

EXHIBIT C

Technical Support Document (TSD) for
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility
Generating Units

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State Plan Considerations

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I. Introduction

As discussed in the preamble, in section VIII.F, the EPA is proposing to give states broad discretion to develop state plans that best suit their circumstances and policy objectives. In developing its plan, a state will need to make a number of decisions that will require careful consideration, in order to ensure that its plan both meets a state's policy objectives and is approvable by EPA. The preamble, in section VIII.F, identified several key decision points and factors that states should consider when developing their plans. In this section of the preamble, the EPA also raised a number of considerations for how it will apply the proposed general plan approvability criteria to different types of state plan approaches. This includes a number of considerations related to appropriate approaches, methods, and materials that are submitted for state plan components in an approvable plan, under different types of state plans. This technical support document (TSD) explains and discusses these considerations in depth, and elaborates options proposed in the preamble where relevant. Topics addressed in this TSD include:

- Description of state plan pathways
 - Provided as context for the discussion of applied considerations that follows
- Enforceability considerations under different plan scenarios
 - Summary of potential enforceable mechanisms under different state plan scenarios
- Incorporating energy efficiency and renewable energy (EE/RE) requirements and programs in state plans, including:
 - Options for adjusting EGU CO₂ emission rates based on the effect of EE/RE requirements and programs
 - Methods for estimating avoided CO₂ emissions that result from EE/RE requirements and programs, for use in projecting emission performance under a state plan and in ex post adjustment of CO₂ emission rates during plan implementation
- Quantification, monitoring, and verification of EE/RE requirements and programs
 - Survey of quantification, monitoring, and verification under existing state and utility EE/RE requirements and programs

- Discussion of possible approaches for minimum requirements or guidance for quantification, monitoring, and verification for EE/RE requirements and programs included in state plans, building off existing state processes and infrastructure
- Discussion of areas where supplemental information would be useful for estimating avoided CO₂ emissions from EE/RE requirements and programs
- Reporting and recordkeeping for responsible parties subject to EE/RE requirements or implementing EE/RE programs included in state plans
 - Survey of reporting and recordkeeping under existing state and utility EE/RE requirements and programs
 - Discussion of possible approaches for EE/RE reporting requirements for state plans, building off existing state processes and infrastructure
 - Discussion of areas where supplemental information would be useful for estimating avoided CO₂ emissions from EE/RE requirements and programs
- Treatment of interstate emission effects
 - Further elaboration of proposed approaches and alternatives discussed in the preamble

It should be noted that the preamble discusses, and solicits comment on, legal issues concerning whether CAA section 111(d) authorizes some of the types of state plans described in this TSD and whether it authorizes state plans to include some of these types of measures. This TSD does not further discuss those legal issues, but solely for the purpose of describing all of the available types of state plans and measures, assumes that all of them are authorized under CAA section 111(d).

II. Description of State Plan Pathways

As discussed in the preamble, the EPA is proposing a state plan approach that could accommodate a diverse set of state requirements, programs, and measures, through two basic approaches – direct emission limits and a portfolio approach. These two basic approaches provide four distinct state plan “pathways” under CAA section 111(d). These pathways include:

- Rate-based CO₂ emission limits applied to affected EGUs;
- Mass-based CO₂ emission limits applied to affected EGUs;
- A state-driven portfolio approach
- A utility-driven portfolio approach

Under this flexible approach, a state plan could include a combination of measures that reduce CO₂ emissions at affected EGUs through the application of emission limits as well as measures that involve actions within the interconnected electricity system that reduce utilization at affected EGUs and thereby avoid EGU CO₂ emissions. Examples of these latter measures include, among others, end-use energy efficiency resource standards and renewable energy portfolio standards, as well as certain components of utility integrated resource plans. A state could either rely solely on CO₂ emission limits that are enforceable against affected EGUs or, alternatively, rely on a portfolio approach, which would include those limits as well as other enforceable measures. Table 1 provides practical examples of possible state plan approaches under each of these pathways, which are discussed in more detail below.

This section elaborates the different plan approaches that are discussed in section VIII.B of the preamble, to provide context for the applied considerations that are discussed throughout the remainder of the TSD. In particular, some of these considerations apply to different types of state plan approaches. For example, section III of this TSD addresses enforceable legal mechanisms that might apply under different types of state plans, such as utility- and state-driven portfolio approaches, which would apply enforceable obligations to different entities. Section IV of this TSD applies to state plans that implement rate-based CO₂ emission limits for affected EGUs that also provide for the adjustment of CO₂ emission rates based on the effect of

enforceable end-use energy efficiency and renewable energy requirements and programs that are incorporated in a plan. Section V of this TSD addresses quantification, monitoring, and verification of end-use energy efficiency and renewable energy programs and measures. Considerations addressed in this section would apply to states implementing a rate-based emission limit approach that provides for adjustment of CO₂ emission rates based on the effect of end-use energy efficiency and renewable energy, as well as states implementing utility- or state-driven portfolio approaches that incorporate end-use energy efficiency and renewable energy requirements and programs. Likewise, section VI of this TSD addresses considerations for reporting and recordkeeping for end-use energy efficiency and renewable energy requirements and programs, which would apply for these types of state plans.

Table 1. Different Illustrative Plan Approaches

Rate-Based Plan (Simple)	Rate-Based Plan (More Complex)	Mass-Based Plan (Simple)	Mass-Based Plan (More Complex)
<ul style="list-style-type: none"> • CO₂ rate limit applied directly to EGUs 	<ul style="list-style-type: none"> • CO₂ rate limit applied directly to affected EGUs <ul style="list-style-type: none"> ➢ Credit for EE/RE can be used toward compliance 	<ul style="list-style-type: none"> • CO₂ mass emissions limit applied directly to affected EGUs 	<ul style="list-style-type: none"> • Portfolio of measures applied to meet a mass CO₂ goal <ul style="list-style-type: none"> ➢ Translation from rate goal to mass goal (plan includes basis and supporting analysis)
<ul style="list-style-type: none"> • Responsible party is EGU owner/operator (subject to state regulations) • Demonstration of compliance based on monitoring and reporting of EGU stack CO₂ emissions and MWh output 	<ul style="list-style-type: none"> • Responsible party is EGU owner/operator (subject to state regulations), <u>along with</u>: <ul style="list-style-type: none"> ➢ Electric distribution utility with regulatory obligations under state EERS and RPS • Demonstration of compliance based on: <ul style="list-style-type: none"> ➢ Monitoring and reporting of EGU stack CO₂ emissions and MWh output, <u>and</u> ➢ EM&V for EE/RE to determine “credits” that can be used to adjust CO₂ rate when demonstrating compliance 	<ul style="list-style-type: none"> • Responsible party is EGU owner/operator (subject to state regulations) • Demonstration of compliance based on monitoring and reporting of EGU stack CO₂ emissions 	<ul style="list-style-type: none"> • Responsible parties include: <ul style="list-style-type: none"> ➢ State (ultimate responsibility for achieving goal) ➢ Electric distribution utility with regulatory obligations under state EERS and RPS ➢ EGU owner/operator (for emission limit component) • Demonstration of plan performance based on monitoring and reporting of EGU stack CO₂ emissions

A. Direct Emission Limits

The first basic state plan approach is CO₂ emission limits that apply directly to affected EGUs, and includes two pathways: 1.) rate-based CO₂ emission limits applied to affected EGUs; and 2.) mass-based CO₂ emission limits applied to affected EGUs. For both types of emission limits, end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions could be a major component of a state's overall strategy for cost-effectively reducing EGU CO₂ emissions.

1. Rate-Based CO₂ Emission Limits Applied to Affected EGUs

Rate-based emission limits would apply a lb CO₂/MWh emission limit to affected EGUs. Depending on a state's approach, compliance flexibility could be provided through different mechanisms, such as averaging among affected sources, or the use of tradable credits for avoided CO₂ emissions resulting from end-use energy efficiency and renewable energy measures as discussed below. In the case of the latter approach, such credits could be used by an affected EGU to adjust its CO₂ emission rate when demonstrating compliance with a rate-based emission limit.¹ Rate-based emission limits could be implemented on a state-by-state basis, or through multi-state averaging or trading. Rate-based emission limits might also be a component of a portfolio approach (described below), where the emission rate limit would not assure full achievement of the required level of emission performance specified for affected EGUs in the state plan, in which case the emission limit would be supplemented with other enforceable measures.

Rate-based emissions limits could incorporate end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions, through an administrative adjustment by the state or tradable crediting system.² These adjustment credits could be used by an affected EGU to

¹ Section IV of this TSD discusses possible approaches for such adjustments.

² Under a tradable credit system, a state would issue adjustment credits based on avoided CO₂ emissions achieved through end-use energy efficiency and renewable energy measures. EGUs could then apply these tradable adjustment credits when demonstrating compliance with a rate-based CO₂ emission limit. These tradable credits might be issued to affected EGUs for free or through purchase. Alternatively, end-use energy efficiency and renewable energy actions undertaken by private parties (including EGU owners and operators) might be eligible for the issuance of adjustment credits. Under an administrative adjustment approach, a state program administrator might administratively adjust an affected EGU's CO₂ emission rate based on avoided CO₂ emissions achieved

comply with the rate-based emission limit, by adjusting the unit's reported CO₂ emission rate.³ Under this approach, end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions would be enforceable components of a state plan. These actions would need to be enforceable components of a state plan to provide assurance that a sufficient amount of adjustment credits will be available to facilitate EGU compliance with the emission rate limit, and that end-use energy efficiency and renewable energy measures that generate adjustment credits are properly quantified, monitored, and verified.⁴

2. Mass-Based CO₂ Emission Limits Applied to Affected EGUs

Mass-based emission limits would apply either an individual limit on CO₂ tons emitted from an affected EGU or establish a finite CO₂ emissions budget for a group of affected EGUs. The latter approach is typically implemented through a tradable allowance system.

With mass-based emission limits, end-use energy efficiency measures that avoid EGU CO₂ emissions could be a major component of a state's overall strategy for cost-effectively reducing EGU CO₂ emissions, but would be complementary to the enforceable state plan (*i.e.*, not included as enforceable measures in a state plan). These actions could be used to help a state cost-effectively achieve the CO₂ emissions limits, or to achieve other policy goals, but CO₂ emissions performance would be assured through the enforceable limit on mass emissions from affected EGUs.

B. Portfolio Approach

The second basic state plan approach uses a portfolio of actions, in which a state plan includes multiple programs and measures that are designed to achieve either a rate-based or mass-based emissions performance goal for affected EGUs. This approach includes two

through state end-use energy efficiency and renewable energy deployment programs or utility compliance with energy efficiency resource standards or renewable energy portfolio standards. These adjustments might be apportioned to affected EGUs based on a predetermined metric. Affected EGUs would then begin with an adjusted CO₂ emission rate when considering additional actions necessary for compliance with the rate-based CO₂ emission limit.

³ Section IV of this TSD discusses possible approaches for such adjustments.

