system, where the other allowance tracking system has been recognized by the Administrative Authority.

6.4 Process for Affected EGUs to Demonstrate Compliance

Consistent with Subpart UUUU, § 60.5825, the State Plan regulations at Chapter 10, § 1005 and § 1011 require affected EGUs (including existing affected EGUs and new EGUs subject to the trading program) to demonstrate compliance with the allowance holding emission standard by holding in the compliance account, and surrendering for compliance, an amount of allowances not less than the total tons of CO_2 emitted by the affected EGU during the compliance period. The Plan requires a subaccount in each facility compliance account for each affected EGU, therefore the authorized account representative is responsible for assigning allowances to a specific affected EGU under the compliance account.

6.5 Requirements to Address Leakage to New Sources

40 C.F.R. § 60.5790(b)(5) specifies that the Plan must include requirements that address potential increases in emissions from new sources, beyond those emissions that would be expected to occur if the state were to implement a rate-based plan imposing the Subpart UUUU Table 1 subcategory performance rates as emission standards for existing affected EGUs. Such emissions increases at new sources are referred to as "leakage." Section 60.5790(b)(5) further provides that the regulation under state law of EGUs covered by Subpart TTTT under the mass-based trading program, using the EPA-provided statewide emission goal plus new source complement as the mass emission budget, meets the requirement to address leakage. This Plan addresses leakage by regulating new EGUs subject to Subpart TTTT under the mass-based trading program, and using the EPA-provided statewide emission goal plus new source complement for each interim step period and final compliance period. Therefore, the Plan meets the requirement to address leakage under § 60.5790(b)(5).

7. Consideration of Grid Reliability

Subpart UUUU requires the plan submittal to include a demonstration that the reliability of the electrical grid has been considered in the development of the plan.[4] The EGs explain that the purpose of consideration of grid reliability during plan development is to ensure that the plan provides enough flexibility for affected EGUs to avoid potential conflict between maintaining reliable electric service and complying with applicable plan provisions and emission standards.[5] The EGs further provide that the State should document that consultation with the Regional Transmission Organization (RTO) or other planning authorities was undertaken as part of the planning process, in order to provide an assessment of any reliability implications of the plan. Consultation with grid reliability planning authorities and experts is intended to assure that the state plan will achieve the emission guidelines in a manner that maintains grid reliability.

As part of the plan development process, beginning with an analysis of EPA's proposed Clean Power Plan in June 2014 and extending through adoption of this final State Plan, the State Department of Environmental Quality has coordinated, consulted and worked closely with three primary authorities with expertise in grid reliability and energy policy: the RTO, MISO; the State Public Service Commission (PSC), and the State Energy Office (SEO). Documentation of various meetings, communications and consultations with these authorities is included as part of this Plan Documentation in Appendix C, Rulemaking Documentation and Appendix D, Stakeholder and Public Participation and Outreach.

The State is part of the Eastern Interconnect, and the independent Regional Transmission Organization (RTO) is MISO. MISO's role as the RTO is to provide consumers with unbiased regional grid management and open access to transmission facilities by power generators across the region. As an independent RTO, MISO does not take policy positions on EPA regulations, but works with stakeholders to analyze how EPA regulations might affect generation, load and resource adequacy, among other things, in MISO's footprint. MISO makes its analyses available to stakeholders in an effort

4 40 C.F.R. § 60.5745(a)(7).

5 80 Fed. Reg. at 64,786.

to help the impacted parties discover the most appropriate compliance solutions.[6]

The State Public Service Commission (PSC) has responsibility for oversight of Integrated Resource Planning (IRP) by regulated utilities, including the retirement of aging EGUs, the reliance on power purchase agreements (PPAs) with independent generators, and the construction of new EGUs.

The State Energy Office, located within the Department of Natural Resource Conservation, has an advisory role for State energy policy and oversees the implementation of various State energy efficiency programs and other energy-related incentive programs.

The State's findings and conclusions based on these consultations and related analyses is summarized below.

7.1 Findings Regarding Grid Reliability Impacts

The Department, in consultation with stakeholders including MISO, PSC, SEO and others, reviewed various modeling analyses, economic analyses, and other information during the course of the plan development. In particular, MISO conducted numerous modeling exercises during our analysis of the proposed CPP,[7] and updated and expanded those analyses to consider specific State Plan options and MISO sub-regional compliance approaches during 2016. In addition, we studied the analyses conducted by EPA and supporting documentation provided with the final Subpart UUUU, which also presented modeling conducted by other ISOs, RTOs and consortiums.

Based on these analyses, the State has concluded that providing a flexible compliance approach is critical to minimizing potential impacts to grid reliability. Most studies have found that an interstate trading approach is predicted to result in fewer grid reliability impacts than an individual state-by-state compliance strategy. Several studies have also concluded that a mass-based trading approach results in lower compliance costs than a rate-based program. Accordingly, the State is adopting a flexible, mass-based trading program that allows affected EGUs and other entities to trade allowances across the grid with other EPA-approved trading-ready mass-based programs.

Nonetheless, MISO and others have advised that increased transmission congestion is projected to occur with implementation of the State Plan with current transmission facilities, even using a regional trading scheme. Regional compliance reduces predicted transmission congestion; however, congestion is increased relative to business as usual (BAU) baseline conditions regardless of the compliance approach, and regardless of whether a coal conversion to gas, new gas build-out, or combined gas, wind and solar generation shift strategy is employed.

These analyses conclude that investment in transmission infrastructure will be necessary to assure grid reliability with Plan implementation. While the planning and approval process for several transmission infrastructure projects across the region has already begun, MISO advises that transmission build out projects can require six to ten years or more to complete.

Based on our consideration of grid reliability, the State has adopted the plan type for which the lowest reliability impacts and lowest compliance costs are predicted. Specifically, the Plan adopts a mass-based allowance system trading program that is designed to allow trading across a wide region. Despite this broad flexibility, the State is cognizant that grid impacts could potentially occur as generation shifts are implemented to reduce CO_2 emissions under the cap. It is likely that the interim period and initial final compliance periods, comprising the first ten to twelve years of program implementation, are somewhat more likely to experience grid reliability impacts such as bulk electric system thermal constraints, as transmission system upgrades are under development.

6 https://www.misoenergy.org/WhatWeDo/EPARegulations/Pages/EPARegulations.aspx.

7 *Ibid*.

A power grid emergency situation could compel one or more particular EGUs, for example, existing coal-fired steam units located in areas where transmission constraints are not occurring, to operate at higher capacity factors in order to avoid power failure. These demands could potentially place an affected EGU in a circumstance where higher utilization levels result in higher emissions that cannot be matched by available allowances under the trading program. Availability of allowances, particularly in the early years of Plan implementation, will be influenced by a number of factors including the fluidity of the market, the schedule and advancement of numerous measures to shift generation to lower- or zero-emitting EGUs across the region, and the status of implementation of new EE programs and measures. In addition, the ability of EGUs in the State to obtain allowances may be impacted by the decisions of other states to participate or not to participate in a mass-based regional trading program and the timing of EPA approval of plans or imposition of a federal plan.

7.2 Grid Reliability Safety Valve

Based on our consideration of potential impacts to grid reliability, the State has elected to adopt provisions to incorporate a reliability safety valve as part of the Plan, as allowed under Subpart UUUU, § 60.5785(e) and § 60.5870(g), as a precautionary measure.

Chapter 10, § 1005.F, incorporates the criteria for emergency events and affected EGUs to trigger the reliability safety valve and for the Administrative Authority to approve a temporary modified emission standard. First, the reliability event must be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event. Second, the relief provided is restricted to EGUs compelled to operate for purposes of providing generation without which the affected electricity grid would face failure. Third, operation of the EGUs in response to the emergency must result in emissions at a level for which allowances could not foreseeably be reasonably obtained in order to comply with the emission standard. Section 1005.F requires the affected EGU to make three notifications to the Administrative Authority, including the information that the State must consider in determining whether to grant the temporary emission standard. The rule also requires the Administrative Authority to notify EPA in accordance with the 48-hour and 7-day notification requirements of the EGs. The provisions of 40 C.F.R. § 60.5870(g)(3), requiring the State to submit a notice no later than 7 days prior to the end of the 90-day temporary relief period, with a schedule for submitting a Plan revision in the event the power system emergency cannot be resolved within 90 days, are incorporated by reference at Chapter 10, § 1005.F.3.

8. Description of State Reporting to EPA

Chapter 10, § 1001.A, incorporates by reference the federally enforceable recordkeeping and reporting requirements of Subpart UUUU at §§ 60.5865, 60.5870 and 60.5875. The State will provide all reports to EPA as required by § 60.5870, using the procedures specified in § 60.5875. Interim period reporting starts with a report covering interim step 1, due no later than July 1, 2025. Subsequent reports from the state to EPA are due no later than July 1 of the year following the end of each plan performance period, including each interim step period and each two-year performance period subject to the final performance goal, commencing with the 2030–2031 performance period. A summary of the required reporting is provided in Table 8.

As required by § 60.5875, the State will submit all state reports and notifications through EPA's State Plan Electronic Collection System (SPeCS), a web-based system accessed through EPA's Central Data Exchange (CDX). Reports will be submitted in both non-editable and editable format.

Table 8 **Schedule of State Reporting to EPA**

Report	Performance Period Dates	State Report Due
Programmatic Milestones Report	September 6, 2018–January 1, 2022	July 1, 2021
Interim Step Period 1 Report	January 1, 2022–December 31, 2024	July 1, 2025
Interim Step Period 2 Report	January 1, 2025–December 31, 2027	July 1, 2028
Interim Performance Period Report	January 1, 2022–December 31, 2029	July 1, 2030
Final Performance Periods	January 1, 2030–December 31, 2031 Ongoing 2-year periods	July 1, 2032 July 1 every 2nd year

The first report to EPA due after Plan submittal is the programmatic milestones report. Milestone steps are listed in the timeline provided in Table 9 of this Plan Documentation.

Table 9 **Schedule of Programmatic Milestones**

Programmatic Milestone	Target Date
Training and outreach for qualified EERs and qualified EGUs; review of eligibility applications	Began October 2017, ongoing
Registration of independent verifiers	Began October 2017, ongoing
Submit Final Plan to EPA	September 6, 2018
Certificates of representation submitted for designated representatives of affected EGUs	December 31, 2018
ATCS open for Chapter 10 account applications	December 31, 2018
Review general account applications and establish accounts as appropriate	Begin January 2019, ongoing
Submit programmatic milestones report to EPA	July 1, 2021
Initial allowance allocations noticed	October 31, 2021

Beginning with the July 1, 2025 report, each report will include the emissions performance achieved by all new and existing affected EGUs, an identification of whether each affected EGU is in compliance with applicable emission standards, and whether the EGUs have collectively met, or are on schedule to meet, the applicable performance emission goals. For the interim step period reports due July 1, 2025 and July 1, 2028, the reports will provide a comparison of the applicable interim emission performance goal to the actual cumulative emissions from all new and existing affected EGUs. Cumulative emissions will be reported in comparison to the interim step emission goals and the interim period emission goal. The report for the interim performance period, due by July 1, 2030, will include a report for performance over the entire interim period (2022 through 2029) and whether the collective emissions from new and existing affected EGUs have met the statewide interim period emission goal.

In addition to the periodic reporting of plan performance, the State will submit reports as required in the event of a power system emergency that triggers the reliability safety valve. As applicable, the State will submit an initial report within 48 hours, a second report within 7 days, and a final report no later than 7 days prior to the end of the 90-day period. Chapter 10, § 1005.F, adopts provisions requiring any EGU that seeks a modified emission standard under the reliability safety valve to submit notifications to the State in advance of these deadlines, with the required information.

In addition, as required by § 60.5745(a)(8), the Plan must include a timeline with the programmatic steps the State intends to take between the time of Plan submittal and January 1, 2022 to assure the plan is effective as of January 1, 2022. It is noted that the Plan is currently in effect, in that the implementing regulations are final. Nonetheless, a schedule of additional steps the State is taking or will take for early implementation elements of the Plan is included below in Table 8.

As required by § 60.5740(a)(5), the State will submit a report to EPA by July 1, 2021, demonstrating that the State has met or is on track to meet programmatic milestone steps from the time of plan submittal to January 1, 2022.

9. Stakeholder and Public Participation and Engagement

Subpart UUUU, § 60.5745(a)(11) and (12) requires the State Plan submittal to provide documentation of public participation and engagement in the plan development as required at 40 C.F.R. § 60.23. In addition, EPA specifies in the preamble to the final rule that, for purposes of Subpart UUUU, compliance with the public participation provisions of 40 C.F.R. § 60.23 must include active engagement with vulnerable communities that may be affected by the State Plan.

9.1 Certification of Public Hearing and Adherence to Procedural Requirements

Records of compliance with the administrative rulemaking process for Chapter 10 are included in Appendix C. These records include copies of the proofs of publication of the public notice for comment on the proposed regulation, proofs of publication of the 30-day notice of a public hearing on the proposed rule, the certified court recorder transcript for the public hearing, a list of witnesses and their affiliations, the public comment and response summary, and notice in the State Register of adoption of the final rule. The supporting documentation included in Appendix C demonstrates the minimum required procedures of 40 C.F.R. § 60.23 are met.

9.2 Stakeholder Engagement

Appendix D includes additional documentation of public engagement and outreach, including records of stakeholder meetings, public listening sessions and numerous planning meetings. In addition, the Department has maintained a public website for the State Plan development, www.sdeq.gov/cpp/publicparticipation, which includes schedules and agendas of meetings, lists of attendees and presenters, copies of meeting handouts and presentations, and many other records related to the Plan development.

The Plan development and rulemaking process went well beyond the minimum-required procedures under 40 C.F.R. § 60.23 in providing for public input and engagement. During the period that Subpart UUUU and EGs were proposed, the Department conducted three public input and listening sessions to assist the Department in evaluating the proposed rule and developing comments. In addition to the three public listening sessions, the Department conducted ten meetings with various groups, including the utilities, MISO, PSC, SEO, municipal cooperatives, energy efficiency service providers, citizen groups, public housing program representatives, and others. In addition to these opportunities for stakeholder and public participation during the proposal phase of EPA's EGs, the State participated in three preliminary planning and discussion meetings with other states in the region between June 2014 and June 2015.

During the 2015 State Legislative Session, the State House of Representatives and State Senate Environmental Committees held a joint meeting to hear from constituents regarding the State's action to comply with the final CPP. In addition, each of the three bills that were ultimately enacted as new State law came first before a House committee, where stakeholders had an opportunity to speak, prior to passage on the House floor, and then passed to the Senate, where an additional opportunity for comment before the Senate Committee on the Environment was provided before passage on the Senate floor.

Once the legislation was adopted, the Department again convened a series of six stakeholder meetings and listening sessions around the state, and held periodic stakeholder meetings with key participants, including representatives of affected EGUs, EE and RE providers, and community representatives.

9.3 Vulnerable Communities Engagement

The Department actively sought to engage vulnerable and overburdened communities, including low-income communities and communities of color, by contacting community faith leaders and requesting notice of the stakeholder meetings be posted. Documentation of early engagement with vulnerable communities was previously provided with the State's initial submittal in September 2016. The State relied upon our knowledge of local communities and locations of affected EGUs, as well as consultation with the EPA Regional Office, community advocates, and citizen groups to support the identification of potentially vulnerable communities and to identify representatives for communication and outreach. In addition, the State consulted EPA's EJ Screening Report for the Clean Power Plan and associated proximity studies and maps to assist in identifying potential target communities. Appendix D includes a list of vulnerable community advocates and community leaders, identifying the specific community or community concern represented.

There is no coal production in the State, therefore no direct impact related to potential loss of employment in the coal mining sector is anticipated. Rather, potential adverse impacts related to the State Plan, as communicated by the vulnerable community residents and leaders, included loss of jobs resulting from the retirement of coal power plants; increased electricity prices impacting low-income and fixed-income communities; displacement of the benefits of pollution reduction to other states or communities under an interstate trading program; and the concern that grid reliability impacts leading to power failure would be most likely to occur in low-income and minority communities, where the housing stock and related transmission facilities are older and more congested than in newer suburbs and higher-income communities.

On the other hand, these communities expressed excitement and encouragement about the likely deployment of expanded demand-side EE programs that would abate increases in or potentially reduce electric bills, particularly for multi-family rental complexes. Interest was also voiced about the potential for new job opportunities in energy efficiency and green energy job markets. Vulnerable and low-income communities also expressed a very strong support for the goals of the State Clean Power Plan to reduce GHG emissions in order to address climate change and avoid or abate the negative impacts of land loss, flooding, hotter summers, and more frequent extreme weather conditions. The reduction of emissions from power plants, including not only CO_2 but also criteria pollutants and toxic air pollutants, was frequently raised as a high priority concern from vulnerable communities and citizen representatives across the state, and particularly in areas where large power plants and other industrial facilities are located in close proximity to residential areas

The State Plan incorporates specific allowance allocation provisions to incentivize the deployment of qualified EERs in vulnerable communities, by adding a multiplier of 1.5 times the allocations that would otherwise be awarded for the same amount of verified energy savings occurring in an area that is not a vulnerable community. For purposes of this allocation provision, a vulnerable community is any census block with a minority population greater than 70% or with greater than 50% low-income households. The allowance incentive portion of the allocation (that is, one-third of the total allowances awarded for certified EE savings in a vulnerable community) is not counted toward the 15% cap on allowance allocations to qualified EERs.

Appendix A

Legislative Authority for Program Development, Program Implementation and Funding

Act 1029, State Clean Power Plan

Act 1340, Creation and Sale of Allowances

Act 1751, Integrated Resource Planning for CO_2 Reductions

Appendix B

State Regulations

SAC 55:VII Chapter 10, State Clean Power Plan

Appendix C

Documentation of State Rulemaking Procedures

Proofs of Publication of Public Notice for Comment
Proofs of Publication of Public Notice for Hearing
Certified Court Recorder Transcript of Hearing
List of Witnesses and Affiliations
Summary of Public Comments and Department Response to Comments
Promulgation of Final Rule

Appendix D

Documentation of Stakeholder and Public Participation, Including Vulnerable Communities

Schedule of Stakeholder Meetings and Public Listening Sessions

Meeting Agendas, Lists of Attendees and Speakers

Documentation of Identification of Vulnerable Communities

List of Community Leaders and Citizen Advocates

Promulgation of Final Rule

Model State Authorizing Legislation

State Clean Power Plan
to Comply with 40 C.F.R. Part 60, Subpart UUUU

Act 1029, Act 1340 and Act 1751 of 2015

Act 1029 as Engrossed

132nd General Assembly
Regular Session 2015

ACT 1029 of 2015

By: Senator Green
By: Representative Venti

Entitled

STATE CLEAN POWER PLAN

Subtitle

AN ACT TO AMEND THE STATE ENVIRONMENTAL QUALITY ACT PERTAINING TO AIR POLLUTION; TO AUTHORIZE THE STATE DEPARTMENT OF ENVIRONMENTAL QUALITY WITH RESPECT TO THE ADOPTION OF A STATE CLEAN POWER PLAN AND TRADING PROGRAM; AND FOR OTHER PURPOSES.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE:

SECTION 1. State Code Subtitle V of Title 60, Chapter 9, § 60:3600 et seq., constituting the State Air Pollution Control Program, is amended to add two additional sections, § 60:3685 and § 60:3686, to read as follows:

60:3685. **State Clean Power Plan.** A. The provisions of these Sections 60:3685 and 60:3686 shall be known as and may be cited as, the "State Clean Power Plan." (2) In accordance with the provisions of 42 U.S.C. § 7411 (Section 111 of the federal Clean Air Act), the State shall establish a State Plan to reduce CO_2 emissions from fossil fuel-fired power plants. It is the intent of this legislature that the State Plan shall be consistent with the federal emission guidelines and be sufficient to obtain approval from U.S. EPA for the State to serve as the primary authority for implementing and enforcing all aspects of the program.