⁴ Section V of this TSD addresses considerations for quantification, monitoring, and verification of end-use energy efficiency and renewable energy measures.

pathways: 1.) a state-driven portfolio approach; and 2.) a utility-driven portfolio approach. A portfolio approach would include emission limits for affected EGUs along with other enforceable end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions. A portfolio approach could be state-driven or utility-driven, depending on the utility regulatory structure in a state.

In general, a portfolio approach is distinguished from an emission limit approach by the fact that achievement of the full level of required emission performance for affected EGUs specified in the plan is not ensured through the application of direct emission limits that apply to affected EGUs.

A portfolio approach would include both direct emission limits that apply to affected EGUs and other indirect measures that avoid EGU CO₂ emissions. Under a portfolio approach, end-use energy efficiency and renewable energy measures that avoid EGU CO₂ emissions would be enforceable components of a state plan. This would be necessary because the emission limit applied directly to affected EGUs would not assure full achievement of the required level of emission performance specified in the state plan.⁵

As discussed below, due to differences in state utility regulatory structure, a portfolio approach implemented in a restructured state with retail competition will likely look quite different from one implemented in a state with vertically integrated, regulated electric utilities. This includes the process for developing the portfolio approach, the mechanisms for implementing it, the responsible parties, and the regulatory and legal relationships among parties and state regulators.

1. State-Driven Portfolio Approach

A state-driven portfolio approach – rather than a utility-driven approach – is more likely to be adopted in a state with a restructured electricity sector. In these states, rate-regulated

⁵ Under a portfolio approach, either a rate-based or mass-based emission limit might be applied. Such plans might also include application of a direct emission limit to a subset of affected EGUs. Both scenarios would necessitate inclusion of supplemental measures, such as end-use energy efficiency and renewable energy, or other measures that directly apply to affected EGUs (e.g., repowering or retirement of one or more high-emitting EGUs), in order to achieve the required level of emission performance for affected EGUs specified in the state plan.

electric utilities have typically divested electric generation assets and there is often also retail competition where non-utility entities can supply retail customers with electricity.⁶ Electric distribution utilities in these states typically purchase electricity from competitive wholesale markets. As a result, utilities in these states typically do not engage in a utility integrated resource planning (IRP) process. IRP processes, which are a natural fit for implementing a portfolio approach, are much more common in states with regulated vertically integrated utilities that own and operate electric generating assets.

In restructured states, policies for increasing end-use energy efficiency and renewable energy are often established through regulations that apply to electric distribution utilities, such as end-use energy efficiency resource standards and renewable portfolio standards. Many of these states have also established independent non-profit entities to administer end-use energy efficiency and renewable energy deployment programs funded through regulated electricity rates.

Under a state-driven portfolio approach a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.

2. Utility-Driven Portfolio Approach

A state with vertically integrated, state-regulated electric utilities is more likely to adopt a utility-driven portfolio approach. In such states, private utilities own and operate electric generation, transmission, and distribution systems necessary to supply retail customers with electricity.⁷ These utilities are overseen by state public utility commissions that approve utility capital investments and oversee utility operations, and allow utilities to recover approved

⁶ In some restructured states, the holding company that owns the distribution utility may also own generating assets which are operated on a competitive basis. In these instances, there typically are legal provisions in place that mandate the independent management and operation of generation and distribution assets.

⁷ In some instances these regulated utilities may supplement electric generation with purchases through wholesale electricity markets and may also sell surplus generation in these wholesale markets on a competitive basis.

investments and operating costs, along with a specified financial rate of return, through regulated retail electricity rates. State utility commissions often require regulated utilities to engage in an integrated resource planning (IRP) process, which seeks to identify the least-cost set of resources available to provide electricity to retail customers over a multi-year period, and often includes evaluation of measures such as end-use energy efficiency, demand-side management, and renewable energy.⁸ Once an IRP is approved by a state public utility commission, a utility's cost recovery and rate of return is often linked to identified measures and metrics in the IRP.⁹

Under a utility-driven portfolio approach, a vertically integrated utility would develop and implement a portfolio of measures designed to meet the rate-based or mass-based emission performance level for its affected EGUs specified in the state plan. This plan would likely be developed and approved through an IRP-like process overseen by the state public utility commission. If there is more than one rate-regulated electric utility in the state, the state might apportion the state emission performance level for affected EGUs among utilities.

A utility plan under this approach might rely heavily on end-use energy efficiency and renewable energy actions, but also might focus on direct actions at affected EGUs, such as repowering to fire a lower-carbon fuel or retirement of high-emitting units. Such plans might also include direct emission limits on affected EGUs, or implementation of an environmental dispatch approach that incorporates CO₂ emission rate into the dispatch protocol used by the utility to schedule electric generation.¹⁰

Under a utility-driven portfolio approach, the entire suite of obligations under the plan would be enforceable against the utility company, which would also be an owner and operator of affected EGUs. If there are other affected EGUs in the state that are not owned and operated by a

⁸ Depending on the state, an IRP process may also assess factors such as fuel diversity and environmental performance, among others, when identifying the least-cost mix of resources for a utility.

⁹ In some cases, an IRP prescribes or authorizes specific actions. In others, an IRP serves as a guide for the utility and the public utility commission when evaluating acquisition or implementation of specific utility resources or programs. In such cases, the specific resource or program is approved through a PUC order that authorizes or requires actions and identifies performance obligations. These orders may or may not be fully consistent with provisions in an IRP.

¹⁰ Vertically integrated utilities, even if they operate within the footprint of a competitive wholesale electricity market, may self-schedule generation assets.

vertically integrated utility, a state plan might need to include other measures that address CO₂ emission performance by these affected EGUs.

A similar approach could be taken by municipally owned utilities or utility cooperatives, which often also engage in an IRP process. However, state public utility commissions (PUCs) often do not regulate these utilities. As a result, implementation of a portfolio approach by these entities would introduce practical enforceability considerations under a state plan.

III. Enforceability Considerations under Different State Plan Scenarios

As discussed in the preamble of the proposal, in section VIII.F.1, a state plan must include enforceable measures. To ensure that its plan is enforceable, a state will need to:

- Identify in its plan the entity or entities responsible for meeting compliance and other enforceable obligations under the plan
- Include mechanisms for demonstrating compliance with plan requirements or demonstrating that other binding obligations are met
- Provide a mechanism(s) for legal action if affected EGUs are not in compliance with plan requirements or if other entities fail to meet enforceable plan obligations

As discussed in the preamble, responsible entities in an approvable state plan may include an owner or operator of an affected EGU, other entities with responsibilities assigned by a state, or the state itself. Other entities might include an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity. State responsibility might include obligations that are assumed directly by a state agency, authority, or other state entity to carry out aspects of a state plan.

While this approach provides states with broad discretion to develop plans that best suit their circumstances and policy objectives, assigning responsibility to other parties regulated by the state, private or public third-party entities, or state entities raises enforceability considerations. This section discusses how the general enforceability approach discussed in the preamble, and described above, might apply in practice under different state plan approaches.

This section describes possible scenarios of responsible entities and legal mechanisms and approaches that might be used to address enforceability considerations under different types of state plans. These scenarios were developed to capture the range of entities that are currently implementing end-use energy efficiency and renewable energy deployment programs in states, or are subject to states requirements such as end-use energy efficiency resource standards (EERS) or renewable portfolio standards (RPS). For each of these examples, this section describes current legal relationships between these entities and the state, and discusses possible legal

instruments that might provide the state with the authority to ensure that obligations in a state plan are met and to address failure to meet those obligations. The mechanisms discussed take different forms, but would specify the three elements described above: obligations, compliance demonstration, and enforcement mechanisms. This section also discusses enforceability considerations in cases where states act jointly through a multi-state plan.

A. Parties Regulated by the State other than Affected EGUs

One likely state plan scenario involves inclusion of enforceable obligations for state-regulated entities other than affected EGUs. An example of a state-regulated entity that is not an owner or operator of affected EGUs may be an electric distribution utility.¹¹ These entities are typically regulated by a state public utility commission. An example of an enforceable state plan measure that might apply to an electric distribution utility is a compliance obligation under a state end-use energy efficiency resource standard (EERS) or renewable portfolio standard (RPS), or implementation of incentive programs for the deployment of end-use energy efficiency and renewable energy technologies.

Another example is where a vertically integrated, state-regulated utility implements a portfolio of enforceable actions under a state plan, which may include actions that apply directly to affected EGUs as well other actions such as end-use energy efficiency and renewable energy deployment programs. While vertically integrated utilities may own and operate affected EGUs, some of the measures implemented may require different enforceability mechanisms than an emission limit applied to an affected EGU.

¹¹ Electric distribution utilities are also often referred to as local distribution companies (LDCs). Here we refer to an electric distribution utility as an entity that owns and operates an electric distribution network but is not the owner and operator of EGUs. As discussed further, vertically integrated utilities own and operate electric distribution networks as well as EGUs.

1. Electric Distribution Utility with Obligations to Meet an EERS or RPS Pursuant to State Regulations

EERS and RPS requirements are typically implemented through state regulations, but may also be implemented through a public utility commission order. State EERS and RPS regulations provide legal instruments generally comparable in enforceability to regulatory emission limits applied to EGUs. These regulations typically specify compliance obligations, reporting, and enforcement. However, many state RPS regulations and some EERS regulations include alternative compliance payment (ACP) provisions that provide the utility with the option of making a payment in lieu of full compliance with the portfolio requirement. Thus, state EERS and RPS mandates may not guarantee achievement of a given level of end-use energy efficiency or renewable energy deployment during a plan performance period.¹²

2. Vertically Integrated Electric Utility with Obligations under a State-Approved Integrated Resource Plan

A utility integrated resource plan (IRP) may include a number of direct and indirect actions that affect EGU CO₂ emissions, and may also include compliance with EERS and RPS regulations. Broadly, IRPs may prescribe or authorize actions for which utilities can recover capital investments and operating costs through regulated retail electricity rates.¹³ This creates strong financial incentives for implementing an action, but may not mandate an action.

For a state plan under this scenario, an enforceability consideration is whether an IRP, and related public utility commission orders, must include additional requirements to implement certain actions, beyond denial of rate recovery or a change to utility tariffs if a utility fails to

¹² We note that some direct emission limits for CO₂ emissions include somewhat similar provisions. For example, both the RGGI state CO₂ emission budget trading programs and the California GHG emission budget trading program include cost containment provisions where more emission allowances are made available to affected sources at certain allowance price thresholds. In both these instances, such relevant characteristics of the state regulations would need to be taken into account when projecting the CO₂ emission performance that will be achieved by affected EGUs under the state plan.

¹³ In some cases, an IRP prescribes or authorizes specific actions. In others, an IRP serves as a guide for the utility and the public utility commission when evaluating acquisition or implementation of specific utility resources or programs. In such cases, the specific resource or program is approved through a PUC order that authorizes or requires actions and identifies performance obligations. These orders may or may not be fully consistent with provisions in an IRP.

meet specified obligations in the IRP. If so, this may require state legislation to provide additional authority to state public utility commissions in some states, or confer additional authority to other agencies (e.g., a state environmental agency).

B. Private or Public Third-Party Entity not Regulated by the State

Another state plan scenario involves public or private third-party entities with enforceable obligations under a state plan. A private or public third-party entity could be a utility entity that is not regulated by a state public utility commission, such as a municipal utility or a utility cooperative.¹⁴ It could also be a private non-profit entity established to administer end-use energy efficiency and renewable energy deployment programs.¹⁵ In most cases, since they often expend electricity ratepayer funds, such non-profit entities are created by state legislation and overseen by state public utility commissions or state-regulated private utilities.

An appropriate legal instrument or agreement applicable to such entities included in a state plan might include legal arrangements similar to those currently used to establish independent entities that expend electricity ratepayer dollars in multiple states. For entities not subject to state oversight, such a mechanism might also include mechanisms where an entity voluntarily submits to the authority of a state, pursuant to state statutory or regulatory authority specified in a state plan. Such agreements might be attached to a funding source. For example, the entity would voluntarily submit to such authority as a condition of receiving certain funds, such as state appropriated funds or funds collected through state-regulated electricity rates. Alternatively, a municipal utility or utility cooperative might voluntarily submit to state authority as a condition of the state agreeing to let the entity implement a portfolio approach, in lieu of the application of certain direct CO₂ emission limits for affected EGUs owned and operated by such entities through a state regulation. In some cases, new state statutory authority might be enacted to support a state plan, specifying enforceable obligations for these private or public third-party entities under the plan.

¹⁴ Here, “not regulated” refers to regulation of electricity rates by a state public utility commission. To the extent that such entities are owners and operators of affected EGUs, these EGUs may be subject to state environmental and other regulations. In some cases these utility entities are also subject to state EERS and RPS regulations, as specified under state law.

¹⁵ Examples include the Energy Trust of Oregon, the Delaware Sustainable Energy Utility, and Efficiency Vermont.

An additional consideration is whether such legal instruments or agreements, if related to a renewable energy or end-use energy efficiency deployment program, should specify a stable budget authority and funding source through each plan performance period. Such authority and funding might be necessary to ensure that suitable funds are made available to achieve the level of energy savings or renewable energy deployment projected in the state plan, which may be necessary to achieve the level of emission performance by affected EGUs that is projected will be achieved through implementation of the plan.

C. State Agency, Authority, or Entity

This state plan scenario involves a state entity with an enforceable obligation in a state plan. For example, state authorities in some states implement renewable energy and end-use energy efficiency deployment programs.¹⁶ In this scenario, the requirement for the state entity would be an enforceable component of the state plan.

One type of legal arrangement that might be applied under this scenario is legislation directing state executive branch agencies or independent state authorities to follow through on obligations under a state plan.

Such legislation might provide independent legal authority under state law to compel executive branch actions, or actions by independent state authorities under the plan, if obligations are not met. Depending on the form of legislation, this could also provide citizens with the ability to compel state action under state law, if obligations are not met under a state plan.¹⁷

An additional consideration is whether such legal arrangements, if related to a renewable energy or end-use energy efficiency deployment program, should also specify a stable budget

¹⁶ A prominent example is the New York State Energy Research and Development Authority (NYSERDA), which administers energy efficiency and renewable energy deployment programs.

¹⁷ We note that under the CAA, measures included in an approved 111(d) state plan would be federally enforceable by EPA, and that citizens would also have the ability to file citizen suits to compel enforcement of state plan obligations, under CAA Section 304 (42 U.S. Code Section 7604).

authority and funding source through the plan performance period, or other provisions, to ensure that programs are implemented as projected under the state plan.

D. Multi-State Approaches

As discussed in the preamble, in section VIII.F.1, multi-state approaches introduce cross-cutting enforceability considerations.

For these multi-state approaches, states would demonstrate emission performance from affected EGUs in aggregate jointly with partner states. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. For example, states taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average CO₂ emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based CO₂ emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of CO₂ emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based CO₂ emission performance goals established in the emission guidelines that apply to each of the participating states.

1. Multi-State Emission Budget or Rate-Based Emission Trading Programs

The Regional Greenhouse Gas Initiative (RGGI) is an example of a multi-state approach to regulation of CO₂ emissions. Through this initiative, nine states are currently implementing coordinated CO₂ emission budget trading programs. The program works as a coordinated regional whole through a shared emission and allowance tracking system and allowance auction process, but is implemented in accordance with materially consistent stand-alone state regulations and individual statutory authority. These regulations recognize CO₂ allowances issued by other participating states for use by affected EGUs when complying with each state's emission limitation, but contain all the necessary components to administer the program

requirements on an individual state basis.¹⁸ As a result, while the initiative is implemented regionally, each CO₂ emission budget trading program regulation is enforceable against affected EGUs at the state level and functions as a discrete program.

As a result, a multi-state emission budget trading program approach, such as RGGI, is enforceable in practice at the state level. A multi-state rate-based emission trading program could also be established in much the same manner as a multi-state emission budget trading program, and could therefore be enforceable at the state level.¹⁹

2. Multi-State Portfolio Approaches

A multi-state portfolio approach could introduce novel enforceability considerations. If it were based on interdependent emission reduction strategies among states that are not tied to emission limits that directly apply to affected EGUs, the emission performance of affected EGUs in one participating state may be dependent, in part, on actions taken in other participating states. If a state (or states) failed to implement commitments under the multi-state plan, this raises the question of whether the EPA should address non-performance of one or more participating states in the context of failure to achieve the required level of multi-state emission performance under the plan, or instead enforce actions at the individual state level for those states that are failing to meet commitments under the multi-state plan.

¹⁸ The emission limitation consists of a requirement to submit CO₂ allowances equal to reported CO₂ emissions during a compliance period. While states have individual emission budgets, representing the total number of allowances issued for a given year that are available for allocation, there are no individual state emission limits. The CO₂ emission constraint is regional, based on the sum of state CO₂ emission budgets.

¹⁹ Enforceability would be contingent, in part, on states having comparable enforcement mechanisms.

IV. Incorporating End-Use Energy Efficiency and Renewable Energy Programs and Measures under a Rate-Based Approach

A. Concept of Adjusting EGU CO₂ Emission Rates based on the Effects of End-Use Energy Efficiency and Renewable Energy

As discussed in the preamble, in section VIII.F.3, the EPA is proposing that RE and demand-side EE requirements, programs, and measures may be incorporated into a rate-based plan approach.²⁰ Measures that avoid CO₂ emissions from affected EGUs, such as quantified and verified end-use energy savings and renewable energy generation, could be used to adjust the CO₂ emission rate of an affected EGU when demonstrating compliance with a rate-based CO₂ emission limit. Alternatively, a state could use the effect of such measures as a basis for administratively adjusting the average CO₂ emission rate of affected EGUs when demonstrating achievement of the required emission rate performance level in a state plan.

Under this approach, affected EGUs could comply with a rate-based CO₂ emission limit through actions at the EGU,²¹ as well as through the use of credits²² for actions that occur elsewhere in the interconnected electricity system that avoid CO₂ emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could administratively adjust the average CO₂ emission rate of affected EGUs through a similar process when demonstrating achievement of the required emission rate performance level in the state plan.

This section explores in depth the mechanics and implications of the different possible approaches for adjusting CO₂ emission rates that are summarized in the preamble. Aspects of this discussion may apply to both retrospective demonstration of CO₂ emission performance achieved by affected EGUs under an approved state plan and projections of CO₂ emission performance by affected EGUs included in a submitted state plan.

²⁰ The EPA is also proposing that RE and demand-side EE measures could be used under a mass-based portfolio approach in an approvable state plan. However, the focus of this section is limited to application of such measures under a rate-based approach.

²¹ This could include an individual affected EGU or group of affected EGUs if a rate-based averaging or trading approach is used.

²² These credits could be tradable, or represent non-tradable credits administratively apportioned to affected EGUs. This latter approach effectively represents an administrative adjustment applied by the state.

B. Approaches for Adjusting EGU CO₂ Emission Rates

As discussed in the preamble, credits or adjustment to an EGU CO₂ emission rate, based on the effect of RE and demand-side EE programs and measures, might represent avoided MWh of electric generation or avoided tons of CO₂ emissions.²³ If adjustment or credits represent avoided MWh, they would be added to the denominator of the lb CO₂/MWh emission rate when determining an adjusted lb CO₂/MWh emission rate. If adjustment or credits represent avoided CO₂ emissions, they would be subtracted from the numerator when determining an adjusted lb CO₂/MWh emission rate. The approach chosen could affect the amount of credit or adjustment provided for RE and demand-side EE programs and measures. These implications are discussed below.

1. Adjustment of CO₂ Emission Rate based on Avoided MWh

One approach is to adjust an EGU's CO₂ emission rate based on avoided MWh of generation from an EGU, or cohort of EGUs, resulting from RE and demand-side EE programs and measures.²⁴ A MWh crediting or adjustment approach implicitly assumes that the avoided CO₂ emissions come directly from the particular affected EGU (or group of EGUs) to which the adjustment or credits are applied. It assumes, in effect, that an additional emission-free MWh is being generated by that respective EGU, and that the RE or demand-side EE measure reduces CO₂ emissions from that individual EGU or group of EGUs.²⁵ In practice, the average or marginal CO₂ emission rate in the power pool or identified region – representing the avoided CO₂ emissions from the generating sources being displaced by a MWh of energy savings or a MWh of renewable energy generation – could differ significantly from the calculated avoided CO₂ emissions derived by adjusting the MWh output of an affected EGU. The following examples highlight these concepts.

²³ The preamble solicits comment on the appropriateness of these different approaches, which are further elaborated in this section.

²⁴ It should be noted that this was the process used by EPA for incorporating end-use energy efficiency, renewable energy, and nuclear energy when calculating state CO₂ emission performance goals for affected EGUs. As discussed in the preamble, states may have flexibility to use a different approach when demonstrating the effect of these measures in a rate-based state plan.

²⁵ As a result, the assumed avoided CO₂ emissions from an individual MWh of energy savings or generation from renewable energy will differ based on the reported CO₂ emission rate of the individual EGU to which the MWh is applied as an adjustment to its MWh output.

Example 1: Assume an EGU with a stack emission rate of 1,500 lb CO₂/MWh generates 1,000 MWh. Also assume that 1,000 emission-free MWh credits for the effect of demand-side EE measures are added to the denominator when calculating the EGU's adjusted CO₂ emission rate. The adjusted CO₂ emission rate is 1,500,000 lb CO₂ divided by 2,000 MWh, which equals a CO₂ emission rate of 750 lb CO₂/MWh. In this example, each MWh credit represents 750 lb of avoided CO₂ emissions.

Example 2: The same calculation applied to an affected EGU with a 2,000 lb CO₂/MWh rate would yield a different result. In this instance the adjusted emission rate is 2,000,000 lb CO₂ divided by 2,000 MWh, which equals a CO₂ emission rate of 1,000 lb CO₂/MWh. In this example, each MWh credit represents 1,000 lb of avoided CO₂ emissions.