B. (1) The Director of the State Department of Environmental Quality is authorized to adopt regulations to establish and implement the State Clean Power Plan, and may adopt and implement a carbon trading program as the platform for the State Plan. (2) If a trading program is adopted, the Director shall be the Administrator of the allowance tracking system and may designate and contract with a private entity to carry out the administrative duties of managing and maintaining the tracking system, provided that the Director shall not delegate any duties related to program enforcement to a private entity.

C. If a trading program is adopted as the platform for the State Clean Power Plan, it is the intent of this legislature that the costs of program implementation and enforcement be fully funded through the auction or sale by the State of carbon allowances. If a trading program is not adopted, it is the intent of this legislature that the costs of program implementation and enforcement be fully funded through new fees on regulated power plants. The Director of the Department of Environmental Quality is authorized to auction or sell allowances, or to propose new fees to be adopted as necessary, to fund the program.

D. To achieve the goals of the program, the Director may regulate both new and existing fossil fuel-fired power plants under the program if the studies required under § 60:3686 support the regulation of new sources. In the event new power plants are regulated under the program, such regulation of new sources shall not be included as a federally enforceable element of the State Plan.

60:3686. The Director of the State Department of Environmental Quality shall conduct a study, in coordination with the State Energy Office and the Public Service Commission, to evaluate the likely least-cost compliance pathways for the design of the State Plan. The study shall seek consultation with the Regional Transmission Operator to evaluate various options for program design, including interstate trading vs. a single-state program and rate-based vs. mass-based designs. In addition, the study shall consider the potential impacts on grid reliability for different program designs and shall seek to avoid any potentially adverse impacts to the reliability of the delivery of electricity to the consumers in the State to the greatest degree practicable.

Act 1340 as Engrossed

132nd General Assembly
Regular Session 2015

ACT 1340 of 2015

By: Senator Green
By: Representative Venti

Entitled

CREATION AND SALE OF ALLOWANCES UNDER THE STATE CO_2 TRADING PROGRAM FOR POWER PLANTS

Subtitle

AN ACT TO AMEND THE STATE FISCAL PROCEDURES ACT PERTAINING TO REVENUES AND FUNDING OF STATE PROGRAMS; TO AUTHORIZE THE STATE DEPARTMENT OF ENVIRONMENTAL QUALITY WITH RESPECT TO THE ADOPTION OF A STATE CARBON TRADING PROGRAM, WITH RESPECT TO THE CREATION, DISTRIBUTION, AUCTION AND SALE OF ALLOWANCES; AND FOR OTHER PURPOSES.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE:

SECTION 1. State Code Subtitle I of Title 15, Chapter 2, § 15:300 et seq., constituting the State Funding and Revenues Program, is amended to add a new section, § 15:6790, to read as follows:

15:6790. **State CO_2 Trading Program for Power Plants.**

A. (1) The provisions of this Section 15:6790 shall be known as and may be cited as, the "State CO_2 Trading Program for Power Plants." (2) In accordance with the provisions of 42 U.S.C. § 7411 (Section 111 of the federal Clean Air Act), the State shall establish a State Plan to reduce CO_2 emissions from fossil fuel-fired power plants, to be known as the State Clean Power Plan. It is the intent of this legislature that the program shall be self-funding. Funding for the program shall be provided through the auction and sale of allowances, if a carbon trading program is adopted as the platform for the State Plan, or through the adoption and collection of fees.

B. (1) The Director of the State Department of Environmental Quality is authorized to adopt regulations and to determine, direct and perform all necessary and appropriate actions related to the creation and distribution of CO_2 allowances under the State CO_2 Trading Program for Power Plants, as provided herein. (2) If a trading program is adopted, the Director shall establish by rule an allowance budget for each compliance period for regulated entities. The Director shall establish the procedures and mechanisms for the distribution of allowances, including free allocations, set-asides for investments in clean energy or consumer programs, auctions and sales, or other mechanisms as adopted by rule, provided that a portion of the allowances from each allowance budget shall be

reserved for auction or sale by the State. The Director is authorized to conduct auctions and sales of allowances as necessary and appropriate, and may designate and contract with a private entity to carry out the administrative duties of executing auctions and sales and otherwise distributing allowances, provided that the Director shall not delegate any duties related to program enforcement to a private entity.

C. The portion of the allowance budget to be reserved for the State for each compliance period shall be no less than 15% and no more than 50%. The specific portion for each compliance period shall be determined by the legislature in adopting the state fiscal budget for the fiscal year that coincides with the year prior to the first year of each compliance period. If the legislature does not adopt a specified portion for a given compliance period, the Director of the State Department of Environmental Quality shall reserve the minimum 15% of the allowance budget.

D. Revenues from the auction or sale of allowances shall be directed to funding of the State Clean Power Plan and the program shall be fully funded by revenues from the auction or sale of allowances, if a trading program is adopted. Proceeds from the sale of allowances in excess of program costs shall be directed by the legislature as deemed appropriate in adopting the state fiscal budget. If a trading program is not adopted, the Director of the State Department of Environmental Quality is authorized and directed to adopt a fee schedule for funding the implementation and enforcement of the State Clean Power Plan. Fees may be based on emissions of CO_2 from regulated sources under the program, or may be based on the fuel usage or capacity of regulated sources.

Act 1751 as Engrossed

132nd General Assembly
Regular Session 2015

ACT 1751 of 2015

By: Senator Green
By: Representative Venti

Entitled

INTEGRATED RESOURCE PLANNING FOR CO_2 REDUCTIONS

Subtitle

AN ACT TO AMEND THE STATE ENERGY ACT PERTAINING TO INTEGRATED RESOURCE PLANNING; TO DIRECT THE STATE PUBLIC SERVICE COMMISSION WITH RESPECT TO THE REDUCTION OF CO_2 EMISSIONS FROM POWER PLANTS; AND FOR OTHER PURPOSES.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE:

SECTION 1. State Code Subtitle VII of Title 35, Chapter 4, § 35:2800 et seq., constituting the State Integrated Resource Planning Program, is amended to add an additional section, § 35:2860, to read as follows:

35:2860. A. Each Integrated Resource Plan (IRP) developed by a utility shall take into consideration the reduction of emissions of CO_2 as required under the State Clean Power Plan and as appropriate for the protection of the environment and natural resources of the State. It is the intent of this legislature that the IRP process shall seek to reduce emissions from power plants in the State wherever practical and cost-effective.

B. The Commissioner of the Public Service Commission, in exercising his oversight of the IRP process, is directed to review each IRP to assure each plan makes a comprehensive and balanced effort toward the reduction of emissions from existing facilities located in the state, while seeking the least-cost option for customers and maintaining grid reliability and safety. The Commissioner is further directed to coordinate with, advise, and share information with the Director of the State Department of Environmental Quality, as appropriate to support the goals of the State Clean Power Plan.

C. Each IRP developed under the State IRP Program shall take into consideration achievement of the emission goals of the State Clean Power Plan when planning for the retirement or repowering of aging units, the availability and utilization of existing generation resources, the construction of new units, and the purchase of power for distribution from independent power producers. In addition, each IRP shall evaluate the cost-effectiveness and emission reduction potential of available options for improving energy efficiency of existing generation resources and for repowering existing generation resources with natural gas, biomass, or other fuels.

Model State Regulations

State Clean Power Plan
to Comply with 40 C.F.R. Part 60, Subpart UUUU

Mass-based Allowance Trading Plan
with New Source Complement
Interstate Trading-Ready

State Regulations

Chapter 10. State Clean Power Plan

Chapter 10. State Clean Power Plan

Section 1001. Purpose and Authority

A. Purpose.

1. This Chapter sets forth regulations to establish and implement the State CO_2 Trading Program for EGUs, comprising part of the State plan to implement 40 CFR part 60 subpart UUUU, Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units. The pollutants regulated under this Chapter are greenhouse gases (GHGs). The GHG limitations in this Chapter are in the form of an emission standard for carbon dioxide (CO_2).
2. The emission standards and other applicable requirements of this Chapter are designed to reduce emissions of CO_2 from affected fossil fuel-fired electric generating units (EGUs) from a 2012 baseline level of 39,746,539 tons to the statewide levels set forth in 40 CFR part 60 subpart UUUU, as shown below in Table 1 of this Section. The State will provide periodic reports to the Administrator of the United States Environmental Protection Agency (EPA) on the progress of both new and existing affected EGUs, as defined under this Chapter, in meeting these emission goals, and will keep records related to the State CO_2 Trading Program for EGUs, as required by 40 CFR §§ 60.5865, 60.5870 and 60.5875.

Table 1 **Statewide Emission Goals for Affected Fossil Fuel-fired Electric Generating Units (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons, 3-yr period)	Interim 2 2025–2027 (total tons, 3-yr period)	Interim 3 2028–2029 (total tons, 2-yr period)	Interim Period 2022–2029 (total tons, 8-yr period)	Final 2030–2031 and After (tons per 2-yr period)	Final Period Annual Average Emissions
108,604,371	100,568,769	63,583,444	272,756,576	61,371,058	30,685,529

B. State and Federal Enforcement Authority for Applicable Requirements.

1. As applicable to existing affected EGUs, all requirements under this Chapter shall be enforceable under both the State Environmental Quality Act and the federal Clean Air Act. All requirements applicable to existing affected EGUs are federally applicable requirements under SAC 55 Regulation V, Chapter 5, Operating Permits for Major Sources, and shall be incorporated into the Title V permit for the facility in accordance with Section 1005 of this Chapter.
2. As applicable to new affected EGUs, all requirements under this Chapter shall be enforced solely under the State Environmental Quality Act and shall not be federally enforceable requirements under the federal Clean Air Act or under any other federal law or regulation. All requirements applicable to new affected EGUs are state-only requirements under SAC 55 Regulation V, Chapter 5, Operating Permits for Major Sources, and shall be incorporated into the Title V permit for the facility in accordance with Section 1005 of this Chapter.

C. Legislative Authority. This Chapter is adopted by the Department of Environmental Quality, Office of Air Quality, pursuant to the State Environmental Quality Act, State Revised Statute SRS 60:3600 through 60:3686, as amended July 15, 2015, the State Fiscal Procedures Act, SRS 15:6790, as amended July 15, 2015, and the State Energy Act, SRS 35:2860, as amended July 15, 2015.

Section 1003. Applicability

A. Designated Representatives, New and Existing Affected EGUs.

1. The requirements of this Chapter apply to the owner and operator of any affected electric generating unit (EGU) located in the State. The owner and operator of each affected EGU shall assign and register a designated representative, and may also assign and register an alternate designated representative, in accordance with Section 1009 of this Chapter.
2. Any provision of this Chapter that applies to an affected EGU at a facility or the designated representative of affected EGUs at a facility shall also apply to the owners and operators of such facility and of the affected EGUs at the facility.
3. An affected EGU under this Chapter is any existing affected EGU or a new affected EGU.
   a. An existing affected EGU is any affected EGU that commenced construction on or before January 8, 2014 and that is not subject to 40 CFR part 60 subpart TTTT.
   b. A new affected EGU is any affected EGU that commenced construction, modification or reconstruction after January 8, 2014, and that is subject to 40 CFR part 60 subpart TTTT.
4. Except as provided in Paragraphs B and C of this Section, an affected EGU is any EGU meeting the following applicability criteria:
   a. The EGU operated at any time on or after January 1, 2012, and meets either Paragraph A.4.b or A.4.c of this Section.
   b. The EGU is a fossil fuel-fired EGU, including steam generating units and IGCC units, that:
      i. serves a generator that is connected to a utility power distribution system and has a nameplate capacity of 25 MW-net or greater; and,
      ii. has a design heat input capacity greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel alone or of fossil fuel in combination with any other fuel.
   c. The EGU is a stationary combustion turbine meeting the definition of combined cycle stationary combustion turbine or combined heat and power (CHP) stationary combustion turbine that:
      i. serves a generator that is connected to a utility power distribution system and has a nameplate capacity of 25 MW-net or greater; and,
      ii. has a design heat input capacity greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel alone or of fossil fuel in combination with any other fuel.

B. Excluded EGUs.

The following are not affected EGUs for any purpose under this Chapter:

1. Any steam generating EGU or IGCC EGU that is currently 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 to 219,000 MWh or less;
2. Any EGU that is capable of combusting 50 percent or more non-fossil fuel, and that has always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or that is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;
3. Any stationary combustion turbine EGU not capable of combusting natural gas. For purposes of this Chapter, an EGU that is not connected to a natural gas pipeline is not capable of combusting natural gas;
4. Any CHP EGU that has always historically limited, or is subject to a federally enforceable permit currently limiting and always historically limiting, annual net-electric sales to a utility distribution system to the design efficiency times the potential electric output or 219,000 MWh (whichever is greater), or less;
5. Any EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;
6. Any EGU that is a municipal waste combustor unit that is subject to 40 CFR part 60 subpart Eb; and,
7. Any EGU that is a commercial or industrial solid waste incineration unit that is subject to 40 CFR part 60 subpart CCCC.

C. Exemption for Permanently Retired Affected EGUs.

1. For an affected EGU that has a permanent retirement date on or before December 31, 2017, the owners and operators shall comply with the requirements of Section 1009 of this Chapter to establish a designated representative. The designated representative of any such affected EGU shall submit a certified statement, no later than March 31, 2018, to the Administrative Authority with notification of the specific date of permanent retirement, which must include a statement that the affected EGU has not emitted and will not emit CO_2 on any date after the date of retirement. The owners and operators of the affected EGU shall retain records as required under Paragraph C.4 of this Section. No other requirements under this Chapter shall apply to any such affected EGU, and the EGU shall not receive any allocations of allowances for any compliance period under Section 1007 of this Chapter.
2. For an affected EGU that has a permanent retirement date on or after January 1, 2018, no later than 90 days after the permanent retirement of the affected EGU the designated representative shall submit a certified statement to the Administrative Authority with notification that the affected EGU was or will be permanently retired on a specified date, which must include a statement that the affected EGU has not emitted and will not emit CO_2 on any date after the date of permanent retirement. Any such affected EGU shall receive allocations under Section 1007 for the first compliance period after the date of permanent retirement.
3. Any affected EGU that is permanently retired is exempt from the CO_2 emission standards of Section 1005 effective on the first day of the compliance period immediately following the compliance period in which the affected EGU was permanently retired.
4. The owners and operators of an affected EGU exempt under this Paragraph C must retain, at the facility where the affected EGU is or was located, records demonstrating that the affected EGU is permanently retired. The owners and operators bear the burden of proof that the affected EGU is permanently retired and has not emitted CO_2 since the date of the retirement.
5. An affected EGU exempt under this Paragraph C is no longer subject to the Monitoring, Recordkeeping and Reporting requirements of this Chapter with respect to the compliance period for which the exemption takes effect and for future compliance periods.
6. An exemption under this Paragraph does not alleviate or obviate any past or ongoing compliance obligation under this Chapter of the owners or operators or designated representative of the affected EGU with respect to any compliance period prior to the effective date of the exemption, including any requirements of the Allowance Tracking and Compliance System (ATCS) or the CO_2 Trading Program.

Section 1005. Emission Standards and Permit Requirements for Affected EGUs

A. Allowance Holding and Surrender Emission Standard.

1. As of the allowance transfer deadline for each compliance period specified in Paragraph B of this Section, the owners and operators of each affected EGU shall hold allowances in the compliance account for the affected EGU, in an amount not less than the total tons of CO_2 emissions from the affected EGU during the compliance period.
2. In cases where an ATCS compliance account has been established for multiple affected EGUs located at the same facility and under common control of the same owners or operators, the owners or operators shall hold allowances, as of the allowance transfer deadline for the compliance period, in an amount not less than the total tons of CO_2 emissions during the compliance period from all affected EGUs named under the facility compliance account, and shall hold such allowances in each subaccount under the facility compliance account in an amount not less than the total tons of CO_2 emissions during the compliance period from each affected EGU named under each subaccount.
3. Allowances from the compliance account for the affected EGU (or for multiple affected EGUs, where applicable) in an amount equal to the total tons of CO_2 emissions from the affected EGU(s) during the compliance period shall be surrendered for compliance upon transfer by the Administrative Authority. The designated representative of

each affected EGU shall submit a request for transfer of allowances to the retirement account for the affected EGU to meet the emission standards of this Section in accordance with Section 1011 of this Chapter.

4. The emissions data determined in accordance with Section 1025 of this Chapter must be used to determine compliance with the CO_2 emission standard under this Section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used to determine compliance must be rounded to the nearest ton.
5. A CO_2 allowance held for compliance with the emission standard of this Section for a particular compliance period must be a CO_2 allowance that was allocated for that compliance period or for a prior compliance period.

B. Compliance Periods and Allowance Transfer Deadlines.

1. Compliance Periods. The allowance holding and surrender emission standard specified in Paragraph A of this Section shall apply to the owners and operators of each affected EGU for the following compliance periods:
   Interim 1: The 3-year period from January 1, 2022 through December 31, 2024;
   Interim 2: The 3-year period from January 1, 2025 through December 31, 2027;
   Interim 3: The 2-year period from January 1, 2028 through December 31, 2029;
   Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even-numbered year and ending December 31 of the next odd-numbered year.
2. Allowance Transfer Deadlines. The allowance transfer deadline for each compliance period shall be May 1 of the calendar year following the end of the compliance period, as follows:
   Interim 1: May 1, 2025
   Interim 2: May 1, 2028
   Interim 3: May 1, 2030
   Final: May 1, 2032 and May 1 of each even-numbered year thereafter.

C. Allowance Budgets.

The allowance budgets as specified in Table 2 of this Chapter shall apply for each compliance period.