2. Adjustment of CO₂ Emission Rate based on Avoided CO₂ Emissions

An alternative approach is to provide an adjustment to the CO₂ emission rate of an EGU, or cohort of EGUs, based on the estimated CO₂ emissions that are avoided in the power pool or identified region as a result of RE and demand-side EE programs and measures. This approach acknowledges that the avoided CO₂ emissions may come from the electric power pool or other identified region as a whole, rather than an individual EGU. The avoided CO₂ emissions are determined based on the MWh saved or generated, multiplied by a CO₂ emission rate for the power pool or region.

This CO₂ emission rate could be based on the average or marginal emission rate in the power pool, region, or state. A marginal avoided emission rate represents the generation that is displaced at the margin for every MWh saved or generated through an RE or demand-side EE program or measure. An average avoided emission rate is based on either all fossil generation in a region or total generation. This approach assumes that every MWh saved or generated equally displaces generation from every generator in a power pool or region.

Another approach that has been suggested by some stakeholders is crediting or adjustment based on the level of the rate-based emission limit for affected EGUs (or the overall rate-based level of emission performance for affected EGUs specified in a state plan). For

example, under this approach, if the emission rate limit were 1,500 lb CO₂/MWh, one MWh of energy savings or renewable energy generation would result in a credit or adjustment representing 1,500 lb of CO₂ that could be subtracted from the numerator of an EGU's CO₂ emission rate. This approach assumes that affected EGUs jointly emit CO₂ from the stack on an average basis at this required compliance level (i.e., consistent with a “closed” averaging system), and that a MWh saved or generated avoids CO₂ emissions from affected EGUs at this average compliance level.²⁶

3. Other Considerations

Some of the CO₂ emissions avoided through RE and demand-side EE measures may be from non-affected EGUs. This may result because affected EGUs are only a subset of the fossil fuel-fired EGU fleet, which also includes (or will include) existing non-affected fossil fuel-fired EGUs, such as simple-cycle combustion turbines used to meet peak demand, as well as new fossil fuel-fired EGUs subject to emission standards under CAA section 111(b). Furthermore, as the fleet capital stock slowly turns over, affected EGUs under section 111(d) will comprise a slowly shrinking subset of the total fossil fuel-fired EGU fleet. These dynamics may need to be addressed in a state plan when crediting or adjusting CO₂ emission rates of affected EGUs based on the effects of RE and demand-side EE measures. The approaches described in more detail later in this section may be able make these distinctions between affected and non-affected fossil fuel-fired EGUs.

²⁶ This outcome might be expected in a closed averaging system, without the use of crediting or adjustment for the avoided emission effects of RE and demand-side EE measures. In this instance an EGU that emitted above the compliance rate would need to average its performance with (or submit tradable credits obtained from) an EGU that performed below the required rate. On balance, all EGUs subject to the emission rate limit would perform at or below the compliance rate.

C. Methods and Tools for Quantifying Avoided CO₂ Emissions from End-Use Energy Efficiency and Renewable Energy

1. Introduction

There are a number of approaches for quantifying the avoided CO₂ emissions resulting from end-use energy efficiency and renewable energy (EE/RE) programs, requirements and measures²⁷ in the electric sector. These approaches range from the application of basic avoided emission rates to using sophisticated electric sector models.²⁸ Annual average avoided emission rates have often been used for rough approximations of CO₂ emissions avoided from reduced electric energy use.²⁹ An annual average avoided emission rate assumes that EE/RE programs and measures reduce electric generation from all generating types on a proportional basis consistent with the generation mix in a region. A marginal emission rate represents the emission rate of an electric generating unit (EGU) or cohort of EGUs likely to be displaced by EE/RE measures (i.e., a marginal avoided emissions rate), based on the last unit(s) to come online to meet electricity load and the first unit(s) to be brought offline when electricity load is reduced.

The primary question underlying estimating CO₂ emissions reductions from EE/RE measures is the determination of which electric generators will be displaced (*i.e.*, cease generation or reduce generation output) in the presence of incremental EE/RE. This section briefly describes a range of avoided emission rates approaches, their underlying assumptions, and considerations associated with the use of different avoided emission rate approaches.

2. Average Emission Rate Approach

An average emission rate (typically expressed in tons of CO₂/MWh) is usually understood to mean the average of all generators' emissions rates, weighted by annual generation. The rate (r_{avg}) is calculated as:

²⁷ As used here, the term "EE/RE measures" refers to any program actions or regulatory requirements that result in the increased use of energy-efficient equipment or practices, or renewable energy generating resources.

²⁸ Electric sector models include simulation dispatch models (i.e. production-cost models) and capacity expansion planning models.

²⁹ See, for example, EPA "Household Carbon Footprint Calculator," available at <http://www.epa.gov/climatechange/ghgemissions/ind-calculator.html>.

$$r_{avg} = \frac{\sum_i e_i}{\sum_i g_i}$$

Where:

e = annual emissions (tCO₂) from all sources i and

g = annual generation (MWh) from all sources i .

Because the average emission rate puts the sum of all generation in the denominator (as MWh), including nuclear, hydroelectric, and renewable generating resources, the rate fundamentally assumes that EE/RE reduces all generating types by an equal proportion, regardless of their type or contribution to the margin.³⁰ EGUs are generally dispatched on an economic merit order, where the least-cost EGUs (on a variable cost basis) are dispatched first, and higher cost resources are dispatched later. Since nuclear, hydro, wind, and solar resources operate at a very low cost,³¹ they are generally dispatched before most fossil units.³² Under current and historical operating conditions, there are few circumstances in which non-fossil resources reduce output in the presence of lower demand. As a result, in states with a moderate contribution of non-emitting resources to total generation, the average emission rate may be lower than could reasonably be expected for reductions from EE/RE programs and measures.³³ Conversely, in states that have significant baseload fossil generation and few non-emitting resources, a state-average emission rate may reflect an emission rate that is too high. This may occur by incorporating emissions from coal-fired EGUs that are less likely to reduce generation with a reduction in electricity load, compared with other lower-emitting fossil fuel-fired EGUs.

³⁰ In other words, a two-percent reduction in energy use would cause all EGUs in the system to reduce generation output by two percent, including coal, gas, nuclear, hydro, and renewable generating resources.

³¹ For representative variable costs for new EGU, see supporting documentation for the Electricity Market Module of the Annual Energy Outlook (AEO) 2013, table 8.2., “Cost and performance characteristics of new central station electricity generating technologies”. Geothermal, wind, and solar generating resources are assumed to have a variable operating cost of \$0/MWh. Hydroelectric generating resources have an assumed variable operating cost of \$2.60/MWh and incur no fuel cost, while nuclear generating resources have an assumed variable operating cost of \$2.10/MWh (exclusive of fuel costs). In contrast, gas and coal units are assumed to have variable operating costs from \$3-\$7/MWh (exclusive of fuel costs).

³² The exception is rare curtailment events for renewable resources when more energy is produced than required, and due to operational constraints, where wind turbines are stalled to maintain system energy balance. Renewable energy generators, such as wind and solar, are sometimes referred to as “non-dispatchable” resources, since the renewable energy resource is intermittent and these generators cannot be called upon to run when the renewable energy resource is unavailable. However, here we refer to economic dispatch of these resources at times when the renewable energy resource is available. In these instances, these generators are often one of the first resources to be called upon, due to their low variable operating costs.

³³ Counting hydroelectric, nuclear, and renewable resources in the denominator would render the emissions rate too low, and thus the avoided emissions smaller than actually realized.

3. Marginal Emission Rate Approach

A marginal emission rate represents the emission rate of the EGU or cohort of EGUs likely to be displaced by EE/RE (*i.e.*, an avoided emission rate). A marginal unit is the highest-cost unit dispatched at any point in time.³⁴ Under most circumstances, and at any given time, the marginal unit is the last unit to be brought online to meet electricity demand and the first unit to be brought offline when electricity load is reduced. Due to constraints on generating unit ramp rates³⁵ and transmission availability, it is not uncommon for multiple units to be dispatched incrementally simultaneously, thus creating a cohort of marginal units. Marginal unit(s) change on a moment-to-moment basis, determined by load requirements and the variable cost of each unit available to generate another unit of power. A marginal unit can either be a unit brought online to meet load or may be an EGU that is already operating, but that is dispatched at a greater level of output to meet load.

The marginal emission rate ($r_{marginal}$) can be expressed for any given hour (t) as a function of the difference between two distinct cases – the reference case (*i.e.*, in the absence of incremental EE/RE programs and measures) and the change case, where the EE/RE programs and measures have been implemented. A formula describing this rate is written as follows:

$$r_{marginal,t} = \frac{\sum_i e_{ref,i,t} - \sum_i e_{EERE,i,t}}{\sum_i g_{ref,i,t} - \sum_i g_{EERE,i,t}}$$

Where:

e_{ref} and e_{EERE} = emissions (tCO₂) from EGUs i in hour t in the reference case (*ref*) and the change case (*EERE*), respectively; and

g_{ref} and g_{EERE} = generation (MWh) from EGUs i in hour t in the reference case (*ref*) and the change case (*EERE*), respectively.

³⁴ See EPA's Roadmap for Incorporating EE/RE Policies and Programs in State Implementation Plans: Appendix B, available at http://www.epa.gov/statelocalclimate/documents/pdf/overview_paper_4-28-2011.pdf

³⁵ Ramp rate refers to the ability of an EGU to respond to increasing load, based on its ability to increase output. Ramp rates are typically determined by technology type, with some technologies, such as combustion turbines, able to more quickly increase output in response to increasing load.

The magnitude of the EE/RE program and the EE/RE load impact shape³⁶ is a key element in determining marginal emissions reductions. In order to obtain a valid estimate of the emission reduction effect of an EE/RE program, an annual marginal avoided emission rate should be calculated that reflects the EE/RE program's load impact shape and magnitude. This annual marginal avoided emission rate may then be applied to other EE/RE programs with similar load impact shapes and magnitudes. The marginal emission rate is highly time sensitive, as are the impacts of EE/RE programs and measures. For example, the EGU that is on the margin and is most likely to be displaced from EE/RE in each hour of the year. In addition, different EE/RE programs may have very different load impact shapes, reducing energy requirements in different hours of the year. The interaction between the pattern of EGUs on the margin and the load impact shape of EE/RE programs and measures results in a specific marginal avoided emission rate. Applying an annual marginal avoided emission rate calculated based on the impact of one specific set of EE/RE programs and measures to another set of EE/RE programs and measures that is substantively different in timing or magnitude of energy savings or generation (*i.e.*, with a different load impact shape and magnitude) may result in erroneous results (*i.e.* the assumption that the wrong EGUs are displaced).³⁷

Several mechanisms have been proposed to estimate the marginal emission rate without the use of a formal electric dispatch simulation model. These mechanisms rely on historic hourly generation and emissions data, collected by EPA's Clean Air Markets Division, to estimate hourly marginal emissions rates for a past historical year. The benefit of these mechanisms is that they are simple to apply, but (a) are difficult to verify or validate without the benefit of a formal model and (b) rely on historical data and patterns of dispatch, which may not represent future patterns of dispatch.

³⁶ The load impact shape of an EE/RE program or measure is the hourly (or, if necessary, daily or seasonal) pattern of either energy savings from an EE program or measure, or generation from an RE generator that is supplied to the grid.

³⁷ For example, an EE program focused on measures that reduce peak electricity demand, such as more efficient air conditioning, or a solar RE program, may result in significant reductions in electricity use from the grid during peak demand hours, and little electricity use reduction during overnight "trough" hours. In contrast, an industrial EE program may result in a relatively constant electricity load reduction over most hours. An EE program focused on peak reduction measures may reduce generating output from primarily peaking units, while an EE program targeting EE measures with a more constant load impact shape may significantly reduce baseload generation during overnight trough hours.

4. Methods and Tools for Estimating Avoided CO₂ Emission Rates and Avoided CO₂ Emissions

4.1. Calculation Tool Method

The EPA has developed a user-friendly tool to estimate the emission reduction impacts of EE/RE requirements, programs and measures. The “AVoided Emissions and geNeRation Tool” (AVERT)³⁸ was developed to help air quality planners quantify NO_x and SO₂ emission impacts, as specified in EPA’s Roadmap for Incorporating EE/RE Programs in NAAQS SIPs.³⁹ AVERT can also be used to quantify the displaced CO₂ emissions of EE/RE measures within the continental United States.

The AVERT method uses historical hourly emissions rates based on recent the EPA data on fossil fuel-fired EGUs’ hourly generation and emissions reported through EPA’s Acid Rain Program.⁴⁰ This method couples historical hourly generation and emissions with the hourly load reduction profiles of EE/RE programs and measures to determine hourly emissions reductions on the margin. AVERT can be used to estimate EE/RE-related emissions reductions in a current or near-future year. However, AVERT estimates for current or future years are based on historical behavior rather than projected economic behavior. As a result, AVERT does not use projections of future fuel or electricity market prices that affected EGU dispatch, and is therefore not an appropriate tool for longer-term projections.

Users of AVERT can analyze how the different load profiles of a variety of EE programs and measures, as well as wind and solar technologies, affect the magnitude and location of CO₂ emissions at the county, state, and regional level. AVERT has a flexible framework with a simple user interface designed specifically to meet the needs of state air quality planners and other interested stakeholders.

³⁸ More information about AVERT, including documentation and a user’s manual, is available at (<http://www.epa.gov/avert>).

³⁹ See Appendix I of the *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs*, available at <http://epa.gov/airquality/eere/pdfs/appendixI.pdf>, for details about how this approach can be used in the different NAAQS SIP pathways.

⁴⁰ <http://ampd.epa.gov/ampd/>.

AVERT may be used to derive marginal emission reductions from historical generation and emissions data, which can be used to derive a marginal avoided CO₂ emission rate. However, AVERT does not quantify average emissions rates. AVERT approximates historical dispatch behavior using a statistical algorithm. It does not represent transmission constraints, or significant changes in grid structures or future economic conditions. To estimate a recent historical marginal CO₂ emissions reduction from existing EE/RE programs or measures, a user would input the MWh related to results from EE/RE programs or measures (representing either MWh of electricity savings or MWh of generation) in a representative historical baseline year as a positive increment to electricity load, and record the emissions incrementally added in the tool.⁴¹ The calculated marginal CO₂ emission rate is the incremental CO₂ emissions added by AVERT, based on historical EGU dispatch patterns, divided by the incremental MWh of EE/RE savings or generation input to AVERT as an increase in electricity load. This approach reflects the marginal impact of EE/RE measures based on historical recorded patterns of emissions and generation.⁴²

4.2. Electricity Sector Modeling Method

Quantification of avoided CO₂ emissions from EE/RE requirements, programs, and measures can be achieved through retrospective modeling approaches. Models can be used to calculate avoided CO₂ emissions by comparing actual realized EGU CO₂ emissions to projected EGU CO₂ emissions that would have occurred in a historical reference case that does not include implementation of the EE/RE that is being evaluated. The appropriate choice of model depends on the look-back period. For short look-back periods of one to three years, an electricity system simulation dispatch model can determine the marginal generation contribution to emissions in a

⁴¹ Because AVERT represents a historical baseline year, EE and RE programs that occurred in a past year are already recorded by the statistics of AVERT. To estimate the emissions impacts of historic EE/RE programs, a user would increase the load by the EE/RE increment to estimate what generation and emissions would have been in the reference case look-back year.

⁴² AVERT reflects fuel and emission control technologies to the extent they have influenced dispatch during the base year chosen. However, AVERT cannot change dispatch based on future economic or regulatory conditions, such as expected fuel prices, emission allowance prices, or specific emissions limits. AVERT should not be used for this type of analysis. When used to review historical data, AVERT will capture the impact of historical fuel prices and other impacts on the variable cost of production, but cannot capture specific emission limits.

historical reference case (*i.e.* absent incremental EE/RE programs).⁴³ Over the short term, simulation dispatch models properly account for EGU economic dispatch considerations, such as fuel and emission allowance prices, and operational constraints, such as ramp rates, outages, and heat rate curves. Look-back periods beyond three to five years would benefit from use of a utility-scale capacity expansion and dispatch planning model to understand the change in build out of new generating capacity, as well as transmission and distribution infrastructure, and its impact on generation between the historical reference case and actual realized historical outcome.

Electricity System Simulation Dispatch Models

Quantifying the CO₂ emissions reductions achieved by EE/RE measures through modeling of a near-term look-back period requires a counterfactual historical reference case model run, which examines how the electric system would have operated in the absence of the EE/RE emission reduction measures under consideration. The emissions projected in this model run may be compared against actual realized emissions during the historical period. The look-back model should be calibrated by running the same model with the EE/RE measures in place and comparing the outcome of that model against realized generation and emissions at an appropriate spatial scale.⁴⁴

Simulation dispatch models can be readily run for historical years provided they are loaded with the accurate input assumptions, including actual historic fuel costs, emission allowance prices, and transmission constraints. While these models will not choose economically optimal EGU retrofit or retirement decisions, they will provide a change in EGU dispatch and the associated change in emissions across a large region in a more detailed manner than capacity expansion planning models.

⁴³ “Reference case” here refers to the case in which additional incremental carbon emissions reduction mechanisms are not employed, in this case resulting from EE/RE programs and measures.

⁴⁴ Generally, simulation models will not capture exact output of individual EGUs relative to reality due to a variety of factors, including outages and other non-economic considerations not reflected in the model. Therefore, a comparison at an individual EGU scale may not be meaningful, but aggregate emissions at a state or regional scale should be expected to be comparable.

Simulation dispatch models may be most relevant as part of ex-post plan reporting, for estimating the avoided CO₂ emissions from affected EGUs that occurred as a result of EE/RE measures included in a plan, during a specified plan reporting period.

Utility-Scale Capacity Expansion and Dispatch Planning Models

Quantifying the CO₂ emissions reductions achieved by EE/RE measures through modeling over a longer-term look-back period requires a counterfactual historical reference case model run, which examines how the electric system would have operated and have been built out, in the absence of the EE/RE measures under consideration. The critical difference between this type modeling approach and the use of a simulation dispatch model is the assessment of changes made at the “build margin” – *i.e.*, new additions to generating capacity that may have been avoided or compelled, or retirements of existing units that may not have occurred in the reference case. The emissions projected in this model run may be compared against actual realized emissions during the historical period. The look-back model should be calibrated by running the same model with the EE/RE measures in place and comparing the outcome of that model run against actual realized generation and emissions at an appropriate spatial scale.

Capacity expansion and dispatch planning models could be run for a longer-term historical period to better reflect what the electricity system would have looked like in the absence of the EE/RE measures. When EE or RE resources have been added over the course of three to five years, these models will reflect how these resources have avoided new power plants, retrofits, or fuel switch decisions. Some models may also be able to reflect avoided transmission investments.

Capacity expansion and dispatch planning models may be more relevant than simulation dispatch models for projecting the emission performance that will be achieved by affected EGUs under a plan. As discussed below, these models are able to assess both the “operating” and “build” margins that impact EGU CO₂ emissions as the result of EE/RE measures.

5. Considerations Associated with use of an Avoided Emissions Rate

Operational versus Build Margin

Avoided emission rates approaches that do not include a capacity expansion model all assume that EE/RE measures only impact the operational margin – *i.e.*, they impact moment-to-moment operations of EGUs in the existing grid. While this is true, deployment of EE/RE over a period of years may have impacts beyond the operational margin. Deployment of significant EE/RE measures over time often impacts decisions to build new fossil generating capacity, retire existing aging generating capacity, and make different decisions about transmission expansion. These different decisions about what infrastructure to build or retire are known as the “build margin,” and may ultimately have a greater impact on long-term emissions outcomes than the operational margin.

While a new wind farm brought online next year has an impact on patterns of generation from existing fossil EGUs, decadal-scale planning associated with a policy meant to encourage EE/RE has an impact on the choice of whether or not to pursue the construction of new fossil generating capacity. A utility pursuing aggressive EE/RE programs may avoid the construction of new fossil generating capacity and expansion of transmission and distribution capability, and may even allow the utility to retire non-economic generating units no longer required for generation or reliability purposes.

The use of an avoided emissions rate calculated based on the operational margin alone may fail to represent the impact of EE/RE measures that occur at the build margin. This differentiation is particularly important in regions where the pursuit of EE/RE measures may result in the retirement of high-emitting, non-economic generating assets. The use of a capacity expansion and dispatch planning model would help accurately assess avoided emissions due to changes at both the build and operational margins.

Quantifying In-State versus Out-of-State Emissions Reductions

The electric system is not confined by state boundaries, and emissions displaced by EE/RE measures may occur over a wide geographic area,⁴⁵ including outside of the state that implemented the EE/RE measures. Without the use of a simulation dispatch model (or, under some circumstances, use of a tool such as AVERT)⁴⁶ it can be challenging to attribute emissions reductions that occur within the implementing state versus emissions reductions that occur across state boundaries. If a state sought to recognize the effect of EE/RE measures and quantified emissions reductions using an approach that did not account for avoided emissions at an appropriate spatial scale, it may inappropriately account for emissions reductions that occur in other states, or conclude that all emissions reductions occur within the state's boundaries.⁴⁷ In interconnected areas in which some states pursue mass-based emissions reductions approaches through their state plans while other states pursue rate-based approaches that include adjustment or crediting for avoided CO₂ emissions from implementation of EE/RE measures, avoiding double-counting of emission effects among states will be an important consideration when quantifying the avoided emissions resulting from EE/RE measures. These considerations are discussed below in section VII of this TSD.

⁴⁵ See California Energy Commission, *Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts (2011)*, available at (<http://ucciee.org/downloads/CAEmissionsReductions.pdf>).

⁴⁶ AVERT captures the magnitude of in-state versus out-of-state emissions reductions, but may not be an accurate assessment tool for edge-cases –*i.e.* states that fall near the boundaries of the AVERT regions – because AVERT does not capture inter-regional transmission.