1. The allowance budget for a given compliance period shall constitute the full complement of new allowances available for issuance by the Administrative Authority, including the State's portion of allowances and all allowances allocated to existing and new affected EGUs and to other entities, in accordance with Section 1007 of this Chapter. Allowances from the budget of a future compliance period may not be borrowed or distributed for any reason.
2. Allowance budgets do not include any allowances held in general accounts or compliance accounts at the end of a previous compliance period that are in excess of those allowances required to be surrendered for that compliance period. Any excess allowances available during a given compliance period are in addition to the allowance budgets set forth below. Excess allowances may be held in or transferred to or from ATCS accounts and may be used for demonstrating compliance for the current or future compliance periods.

Table 2 **CO_2 Allowance Budgets (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons, 3-yr period)	Interim 2 2025–2027 (total tons, 3-yr period)	Interim 3 2028–2029 (total tons, 2-yr period)	Final 2030–2031 and After (tons per 2-yr period)
108,604,371	100,568,769	63,583,444	61,371,058

D. Allowance Denomination, Constitution of Authorization and Provision for Interstate Trading.

1. Each allowance shall be denominated as a single ton, and shall constitute a limited authorization to emit one ton of CO_2 for an affected EGU under this Chapter, or for an affected source in another State or jurisdiction subject to an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart MMM, where the mass-based plan provides for interstate trading of allowances and utilizes an allowance tracking system designated as authorized for trading under this Chapter by the Administrative Authority.
2. A CO_2 allowance does not constitute or confer a property right.
3. Allowances issued by the Administrative Authority under this Chapter may be transferred among affected EGUs or to other entities through the ATCS in accordance with Section 1011 of this Chapter.
4. Allowances issued by an administrative authority in another State or jurisdiction, or by their designee, under an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart MMM may be utilized for compliance by an affected EGU under this Chapter, provided the mass-based plan in the other State or jurisdiction provides for interstate trading of allowances and utilizes either the same ATCS designated for compliance purposes in accordance with Section 1011 of this Chapter, or an interconnected tracking system designated as authorized for trading by the Administrative Authority. Only valid allowances held in the compliance account of the affected EGU at the end of a compliance period and meeting all requirements of this Chapter may be utilized for demonstrating compliance.

E. Air Permit Requirements.

1. Existing Affected EGUs. Except as specified in Paragraph E.5 of this Section, the emission standards, monitoring, recordkeeping and reporting requirements of this Chapter applicable to an existing affected EGU are applicable requirements that must be included in the Major Source Operating Permit for the affected EGU. All permit terms and conditions incorporating the requirements of this Chapter for an existing affected EGU shall be federally enforceable terms and conditions enforceable by both the Administrative Authority and the EPA Administrator, as well as third parties in accordance with the federal Clean Air Act.
2. New Affected EGUs. Except as otherwise specified in Paragraph E.5 of this Section, the emission standards, monitoring, recordkeeping and reporting requirements of this Chapter applicable to a new affected EGU are state-only applicable requirements that must be included in the Major Source Operating Permit for the affected EGU. All permit terms and conditions incorporating the requirements of this Chapter for a new affected EGU shall be state-only terms and conditions enforceable by the Administrative Authority.
3. The applicable requirements of this Chapter, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a Major Source Operating Permit using minor permit revision procedures in accordance with Chapter 5, Major Source Operating Permits, provided such changes do not require modification to any existing terms or the addition of any new terms to the permit, where the modification or addition of such terms would in and of themselves be considered a significant permit revision.
4. For any permit with 3 or more years remaining on the term of the permit as of the effective date of this Chapter, a permit revision to incorporate the applicable requirements of this Chapter shall be made within 18 months of the effective date of this Chapter. For any permit with less than 3 years remaining on the term of the permit as of the effective date of this Chapter, the permit revision to incorporate the applicable requirements of this Chapter shall be made no later than the time of the next permit renewal.
5. No permit revision will be required for the establishment, revision, or closing of any account, or for any allocation, recording, deduction, or transfer of allowances in accordance with this Chapter or through the ATCS.

F. Reliability Safety Valve.

1. Notwithstanding any other provision of this Section 1005, the Administrative Authority may grant a temporary modification of the emission standard applicable under Paragraph A of this Section to an affected EGU in response to a power system emergency or catastrophic event. All conditions of this Paragraph F of this Section must be met for the Administrative Authority to grant a temporary modification of the emission standard to an affected EGU.

2. Nature of the Emergency and Impact to Affected EGUs. To qualify for the temporary modification of an emission standard, the event and impact to an affected EGU must meet the following criteria:
   a. The event is an unforeseeable circumstance brought about by an extraordinary, unanticipated and potentially catastrophic event that did or could compromise the reliability of the supply of electricity to consumers on the grid.
   b. The EGU for which the modified emission standard applies is or will be compelled to operate at levels that would result in a violation of the applicable emission standard under Paragraph A this Section, for the purpose of providing electricity to the grid without which the affected grid would face failure, or consumers would be without power or would face constraints on the use of power.
3. Notifications and Approval Procedural Requirements. An affected EGU requesting or operating under a modified emission standard must comply with the following procedural requirements:
   a. An initial notification shall be provided by the designated representative to the Administrative Authority within 24 hours of the initiation of the emergency occurrence.
      i. Verbal notification within 24 hours in accordance with the State emergency notification procedures is acceptable; however, initial verbal notification must be followed by written notification no later than 36 hours from the initiation of the emergency occurrence.
      ii. The initial notification must include the following information:
         a) identify that a temporary emission standard modification is being requested under this Chapter;
         b) include a description of the emergency situation;
         c) identify the affected EGU for which the request is being made;
         d) explain why the affected EGU is or will be compelled to operate to provide power in response to the emergency at levels that would result in a violation of the applicable emission standard under Paragraph A of this Section; and,
         e) provide an initial estimate of the projected excess emissions that would occur, which shall not exceed a 90-day time period, and for which the owners and operators of the affected EGU, foreseeably, could not reasonably obtain allowances to meet the applicable emission standard of Paragraph A of this Section 1005.
      iii. If the Administrative Authority determines, upon review of the initial notification, that a temporary modification to the emission standard is warranted, then the Administrative Authority will provide an initial notification to the EPA Regional Administrator within 48 hours of the emergency occurrence, including the initial notification received from the designated representative and identifying the affected EGU and the level and duration of emissions that are authorized to occur in response to the emergency.
   b. A second notification shall be submitted by the designated representative to the Administrative Authority within 5 days of the initial 24-hour notification provided under Paragraph F.3.a.i of this Section.
      i. The second notification must be in writing and must provide:
         a) an update regarding the description and status of the emergency situation;
         b) a description of the status of operation of the affected EGU in response to the emergency;
         c) an estimate of the total excess CO_2 emissions that have occurred and that continue to occur;
         d) an explanation of why, foreseeably, allowances could not reasonably be obtained in sufficient amounts to meet the applicable emission standard under Paragraph A of this Section by the allowance transfer deadline for the compliance period;
         e) any appropriate adjustments to the level and duration of excess emissions initially authorized under the modified emissions standard; and,
         f) a written statement from the appropriate energy grid reliability authority describing the reliability concern that resulted from the emergency, and providing concurrence that the affected EGU was, and if applicable, will continue to be, a critical EGU compelled to provide power during the emergency.
      ii. Upon review of the second notification, the Administrative Authority will provide a second notification to the EPA Regional Administrator within 7 days of the initial notification to the EPA Regional Administrator, including the second notification received from the designated representative, either confirming that a temporary emission standard modification is warranted with a determination of the level of emissions

authorized and the duration of the effectiveness of the modified emission standard, not to exceed 90 days, or rescinding the modified emission standard granted under the initial notification. The notification will also include a description of how the Administrative Authority and grid reliability coordinators are coordinating to alleviate the emergency condition in an expedited manner, and a report of any analysis of the reliability concern that has been conducted by the planning authority.

c. A third notification shall be submitted by the designated representative to the Administrative Authority within 75 days of the start of the emergency occurrence, documenting that either:
   i. the reliability emergency has been resolved and the affected EGU has resumed operation under the applicable emission standard of Paragraph A of this Section or will do so by the end of the approved duration of the modified emission standard; or,
   ii. there is still a serious, ongoing reliability issue that necessitates the affected EGU to emit at levels that will exceed the applicable emission standard under Paragraph A. Such notice does not authorize an extension of the modified emission standard.

d. The Administrative Authority will submit a notification to the EPA Regional Administrator no later than 83 days after the initial occurrence of the emergency situation, as required under 40 CFR § 60.5870(g)(3).

4. Temporary Emission Standard. Notification to EPA by the Administrative Authority within 48 hours of the occurrence of the emergency, in accordance with this Paragraph, shall constitute the approval of a temporary modification of the emission standard for the affected EGU, provided that the second notification is submitted in a timely and complete manner by the designated representative to the Administrative Authority and subsequently by the Administrative Authority to EPA. The temporary modified emission standard shall not relieve the owners or operators of the affected EGU from the obligation to comply with the emission standard of Paragraph A of this Section 1005 with regard to any emissions not specifically authorized as additional emissions under the temporary modified emission standard. The temporary modified emission standard shall comprise two components:
   a. Authorization to emit a specified number of tons of CO_2 over a specified number of days, not to exceed 90 days, for which allowances are not required to be surrendered in accordance with Paragraph A of this Section; and,
   b. The requirement to surrender allowances in an amount equal to any emissions of CO_2 during every other day of the compliance period and any emissions of CO_2 during each day of the modified emission standard that are in excess of those authorized to be emitted without surrendering allowances, in accordance with Paragraph A of this Section. Any emissions from the affected EGU that foreseeably would have occurred during the time period of the authorized temporary standard, had the emergency not occurred, must be subject to the emission standard of Paragraph A of this Section.

Section 1007. Distribution of Allowances by Auction, Sale and Allocation

A. Qualifying Entities to Receive Allowances.

1. After subtracting the State share of allowances from the budget in accordance with Paragraph C of this Section, the Administrative Authority shall allocate and distribute the remaining allowances from the allowance budget for each compliance period in accordance with the provisions of this Section. Providing or not providing an allocation to an entity does not constitute a determination of applicability or non-applicability under this Chapter by the Administrative Authority.
2. The following entities may qualify for allocation of allowances to be distributed by the Administrative Authority.
   a. Existing affected EGUs;
   b. New affected EGUs;
   c. Qualified EGUs registered in accordance with Section 1017 of this Chapter;
   d. Qualified Energy Efficiency Resources (EERs) registered in accordance with Section 1015 of this Chapter.

B. Timing and Process for Determining Allocations.

1. No later than December 1 of the year prior to the first year of each multiyear compliance period, the Administrative Authority will allocate allowances to qualifying entities for the compliance period and provide public notice and notice to qualifying entities of such allocations.
   a. The total number of allowances allocated to all qualifying entities shall be the budget for the compliance period specified in Table 2 of this Chapter, minus the State portion as specified in Paragraph C of this Section.
   b. The Administrative Authority or the ATCS Administrator shall record the total allowances allocated to each entity in the ATCS general account, for each entity that is not an affected EGU, or in the compliance account, for each entity that is an affected EGU, no later than August 1 of the first year of each compliance period.
2. In determining the allocation of allowances under this Paragraph, the Administrative Authority shall start with the total budget for the compliance period, and first adjust the total budget by subtracting the total number of allowances to be auctioned or sold by the Administrative Authority, as specified in Paragraph C of this Section. The total number of allowances constituting the State's portion shall be no less than fifteen percent (15%) and no more than fifty percent (50%) of the budget for any compliance period.
3. After subtracting the total number of allowances that constitutes the State's portion from the allowance budget, the Administrative Authority shall next determine the total number of allowances to be allocated to qualified EERs, in accordance with Paragraph D of this Section. The total number of allowances allocated to qualified EERs shall not exceed fifteen percent (15%) of the budget remaining after deduction of the State's portion, except that the enhanced portion of any allowance allocation for energy savings occurring in a vulnerable community in accordance with Paragraph D.3 of this Section shall not be counted toward the 15% cap.
4. After subtracting the State's portion of allowances and allocating allowances to qualified EERs, the Administrative Authority shall then determine the total number of allowances to be allocated to new affected EGUs, in accordance with Paragraph E of this Section. The total number of allowances allocated to new affected EGUs shall not exceed the new source budget for any compliance period as specified in Table 3 of this Chapter.
5. After subtracting the State's portion of allowances and allocating allowances to qualified EERs and new affected EGUs, the remainder of the budget for the compliance period shall be allocated to existing affected EGUs and other qualified EGUs in accordance with Paragraph F of this Section.
6. Qualifying entities shall be allocated allowances for each compliance period based on the amount of energy generated or saved, in MWh-net, during the three- or two-year period ending the calendar year two years before the beginning of each compliance period. The term "allocation basis period" as used in this Section, shall mean the periods of energy generation or savings on which allocations for each compliance period are based, as provided below.
   a. For Interim 1 (January 1, 2022 through December 31, 2024), allocations shall be based on energy generation or savings occurring January 1, 2018 through December 31, 2020;
   b. For Interim 2 (January 1, 2025 through December 31, 2027), allocations shall be based on energy generation or savings occurring January 1, 2021 through December 31, 2023;
   c. For Interim 3 (January 1, 2028 through December 31, 2029), allocations shall be based on energy generation or savings occurring January 1, 2024 through December 31, 2026;
   d. For each Final compliance period, allocations shall be based on the two-year period that ends on December 31st of the even-numbered year two years before the first year of the compliance period. For example, for the first Final compliance period (January 1, 2030 through December 31, 2031), allocations shall be based on energy generation or savings occurring January 1, 2027 through December 31, 2028.

C. State's Portion of Allowances for Auction or Sale.

1. A portion of allowances for auction or sale by the State, which shall be no less than fifteen percent (15%) and no more than fifty percent (50%) of the allowance budget for each compliance period, shall be established by the State Legislature in adopting the fiscal year budget. Revenues from the auction or sale of allowances shall be used to fund the implementation of the State CO_2 Trading Program for EGUs, including all aspects of the program including but not limited to administration of the ATCS and enforcement of emission standards. Any revenues generated in

excess of program costs may be appropriated to the General Fund or to one or more special or dedicated funds.

2. Deduction of the State's portion as established for a particular fiscal year budget will be made on a schedule to coincide with the compliance periods of this Chapter, as follows:
   a. The State's portion of allowances as adopted with the budget for State Fiscal Year 2021–2022 will remain in effect for three consecutive Fiscal Years and will be deducted from the budget for the Interim 1 compliance period, the 3-year period from January 1, 2022 through December 31, 2024;
   b. The State's portion of allowances as adopted with the budget for State Fiscal Year 2024–2025 will remain in effect for three consecutive Fiscal Years and will be deducted from the budget for the Interim 2 compliance period, the 3-year period from January 1, 2025 through December 31, 2027;
   c. The State's portion of allowances as adopted with the budget for State Fiscal Year 2027–2028 will remain in effect for two consecutive Fiscal Years and will be deducted from the budget for the Interim 3 compliance period, the 2-year period from January 1, 2028 through December 31, 2029;
   d. The State's portion of allowances as adopted with the budget for the State Fiscal Year 2029–2030 or thereafter will remain in effect in perpetuity, unless and until a different time period or portion is established by the State Legislature, and will be deducted from the budget for each 2-year Final compliance period.
3. For each compliance period, the Administrative Authority shall deduct allowances from the allowance budget for auction or sale in accordance with the state budget as adopted by the State Legislature. Auctions and sales of the State's portion of allowances shall be conducted in accordance with Section 1029 of this Chapter.

D. Allocations to Qualified Energy Efficiency Resources (EERs).

1. Energy savings used to determine the allocation of allowances must be quantified and verified in accordance with the applicable evaluation, measurement and verification (EM&V) plan and annual monitoring and verification (M&V) report under Section 1021 of this Chapter and must be certified by the National Energy Efficiency Registry or other entity approved by the Administrative Authority. To qualify for allocations for a compliance period, the certification of verified energy saving must be submitted to the Administrative Authority on or before August 15th of the year in which the allocations for the compliance period are made.
2. Allocations for qualified EERs shall be calculated by multiplying the total MWh of verified and certified energy savings times an emission factor, which shall be the average emission rate (tons/MWh-net) of new and existing EGUs and other qualified EGUs during the previous compliance period.
   a. The formula for determining the emission factor to be used in calculating allowance allocations for qualified EERs is as follows:

$$\mathbf{EF} = \frac{\mathbf{CO2_{Affected\ EGUs}}}{\mathbf{MWh_{Affected\ EGUs}} + \mathbf{MWh_{Qualified\ EGUs}}}$$

   b. The formula for calculating allowances to be allocated to a qualified EER for energy savings that are from projects not implemented in a vulnerable community, as defined in Section 1031 of this Chapter, is as follows:

$$\mathbf{A_{EER}} = \mathbf{MWh_{Certified}} * \mathbf{EF}$$

Where:

EF is the emission factor used to calculate allocations for each qualified energy efficiency resource;

$\mathbf{CO2_{Affected\ EGUs}}$ is the total amount of CO_2 reported for the allocation basis period for all affected EGUs, collectively, in whole tons;

$\mathbf{MWh_{Affected\ EGUs}}$ is the total amount of MWh-net, as defined under this Chapter, reported by affected EGUs for the allocation basis period;

$\mathbf{MWh_{Qualified\ EGUs}}$ is the total amount of MWh-net eligible for allocations of allowances, as reported by all registered qualified EGUs under this Chapter, for the allocation basis period;

$\mathbf{A_{EER}}$ is the calculated number of allowances to be issued to the qualified EER, without including any fraction of a ton that results from the calculation; and,

$\mathbf{MWh_{Certified}}$ is the total amount of verified and certified energy savings provided by the qualified EER during the allocation basis period, as documented in accordance with Section 1021 of this Chapter.

c. Allocations of allowances shall be made at an enhanced rate to any qualified EER providing energy savings in a vulnerable community, as defined in Section 1031 of this Chapter. For such energy savings, the allocation rate shall be 1.5 times the number of allowances that would otherwise be awarded for the same amount of verified energy savings, had it occurred in any location that is not a vulnerable community. The enhanced portion of any allowance allocation for energy savings in a vulnerable community (that is, one-third of the total allocation) shall not be counted toward the 15% cap on allocations to qualified EERS, as specified in Paragraph B.3 and Paragraph D.3 of this Section. The formula for calculating allowances to be allocated to a qualified EER for energy savings from projects implemented in a vulnerable community, as defined in Section 1031 of this Chapter, is as follows:

$$\mathbf{A_{EER} = MWh_{Certified} \star EF \star 1.5}$$

Where all terms have the same meaning as provided in Paragraph D.2.b of this Section.

3. The total amount of allowances allocated to qualified EERs shall not exceed fifteen percent (15%) of the budget remaining after the State's portion is deducted for any compliance period, except that the enhanced portion of any allowances allocated for energy savings occurring in a vulnerable community shall not be counted toward the 15% cap. In the event the sum of the total calculated allowances for all qualified EERs, as determined in accordance with Paragraphs D.2 of this Section, is greater than 15% of the budget remaining after the State's portion is deducted, the Administrative Authority shall reduce the calculated allocation of allowances for each qualified EER in equal proportion, by multiplying the calculated allocation times the ratio of 15% of the budget remaining after the State's portion is deducted to the sum of the calculated allowances for all qualified EERs.