⁴⁷ In the simplest case, a state without any fossil generating capacity that implements EE/RE measures would cause emissions reductions in neighboring states, and none within its own borders. Similarly, a state with significant, predominantly baseload fossil generation may also cause little in-state emissions reductions from implementation of EE/RE measures because those emissions reductions may occur at marginal generators located outside of the state. Conversely, a state with significant marginal fossil generating capacity might realize reductions in emissions from EE/RE measures implemented in other states. These complications may arise regardless of if a state is a net importer or net exporter of energy. The key differentiation is if the state's EGUs are generally on the margin relative to interconnected EGUs in neighboring states.

V. Quantification, Monitoring, and Verification of End-Use Energy Efficiency and Renewable Energy Programs and Measures

As discussed in the preamble, in section VII.F.4, a key consideration for state plans is the process and requirements for quantifying, monitoring, and verifying the effect of renewable energy and demand-side energy efficiency measures that result in electricity generation or savings.⁴⁸ In the preamble, the EPA proposes that a state plan that includes enforceable RE and demand-side EE measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. An EM&V plan will specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy generation and energy savings related to RE and demand-side EE measures. As discussed in the preamble, an EM&V plan would be subject to EPA approval as part of a state plan. In the preamble, the EPA also discusses its intent to develop guidance for acceptable EM&V methods that could be incorporated in an approvable EM&V plan included as part of an approvable state plan. The EPA seeks comment in the preamble on the critical features of such guidance, including scope, applicability, and minimum requirements, as well as the appropriate basis for and technical resources used to establish such guidance, including existing state and utility protocols and existing international, national, and regional consensus standards or protocols. This section further elaborates these considerations discussed in the preamble, with individual subsections addressing RE and demand-side EE programs and measures.

The appropriate type of EM&V for RE and demand-side EE programs and measures will depend on the state plan approach. For states implementing a mass-based portfolio approach, the effect of renewable energy and demand-side energy efficiency requirements, programs, and measures in helping to achieve the required level of CO₂ emission performance under a state

⁴⁸ In particular, this consideration applies to states implementing a rate-based emission limit approach that provides for adjustment of CO₂ emission rates based on the effect of end-use energy efficiency and renewable energy, as well as states implementing utility- or state-driven portfolio approaches that incorporate end-use energy efficiency and renewable energy requirements and programs.

plan will be directly evident in reductions in the monitored CO₂ emissions from affected EGUs.⁴⁹ In effect, the overall impact of these measures could be tracked through CO₂ emission monitoring, reporting, and record-keeping requirements applied to affected EGUs. However, for states implementing a rate-based plan approach, an approvable plan will need to include quantification, monitoring, and reporting requirements related to RE and demand-side EE requirements, programs, and measures incorporated in a state plan.

Utilities and states have conducted ongoing EM&V of end-use energy efficiency and renewable energy measures and programs for several decades. These evaluations, which include quantification, monitoring and verification of results, generally rely upon a well-defined set of industry-standard practices and procedures. However, measurement approaches vary by state based on multiple factors, including the measure and program type being evaluated, the level and nature of regulatory oversight, the degree of state and utility experience with these measures and programs, and the overall magnitude of program impacts.

This section of the TSD discusses current state and utility evaluation, monitoring, and verification approaches for end-use energy efficiency and renewable energy programs and mandates. This section also discusses the potential suitability of these approaches in the context of an approvable state plan, and whether harmonization of state approaches, or supplemental actions and procedures, might be warranted in an approvable state plan. In particular, this section discusses considerations related to the establishment of requirements and guidance for quantification, monitoring, and verification of end-use energy efficiency and renewable energy measures for an approvable state plan. It also discusses the possible appropriate basis for and resources used to establish such requirements and guidance. This discussion includes consideration of existing state and utility protocols, as well as any international, national, and regional consensus standards or protocols.

This section also discusses the types of end-use energy efficiency and renewable energy measures and programs for which EM&V of results is relatively straightforward. Such

⁴⁹ There could be exceptions, for example where a state plan includes acknowledgement of avoided CO₂ emissions that occur outside state borders as a result of state plan measures. See section VII of this TSD for further discussion of the treatment of interstate effects.

approaches might be subject to streamlined review of EM&V protocols included in an approvable plan, provided that such protocols are applied in accordance with EPA requirements and guidance. For example, many utilities have implemented a similar core set of end-use energy efficiency and renewable energy measures and programs for utility customers. For these types of measures and programs, a substantial base of experience has been established nationally for quantification, monitoring, and verification of measure and program outcomes.

In the preamble, at section VIII.F.4, the EPA notes that it is not proposing to limit the types of RE and demand-side EE programs and measures that may be included in a state plan. However, less established types of measures and programs, such as new and innovative demand-side EE programs that seek to alter consumer and building occupant behavior may pose quantification and verification challenges. Still other types of measures, such as state energy-efficient appliance standards and building codes, have not typically been subject to similar evaluation of energy savings results. These types of approaches may have substantial impacts, but may require additional documentation of EM&V methods in accordance with EPA guidance, including development of appropriate quantification, monitoring, and verification protocols if they do not currently exist.

A. Quantification, Monitoring, and Verification for End-Use Energy Efficiency

1. Introduction

For rate-based state plans, a key element of the plan is a demonstration of how the state, and related entities with enforceable obligations under the plan, will measure and verify energy savings to be achieved through the implementation of end-use energy efficiency measures incorporated in the plan.⁵⁰ In the context of demand-side energy efficiency programs currently overseen by state PUCs, this function is typically addressed through an evaluation, measurement, and verification plan (EM&V plan). This section discusses current state and utility EM&V

⁵⁰ In this section we use the term “end-use energy efficiency measure” or “energy efficiency measure” to refer to an end-use energy efficiency requirement (such as an EERS), and energy efficiency program, or individual installed energy efficiency measure, such as installation of an energy-efficient air conditioner through an energy efficiency program.

practice for end-use energy efficiency programs and discusses considerations related to acceptable EM&V plans and evaluation approaches for a state plan under CAA section 111(d).

2. Background on Evaluation, Monitoring, and Verification (EM&V) of Energy Efficiency Measures

From the time that demand-side energy efficiency (EE) emerged as an important energy strategy in the 1970s,⁵¹ efforts to evaluate the impacts of EE actions have been critical to their success, credibility, and expansion. Starting with measurement and verification (M&V) of individual projects, these efforts have evolved to the point where there is now a mature and rigorous evaluation, measurement, and verification (EM&V) industry. This industry includes many professional firms, protocols and guidelines, training and certification programs, regulatory oversight, and established conferences with a rich library of published reports and publically available data and analyses.

State agencies responsible for planning, implementing, and evaluating demand-side energy efficiency programs and policies utilize EE savings values, as follows:⁵²

- Projected savings: values reported by a program implementer or administrator before the efficiency activities are completed
- Claimed savings: values reported by a program implementer or administrator after the efficiency activities have been completed, prior to independent evaluation of savings
- Evaluated savings: values reported by an independent third-party evaluator after the efficiency activities and an impact evaluation have been completed.

Both claimed and evaluated energy savings involve real-time and/or retrospective assessments of the performance and implementation of an energy efficiency program or a portfolio of programs. Important impacts for evaluation include energy and demand savings and non-energy benefits (e.g., avoided emissions, health benefits, job creation and local economic

⁵¹ National Energy Program Fact Sheet on the President's Program, April 20, 1977.

⁵² State and Local Energy Efficiency Action Network. 2012. *Energy Efficiency Program Impact Evaluation Guide*. Prepared by Steven R. Schiller, Schiller Consulting, Inc., available at <http://www.seeaction.energy.gov>.

development, energy security, transmission and distribution benefits, and water savings). Impact evaluations also support cost-effectiveness analyses aimed at determining the value of energy efficiency programs to utility customers and identifying relative program costs and benefits of energy efficiency compared to other energy resources, including both demand- and supply-side options.

Regardless of how the energy savings of an energy efficiency measure are determined, all energy savings values are *estimates* of savings and not directly measured. Savings are determined by comparing energy use after an energy efficiency project or measure is installed (the reporting period) with what is assumed to be the energy use in the absence of the project or measure (the “counterfactual” scenario, or baseline). Savings therefore depend critically on baseline assumptions, which are necessarily estimated with varying degrees of accuracy. Figure 1-1 illustrates this concept.

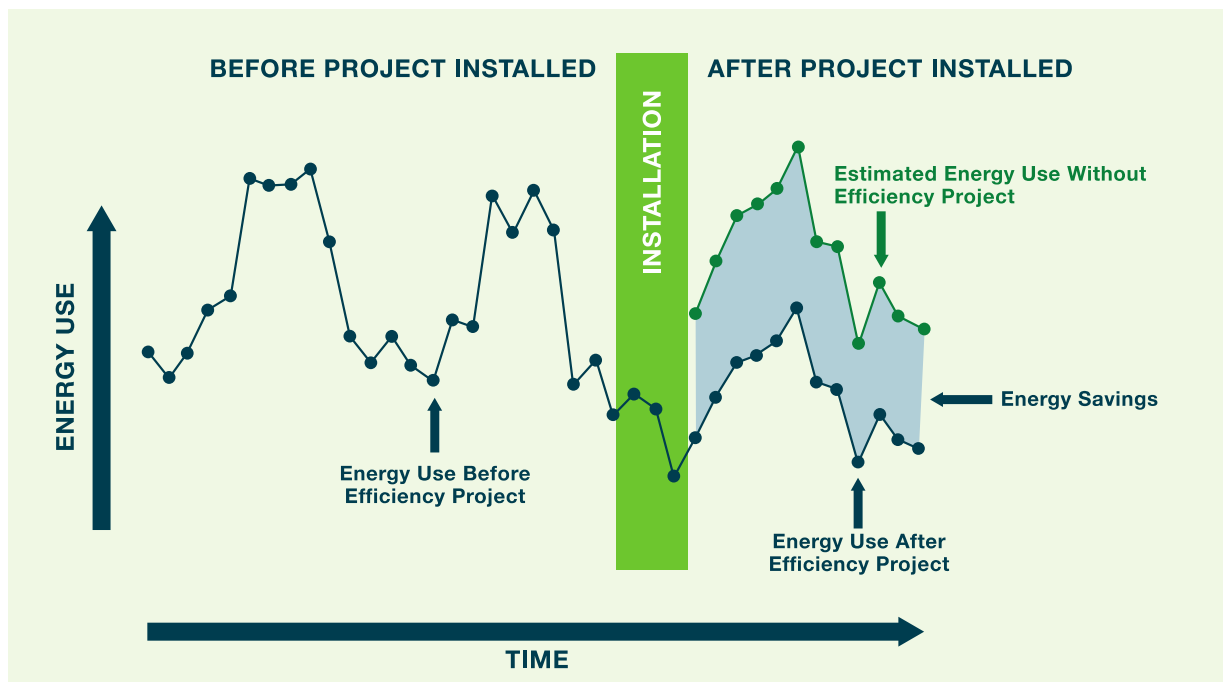


Figure 1. Energy Use Before, During, and After an Energy Efficiency Project is Installed⁵³

⁵³ Ibid.

3. Current EM&V Practices in States

3.1 EM&V for Demand-Side Energy Efficiency Programs Overseen by State PUCs

Current practice with EM&V for demand-side energy efficiency programs in the U.S. is primarily defined by state utility commission (PUC)⁵⁴ requirements for customer-funded efficiency programs. The level of PUC oversight varies from state to state, but this oversight process has generated the majority of the industry guidance and protocols for documenting energy savings from energy efficiency programs. Typically, impact evaluation reports are prepared based on the requirements established by PUCs and submitted (usually annually) for PUC review, approval, and use in resource planning and performance assessment. According to a recent survey, most states (79 percent) rely on independent consultants and contractors to conduct evaluations, while some states (21 percent) use utility and/or government agency staff.⁵⁵

The range of EM&V budgets varies significantly between states, typically from two percent to six percent of total energy efficiency program expenditures.⁵⁶ The average EM&V budget in 2011 was about 3.6 percent of program expenditures. Reasons for this disparity may include the fact that as states expand energy efficiency programs, they may implement more complex programs, which require additional EM&V.⁵⁷ EM&V effort in states also typically increases as the magnitude of program expenditures and energy savings impacts increase, and as states and utilities gain experience in implementing energy efficiency programs.

States at the low end of this EM&V expenditure range typically rely heavily on *deemed savings* approaches, which are a common and relatively low-cost strategy for documenting energy savings. Deemed savings are measure-specific stipulated values based on historical and

⁵⁴ In some states these government entities are referred to as a public service commission (PSCs) or board of public utilities (BPU), as well as other names.

⁵⁵ Kushler, M.; Nowak, S.; Witte, P. , A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs, American Council for an Energy-Efficient Economy (ACEEE) (February 2012), Report Number U122 Available at <http://www.aceee.org/research-report/u122>.

⁵⁶ Wallace, P.; Forster, H.J. (2012). State of the Efficiency Program Industry Budgets, Expenditures, and Impacts 2011. Consortium for Energy Efficiency. www.cee1.org/files/2011_CEE_Annual_Industry_Report.pdf .

⁵⁷ Expansion of energy efficiency programs may also lead to a reduction in EM&V costs per unit of energy savings, as programs achieve economies of scale and experience in conducting EM&V activities.

verified data (in some cases using the results of prior EM&V studies). Unlike other EM&V approaches, with deemed savings there are no – or very limited – measurement activities. Instead, only the quantity of energy efficiency measures implemented is verified (e.g., number of motors installed correctly, number of energy-efficient air conditioners that were purchased using a program rebate). The verified installed energy efficiency measures are then multiplied by the estimated (or deemed) energy savings per measure to derive energy savings for each measure and energy savings for the total number of measures installed through an energy efficiency program. The use of deemed energy savings is only considered appropriate for efficiency actions with well-known characteristics. A variant of this approach is the *deemed savings calculation*, which involves the use of one or more agreed-upon (stipulated) engineering algorithms used to generate energy and/or demand savings associated with energy efficiency measures. These calculations may include predetermined assumptions for one or more parameters in the algorithm, but typically require users to input data associated with the actual installed measure into the algorithm.⁵⁸

The deemed savings values, themselves, are typically centrally located in a “Technical Reference Manual” (TRM). The content and format of these TRMs vary, but in most cases consists of a database of standardized, state- or region-specific algorithms (deemed calculations) and associated energy savings estimates (deemed savings values) for energy efficiency measures. TRMs also include various data assumptions, sample calculations, and other inputs that the state uses to develop energy savings values for the range of energy efficiency programs in place. The benefits to energy efficiency program administrators of using a TRM include reduced EM&V costs and greater certainty regarding projected, claimed, and evaluated energy savings values (see definitions above). There are about 20 states currently using TRM databases.⁵⁹

⁵⁸ Examples of equipment types that are commonly evaluated using deemed savings values and calculations include energy-efficient washing machines, computer equipment, and refrigerators, and lighting retrofit projects with well-understood operating hours. For deemed savings calculations, evaluators collect information about the actual installed measures -- such as hours of usage, wattage, and/or equipment capacity -- and combine this with predetermined assumptions in the algorithm.

⁵⁹ State and Local Energy Efficiency Action Network, *Scoping Study to Evaluate Feasibility of National Databases for EM&V Documents and Measure Savings*, prepared by Jayaweera, T.; Haeri, H.; Lee, A.; Bergen, S.; Kan, C.; Velonis, A.; Gurin, C.; Visser, M.; Grant, A.; Buckman, A.; The Cadmus Group Inc. (June 2011), available at http://www.eere.energy.gov/seeaction/pdfs/emvscoping__databasefeasibility.pdf.

It should be noted that TRM values for individual energy efficiency measures are not always formally vetted in a regulatory process, although this is a good practice.⁶⁰ A recent survey of TRMs found that deemed energy savings values for comparable energy efficiency measures vary across states and regions.⁶¹ The reasons for these variations include the use of different calculation methodologies, technical assumptions, and input variables. Some of these differences are expected based on relevant differences in weather and baseline assumptions (e.g., existing building stock and common practices vary from one state to another). However, other differences are related to out-of-date input assumptions and calculation errors. In the context of state plans, this variation, and in particular data quality issues with some TRMs, raises consideration of whether complete reliance on existing TRM resources for state plans is prudent and appropriate, including how such reliance could or should be circumscribed.

In addition to the use of deemed savings, states on the higher end of the EM&V expenditure range rely to a greater extent on a variety of direct measurement approaches for documenting energy savings. Rather than mandating which EM&V methods must be used in a particular situation, PUCs typically allow utilities and other program administrators to select from a range of appropriate EM&V approaches that are consistent with standard practice in the energy efficiency industry. EM&V analyses and calculations are then carried out, in most cases by an independent, third-party evaluator, through a process that is unbiased, uses technically rigorous methods, effective peer review, and is subject to public review and comment. In addition, energy savings are frequently certified by the PUC as compliant with requirements defined in a pre-approved EM&V plan.

EM&V requirements in states with the most experience implementing and overseeing energy efficiency programs are typically based upon the following industry best practices:

⁶⁰ State and Local Energy Efficiency Action Network, *Energy Efficiency Program Impact Evaluation Guide*, prepared by Steven R. Schiller, Schiller Consulting, Inc. (2012), available at <http://www.seeaction.energy.gov> .

⁶¹ Ibid.

- Use of one or more of the industry-standard EM&V protocols or guidelines (listed below), as well as the use of deemed savings values for well-understood energy efficiency programs and measures
- Consideration of local factors, such as climate, building type, and occupancy.
- Involvement of stakeholders and solicitation of expert advice regarding EM&V processes and resulting energy savings impacts.
- Conduct of EM&V activities (e.g., direct equipment measurements, application of deemed savings, and reporting of impacts) on a regular basis.
- Provision of interim and annual reporting of achieved energy savings.

Despite this well-defined and generally accepted set of industry best practices, many states with energy efficiency programs use different input values and assumptions (e.g., net versus gross savings, run-time of equipment, measure lifetime) in applying these practices. This can result in significant differences in claimed energy savings values for similar energy efficiency measures between states, even when the same measure type is installed under otherwise identical circumstances. In response to a growing awareness of this lack of cross-state comparability, policy makers, regulatory agencies, and other stakeholders are increasingly advocating for the use of common evaluation approaches across jurisdictions. Several national and regional EM&V efforts have emerged to promote collaboration and information sharing across states. These initiatives include the Northeast Energy Efficiency Partnership's (NEEP) EM&V Forum, which is active in New England, New York, and the Mid-Atlantic, and the Pacific Northwest's Regional Technical Forum (RTF). Both efforts aim to promote multi-state coordination in EM&V practices, make EM&V results more transparent and publicly available, and support the adoption of similar definitions, methods, and input assumptions.⁶²

In addition to stakeholder efforts to promote EM&V collaboration and information sharing, a growing number of EM&V protocols and guidelines, some of which have recently been developed, are being used in the U.S. to promote greater consistency of measurement techniques and methodologies:

⁶² For a list of EM&V resources, including more information about these regional EM&V collaboratives, see <http://www1.eere.energy.gov/seeaction/evaluation.html>.

- a. U.S. DOE Uniform Methods Project (UMP) Protocols⁶³
- b. International Performance Measurement and Verification Protocol (IPMVP)⁶⁴
- c. Federal Energy Management Program (FEMP) M&V Guidelines⁶⁵
- d. American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Guideline 14, Measurement of Energy and Demand Savings⁶⁶
- e. California Evaluation Protocols⁶⁷
- f. ISO New England (ISO-NE) Manual for Measurement & Verification of Demand Resources⁶⁸
- g. PJM Energy Efficiency Measurement and Verification Manual⁶⁹
- h. State and Local Energy Efficiency Action Network, Energy Efficiency Program Impact Evaluation Guide⁷⁰
- i. U.S. DOE Superior Energy Performance Measurement and Verification Protocol for Industry⁷¹

⁶³ U.S. Department of Energy (DOE), *Uniform Methods Project* (April 2013), available at: <http://energy.gov/eere/about-us/initiatives-and-projects/uniform-methods-project-determining-energy-efficiency-program-savings>.

⁶⁴ Efficiency Valuation Organization (EVO), *International Performance Measurement and Verification Protocol* (2012), available at: <http://www.evo-world.org/>.

⁶⁵ FEMP, *M&V Guidelines: Measurement and Verification for Federal Energy Projects, Version 3.0* (April 2008), available at: https://www1.eere.energy.gov/femp/pdfs/mv_guidelines.pdf.

⁶⁶ American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), *Guideline 14: Measurement of Energy and Demand Savings* (June 2002), available at: https://gaia.lbl.gov/people/ryin/public/Ashrae_guideline14-2002_Measurement%20of%20Energy%20and%20Demand%20Saving%20.pdf.

⁶⁷ California Public Utilities Commissions (CPUC), *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals* (2006), available at: http://www.calmac.org/events/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf.

⁶⁸ ISO-New England (ISO-NE), *Measurement and Verification of Demand Reduction Value from Demand Resources* (2013), available at http://www.iso-ne.com/rules_proceeds/isone_mnls/MMVDR/index.html.

⁶⁹ PJM, *Manual 18B: Energy Efficiency Measurement & Verification* (2010), available at <http://www.pjm.com/~media/documents/manuals/m18b.ashx>.

⁷⁰ U.S. DOE State and Local Energy Efficiency Action Network (SEE Action), *Energy Efficiency Program Impact Evaluation Guide* (December 2012), available at: http://www1.eere.energy.gov/seeaction/pdfs/emv_ee_program_impact_guide.pdf.

⁷¹ U.S. DOE, *Superior Energy Performance Measurement and Verification Protocol for Industry* (2012), available at: http://superiorenergyperformance.energy.gov/pdfs/sep_mv_protocol.pdf.

While many states are currently relying upon these protocols and guidelines, other states and regional organizations (e.g., ISOs and RTOs) take the additional step of specifying accuracy and uncertainty requirements for energy savings estimates. For example, ISO-NE requires that energy efficiency bids into its Forward Capacity Market (FCM) ensure that impact evaluations achieve ± 10 percent statistical precision at the 80% confidence interval (see below for more on FCMs).