E. Allocations to New Affected EGUs.

1. The determination of the allocation of allowances to a new affected EGU shall be dependent on the initial startup date of the new affected EGU in relation to the compliance period for which allocations are being determined. For purposes of this Paragraph, the initial startup date is the first day on which the affected EGU delivers power to the grid.
2. For any new affected EGU with an initial startup date on or before January 1, 2018, the new affected EGU shall be treated as an existing affected EGU for purposes of allocating allowances, and the calculated allowances for all compliance periods shall be determined the same as for existing affected EGUs and qualified EGUs in accordance with Paragraph F of this Section, except that allocations of allowances to the new affected EGU shall be adjusted if required in accordance with Paragraphs E.5 and E.6 of this Section.
3. For any new affected EGU with an initial startup date after January 1, 2018 but before January 1, 2021, allocations for the Interim 1 period shall be calculated as follows, and for all subsequent periods shall be calculated pursuant to Paragraph F of this Section.

$$\mathbf{A_{Calc}} = \left(\frac{\mathbf{MWh_{EGU}}}{\mathbf{MWh_{Affected\ EGUs} + MWh_{Qualifying\ EGUs}}}\right)\left(\frac{\mathbf{1096}}{\mathbf{Days_{SU}}}\right) \star \mathbf{Budget_{R1}}$$

Where:

$\mathbf{A_{Calc}}$ is the calculated number of allowances to be issued to the new affected EGU, in whole tons;

$\mathbf{MWh_{EGU}}$ is the net energy output of the affected EGU for the period January 1, 2018 to December 31, 2020, in MWh;

$\mathbf{MWh_{Affected\ EGUs}}$ is the total amount of MWh-net, as defined under this Chapter, reported by all affected EGUs for the period January 1, 2018 to December 31, 2020;

$\mathbf{MWh_{Qualified\ EGUs}}$ is the total amount of MWh-net, as defined under this Chapter, reported by all registered qualified EGUs under this Chapter, for the period January 1, 2018 to December 31, 2020;

1096 is the total number of days in the period January 1, 2018 through December 31, 2020;

$Days_{SU}$ is the total number of days from initial startup of the new affected EGU through December 31, 2020; and,
$Budget_{R1}$ is the budget for the Interim 1 period as specified in Table 2 of this Chapter, minus the State's portion under Paragraph C and minus allocations to qualified EERs under Paragraph D of this Section.

4. For any new affected EGU with an initial startup date on or after January 1, 2021, allowance allocations shall be calculated as follows.
   a. The owner or operator shall notify the Administrative Authority of the planned startup date for the unit no later than March 1 of the year prior to the beginning of the first compliance period during which the new affected EGU will first operate. Failure to timely notify the Administrative Authority shall result in the forfeiture of allowance allocations for the first compliance period of operation.
   b. For the first compliance period during which a new affected EGU is scheduled to operate, the number of calculated allowances to be allocated to the new affected EGU shall be determined using the following equation:

$$A_{CALC} = 0.55C * H * 0.50$$

Where:
A_{CALC} is the calculated number of allowances to be issued to the new affected EGU, in whole tons;
C is the nameplate capacity of the new affected EGU, in MW;
H is the total number of hours in the compliance period after the scheduled startup date of the new affected EGU, in units of hours; and,
0.50 is the performance standard for new NGCC EGUs subject to 40 CFR part 60 subpart TTTT, in units of tons/MWh.

   c. For the second compliance period during which the new affected EGU is in operation, the number of allowances to be allocated shall be determined in the same manner as for existing affected EGUs in accordance with Paragraph F of this Section, except that the allocation shall be adjusted as necessary to subtract the number of any excess allowances allocated for the previous compliance period based on a difference between the dates of actual startup and planned startup. In addition, allocations of allowances to the new affected EGU shall be adjusted if required in accordance with Paragraph E.5 and E.6 of this Section. If startup of a new affected EGU occurred later than the startup date relied upon for issuance of allowances in the first compliance period of operation, then the number of unadjusted allowances calculated in Paragraph E.4.b of this Section shall be adjusted by subtracting any allowances issued for days in the allocation basis period prior to the actual startup date of the new affected EGU. The adjustment shall be calculated as follows:

$$A_{ADJ} = 0.55C * 24 * Days_{ADJ} * 0.50$$

Where:
A_{ADJ} is the calculated allowance adjustment, that is, the number of allowances to be subtracted from the number of allowances calculated in accordance with Paragraph F of this Section, in whole tons;
C is the nameplate capacity of the new affected EGU, in MW;
24 is the number of hours in a day, in hours;
$Days_{ADJ}$ is the number of days from the date of planned startup relied upon to issue allowances for the first compliance period of operation to the date of actual startup for the affected EGU; and,
0.50 is the performance standard for new NGCC EGUs subject to 40 CFR part 60 subpart TTTT, in units of tons/MWh.

   d. For all subsequent compliance periods after the second compliance period of operation for a new affected EGU, the new affected EGU shall be treated as an existing affected EGU for the purpose of calculating allowances, and the total number of allowances to be allocated to the new affected EGU shall be calculated in the same manner as for existing affected EGUs, in accordance with Paragraph F of this Section, except that calculated allocations to the new affected EGU shall be adjusted if required in accordance with Paragraph E.5 and E.6 of this Section.

5. Total allowance allocations for new affected EGUs, as defined in Section 1003.A.2, shall not exceed the new source budget specified in Table 3 for any compliance period.
6. In determining initial allocations of allowances for new affected EGUs, the Administrative Authority shall first

Table 3 **CO_2 Allowance Not-to-Exceed Budgets for New Affected EGUs (Short Tons of CO_2)**

Interim 1 2022–2024 (total tons, 3-yr period)	Interim 2 2025–2027 (total tons, 3-yr period)	Interim 3 2028–2029 (total tons, 2-yr period)	Final 2030–2031 and After (tons per 2-yr period)
506,358	1,708,206	1,075,956	725,794

calculate allocations for new affected EGUs in accordance with Paragraphs E.2 through E.4 of this Section, and for existing affected EGUs and qualified EGUs in accordance with Paragraph F of this Section. The total calculated allocations for all new affected EGUs shall then be summed and compared to the new source budget for the compliance period.

a. In the event the sum of the total calculated allowances for all new affected EGUs as determined in accordance with Paragraphs E.2 through E.4 of this Section is greater than the new source budget for the compliance period, then the calculated allowance allocation for each new affected source shall be reduced in equal proportion by the ratio of the new source budget to the sum of the calculated allowances. Such adjustments to the calculated allocations for new affected EGUs shall be determined as shown in the following equation:

$$A_{ADJ} = \left(\frac{Budget_{NS}}{\Sigma A_{Calc}}\right) * A_{Calc}$$

Where:

A_{ADJ} is the calculated adjusted number of allowances to be issued to the new affected EGU, in whole tons;

$Budget_{NS}$ is the budget for new affected sources for the compliance period as specified in Table 3 of this Chapter;

A_{Calc} is the number of calculated allowances for the EGU as determined in accordance with Paragraphs E.2 through E.4, in whole tons; and,

ΣA_{Calc} is the sum of the calculated allowances for all new affected EGUs for the compliance period, as determined in accordance with Paragraphs E.2 through E.4 of this Section.

b. All allocations taken to make the adjustments in this Paragraph E.6, including adjustments from any new affected EGUs that were treated as existing affected EGUs and for which the initial allocation was determined under Paragraph F of this Section, shall be applied to increase calculated allocations to the existing affected EGUs only, in equal proportion to the generation of those existing affected EGUs for the previous compliance period.

F. Allocations to Existing Affected EGUs and Qualified EGUs.

1. For each existing affected EGU, each new affected EGU to be treated as an existing affected EGU for purposes of allocating allowances in accordance with Paragraph E of this Section, and each registered qualified EGU, the number of allowances to be issued by the Administrative Authority shall be determined based on the unit's eligible generation relative to total statewide generation during the allocation basis period.
2. Any existing affected EGU that becomes a new affected EGU as a result of reconstruction shall continue to be treated as an existing affected EGU for the purpose of calculating allowances, and shall not be treated as consuming allowances under the new source budget.
3. For each qualified EGU that utilizes qualified biomass feedstock, including each qualified EGU that is a waste-to-energy (WTE) facility, allocations shall only be provided for generated electricity derived from the qualified biomass feedstock or biogenic portion of the waste feedstock, as applicable. For each qualified CHP EGU that utilizes fossil fuel to produce electricity or useful thermal or mechanical output, the EGU's net electrical output must be adjusted

in accordance with Section 1019 to determine the portion of the generation that is eligible for allocation of allowances. For purposes of determining allocations under this Section, for such qualified EGUs, the terms "MWh," "MWhQualified EGUs" or "net energy output" refer only to the portion of energy generated by the qualified EGU that is eligible to receive allocations of allowances, as reported in accordance with this Chapter.

4. Allocation of allowances shall be determined using the following equation:

$$A_{Calc} = \left(\frac{MWh_{EGU}}{MWh_{Affected\ EGUs} + MWh_{Qualified\ EGUs}} \right) * Budget_{R2}$$

Where:

A_{Calc} is the calculated number of allowances to be issued to the EGU, in whole tons;

MWh_{EGU} is the net energy output of the EGU for the allocation basis period, in MWh (using only the portion of output eligible for allocations for each qualified EGU);

$MWh_{Affected\ EGUs}$ is the total amount of MWh-net, as defined under this Chapter, reported by affected EGUs for the allocation basis period;

$MWh_{Qualified\ EGUs}$ is the total amount of MWh-net eligible for allocations, reported by all registered qualified EGUs under this Chapter, for the allocation basis period;

$Budget_{R2}$ is the budget for the compliance period for which allocations are being calculated, as specified in Table 2 of this Chapter, minus the State's portion, minus allocations to qualified EERs, and minus allocations to new affected EGUs, as determined in Paragraphs C, D and E of this Section.

5. After making the initial determinations of allowances for all qualified entities, allocations shall be adjusted if required to reduce allocations to new affected EGUs in accordance with Paragraph E.6, and the resulting increases in available allowances shall be allocated among existing affected EGUs only, in direct proportion to each affected EGU's generation for the allocation basis period.

G. Correction of Errors in Allocations.

1. The Administrative Authority may take appropriate action to correct any administrative or inadvertent error discovered in the allocation of allowances under this Section. Such appropriate action may include, but is not limited to, the following:
   a. If the error is discovered after notification of allowance allocations has been made but prior to recording allowances in the ATCS account of the receiving entities, the Administrative Authority shall correct the error, record allowances based on the corrected allocation, and provide notice to all entities affected by the correction.
   b. If the error is discovered after allowances have been recorded in the ATCS account of the receiving entities and before the end of the compliance period, the Administrative Authority may freeze the affected ATCS accounts and make the required transfers among accounts to correct the error, after providing sufficient notice to all affected entities and provided sufficient allowances are available in an account from which a deduction would be required. The intent of the transfers is to correct the error by redistribution of allowances in the manner consistent with the allocation provisions of this Paragraph.
   c. If the error is discovered after allowances have been recorded in the ATCS account of the receiving entities and before the end of the compliance period, and an account from which a deduction would be required to correct the error has insufficient allowances to cover the deduction, then the Administrative Authority may freeze the ATCS account, deduct available allowances and provide notice to the affected entity that the remaining allowances needed to correct the error must be provided within a reasonable time period to be determined by the Administrative Authority.
   d. If an error in allocations is discovered after the end of the compliance period for which the allocations were made, the Administrative Authority may exercise discretion to determine whether a correction is necessary and appropriate. In making the determination, the Administrative Authority will consider the cause, nature and gravity of the error and its effect on the entities involved. If the Administrative Authority determines a correction is appropriate, the correction may be made by adjusting allocations in the next compliance period

in the amounts necessary to account for the error.

2. In the event of any error in allocations resulting from error, misinformation or reporting inaccuracies in information received from an affected EGU, qualified EGU or qualified EER, the Administrative Authority may take the following actions:
   a. Freeze the affected ATCS account(s)and revoke or transfer allowances to address the error;
   b. Temporarily suspend the issuance of allocations to the affected EGU, qualified EGU or qualified EER pending investigation and correction of the errors;
   c. Permanently suspend issuance of allocations to the affected EGU, qualified EGU or qualified EER, and/or revoke the qualified status of the EGU or EER, in cases of egregious or repeated error, misstatement or misrepresentation;
   d. In the case of an affected EGU, initiate enforcement action as provided under Section 1027 of this Chapter.
3. Any allowances recovered as a result of action by the Administrative Authority may be retired or distributed by auction, sale or allocation, at the discretion of the Administrative Authority.

Section 1009. Requirements for Designated Representatives of Affected EGUs

A. Submittals to be Made by Designated Representative or Alternate Designated Representative.

1. Except as provided under this Paragraph concerning delegation of authority to make submittals, each submittal with respect to an affected EGU under this Chapter shall be made, signed, and certified by the designated representative or alternate designated representative for each facility and affected EGU for which the submittal is made. Each such submittal must include the following certification statement by the designated representative or alternate designated representative:

   "I am authorized to make this submittal on behalf of the owners and operators of the facility or affected EGUs for which the submittal 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."
2. The Administrative Authority will act on a submittal made for a facility or an affected EGU only if the submittal has been made, signed, and certified in accordance with this Paragraph. Submittals made by any other party, or not in accordance with this Paragraph, shall not be recognized to meet the compliance obligations of the owners or operators of an affected EGU under this Chapter.
3. A designated representative or alternate designated authority may delegate, to one or more natural persons, his or her authority to make an electronic submittal to the Administrative Authority to the ATCS, or another designated electronic system with an internet-based user interface specifically provided for or required under this Chapter. Delegation of authority may not extend to submittals made to or from personal, corporate or government email accounts.
   a. Any such delegation of authority to make an electronic submittal shall be made in accordance with the applicable procedures for making and certifying electronic submittals under the particular system to which the submittal is made.
   b. Any electronic submittal made by a delegated authority in accordance with this Paragraph shall be deemed to be an electronic submittal by the designated representative or alternate designated representative for the affected EGUs at the facility.

B. Establishing the Designated Representative and Alternate Designated Representative.

1. No later than June 1, 2017, the owners and operators of each affected EGU shall submit a certificate of representation as provided under Paragraph C of this Section, naming one and only one designated representative with regard to all matters under this Chapter, for each facility at which one or more affected EGUs are located.
2. The owners and operators of each affected EGU may select one and only one alternate designated representative for each facility at which one or more affected EGU is located. If an alternate designated representative is selected, the owners and operators, or the designated representative of the facility, shall submit a certificate of representation as provided under Paragraph C of this Section, naming the alternate designated representative.
3. The designated representative or alternate designated representative may be changed at any time upon receipt by the Administrative Authority of a superseding complete certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submittals by all previous designated representatives or previous alternate designated representatives before the time and date when the Administrative Authority receives the superseding certificate of representation shall continue to be binding on the new designated representative, the new alternate designated representative, and the owners and operators of the facility and the affected EGUs at the facility. In addition, any decision or order issued by the Administrative Authority to any previous designated representative or previous alternate designated representative that is still in effect shall continue to be binding on the new designated representative, the new alternate designated representative and the owners and operators of the affected EGUs at the facility.
4. The designated representative and alternate designated representative must act in accordance with the certification statement as provided under Paragraph C of this Section. Upon and after receipt by the Administrative Authority of a complete certificate of representation:
   a. The designated representative and alternate designated representative shall represent and, by his or her representations, actions, inactions, or submittals, legally bind each owner and operator of the facility and of each affected EGU at the facility in all matters pertaining to the requirements of this Chapter, notwithstanding any agreement between the designated representative or alternate designated representative and such owners and operators; and,
   b. The owners and operators of the facility and of each affected EGU at the facility shall be bound by any decision or order issued to the designated representative or alternate designated representative by the Administrative Authority regarding the facility or any such affected EGU.
5. Except when used in this Section, and in Section 1031, Definitions, whenever the term "designated representative" is used in this Chapter, the term shall be construed to refer to the designated representative or alternate designated representative for the facility.

C. Certificates of Representation.

1. 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 Administrative Authority:
   a. Identification of the facility, and each affected EGU at the facility, for which the certificate of representation is submitted, including facility and affected EGU names, facility category and NAICS code (or, in the absence of a NAICS code, an equivalent code), the U.S. Department of Energy (DOE) plant identification 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 such affected EGU, actual or projected date of commencement of commercial operation, net summer capacity at the 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.
   b. The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative or alternate designated representative to whom the certificate applies.
   c. A list of the owners and operators of the facility and of each affected EGU at the facility.
   d. The following certification statements by the designated representative or alternate designated representative to whom the certificate applies:

"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 facility and of each affected EGU at the facility. I certify that I have all the necessary authority to carry out my duties and responsibilities under the State CO_2 Trading Program for EGUs on behalf of the owners and operators of the facility and of each affected EGU at the facility and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submittals and by any decision or order issued to me by the Administrator regarding the facility or unit. 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 under the State CO_2 Trading Program for EGUs 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."

e. The signature of the designated representative and any alternate designated representative and the dates signed.

2. Unless otherwise required by the Administrative Authority, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrative Authority. The Administrative Authority shall not be under any obligation to review or evaluate the sufficiency of such documents, regardless of whether the documents are submitted.
3. Once a complete certificate of representation has been submitted and received, the Administrative Authority will rely on the certificate of representation unless and until a superseding complete certificate of representation under this Section is received by the Administrative Authority.
4. Except as provided in Paragraph C.3 of this Section, no objection or other communication submitted to the Administrative Authority by any party concerning the authorization of, or concerning any representation, action, inaction or submittal made by, 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 Administrative Authority under this Chapter.

Section 1011. Allowance Tracking and Compliance System (ATCS) Procedures

A. Allowance Tracking.

1. Allocations, recordations, deductions, transfers, tracking and accounting of CO_2 allowances shall be made by the Administrative Authority, or his or her designee, through the electronic Allowance Tracking and Compliance System (ATCS) in accordance with this Section.
2. The ATCS shall provide an electronic, internet-based user interface, with public accessibility to generate reports of public information. Public information shall include information related to the eligibility of qualified EERs and qualified EGUs, such as eligibility applications, EM&V plans, M&V reports, and independent verifier reports. Public information shall also include summary reports related to the number of allowances retired from each facility compliance account for each compliance period.
3. The Administrative Authority shall be the ATCS Administrator, responsible for maintaining and operating the ATCS, or may designate another entity as the ATCS Administrator to act on behalf and under the direction of the Administrative Authority. If the Administrative Authority designates another entity outside of the State Department of Environmental Quality as the ATCS Administrator, such designation shall not confer any authority to enforce the emission standards or other applicable requirements of this Chapter to the designated ATCS Administrator.
4. Each CO_2 allowance used to demonstrate compliance under this Chapter must be initially recorded in, held in, deducted from, and transferred into, out of, or between accounts under the ATCS as designated under this Chapter,

except that allowances issued by an administrative authority in another State or jurisdiction, or by their designee, under an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart MMM may be utilized for compliance by an affected EGU under this Chapter, provided the mass-based plan in the other State or jurisdiction provides for interstate trading of allowances and utilizes either the same ATCS designated for compliance purposes in accordance with this Section 1011, or an interconnected tracking system designated as authorized for trading by the Administrative Authority. Only valid allowances held in the compliance account of the affected EGU at the end of a compliance period and meeting all requirements of this Chapter may be utilized for demonstrating compliance.

5. Each allowance issued by the Administrative Authority under this Chapter or recognized as a compliance instrument under the reciprocity provisions of Paragraph B of this Section must be tracked in the ATCS or another designated allowance tracking system for the entire life of the allowance, from initial issuance through surrender and retirement. Any gaps in the tracking of or accounting for an allowance shall render the allowance invalid.
6. The Administrative Authority will assign a unique identifying number to each account established in the ATCS.
7. Each general account and compliance account established in the ATCS must have a designated authorized account representative, and may have a designated alternate authorized account representative. The Administrative Authority will accept or act on a submittal pertaining to the account, including, but not limited to, submittals to execute the transfer of CO_2 allowances into or out of the account, only if the submittal has been made, signed, and certified by the authorized account representative or alternate authorized account representative in accordance with this Section.

B. Reciprocity and Interstate Recognition of Allowances and Tracking Systems. Any valid CO_2 allowance issued by an administrative authority in another State, or by his or her designee, under an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart MMM shall be recognized as a valid allowance under this Chapter and may be transferred into or out of an account under the ATCS, subject to all requirements of this Section, provided the mass-based plan in the other State provides for interstate trading of allowances and utilizes either the same ATCS designated for compliance purposes under this Chapter, or an interconnected tracking system designated as authorized for trading by the Administrative Authority.

C. Account Holders and Types of Accounts.

1. Compliance Accounts
   a. The ATCS Administrator shall establish and maintain a designated compliance account for each facility at which an affected EGU is located, which shall include a subaccount for each affected EGU at the facility. Where two or more affected EGUs share a common stack and emissions are monitored and measured at the common stack in lieu of monitoring each affected EGU separately, in accordance with Paragraph C of Section 1025, then a single subaccount may be established for all affected EGUs sharing the common stack.
   b. The designated representative and any alternate designated representative of the facility, as established in accordance with Section 1009, shall be the authorized account representative and the alternate authorized account representative, respectively, of each compliance account.
   c. Allowances allocated to each affected EGU for each compliance period, as determined by the Administrative Authority in accordance with Section 1007 of this Chapter, shall be recorded in the compliance account for the facility where the EGU is located by the ATCS Administrator.
   d. Allowances may be transferred into or out of a compliance account by the designated representative during each compliance period.
   e. The designated representative of each facility shall use the compliance account to hold allowances as required to meet the emission standards of Section 1005 of this Chapter.
   f. The Administrative Authority may freeze a compliance account for cause in accordance with Sections 1007, this Section 1011, or Section 1027 of this Chapter.
2. Retirement Accounts
   a. The ATCS Administrator shall establish and maintain a designated retirement account for each facility at which

an affected EGU is located, which shall include a subaccount for each affected EGU at the facility. Where two or more affected EGUs share a common stack and a single subaccount of the facility compliance account has been established for the multiple affected EGUs, a single subaccount of the retirement account shall also be established for such affected EGUs.

b. The Administrative Authority shall be the account holder of each retirement account.

c. The designated representative of each facility shall surrender allowances into the facility retirement account for each affected EGU for each compliance period, for use in demonstrating compliance with the emission standards of Section 1005 of this Chapter, by making a transfer request as specified under Paragraph D of this Section.

d. Each allowance may be used only once for demonstrating compliance. Each allowance surrendered into a retirement account is permanently retired and is no longer transferable to another account in the ATCS or any other allowance tracking system.

3. State Account

a. The ATCS Administrator shall establish and maintain a State Account for allowances held by the State for sale or auction.

b. The Administrative Authority shall be the account holder of the State Account.

c. The State's portion of allowances for sale or auction for each compliance period, as determined in accordance with Section 1007 of this Chapter, shall be recorded in the State Account by the ATCS Administrator.

d. Within 30 days of execution of sale or auction of allowances by the State in accordance with this Chapter, the Administrative Authority shall have the allowances transferred to the general account of the entity purchasing the allowances.

4. General Accounts. Any person may apply to open a general account for the purpose of holding and transferring CO_2 allowances, by submitting to the ATCS Administrator a complete application for a general account. Any entity applying for registration as a qualified EERS or qualified EGU shall apply to open a general account. General accounts shall be established and operated in accordance with Section 1013 of this Chapter.

D. Procedures for Recording, Transferring, Surrendering and Retiring Allowances.

1. Recording of Allowances. For each compliance period, the Administrative Authority or ATCS Administrator will record all allowances allocated to affected EGUs, qualified EERs and qualified EGUs on the electronic ledger of the compliance account (for an affected EGU) or general account (for a qualified EER or qualified EGU) no later than August 1 of the first calendar year of the compliance period. Each allowance so allocated and recorded constitutes a newly issued limited authorization to emit one ton of CO_2 in accordance with Section 1005 of this Chapter. Upon issuance, the ATCS Administrator shall assign each allowance a unique serial number that will include digits identifying the year of the compliance period for which the allowance was issued. Once recorded, all allowances shall be available for transfer by the account holder unless such transfer is otherwise suspended or prohibited in accordance with Sections 1007, this Section 1011, or Section 1027 of this Chapter.

2. Transfers of Allowances

a. The authorized account representative may transfer an allowance from an ATCS account by submitting a complete and accurate transfer request to the ATCS Administrator in a format prescribed by the Administrative Authority. Each transfer request must include the following information:

i. The ATCS account numbers 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 of the transferor account and the date signed.

b. Transfers of allowances issued by another State, and transfers to or from accounts in another allowance tracking system, where interstate trading with the other State and/or allowance tracking system has been recognized by the Administrative Authority in accordance with Section 1005 of this Chapter, may be made in the same manner as transfers within the ATCS and any additional guidelines and procedures prescribed by the Administrative Authority.

c. Transfers will be recorded by the ATCS Administrator within 5 business days of receiving a complete and accurate transfer request, by removing the specified allowances from the transferor account to the transferee account, except:
   i. No transfers will be made to or from a compliance account during the time period commencing the day following a compliance transfer deadline and until after the Administrative Authority completes and verifies the deductions from all compliance accounts for the compliance period.
   ii. The ATCS Administrator will not act on any transfer request for any allowance that is not in the transferor's ATCS account as identified on the transfer request, or on any transfer request that is not complete and accurate. Within 10 business days of receipt of an incomplete or inaccurate transfer request or receipt of a request to transfer allowances determined not to be in the transferor account, the ATCS Administrator will notify the authorized account representatives of both accounts subject to the transfer that the transfer has not been made and the reasons therefor.

3. Surrender and Retirement of Allowances for Compliance
   a. On the date of the transfer deadline for each compliance period, each CO_2 allowance held in the compliance account of an affected EGU, whether issued for that compliance period or a prior compliance period, is considered available for surrender for compliance with the emission standard of Section 1005 of this Chapter.
   b. No later than the transfer deadline for each compliance period, the designated representative for each affected EGU shall submit a complete and accurate transfer request to surrender allowances to the affected EGU retirement account as necessary to meet the emission standard of Section 1005 of this Chapter. The transfer request shall specify the total number of allowances to be transferred to the facility retirement account from the facility compliance account, the number of allowances to be transferred to each affected EGU subaccount, and the serial number of each allowance to be surrendered for each affected EGU.
   c. The ATCS Administrator will transfer allowances from the compliance account to the retirement account for each affected EGU as requested by the designated representative and will record the transfers. Each allowance so transferred to a retirement account will be permanently retired.
4. Deductions for Excess Emissions
   a. For each affected EGU, the Administrative Authority will determine if the total number of allowances recorded in the retirement account is equal to the total tons of CO_2 emitted from the affected EGU for the compliance period, except to the extent additional emissions have been authorized under a temporary modified emission standard in accordance with Paragraph F of Section 1005. In the event excess emissions have occurred (i.e., insufficient allowances were surrendered), the Administrative Authority shall deduct, from the facility compliance account or general account for the affected EGU, available CO_2 allowances as necessary up to an amount equal to two tons of CO_2 allowances for each ton of excess emissions. All such deductions will be recorded by the ATCS Administrator.
   b. Each ton of excess CO_2 emissions shall constitute a separate violation by the owners and operators of the affected EGU of the emission standard in Section 1005 of this Chapter, which shall be subject to enforcement action in accordance with Section 1027 of this Chapter.

Section 1013. ATCS General Accounts and Authorized Account Representatives

A. Submittals to be Made by Authorized Account Representative or Alternate Authorized Account Representative.

1. Any person may apply to open a general account, for the purpose of holding and transferring CO_2 allowances, by submitting to the ATCS Administrator a complete application in accordance with this Section. Each application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.
2. Except as provided under this Paragraph concerning delegation of authority to make submittals, each submittal

with respect to a general account shall be made, signed, and certified by the authorized account representative or alternate authorized account representative. Each such submittal must include the following certification statement by the authorized account representative or alternate authorized account representative:

"I am authorized to make this submittal 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."

3. The ATCS Administrator will act on a submittal made for a general account only if the submittal has been made, signed, and certified in accordance with this Paragraph. Submittals made by any other party, or not in accordance with this Paragraph, shall not be recognized to authorize any action with regard to the general account.
4. An authorized account representative or alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submittal to the ATCS Administrator as provided for or required under this Chapter. Delegation of authority may not extend to submittals made to or from personal, corporate or government email accounts.
   a. Any such delegation of authority to make an electronic submittal shall be made in accordance with the applicable procedures for making and certifying electronic submittals under the particular system to which the submittal is made.
   b. Any electronic submittal made by a delegated authority in accordance with this Paragraph shall be deemed to be an electronic submittal by the authorized account representative or alternate authorized account representative for the general account.

B. Establishing the Authorized Account Representative and Alternate Authorized Account Representative.

1. As part of the initial application to open a general account, the persons having an ownership interest with respect to the CO_2 allowances held in the general account shall submit a certificate of representation as provided under Paragraph C of this Section, naming one and only one authorized account representative, and, if an alternate authorized account representative is selected, shall submit a certificate of representation as provided under Paragraph C of this Section naming the alternate authorized account representative.
2. The designated authorized account representative or designated alternate authorized account representative may be changed at any time upon receipt by the ATCS Administrator of a superseding complete certificate of representation, which shall contain all of the information required for a complete application under Paragraph C of this Section. Notwithstanding any such change, all representations, actions, inactions, and submittals by any previous authorized account representative or alternate authorized account representative before the time and date when the ATCS Administrator receives the superseding certificate of representation shall continue to be binding on the new authorized account representative, the new alternate authorized account representative, and the persons having an ownership interest with respect to the CO_2 allowances held in the general account.
3. The authorized account representative and alternate authorized account representative must act in accordance with the certification statement as provided under Paragraph C of this Section. Upon and after receipt by the Administrative Authority of a complete certificate of representation:
   a. The authorized account representative shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person having an ownership interest with respect to the CO_2 allowances held in the general account in all matters pertaining to the requirements of this Chapter, notwithstanding any agreement between the authorized account representative and such persons; and,
   b. Each person having an ownership interest with respect to the CO_2 allowances held in the general account shall be bound by any decision or order issued to the designated representative by the Administrative Authority regarding the CO_2 allowances held in the general account in all matters pertaining to the

requirements of this Chapter.

4. Except when used in this Section, and in Section 1031, Definitions, whenever the term "authorized account representative" is used in this Chapter, the term shall be construed to refer to the authorized account representative or any alternate authorized account representative for the general account.

C. Application for a General Account and Certificates of Representation.

1. A complete application for a general account must include the following elements in a format prescribed by the Administrative Authority or designated ATCS Administrator:
   a. Name, mailing address, email 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. If the general account is for a qualified EER, a statement to that effect and the EER name and registration number as documented in the National Energy Efficiency Registry;
   d. If the general account is for a qualified EGU or for a facility at which one or more qualified EGUs are located, a statement to that effect and the facility and/or EGU names(s), location, type of technology used, and nameplate generating capacity;
   e. A list of all persons 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;
   f. A certificate of representation containing the following certification statement by the authorized account representative or alternate authorized account representative for whom the certification is being submitted:

      "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 State CO_2 Trading Program for EGUs on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submittals and by any decision or order issued to me by the Administrator regarding the general account"; and,

   g. The signature of the authorized account representative or alternate authorized account representative, as applicable, and the date signed.
2. Unless otherwise required by the Administrative Authority, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrative Authority or ATCS Administrator. The Administrative Authority shall not be under any obligation to review or evaluate the sufficiency of such documents, regardless of whether the documents are submitted.

D. Establishment and Maintenance of a General Account.

1. Once a complete application and certificate of representation has been submitted and received, the ATCS Administrator will establish a general account for the person or persons for whom the application is submitted.
2. Upon and after receipt of a complete application and certificate of representation by the Administrative Authority:
   a. The authorized account representative of the general account shall be authorized to represent, 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 State CO_2 Trading Program for EGUs, notwithstanding any agreement between the authorized account representative and such person;
   b. Any alternate authorized account representative shall be authorized to represent, and shall represent, each person who has an ownership interest with respect to CO_2 allowances held in the general account, and, any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submittal 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 Administrative Authority or ATCS Administrator regarding the general account.

3. Omissions or Changes in Persons with Ownership Interest.
   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 submittals of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrative Authority, 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 the 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 CO_2 allowances in the general account to include the change.
4. Objections concerning authorized account representative and alternate authorized account representative:
   a. Once a complete application for a general account has been submitted and received, the ATCS Administrator will rely on the application unless and until a superseding complete application for a general account under this Section is received by the ATCS Administrator.
   b. Except as provided in Paragraph D.1 of this Section, no objection or other communication submitted to the Administrative Authority or ATCS Administrator by any party concerning the authorization of, or concerning any representation, action, inaction or submittal made by, an authorized account representative or alternate authorized account representative, shall affect any representation, action, inaction, or submission of the authorized account representative or alternate authorized account representative or the finality of any decision or order by the Administrative Authority under this Chapter.
5. Closing a general account.
   a. The authorized account representative or alternate authorized account representative of a general account may submit to the ATCS Administrator a request to close the account. Such request must include a correctly submitted CO_2 allowance transfer for any CO_2 allowances in the account to one or more other accounts.
   b. 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 ATCS Administrator may notify the authorized account representative 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 ATCS Administrator receives a correctly submitted CO_2 allowance transfer to the account or a statement submitted by the authorized account representative or alternate authorized account representative requesting that the account not be closed.
6. Freezing a general account. The Administrative Authority, or the ATCS Administrator at the direction of the Administrative Authority, may freeze the general account of a qualified EER or qualified EGU at any time for cause:
   a. If the Administrative Authority determines that allowances held in the account have been improperly issued based on a misrepresentation or misstatement in an eligibility application or M&V report;
   b. Pending investigation of potential misrepresentation or misstatement in an eligibility application or an M&V report which was the basis for issuance of allowances held in the account; or,
   c. If the general account is for a qualified EER or qualified EGU and the Administrative Authority determines that the EER or EGU does not meet the qualification criteria or requirements.

Section 1015. Qualifying Criteria and Registration Requirements for Qualified Energy Efficiency Resources (EERs)

A. Qualifying Criteria for EERs. An energy efficiency resource (EER) may qualify for the allocation and receipt of allowances under Section 1007 of this Chapter only if the EER meets all qualifying criteria as set forth in this Paragraph.

1. All persons with an ownership interest in the energy savings attributes of the energy efficiency resource (EER) and CO_2 allowances allocated to energy savings resulting from the EER must apply to open a general account in the ATCS in accordance with Section 1013 of this Chapter.
2. The EER must be registered with the National Energy Efficiency Registry or other registry designated by the Administrative Authority in accordance with Paragraph B of this Section.
3. Each Qualified EER must meet the following minimum eligibility criteria:
   a. The EER must produce verifiable energy savings on or after January 1, 2018;
   b. The EER strategy must be connected to and must produce energy savings from the electric grid in the Eastern Interconnect; and,
   c. The EER must implement energy savings strategies in one or more of the following categories:
      i. Residential or commercial energy efficiency (EE) programs implemented in the State. For purposes of this Chapter, electricity generated by residential or commercial installations of distributed energy net-metering solar panels, whether such electricity is consumed on site or delivered to the grid, may be considered energy savings from a residential or commercial energy efficiency measure;
      ii. Energy Savings Performance Contracting, excluding contracts implemented at State-owned buildings or facilities, implemented at buildings or facilities within the State;
      iii. Above-code building certification programs implemented at buildings that commenced construction in the State on or after January 1, 2013; or,
      iv. Industrial energy efficiency programs at industrial facilities in the State, based on implementation of a certified Energy Management System conforming to ISO 50001:2011 or later, or through a DOE Superior Energy Performance certification program.
4. Only verified energy savings resulting from the qualified EER that occur within the State, as certified by the National Energy Efficiency Registry, shall be eligible for allocation of allowances. No later than May 1 of each calendar year, the authorized account representative for the EER ATCS general account shall obtain a certification of verified energy savings from the National Energy Efficiency Registry, and provide a copy of such certification to the Administrative Authority. Certifications of verified energy savings shall be relied upon in allocating allowances to qualified EERs in accordance with Section 1007 of this Chapter.
5. Electricity savings from a qualified EER for which allowances are issued under this Chapter shall not also be issued ERCs or allowances by another State or jurisdiction to be used for demonstrating compliance with any requirement of a state or tribal plan under 40 CFR part 60 subpart UUUU, or with any requirement of a federal plan under 40 CFR part 62 subparts MMM or NNN administered by the EPA Administrator or the Administrator's agent.

B. Qualified EER Registration with the National Energy Efficiency Registry.

1. To register as a qualified EER under this Chapter, the authorized account representative for the general account of the EER must submit an eligibility application to the Administrative Authority, or to his or her designee, in a format specified by the Administrative Authority.
2. Upon approval of the eligibility application, the Administrative Authority, or his or her designee, will register the EER as a qualified EER in the approved National Energy Efficiency Registry, or other registry as designated by the Administrative Authority.
3. Each application for eligibility must include the following information:
   a. Name, mailing address, email address, telephone number, and facsimile transmission number of the authorized

account representative and any alternate authorized account representative;
b. An identifying name for the EER;
c. A description of the EER, including the energy savings measures to be implemented and the anticipated geographic scope and timeline for implementation;
d. A certification by the authorized account representative that an eligibility application for the same EER has not been submitted to any other State for the receipt of rate-based ERCs or mass-based allowances under a state or federal plan to implement 40 CFR part 60 subpart UUUU or 40 CFR part 62 subparts MMM or NNN;
e. An evaluation, measurement and verification (EM&V) plan that meets the requirements of Section 1019 of this Chapter; and,
f. A verification report from an independent verifier meeting the requirements of Section 1023 of this Chapter, verifying the eligibility of the EER to be issued allocations of allowances under this Chapter, and verifying that the EM&V plan meets the requirements of Section 1019 of this Chapter.

C. Revocation of Qualified EER Status.

1. If a registered qualified EER is found to not meet the qualification requirements of this Section 1015, then the Administrative Authority will revoke the qualified status of the EER and the eligibility of the EER to be issued allocations of allowances under this Chapter. In addition, the provisions for correction of errors in the issuance of allowances, as set forth in Section 1007 and Section 1013 of this Chapter, may apply with regard to allowances issued to the EER at any time the EER did not meet all qualification criteria and requirements.
2. Any instance of intentional misrepresentation in an eligibility application or M&V report may be cause for revocation of the qualified status of an EER.
3. Repeated instances of error or misstatement of MWh of electricity savings in submitted M&V reports, or repeated instances of error or misstatement of any other nature or in the EM&V application, M&V reports, or any other submittals, may be cause for the Administrative Authority to revoke the eligibility of an EER to be issued allocations of allowances.
4. In the event of an intentional misrepresentation, or repeated instances of error or misstatement in submittals by the authorized account representative of the qualified EER, the Administrative Authority may prohibit the EER from any further eligibility to be issued allowances. In addition, the provisions for correction of errors in the issuance of allowances, as set forth in Section 1007 and Section 1013 of this Chapter, may apply.

Section 1017. Qualifying Criteria and Registration Requirements for Qualified EGUs

A. Qualifying Criteria for Non-affected EGUs. An EGU that is not an affected EGU under this Chapter may qualify for the allocation and receipt of allowances under Section 1007 of this Chapter only if the EGU meets all qualifying criteria as set forth in this Paragraph.

1. All persons with an ownership interest in the CO_2 allowances allocated to energy generated by the EGU must apply for and maintain a general account in the ATCS in accordance with Section 1013 of this Chapter.
2. The EGU must be registered as a qualified EGU with the Administrative Authority in accordance with Paragraph B of this Section.
3. Each qualified EGU must meet the following minimum eligibility criteria:
   a. The EGU produces electricity using one or more of the following categories of technologies and fuels:
      i. Renewable electric generating technologies using wind, utility-scale solar photovoltaic (PV) or concentrating solar power (CSP), geothermal, hydropower, wave or tidal energy;
      ii. Nuclear power;
      iii. CHP units, including waste heat power (WHP) generating units, that are not affected EGUs under this

Chapter, provided that for such EGUs, only the eligible portion of electricity generated, in accordance with the approved EM&V plan, shall be eligible for allocation of allowances;

iv. Generation of electricity using qualified biomass, including biogenic municipal solid waste at a waste-to-energy (WTE) facility, provided that for such qualified EGUs, only the portion of electricity generated from the qualified biomass shall be eligible for allocation of allowances.

b. The EGU must meet the following design, location and operating criteria:
   i. Have a nameplate capacity equal to or greater than 10 MW;
   ii. Be located within the State;
   iii. Be connected to and provide electricity to the electric grid for the Eastern Interconnect; and,
   iv. Have installed and operate, in accordance with Section 1025 of this Chapter, a revenue-quality meter for measuring generation on a continuous basis.

4. For purposes of this Chapter, qualified biomass includes any biomass feedstock listed as pre-approved by EPA under 40 CFR part 62. Other biomass may be approved by the Administrative Authority as a qualified biomass provided the following criteria are met:
   a. The biomass belongs to one of the following categories:
      i. waste-derived biomass feedstocks (e.g., landfill gas, biogenic municipal solid waste including residential food and yard wastes, livestock waste, biogenic sludge from wastewater treatment plants, and commercial food waste);
      ii. industrial and agricultural byproduct feedstocks (e.g., black liquor or bagasse) with no alternative markets;
      iii. biomass waste from sustainable forestry management; or,
      iv. biomass from sustainably managed energy plantations or farming operations.
   b. The EM&V plan provided as part of the qualified EGU eligibility application must demonstrate that each biomass source proposed to be approved as a qualified biomass will serve as a method to control increases of CO_2 levels in the atmosphere. Such a demonstration should be supported by an analysis of the net carbon benefits of the biomass as compared to traditional fossil fuels, taking into consideration the lifecycle of the biomass, including production, transport, processing, and combustion, using methods described in EPA's Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources or equivalent methods.
5. Only metered electricity generated by a qualified EGU and delivered to the grid, as monitored and reported in accordance with Section 1025 of this Chapter, will be eligible to receive allocations of allowances.
6. Electricity generated by a qualified EGU for which allowances are issued under this Chapter shall not also be issued ERCs or allowances by another State or jurisdiction to be used for demonstrating compliance with any requirement of a state or tribal plan under 40 CFR part 60 subpart UUUU, or with any requirement of a federal plan under 40 CFR part 62 subparts MMM or NNN administered by the EPA Administrator or the Administrator's agent.

B. Qualified EGU Registration with the Administrative Authority.

1. To register as a qualified EGU under this Chapter, the authorized account representative of the EGU must submit an eligibility application to the Administrative Authority, or to his or her designee, in a format specified by the Administrative Authority.
2. Upon approval of the eligibility application, the Administrative Authority, or his or her designee, will register the EGU as a qualified EGU in a registry established and maintained by the Administrative Authority or his or her designee, which may be a registry operated within the ATCS.
3. Each application for eligibility must include the following information:
   a. Name, mailing address, email address, telephone number, and facsimile transmission number, of the authorized account representative and any alternate authorized account representative;
   b. An identifying name for the EGU, the facility where the EGU is located, and the physical and mailing address of the location;
   c. A description of the EGU, including the prime mover and technology type used to generate electricity, the nameplate capacity, the generator category (e.g., wholesale, wholesale also serving onsite), EGU IDs such

as EPA ORIS Code and/or Facility Registration System Code, and a copy of the most recent filing of the EGU's U.S. EIA Annual Electric Generator Report Form EIA-860;

d. The following statement authorizing inspections by the Administrative Authority or his or her designee:

"I authorize the Administrative Authority, or his or her designee, to enter and inspect the facility and EGU for which this application applies, including inspections of the electricity generation meter and associated components and any and all records pertaining to the generation of electricity for which eligibility to receive allocations of allowances is claimed under the State CO_2 Trading Program for EGUs, at any time at the discretion of the Administrative Authority, to verify the information provided in the EM&V plan provided herein or any other data submitted in relation to the State CO_2 Trading Program for EGUs and to verify that all aspects of participation in the State CO_2 Trading Program for EGUs are being properly implemented with respect to the qualified EGU at the facility.";

e. A certification by the authorized account representative that an eligibility application for the same EGU has not been submitted to any other State for the receipt of rate-based ERCs or mass-based allowances under a state or federal plan to implement 40 CFR part 60 subpart UUUU or 40 CFR part 62 subparts MMM or NNN;

f. A statement that the EGU is equipped with the monitoring system required under Paragraph A of this Section, and that the owners and operators will comply with the monitoring and reporting requirements of this Chapter for purposes of quantifying the amount of generation eligible for the allocation of allowances for each compliance period;

g. For an EGU that is a CHP unit, a WHP generating unit, a qualified biomass unit, or a WTE facility, an evaluation, measurement and verification (EM&V) plan that meets the requirements of Section 1019 of this Chapter;

h. The signature of the authorized account representative, certifying all statements and information contained in the application with the following statement:

"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."; and,

i. A verification report from an independent verifier meeting the requirements of Section 1023 of this Chapter, verifying the eligibility of the EGU to be issued allocations of allowances under this Chapter; and, for applications requiring an EM&V plan, verifying that the EM&V plan meets the requirements of Section 1019 of this Chapter.

C. Revocation of Qualified EGU Status.

1. If a registered qualified EGU is found to not meet the qualification requirements of this Section 1017, then the Administrative Authority will revoke the qualified status of the EGU and the eligibility of the EGU to be issued allocations of allowances under this Chapter. In addition, the provisions for correction of errors in the issuance of allowances, as set forth in Section 1007 and Section 1013 of this Chapter, may apply with regard to allowances issued to the EGU at any time the EGU did not meet all qualification criteria and requirements.
2. Any instance of intentional misrepresentation in an eligibility application or M&V report may be cause for revocation of the qualification status of an EGU.
3. Repeated instances of error or misstatement of MWh of qualified electricity generation in submitted M&V reports, or repeated instances of error or misstatement of any other nature or in any other submittals, may be cause for the Administrative Authority to revoke the eligibility of an EGU to be issued allocations of allowances.
4. In the event of an intentional misrepresentation, or repeated instances of error or misstatement in submittals by the authorized account representative of the qualified EGU, the Administrative Authority may prohibit the EGU from any further eligibility to be issued allowances. In addition, the provisions for correction of errors in the issuance of allowances, as set forth in Section 1007 and Section 1013 of this Chapter, may apply.

Section 1019. Evaluation, Measurement and Verification (EM&V) Plan Requirements for Qualified EERs and Certain Qualified EGUs

A. General EM&V Plan Requirements.

1. An evaluation, measurement and verification (EM&V) plan is required to be submitted with an application for eligibility, as specified pursuant to Section 1015 for each qualified EER, and Section 1017 for each qualified EGU that is a CHP, WHP, qualified biomass, or WTE facility.
2. Each EM&V plan submitted pursuant to this Section must include the following certification by the authorized account representative of the ATCS general account for the EER or EGU addressed in the application:

   "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."
3. Each EM&V plan must be verified by an accredited independent verifier meeting the requirements of Section 1023 of this Chapter.

B. EM&V Plan Requirements for Qualified EERs.

1. Each EM&V plan for a qualified EER must specify how each of the requirements in this Paragraph B of this Section will be met in quantifying the electricity savings resulting from implementation of the EER measures. Reliance on examples or templates of protocols, guidelines, common practice baselines, or other EM&V components for specific energy efficiency measures as provided in EM&V guidance issued by EPA will be accepted.
2. All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are developed prior to implementing the subject energy efficiency measure, and that are not quantified using EM&V methods and procedures.
3. All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:
   a. Have gone through a peer review process that shows the applicable methods to be valid through empirical testing; and,
   b. Have been accepted and approved for use by identifiable state regulatory commissions in this or another state, or accepted and approved for use by an identifiable federal agency such as EPA or DOE.
4. All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed, or that a typical consumer or building owner would have continued using, in a given circumstance (i.e., a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE measure covered in the EM&V plan, based on:
   a. Characteristics of the EE measure;
   b. The delivery mechanism used to implement the EE measure (e.g., installed as part of a utility EE program versus a point-of- sale rebate);
   c. Local consumer and market characteristics;
   d. Applicable building energy codes and standards and average compliance rates; and,

e. The method applied: project-based monitoring and verification (PB–MV), comparison group approaches, or deemed savings.

5. All electricity savings must be quantified by applying one or more of the following methods: PB–MV, comparison group approaches, or deemed savings.
   a. If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines.
   b. If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.
6. All EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan.
   a. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience, for example, with new and innovative EE program types, necessitates more frequent quantification).
   b. To the greatest extent practicable, time intervals for quantifying energy savings should be scheduled in the EM&V plan to coincide with the time periods for determining the allocation of allowances in accordance with Section 1007 of this Chapter. Allocations of allowances will be made based on verified electricity savings from qualified EERs during the following time periods:
      i. For Interim 1, the allocation basis period is January 1, 2018 to December 31, 2020;
      ii. For Interim 2, the allocation basis period is January 1, 2021 to December 31, 2023;
      iii. For Interim 3, the allocation basis period January 1, 2024 to December 31, 2026;
      iv. For the first Final Period, the allocation basis period is January 1, 2027 to December 31, 2028; and,
      v. For subsequent Final Periods, the allocation basis period is every 2-calendar year period thereafter, commencing with January 1, 2029 to December 31, 2030.
   c. The time intervals for quantifying energy savings established in the EM&V plan should end no sooner than the last day of the effective useful life of the EE measure, and must be no longer than:
      i. 2 or 3-year intervals for building energy codes and product standards;
      ii. 1, 2 or 3 years for public or consumer-funded EE measures, as relevant for the type of EE measure; and,
      iii. Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.
7. EM&V plans must specify and document how the following EM&V components will be addressed in the quantification and verification of electricity savings:
   a. The effects of changes in independent factors on reported electricity savings (i.e., factors that are not directly related to the EE measure, such as weather, occupancy, and production levels).
   b. The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

i. If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.
ii. If industry best-practice persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

c. The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:
i. For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.
ii. For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.
iii. For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and,
iv. For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

d. The EE savings verification approaches for ensuring that EE measures have been properly installed, are operating as intended, and therefore have the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE measure using best-practice approaches, such as physical inspections at a customer's premises, phone and mail surveys, and reviews of sales receipts and other documentation.

e. The interactive effects of EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occur outside of specific end-uses(s) targeted by the EE measure (e.g., lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

8. The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise.
9. If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than ±10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.
10. All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.
11. Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified.

C. EM&V Plan Requirements for Qualified Biomass, WTE, CHP, and WHP EGUs.

1. Each EM&V plan for a qualified EGU that is a biomass-fired EGU (including a municipal solid waste WTE EGU) or a CHP EGU (including a WHP EGU) must specify that electricity generation data will be monitored on a continuous basis using a revenue-quality meter in accordance with the monitoring requirements of Section 1025 of this Chapter.
2. For each biomass source proposed to be used as a qualified biomass, in addition to the monitoring requirements for measuring generation in Paragraph C.1 of this Section, each EM&V plan must either document that the biomass source is pre-approved by EPA under 40 CFR part 62 or for the purposes of 40 CFR part 60, or that the biomass belongs to one of the qualifying biomass categories listed in Section 1017 of this Chapter. For a biomass source that is not pre-approved by EPA, the EM&V plan must demonstrate that the biomass will serve as a method to control increases of CO_2 levels in the atmosphere. Such a demonstration should be supported by an analysis of the net carbon benefits of the biomass as compared to traditional fossil fuels, taking into consideration the lifecycle of the biomass, including production, transport, processing, and combustion, using methods described in EPA's

Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources or equivalent methods.

3. For a municipal WTE EGU and any other qualified EGU that utilizes qualified biomass feedstock as well as other fuels, in addition to the requirements in Paragraphs C.1 and C.2 of this Section, each EM&V plan must provide the methods for determining and recording the specific portion of the total net energy output from the EGU that is related to the biogenic portion of the waste or biomass portion of the fuel, as applicable, according to the following requirements. Only the calculated net electricity generation from qualified biogenic materials will be considered eligible generation for purposes of allowance allocation.
   a. The following equation shall be used to determine the portion of net electricity output derived from biogenic materials:

$$\mathbf{MWh_{Bio} = MWh_T \star F_{Bio} \star \left(\frac{HHV_{Bio}}{HHV_{EGU}} \right)}$$

   Where:
   MWh_{Bio} is the calculated net electricity generation from biogenic materials (MWh);
   MWh_T is the total net electricity output to grid as measured and reported per the state plan requirements (MWh);
   F_{Bio} is the fraction of total CO_2 emissions from biogenic material as measured and reported pursuant to 40 CFR § 98.34(d), used as a surrogate for the fraction of biogenic waste in the total waste feed stream;
   HHV_{Bio} is the annual average high heating value for biogenic waste received by the WTE facility; and,
   HHV_{EGU} is the annual average high heating value for total fuel input used by the EGU.

   b. The EM&V plan shall provide that CO_2 emissions will be monitored and reported in accordance with 40 C.F.R. part 98 subpart C, §§ 98.3(c), 98.34(d), 98.36(b)–(d), and subpart D, §§ 98.43(b) and 98.46.
   c. The EM&V plan shall include a specific method for determining the ratio of HHV_{Bio}/HHV_{EGU}. The method for determining high heating values for biogenic and total fuel may rely on periodic sampling and analysis of waste and fuel streams received at the facility, or the applicant may propose to rely upon representative values from U.S. government studies or studies published in peer-reviewed scientific or trade journals.
4. For a CHP EGU that is a bottoming cycle unit using waste heat from an industrial process or combustion source to generate electricity, where the electricity is produced without any incremental consumption of fossil fuel, in addition to the requirements of Paragraphs C.1, C.2 and C.3 as applicable, the EM&V plan must document the mode of operation and certify that no incremental consumption of fossil fuel will be used in the production of electricity. For such bottoming cycle CHP qualified EGUs, all electricity generated may be eligible for allocation of allowances, provided all other requirements of this Chapter are met.
5. For a CHP EGU that is a bottoming cycle unit that supplements waste heat with incremental consumption of fossil fuel to generate electricity, or a CHP that is a topping cycle unit that uses fossil fuel to generate electricity, in addition to the requirements of Paragraph C.1, and the requirements of Paragraphs C.2 and C.3 if applicable, the EM&V plan must include the method that will be used to determine the portion of electrical generation from the qualified CHP that is eligible for allocation of allowances, according to the following requirements:
   a. The CHP electrical CO_2 emission rate, in lb/MWh-net, is calculated for each year using the following formula:

$$\mathbf{ER_{CHP} = [((F \star EF_{Fuel}) - (UTO/Eff_{Boiler})) \star EF_{Fuel}]/ MWh_{CHP}}$$

   Where:
   ER_{CHP} is the calculated CHP net electrical CO_2 emission rate for the year, in lb/MWh-net;
   F is the total annual fuel input to the CHP;
   EF_{Fuel} is the annual average emission factor for the fuel used by the CHP, as determined based on Appendix G of 40 CFR part 75;
   UTO is the useful thermal output from the CHP for the year;
   Eff_{Boiler} is the nominal efficiency of an industrial boiler that presumably would have been used to provide the thermal output in the absence of the CHP unit, as established with supporting documentation in the EM&V plan; and,
   MWh_{CHP} is the net electrical output of the CHP for the year.

b. The CHP electrical CO_2 emission rate reference factor is calculated for each year using the following formula:

$$\mathbf{ERf_{CHP} = ER_{CHP}/ER_{Ref}}$$

Where:

ERf_{CHP} is the calculated emission rate reference factor, which is a unitless ratio with a value between 0 and 1, expressing the emission rate of the CHP relative to the applicable fossil fuel-fired EGU reference emission rate;

ER_{CHP} is the net electrical emission rate of the CHP, as calculated in this Paragraph, expressed in lb/MWh-net; and,

ER_{Ref} is the reference emission rate for fossil fuel-fired EGUs in the State for the year, which shall be the following emission rates expressed in lb/MWh-net:
Calendar years 2018 through 2024: 1,411 lb/MWh-net
Calendar years 2025 through 2027: 1,276 lb/MWh-net
Calendar years 2028 and 2029: 1,185 lb/MWh-net
Calendar years 2030 and beyond: 1,130 lb/MWh-net

c. The CHP electrical output that is eligible for receiving allocations of allowances is calculated using the following formula:

$$\mathbf{Eligible\ MWh_{CHP} = (1- ERf_{CHP}) * MWh_{CHP}}$$

Where:

Eligible MWh_{CHP} is the amount of electrical output from the CHP for the calendar year that is eligible for allocations of allowances under this Chapter, provided all other requirements are met;

ERf_{CHP} is the calculated unitless ratio with a value between 0 and 1, expressing the emission rate of the CHP relative to the applicable fossil fuel-fired EGU reference emission rate, as calculated in this Paragraph; and,

MWh_{CHP} is the net electrical output of the CHP for the year.

Section 1021. Monitoring and Verification (M&V) Reporting Requirements for Qualified EERs and Qualified EGUs

A. General M&V Reporting Requirements.

1. Each registered qualified EER and each registered qualified EGU shall submit an annual monitoring and verification (M&V) report, no later than June 30 of each year, documenting the energy generation or energy savings that have been quantified and verified since the previous year's report, that result from the qualified EER or qualified EGU, and that are eligible for the allocation of allowances in accordance with Section 1007 of this Chapter.
2. M&V reports shall be submitted to the Administrative Authority, or his or her designee, in a format specified by the Administrative Authority. For qualified EERs, the M&V report shall also be submitted to the National Energy Efficiency Registry.
3. A report is not required for any year in which eligible energy savings or generation did not occur, or, for a qualified EER, if any energy savings occurring since the last M&V report have not yet been quantified and verified.
4. Timeliness of M&V reports relative to electricity generation and savings.
   a. For each qualified EGU, electricity generation must be reported in the year following when the electricity was generated. For each qualified CHP, WHP, WTE and biomass EGU, CO_2 emissions must be reported in the year following when the emissions occurred.
   b. For a qualified EER, energy savings should be reported in the earliest year following when the savings data

are quantified and verified. Energy savings may be reported in a year later than the first year after the savings occurred, provided that:

i. the schedule for quantification in the approved EM&V plan is met;

ii. the savings are reported no later than the first year after they are quantified; and,

iii. the savings are reported no later than June 30 of the first year following the period for which the energy savings would be allocated allowances.

a) Savings occurring during January 1, 2018 to December 31, 2020 must be reported no later than June 30, 2021;

b) Savings occurring during January 1, 2021 to December 31, 2023 must be reported no later than June 30, 2024;

c) Savings occurring during January 1, 2024 to December 31, 2026 must be reported no later than June 30, 2027;

d) Savings occurring during January 1, 2027 to December 31, 2028 must be reported no later than June 30, 2029; and so forth for each 2-Calendar-Year period thereafter.

c. Failure to submit a timely M&V report shall result in forfeiture of eligibility for allocations of allowances for the electricity savings or generation that were not timely reported.

5. The first M&V report submitted for a qualified EER or qualified EGU shall document that the electricity saving measures or generating unit were installed and/or implemented consistent with the description in the approved eligibility application.

6. The authorized account representative for the qualified EER or qualified EGU must certify each M&V report with the following statement:

"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."

7. Each M&V report must be verified by an accredited independent verifier meeting the requirements of Section 1023 of this Chapter.

Each M&V report must include the following information:

B. M&V Report Required Content. Each M&V report must include the following information:

1. Identification of the time period covered by the M&V report;
2. A summary report of the amount of electricity savings or generation being reported as eligible for the allocation of allowances and the allocation basis period in which the savings or generation occurred, including a summary of any eligible electricity savings or generation previously reported for the same allocation basis period;
3. A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to achieve the MWh of electricity savings or generation;
4. Documentation (including data) of the electricity savings or generation from any qualified EE measure or qualified EGU, project, measure, or program addressed in the M&V report, quantified and verified in MWh for the period covered by the M&V report in accordance with the applicable EM&V plan, and based on ex-post energy savings or generation;
5. Documentation of the total annual CO_2 emissions data for qualified EGUs that are CHP, WHP, WTE or biomass EGUs that also fire fossil fuel, as reported under Section 1021 of this Chapter, documentation of the portion of generation that is eligible for allocations of allowances, and all other generation- and emissions-related data required under the applicable EM&V plan for the qualified EGU. Hourly data are not required to be submitted as part of the M&V report.
6. Documentation of any change in the energy generation capacity or savings capability of the qualified EGU or qualified EER during the period covered by the M&V report and the date on which the change occurred,

and either certification that the qualified EER or qualified EGU continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes from the description in the approved eligibility application, which must include any change in the electricity generation capacity or savings capability of the qualified EER or qualified EGU (including the date or estimated date of the change); and,

7. Documentation of any change in ownership interest of the qualified EER or qualified EGU (including the date of the change).

C. Recordkeeping Requirements.

1. The authorized account representative of each qualified EGU and qualified EER required to report under this Section must maintain records for at least 5 years following the end date of each compliance period of all information generated during the compliance period related to the electricity savings or generation of the qualified resource under this Chapter, including data related to emissions, electrical output, allocations, allowance transfers and holdings, as well as any report or records related to qualified EGU maintenance or corrective action.
2. All records must be maintained at the physical address of the qualified EER or qualified EGU for at least 2 years after the end date of each compliance period or the date of occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest. For the remaining three years of the required retention, records may be maintained off site and electronically.
3. The authorized account representative must keep all of the following records:
   a. All required emissions monitoring information, if applicable, in accordance with this Chapter;
   b. Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate the amount of eligible electricity savings or generation under this Chapter and any other requirements of the State CO_2 Trading Program for EGUs;
   c. Data that are required to be recorded by 40 CFR part 75 subpart F; and,
   d. Data with respect to any allowances allocated to the qualified EER or qualified EGU.

Section 1023. Requirements for Independent Verifiers and Verification Reports

A. Verification Reports.

1. Each verification report that is required as part of an eligibility application, EM&V plan, or M&V report shall be submitted under separate cover to the Administrative Authority by the independent verifier. The verification report shall clearly identify the specific eligibility application, EM&V plan, or M&V report of which it is a part.
2. A verification report included as part of an eligibility application, an EM&V plan, or an M&V report must include the following:
   a. A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data that is the subject of the verification report, including an assessment of whether the eligibility application, EM&V plan or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements of this Chapter. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.
   b. 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."

3. A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:
   a. The eligibility of the EER or EGU to be issued allowances under this Chapter, including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets all criteria for qualification;
   b. The EER savings or EGU generation is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan;
   c. The EER or EGU exists or the operation or activity will be implemented in the manner specified in the eligibility application;
   d. The EM&V plan meets the requirements of Section 1019 of this Chapter;
   e. Disclosure of any mandatory or voluntary programs to which data are reported relating to the EGU or EER; and,
   f. Any other information required by the ATCS Administrator or Administrative Authority that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.
4. A verification report included as part of an M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the following information:
   a. The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electricity generation or savings, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all energy savings data are within a technically feasible range for that specific eligible resource. For all electricity saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved;
   b. The M&V report meets the requirements of Section 1021 of this Chapter; and,
   c. Any other information required by the Administrative Authority or ATCS Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

B. Accreditation Procedure for Independent Verifiers.

1. Only independent verifiers accredited by the Administrative Authority, or by his or her designee, may provide a verification report for an eligibility application, EM&V plan, or M&V report under this Chapter. Independent verifiers must be accredited and must meet the requirements of this Paragraph at all times when providing verification services.
2. Applications for accreditation must follow a procedure and form specified by the Administrative Authority, and shall include a demonstration by the verifier that it meets the requirements of this Paragraph.
3. Independent verifiers must have the skills, experience, and resources (personnel and otherwise) to provide verification reports, including the following:
   a. Appropriate technical qualification 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;
   b. Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;
   c. Knowledge of the requirements of the State Clean Power Plan, the State CO_2 Trading Program for EGUs, ATCS procedures, and related regulations and guidance;
   d. 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,
   e. Capability to perform key verification activities, such as development of a verification report; 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 opinion, list of findings, and verification report; and internal review of the verification findings and report.

4. Independent verifiers must document, in the application for accreditation, the names of the individuals that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, the accredited independent verification team) and demonstrate that they meet the requirements of this Paragraph. Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the Administrative Authority may provide a verification report.
5. 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.
6. Prospective independent verifiers must demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.
7. An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the 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.
8. 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 to the designated account representative the level of professional liability insurance it possesses when entering into contracts to provide verification services pursuant to this Chapter.

C. Conflict of Interest Avoidance.

1. Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), as described in this paragraph.
   a. Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;
   b. Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;
   c. Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of allowances, beyond the provision of verification services;
   d. Accredited independent verifiers 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, allowance issuance, or the number of allowances issued);
   e. Accredited independent verifiers must not own, buy, sell, or hold allowances, or other financial derivatives related to allowances, or have a financial relationship with other parties that own, buy, sell, or hold allowances or other related financial derivatives, other than to provide independent verification services;
   f. An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and
   g. An accredited independent verifier must ensure that the subject of any verification report does not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrative Authority.
2. A contract with an eligible resource for the provision of verification services does not constitute financial interest or financial relationship for the purpose of determining whether a COI exists.
3. Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate

that it has no COI related to the eligible resource. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, then an accredited independent verifier may take steps to eliminate the COI, which may include, where practicable and where such steps would be effective in eliminating the COI, prohibiting the person or persons with the conflict from any involvement in the matter subject to 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 related to the verification services.

4. Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrative Authority any potential COI related to an eligible resource, and must document all steps taken to eliminate the COI. Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in this Paragraph.
5. The Administrative Authority may reject a verification report from an accredited independent verifier, if the Administrative Authority determines that the accredited independent verifier has a COI as defined in this Paragraph.
6. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and the authorized account representative will be notified of the finding. The allocation of allowances for the energy savings covered in the M&V report shall be forfeited, unless an accredited independent verifier report that does not involve a COI is received by the Administrative Authority by a date provided by the Administrative Authority. The opportunity to provide a replacement accredited independent verifier report that does not involve a COI is at the discretion of the Administrative Authority, and the Administrative Authority shall consider the schedule for determining allocations of allowances in deciding whether to provide such an opportunity.

D. Revocation of Independent Verifier Accreditation Status. The Administrative Authority may revoke the accreditation of an independent verifier at any time for cause, including but not limited to the reasons specified in Paragraphs D.1 through D.5 of this Section.

1. The accredited independent verifier engaged in a COI as described in Paragraph C of this Section.
2. The accredited independent verifier failed to fully disclose any issues that may lead to a COI with respect to an EER, or other related entity, in accordance with Paragraph C of this Section.
3. The accredited independent verifier is no longer qualified to provide verification services.
4. The accredited independent verifier exercised negligence in the conduct of verification activities, or neglect of responsibilities.
5. The accredited independent verifier intentionally misrepresented data in a verification report.

Section 1025. Emissions and Electricity Generation Monitoring, Reporting and Recordkeeping for Qualified EGUs and Affected EGUs

A. Electricity Generation Monitoring Requirements for Qualified EGUs. To qualify for receiving allocation of allowances under this Chapter, each qualified EGU shall comply with the following monitoring and reporting requirements:

1. Generation shall be physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20. Code for Electricity Metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation by the Administrative Authority.
2. The generation data shall be measured at the generator's bus bar and data from only one qualified EGU may

be associated with each meter, except where the use of a single meter for multiple qualified EGU at the same facility has been approved by the Administrative Authority as part of the EM&V plan.

3. The generation data shall be collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly.
4. Each qualified nuclear and renewable energy EGU shall use the data collected by monitoring in accordance with this Paragraph to determine net electricity output in the form of MWh-net in accordance with Paragraph B of this Section.
5. Each qualified EGU that is required to adjust the total EGU net electrical output in order to determine the portion of the EGU total net electrical output that is eligible for allocations of allowances under this Chapter shall use the data collected by monitoring in accordance with this Paragraph to determine the total net electrical output under Paragraph B, which shall be adjusted as required under the applicable EM&V plan for each qualified CHP, WHP, WTE and biomass-fired EGU.

B. Electricity Generation and Useful Thermal Output Monitoring Requirements for Affected EGUs and Qualified EGUs.

1. The owner or operator of each affected EGU and each qualified EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU or qualified EGU that is a CHP 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}).
2. For each operating hour of each calendar year, determine P_{net} (the hourly net energy output in MWh) according to the procedures of this Paragraph, as appropriate for the type of affected or qualified EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to this Section, if there is no gross or net electrical output but there is mechanical or useful thermal output, 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 but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, that hour is not omitted from the compliance determination for an affected EGU or from the determination of the qualified EGU emission rate, where applicable. 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. Sum all of the hourly P_{net} values over the entire calendar year and over the entire multiyear compliance period, as appropriate, to determine total net energy output for the EGU.
3. Calculate the net energy output, P_{net}, for the affected EGU or qualified 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 as reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

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

Where:

$\mathbf{P_{net}}$ = Net energy output of the EGU in MWh.

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

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

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

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

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in 40 CFR § 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 EGU, as determined under Paragraph B.4 of this Section.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in 40 CFR § 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 40 CFR § 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 EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a CHP 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.

4. If applicable to the EGU (for example, for CHP), calculate the useful thermal output of steam, (Pt)PS, using the following equation:

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

Where:

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in 40 CFR § 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 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 40 CFR § 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 x 109 J/MWh or 3.413 x 106 Btu/MWh.

C. CO_2 Emissions Monitoring Requirements for Affected EGUs and Certain Qualified EGUs.

1. The owner or operator of an affected EGU and each qualified EGU that fires fossil fuel or other carbon-based fuel in addition to qualified biomass must monitor and report CO_2 mass emissions according to 40 CFR part 75. Unless an equivalent plan is already in place, the owner or operator shall prepare a monitoring plan in accordance with the applicable provisions of 40 CFR § 75.53(g) and (h) to implement the monitoring and reporting requirements of this Paragraph.
2. Measure and report the hourly CO_2 mass emissions (lbs) from each EGU using the procedures in this Paragraph C.2 of this Section, except as otherwise provided in Paragraph C.3 of this Section.
   a. Monitoring Equipment.
      i. Except as provided in Paragraph C.3(a)(ii) of this Section, the owner or operator of each affected EGU and each qualified EGU that fires fossil fuel or another carbon-based fuel that is not qualified biomass 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 EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to 40 CFR § 75.10(a)(3)(i).
      ii. As an alternative to direct measurement of CO_2 concentration, provided that the EGU does not use carbon separation (e.g., carbon capture and storage), the owner or operator of an EGU may use data from a certified oxygen (O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR § 75.10(a)(3)(iii). However, when an O2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (e.g., from sorbent injection), then this additional CO_2 must be accounted for, in accordance with Section 3 of

Appendix G to 40 CFR part 75.

iii. If CO_2 concentration is measured on a dry basis, then the owner or operator of the EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR § 75.11(b). Alternatively, the owner or operator of the EGU may either use an appropriate fuel-specific default moisture value from 40 CFR § 75.11(b) or an EPA-approved site-specific default moisture value.

iv. For each continuous monitoring system used to determine the CO_2 mass emissions from an affected or qualified EGU, the monitoring system must meet the applicable certification and quality assurance procedures in 40 CFR § 75.20 and Appendices A and B to 40 CFR part 75.

b. For each operating hour, calculate the hourly CO_2 mass (tons) using the data recorded under 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 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 where valid data are missing. Where such substitute data are recorded under 40 CFR part 75, the substitute data so recorded shall be used under this Paragraph.

c. Sum all of the hourly CO_2 mass emissions values over the entire calendar year and over the entire multiyear compliance period, as appropriate, to determine total CO_2 emissions for the EGU.

d. Calculate and report the hourly CO_2 mass emissions (lbs) from each EGU using the following procedures:

i. Calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in Section 4.2 of Appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

ii. Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours, to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

iii. The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions must be recorded under 40 CFR § 75.57(e) and must be reported electronically under 40 CFR § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

iv. Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in this Paragraph over the entire calendar year and over the entire compliance period to determine the total CO_2 mass emissions for each period.

3. The owner or operator of an EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with Paragraph C.3 of this Section, determine the hourly CO_2 mass emissions according to this Paragraph C.4 of this Section.

a. Implement the applicable procedures in accordance with Section 2.2 or 2.3 of Appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. 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 of 40 CFR part 75 (except for qualifying commercial billing meters).

b. For each measured hourly heat input rate, use Equation G–4 in Appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/hr).

c. Determine the hourly CO_2 mass emission rate (tons/hr) either from Equation F–11 in Appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in Section 4.2 of Appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis), and multiply it by the EGU or stack operating time in hours to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

d. The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions must be recorded under 40 CFR § 75.57(e) and must be reported electronically under 40 CFR § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly

CO_2 mass emissions.

e. Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in this Paragraph over the entire calendar year and over the entire compliance period to determine the total CO_2 mass emissions for each period.

f. The owner or operator of an EGU may determine site-specific carbon-based F-factors (Fc) using Equation F–7b in Section 3.3.6 of Appendix F to 40 CFR part 75, and may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G–4 nomenclature.

4. If two or more affected EGUs 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 EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facilities and the operating time must be expressed as "stack operating hours," as defined in 40 CFR § 72.2.
5. If the exhaust gases from an EGU are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and monitors are located in the ducts), the hourly CO_2 mass emissions and the "stack operating time" (as defined in 40 CFR § 72.2) at each stack or duct must be monitored separately and the resulting mass CO_2 emissions for each stack or duct must be summed to determine mass CO_2 emissions from the EGU.

D. Reporting Requirements. The designated representative of each affected EGU and the authorized account representative of each qualified EGU required to monitor emissions under this Section must prepare and submit reports according to this Paragraph D, as applicable.

1. Submit reports as required under subpart G of 40 CFR part 75 and include the following information, as applicable in the quarterly reports:
   a. The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to 40 CFR part 75, for each unit or stack operating hour;
   b. The calculated CO_2 mass emissions (tons) for each unit or stack operating hour;
   c. The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours;
   d. The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour;
   e. The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period; and,
   f. For an affected EGU, if the report covers the final quarter of a compliance period, then include the EGU's calculated emissions as a cumulative mass in units of tons, and a list of all unique allowance serial numbers retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired.
2. All reports required under this Section shall be submitted in electronic format using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the EPA Office of Atmospheric Programs, and/or another electronic data submittal system as designated by the Administrative Authority.
3. For an affected EGU that captures CO_2 to meet the applicable emission standard, report in accordance with the requirements of 40 CFR part 98 subpart PP, of this chapter, and either:
   a. Report in accordance with the requirements of 40 CFR part 98 subpart RR if injection occurs on-site; or
   b. Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR, if injection occurs off site.
4. In addition to the reporting to ECMPS, each affected EGU and each qualified EGU required to report emissions under this Chapter shall submit an annual summary report to the Administrative Authority of the prior year's emissions (in tons) and generation (in MWh-net), no later than April 15 of each calendar year. Each qualified EGU shall include the summary report as part of the M&V report required under Section 1021 of this Chapter. The designated representative of each facility at which an affected EGU is located shall submit a report, in a format prescribed by the Administrative Authority, of the tons of CO_2 emitted and MWh-net of electricity generated by each affected EGU at the facility for the prior calendar year, which shall be based on and consis-

tent with the emissions as reported to ECMPS for the four calendar quarters. Hourly data are not required to be submitted as part of the annual report to the Administrative Authority.

E. Recordkeeping Requirements.

1. The designated representative of each affected EGU, and the authorized account representative of each qualified EGU required to report under this Section, must maintain records for at least 5 years following the end date of each compliance period of all information generated during the compliance period related to compliance with obligations and emission standards under this Chapter, including data related to emissions, electrical output, allocations, allowance transfers and holdings, as well as any report or records related to an affected EGU or qualified EGU maintenance or corrective action.
2. For affected and qualified EGUs, all records must be maintained on site for at least 2 years after the end date of each compliance period or the date of the compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest. For the remaining three years of the required retention, records may be maintained off site and electronically.
3. The owner or operator and designated representative of an affected EGU must keep all of the following records:
   a. All emissions monitoring information, in accordance with this Chapter;
   b. 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 this Chapter and any other requirements of the State CO_2 Trading Program;
   c. Data that are required to be recorded by 40 CFR part 75 subpart F; and,
   d. Data with respect to any allowances used by the affected EGU in its compliance demonstration.

Section 1027. Enforcement Liabilities and Penalties

A. Enforcement Liability.

1. Any provision of this Chapter that applies to an affected EGU at a facility or to the designated representative of an affected EGU at a facility also applies to the owners and operators of such affected EGU and such facility.
2. Any provision of this Chapter that applies to the owners and operators of an affected EGU applies wholly and separately to each owner and operator of the affected EGU, and applies to the designated representative of such affected EGU.

B. Effect on Other Authorities. No provision, requirement, exemption or exclusion under this Chapter shall be construed to exempt or exclude the owners or operators or designated representative of any affected EGU from the obligation to comply with any applicable requirement under any other provision of the State Administrative Code, State Environmental Quality Act, or federal Clean Air Act.

C. Severability. The provisions of this Chapter are severable. If any provision of this Chapter or the application of any provision of this Chapter to any person, situation or circumstance is for any reason adjudged invalid, the adjudication does not affect any other provision of this Chapter or the application of any adjudicated provision of this Chapter to any other person, situation or circumstance not adjudged invalid.

D. Violations. Total CO_2 emissions during any compliance period in excess of the CO_2 allowances surrendered from the compliance account for the affected EGU as required by Section 1005 and in accordance with Section 1011 of this Chapter shall constitute a violation, by the owners and operators of the affected EGU of this Chapter, of the State Environmental Quality Act and, for an existing affected EGU, of the federal Clean Air Act. Each ton of excess CO_2 emissions will constitute a separate violation.

E. State and Federal Enforcement. In addition to the stipulated penalties and corrective actions imposed under this Section, for each violation of this Chapter the owners and operators of each affected EGU are subject to enforcement pursuant to the State Environmental Quality Act and, for existing affected EGUs, subject to enforcement pursuant to the federal Clean Air Act, including potential injunctive remedies, fines, penalties, or any other remedy imposed pursuant to the applicable laws thereunder.

F. Initial Remedy. The following corrective actions and remedies shall apply for each violation of an emission standard of Section 1005 of this Chapter.

1. Upon making the transfers for surrender from the compliance account to the retirement account for an affected EGU for compliance under Section 1005 of this Chapter, if the Administrative Authority determines that the allowances held in the retirement account are insufficient and that excess emissions have occurred for a compliance period, then the Administrator will deduct from the facility's compliance account or general account, as available, an amount of allowances up to two times the number of tons of the facility's excess emissions. Regardless of whether the Administrative Authority obtains allowances from the compliance or general account in an amount to equal the excess emissions or more, failure of the authorized account representative for the affected EGU to submit a request by the transfer deadline to surrender sufficient allowances to the retirement account shall constitute a violation of the applicable emission standard.
2. The owners and operators of an affected EGU with excess emissions for any compliance period shall obtain as necessary and surrender allowances in an amount equal to two times the number of tons of the affected EGU's excess emissions. Allowances required under this Paragraph shall be surrendered no later than December 31 of the year following the close of the compliance period in which the excess emissions occurred. A CO_2 allowance relied upon for providing the initial remedy under this Paragraph must be a CO_2 allowance that was allocated for a compliance period before the compliance period in which the excess emissions occurred, the compliance period during which the excess emissions occurred, or the compliance period immediately following the compliance period in which the excess emissions occurred.

G. Stipulated Penalties. Nondiscretionary stipulated penalties shall apply upon a finding of violation of the emission standards of Section 1005 of this Chapter.

1. The Administrative Authority shall issue a penalty notice in an amount equal to three times the allowance market value, as determined by the most recent State sale or auction held in accordance with Section 1029 of this Chapter, for each ton of excess CO_2 emissions for each violation.
2. In addition to the penalty assessed under Paragraph G.1 of this Section, in the event the owners and operators fail to timely surrender any allowance due under Paragraph F.2 of this Section, the Administrative Authority shall issue a penalty notice in an amount equal to two times the allowance market value, as determined by the most recent State sale or auction held in accordance with Section 1029 of this Chapter, for each allowance that the owner or operator fails to timely surrender. Neither the issuance nor the payment of a penalty issued under this Paragraph G.2 shall relieve the owners and operators from the obligation to surrender the full number of allowances due under Paragraph F.2 of this Section.
3. Stipulated penalties shall be paid within 90 days of service of the penalty notice.

Section 1029. Procedures for State Auctions and Sales of Allowances

A. Administrative Provisions for State Auctions and Sales of Allowances.

1. For each compliance period, the Administrative Authority shall offer the full complement of the State's portion of allowances for auction or sale. The Administrative Authority is not required to offer the full State's portion of allowances at the first auction or sale for a compliance period, and may offer a portion of the allowances for

auction and a portion for sale. The Administrative Authority may schedule auctions or sales at his or her discretion, provided an initial offering of the full quantity of allowances comprising the State's portion is made no later than June 1 of the final year of the compliance period.

2. The Administrative Authority may choose to participate in a multi-state auction including other States participating in interstate trading with the State CO_2 Trading Program for EGUs.
3. Implementation and administrative support functions for any auction or sale conducted under this Chapter may be delegated by the Administrative Authority to an agent qualified to conduct auctions or sales, at the discretion of the Administrative Authority.
4. Any allowances that are unsold at the close of any auction or sale under this Chapter will be held in the State ATCS account and may be made available in a succeeding auction or sale.
5. Advance Notice of Auction or Sale. At least 30 days prior to each auction or sale of allowances, the Administrative Authority will publish a Notice of Auction or Notice of Sale, providing information about the auction or sale. Each notice will provide a specific description of the auction or sale format, including all participation requirements, and shall include but not be limited to the following information: the date, time, location and/or electronic address of the auction or sale; the quantity of CO_2 allowances to be offered for auction or sale; the amount and type of security required for participants; the reserve price (for auctions) or sale price (for sales) of the CO_2 allowances; the limit on the amount of CO_2 allowances any one buyer or group of buyers may purchase; application instructions; other pertinent rules of the event; and, identification of a contact person for further information.
6. After each auction or sale and within 30 days of receipt by the Administrative Authority of payments from successful bidders or buyers, the Administrative Authority shall transfer purchased CO_2 allowances to the purchaser's ATCS compliance account or general account.
7. The Administrative Authority will publish on a central auction or sale website or the Department's website, at his or her discretion, the results of each auction and sale, including the sale price(s) and number of allowances sold.

B. Provisions Governing the State Auction and Sale of Allowances.

1. CO_2 allowances will be auctioned and sold in lot sizes of 1,000 allowances, except where available supply requires a smaller lot size.
2. Prior to each auction, the Administrative Authority shall set a binding reserve price to be accepted for CO_2 allowances. No allowances shall be sold at any auction for a price below the reserve price for that auction. If the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.
3. Prior to each sale, the Administrative Authority shall set a binding sale price to be accepted for CO_2 allowances. No allowances shall be sold for a price below the set price for that sale offering. If the total demand for allowances for a sale event is greater than the total number of allowances available, then sales will be distributed among buyers by prorating based on the number of allowances requested for purchase by each prospective buyer.
4. No bidder or combination of bidders that have related beneficial interest may bid on or purchase more than 25% of the allowances available in any given auction or sale.

C. Requirements for Participating Bidders and Buyers.

1. Any prospective bidder or buyer must provide financial security in the form of a bond, cash, certified funds, or an irrevocable stand-by letter of credit, in a form and manner specified by the Administrative Authority in the Notice of Auction or Notice of Sale. A prospective bidder's eligibility to bid in any auction or a buyer's eligibility to buy allowances shall be limited to the level of financial security provided. Financial security may be forfeited to and retained by the Administrative Authority or its agent in the event the bidder's offer is accepted in a CO_2 allowance auction and the bidder fails to tender payment of the full amount when due.
2. Bidders or buyers may request return of their financial security at any time prior to or following any CO_2 allowance auction or sale. The Administrative Authority shall return the financial security provided that there is no current or pending claim to such security as a result of a successful bid or sale.

3. Any party wishing to participate in an auction or sale shall be required to have an active ATCS compliance account or a general account, and complete an application to qualify as a bidder or purchaser.
4. Applicants wishing to participate in an auction or sale and who have not previously been approved as a qualified bidder or purchaser shall submit an application in the form requested by the Administrative Authority or its agent on or before the deadline specified in the Notice, which shall be no sooner than fifteen (15) days following the date of publication of the Notice. Application information and forms shall be made available electronically on the central auction or sale website or the Department's website.
5. The Administrative Authority or its agent will review each application and make a determination as to whether an applicant is deemed qualified. Failure to provide any information required by the Notice or this regulation may result in the application being denied. Prospective bidders and buyers that qualify for participation under this subsection will be qualified for all subsequent CO_2 allowance auctions and sales, and will be eligible to place bids or make purchases provided that the required financial security requirements are met for each auction and sale.
6. Prior to each CO_2 allowance auction or sale, a prospective bidder or buyer that has qualified under this subsection must notify the Administrative Authority of its intent to participate in the upcoming auction or sale. This notification shall include either a statement that there has been no material change to the information provided in the application, or a revised application if material changes have occurred.
7. The Administrative Authority may suspend or revoke its approval of an application if the bidder or buyer fails to comply with requirements of this Chapter, or if the Administrative Authority determines that a bidder or buyer has provided false or misleading information, or has withheld pertinent information in its application, or has otherwise failed to comply with this Chapter.

Section 1031. Definitions

Terms used in this Chapter have the meanings set forth in this Section.

Administrative Authority means the Director of the State Department of Environmental Protection or his or her delegate.

Affected electric generating unit or Affected EGU means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in Section 1003 of this Chapter.

Allocation means, (verb) the distribution of allowances comprising the mass emissions budget for a compliance period by the Administrative Authority to qualifying entities in proportions in accordance with the provisions of Section 1007 of this Chapter; (noun) the portion of allowances from the mass emissions budget for a compliance period received by a qualifying entity.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrative Authority and/or the ATCS Administrator documents the allocation, recordation, deductions, transfers, surrender and retirement of CO_2 allowances under the State CO_2 Trading Program for EGUs.

Allowance transfer deadline means the date by which the designated representative of an affected EGU must submit a request for transfer of allowances from the compliance account to the retirement account for the affected EGU in amount equal to the mass emissions of CO_2 for the compliance period, for purposes of complying with the emission standard of Section 1005 of this Chapter. The allowance transfer deadline is May 1 of the calendar year following the end of each compliance period.

Alternate designated representative means the person who is authorized by the owners and operators of a facility and all affected EGUs at the facility, in accordance with this Chapter, to act on behalf of the designated representative in matters pertaining to the CO_2 Trading Program.

Annual capacity factor means the ratio between the actual heat input to an affected EGU during a calendar year and the potential heat input to the affected EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the person who is authorized, in accordance with this Chapter, to transfer and otherwise dispose of CO_2 allowances held in the general account and, with regard to a compliance account, the designated representative of the facility.

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 Chapter.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (e.g., trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that is not a Saturday, a Sunday, a state holiday, or a federal holiday.

Capacity factor means the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Clean Air Act means the federal Clean Air Act, 42 U.S.C. § 7401, et seq.

CO_2 allowance means a limited authorization to emit one ton of CO_2 during the compliance period for which the allowance is issued or any compliance period thereafter, issued and allocated by the Administrative Authority under this Chapter, or by EPA or another State or jurisdiction as designated under an EPA-approved or EPA-administered mass-based plan under 40 CFR part 60 subpart UUUU or 40 CFR part 62 subpart MMM where the mass-based plan provides for interstate trading of allowances and utilizes an allowance tracking system designated as authorized for trading by the Administrative Authority.

CO_2 allowance deduction or ***deduct CO_2 allowances*** means the permanent withdrawal of CO_2 allowances by the Administrative Authority from a compliance account (e.g., in order to account for compliance with the CO_2 emission standard).

CO_2 allowances held or ***hold CO_2 allowances*** 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:

i. Have been recorded by the Administrative Authority in the account or transferred into the account by a correctly submitted CO_2 allowance transfer in accordance with this Chapter (allowances are treated as held in the account from the time the transfer request is submitted, regardless of whether it has been recorded); and,

ii. Have not been transferred out of the account by a correctly submitted CO_2 allowance transfer in accordance with this Chapter (allowances are treated as transferred out of the account and not held in the account from the time the transfer request is submitted, regardless of whether it has been recorded).

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 facility as of the transfer deadline for that compliance period, under the provisions of Section 1011 of this Chapter.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or ***CHP unit*** (also known as "cogeneration") means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Common practice baseline (CPB) means a calculated level or energy usage derived by assuming a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

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 Administrative Authority, 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 a given year in complying with the facility's CO_2 emission standard.

Compliance period means a multi-year period for which compliance with the emission standard of Section 1005 of this Chapter applies. Compliance periods are as follows:

Interim 1: The 3-year period from January 1, 2022 through December 31, 2024;

Interim 2: The 3-year period from January 1, 2025 through December 31, 2027;

Interim 3: The 2-year period from January 1, 2028 through December 31, 2029;

Final: Each 2-year period, beginning with January 1, 2030 through December 31, 2031, and thereafter commencing January 1 of each even numbered year and ending December 31 of each odd numbered year.

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. The following systems are the principal types of continuous emission monitoring systems:

i. 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;

ii. A moisture monitoring system providing a permanent, continuous record of the stack gas moisture content, in percent H2O;

iii. 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

iv. 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.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: 1) has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and, 2) is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including effective useful life (EUL) values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or ***demand-side EE*** means energy efficiency activities, projects, programs or measures resulting in electricity savings.

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, for a facility and each affected EGU at the facility, the person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility to represent and legally bind each owner and operator in matters pertaining to the CO_2 Trading Program.

Design efficiency means the rated overall net efficiency (e.g., electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means any fuel oil that complies with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98; diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a; kerosene, as defined by ASTM International in ASTM D3699; biodiesel as defined by ASTM International in ASTM D6751; or biodiesel blends as defined by ASTM International in ASTM D7467.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by EE program.

Energy efficiency measure or ***EE measure*** means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

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 project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or ***EE project*** means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of an EE measure.

EM&V plan means an evaluation, measurement and verification plan that meets the requirements of this Chapter.

Energy service company means a private enterprise engaged in delivering electricity savings directly for an end-use customer or as an agent of a sponsoring entity such as a utility.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating facility for generating allowances pursuant to this regulation, including the type of facility.

Excess emissions means any ton of emissions from the affected EGUs at a facility during a compliance period that exceeds the CO_2 emissions limitation for the facility for such compliance period.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

General account means an ATCS account established for the purpose of holding or transferring allowances in accordance with Section 1013 of this Chapter.

Generator means a device that produces electricity.

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, 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 Administrative Authority by the designated representative 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.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or ***IGCC facility*** means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator or the Administrative Authority may waive the 50 percent solid-derived fuel requirement for periods of the gasification system construction, startup and commissioning, shutdown, or repair. In an IGCC facility, solid feed (e.g., coal) is gasified to derive gaseous fuel for combustion. No solid fuel is directly burned in the combustion unit during operation.

ISO conditions means 288 Kelvin (15°C), 60 percent relative humidity and 101.3 kilopascals pressure.

Low-income household means a household where the household income is less than or equal to twice the federal poverty level, as defined under the most recent US Department of Health & Human Services Poverty Guidelines.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Minority population means the number or percent of individuals in a census block group who, based on the most recent U.S. Census Bureau data, list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino; that is, all people other than non-Hispanic, non-Latino, white-alone individuals.

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) 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) of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation an EGU produces (including, but not limited to, output from steam turbines, combustion turbines, and gas expanders), as measured at the generator terminal, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

i. The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (e.g., steam delivered to an industrial process for a heating application); and

ii. For CHP facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (e.g., steam delivered to an industrial process for a heating application).

Operate or ***operation*** means, with regard to an affected EGU, to combust fuel.

Operator means, for a facility or an affected EGU at a facility respectively, any person who operates, controls, or supervises an affected EGU at the facility or the affected EGU 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 or an affected EGU at a facility respectively, any of the following persons:

i. Any holder of any portion of the legal or equitable title in an affected EGU at the facility or the affected EGU;

ii. Any holder of a leasehold interest in an affected EGU at the facility or the affected EGU, 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 affected EGU; and

iii. Any purchaser of power from an affected EGU at the facility or the 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 and operators: 1) have taken on as enforceable obligations in the operating permit that covers the affected EGU conditions that prohibit operation and emissions; or 2) have rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the federal Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere, as approved by the Administrative Authority or EPA under this Chapter.

Recordation, record, or ***recorded*** means, with regard to CO_2 allowances, the moving of CO_2 allowances by the Administrative Authority into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

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).

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

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25°C, 77°F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any CHP combustion turbine system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly, then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or ***serve*** means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation. Compliance with a submittal or service deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

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 energy efficiency measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity losses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or ***hour of unit operation*** means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for any affected EGU with no condensate return (or other thermal energy input to the affected EGU) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Vulnerable community means, for purposes of determining the allocation of allowances for qualified EERs under this Chapter, any census block that has a minority population greater than 70% or that has greater than 50% low-income households, as determined in accordance with the most recent U.S. Census data.

Waste-to-Energy means a process or unit (e.g., solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity or heat.

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