Regardless of the evaluation approach followed, the majority of state PUCs and energy efficiency program administrators aim to strike a balance between the transaction costs of EM&V activities (i.e., expense, time, staff effort) and the resulting reliability, validity, and usefulness of the estimated energy savings results. The appropriate balance between EM&V costs and the rigor of EM&V – and the related certainty of energy savings estimates – is often determined based on the type of program (including program purpose and goals), level of program expenditures, and magnitude of anticipated energy savings.

3.2 EM&V for Energy Efficiency Measures used in ISO Forward Capacity Markets

Two Independent System Operators (ISOs) responsible for operating regional electricity grids and overseeing wholesale electricity markets in certain regions of the country have established forward capacity markets (FCMs) that pay suppliers to ensure sufficient electric generating capacity is available to meet future peak electricity demand. In operating these markets, ISO New England (ISO-NE) and PJM both allow demand-side energy efficiency programs and other demand-side resources to compete directly with electric generators to meet the regional capacity needs. One requirement for utilities and other energy efficiency program administrators seeking to bid into the market is to submit an evaluation plan. ISO acceptance of this evaluation plan “qualifies” energy efficiency programs and projects as prospective market resources. The evaluation plan specifies the amount of energy and demand savings to be delivered over the contract period (typically three years into the future), and documents how the requirements of the ISO’s M&V standards manual will be satisfied.

Based on experience to-date, states bidding their energy efficiency programs into both the ISO-NE and PJM forward capacity markets are typically subjected to EM&V requirements that

go beyond the evaluation already conducted for the purpose of meeting PUC requirements. This is because, while PUCs typically require evaluation protocols and procedures for documenting the cost-effectiveness of annual energy (MWh) savings, FCMs require the measurement and verification of capacity (MW) savings during specific peak demand hours. In addition to the evaluation of energy savings, a separate set of measurement techniques and data collection protocols are required to document peak demand reduction impacts. Furthermore, attaining the level of statistical precision and confidence described above typically requires additional sampling⁷² than is required by PUCs. One consideration is whether EM&V requirements in ISO capacity markets include components that would facilitate better estimation of avoided CO₂ emissions related to energy efficiency programs include in state plans.

For the states located in ISO-NE and PJM, the common evaluation requirements for FCM participation have created an impetus for regional collaboration on EM&V practices. New England and Mid-Atlantic states continue to work together to establish consistent evaluation protocols through the creation of an “EM&V Forum,” which is convened by the Northeast Energy Efficiency Partnerships (NEEP) and supports common evaluation methods, reporting metrics, and cost sharing on research studies.⁷³ The Forum also serves as a venue for information exchange to address common EM&V challenges encountered with FCM participation.

3.3 EM&V for Programs and Policies Not Typically Overseen by PUCs

In contrast to energy efficiency programs overseen by PUCs, EM&V is less common for other types of energy efficiency requirements or programs, especially for minimum energy efficiency requirements that do not involve the expenditure of electricity ratepayer dollars. Examples include building energy codes, appliance efficiency standards, various energy efficiency financing programs, behavioral change programs, and market transformation programs that target both the suppliers of energy-efficient products and increasing consumer demand for those products. While these approaches often have substantial impacts in reducing

⁷² With additional sampling requirements, energy efficiency program evaluators are typically required to measure a larger percentage of the energy efficiency measures installed within the total population of all measures installed through an energy efficiency program.

⁷³ More information about the EM&V Forum is available through Northeast Energy Efficiency Partnerships, at <https://neep.org/emv-forum/index>.

energy use, they may also face EM&V challenges. In some cases, appropriate evaluation protocols and approaches have not been developed for some programs and measures. In cases where appropriate EM&V methods do exist, there may also be less experience applying them.⁷⁴

4. Considerations for EM&V of End-Use Energy Efficiency Programs and Measures in State Plans

A key consideration for state plans is the process and requirements for EM&V of RE and demand-side EE measures that result in electricity generation or savings. As described in the preamble, at section VII.F.4, the EPA intends to develop guidance on acceptable methods that can be incorporated in an EM&V plan included as part of an approvable state plan. Critical features of such EM&V guidance, including scope, applicability, and minimum criteria, are discussed in this section.

4.1 Accuracy of Energy Savings Estimates

To document and verify that avoided CO₂ emissions from energy efficiency programs and measures are real and persistent, impact evaluation must be rigorous and transparent. Impact assessment should also consider the appropriate balance between certainty of results and the EM&V costs to achieve a specified level of certainty. Because energy savings data are *estimates*, their use as part of the basis for determining the avoided CO₂ emissions resulting from energy efficiency programs and measures in a state plan will depend upon the level of accuracy of this information. Therefore, evaluation results should be reported as “expected values”—that is, energy savings values are expected to be correct within an associated range of certainty. Key considerations for EM&V of energy efficiency programs and measures in state plans are similar to those faced in the design of any program evaluation approach: (1) the level of certainty that is required given a program’s objectives and requirements, and (2) how achievement of that necessary level of certainty is balanced with the amount of effort (e.g., resources, time, money) used to obtain that level of certainty.

⁷⁴ Examples of such EM&V methods are described in the PNNL report, “Building Energy Codes Program: National Benefits Assessment: 1992-2040.”; and in Meyers et al, “Energy and Economic Impacts of U.S. Federal Energy and Water Conservation Standards Adopted From 1987 through 2012” LBNL-6217E.

4.2 EM&V Technical Considerations for State Plans

Using energy efficiency requirements, programs, and measures as an emission reduction approach in state plans requires consideration of several evaluation-related technical considerations. The following sections describe these considerations.

4.2.1 Qualifying Demand-Side Energy Efficiency Actions

States are currently implementing a wide range of demand-side energy efficiency requirements, programs, and measures. However, EM&V of some of these programs and measures are associated with greater levels of measurement precision and certainty than others, based in part on the EM&V procedures currently in place. For example, energy efficiency programs subject to PUC oversight and review are frequently evaluated using rigorous evaluation procedures that are based upon several decades of research and experience. These energy efficiency programs are subject to a quasi-judicial, public, and transparent review process, which can lead to adoption of EM&V protocols that convey a relatively high level of certainty for EM&V results.

In contrast, other energy efficiency requirements and measures, some of which may result in very significant and cost-effective energy savings (e.g., building energy codes, local tax credits, EE loan programs, etc.), are not subject to PUC oversight and typically have comparably fewer EM&V requirements. There are also some newer EE program designs (e.g., certain behavior-based programs and some market transformation programs⁷⁵) for which rigorous EM&V methodologies or a track record of energy savings persistence do not yet exist.⁷⁶

⁷⁵ *Behavior-based* energy efficiency programs aim to affect consumer energy-use behaviors in order to achieve energy and/or peak demand savings. Techniques to measure the impacts of these program designs are emerging and currently under development. *Market transformation* programs are characterized by strategic intervention in a market to address market barriers and market failures to accelerate market adoption of energy-efficient technologies and practices, and create lasting market change. While market transformation approaches can have very high energy savings impacts, by creating sustained deployment of energy-efficient technologies and practices, evaluation of these strategies is challenging due to the involvement of numerous market players and the multi-year timeframe for achieving energy savings.

⁷⁶ We note that EM&V approaches and protocols for behavior-based end-use energy efficiency programs do exist, but they have not been widely applied. For examples, see State and Local Energy Efficiency Action Network (SEE Action), *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations* (2012), Prepared by A. Todd, E. Stuart, S. Schiller, and C. Goldman,

As discussed in the preamble, while the EPA does not intend to limit the types of RE and demand-side EE measures and programs that can be included in a state plan – provided that supporting EM&V is rigorous, complete, and consistent with EPA requirements and guidance – the level and type of documentation required by EPA in an approvable state plan may depend on whether EM&V practices for that type of program or measure are well established. One option for organizing these variations in EM&V practices is with a qualitative hierarchy, as follows:

- *EM&V procedures and protocols well established* – for example, rebate and direct install programs for appliances, HVAC, and lighting equipment
- *EM&V procedures and protocols moderately well established* – for example, building codes and standards
- *EM&V procedures and protocols less well established* – for example, building disclosure and labeling programs

Table 2 provides an illustrative characterization of the relative level of EM&V uncertainty for different types of energy efficiency programs and measures under this approach. This information is illustrative and generalized. In particular, there are numerous exceptions to the categorization of the relative uncertainty of EM&V results for different types of programs and measures listed in Table 2.

Table 2. Illustrative Characterization of EM&V Procedures and Protocols for Common Energy Efficiency Programs and Policies⁷⁷

EM&V Procedures and Protocols Well Established	EM&V Procedures and Protocols Moderately Well Established	EM&V Procedures and Protocols Less Well Established
<ul style="list-style-type: none"> • Direct install incentive programs for building equipment (retrofits and new construction), including: <ul style="list-style-type: none"> ○ lighting ○ heating, ventilation, and air conditioning (HVAC) ○ refrigeration ○ motors • Consumer-direct and mid-stream rebates for ENERGY STAR-certified lighting, appliances (including residential refrigerator recycling), and HVAC equipment • Building commissioning and retro-commissioning • Incentives for certified energy-efficient residential new construction, such as ENERGY STAR Homes • Combined heat and power (CHP) installations/retrofits • Electrical distribution system and transmission system upgrades 	<ul style="list-style-type: none"> • Building energy codes (requirements and incentive programs for new construction, remodels) • State government building/operations programs (procurement, design standards, etc.) • Product-specific upstream market transformation programs directed at manufacturers • Industrial energy efficiency new construction or retrofits 	<ul style="list-style-type: none"> • General education programs for consumers, contractors, distributors, suppliers • Targeted training programs • Building labeling and disclosure programs • Targeted consumer behavior programs

⁷⁷ This table is intended as a generalized description, based upon numerous conversations with professional energy efficiency program evaluators. It should be noted that there are states with building energy codes, behavior programs, and market transformation programs that are well documented and subject to rigorous EM&V. In addition, such characterizations will change over time, as EM&V approaches for new and innovative programs and measures become standard practice.

As discussed in the preamble, at section VIII.F.4, EPA is proposing to allow a wide (or unlimited) set of energy efficiency program and measure types in state plans, as long as the energy savings are adequately documented according to rigorous EM&V methods and appropriate state regulatory oversight. Recognizing these variations in EM&V procedures and protocols, one option for EM&V requirements and guidance for state plans is to streamline review of EM&V plans for a pre-defined list of well-understood program types for which evaluation is straightforward and energy savings results are subject to a relatively low level of uncertainty.⁷⁸ Other programs and measures with less well developed EM&V approaches would require greater documentation in state plans of EM&V methods that will be applied. This proposed approach is intended to maximize state flexibility and accommodate the full range of state energy efficiency programs, while simultaneously maintaining EM&V rigor and transparency. As discussed in the preamble, at section VIII.F.4, EPA is also taking comment on the option of limiting the eligible types of energy efficiency programs and measures that could be included in a state plan to a pre-defined list of well-understood program types for which evaluation is straightforward and energy savings results are subject to a relatively low level of uncertainty.

4.2.2 Avoided Transmission and Distribution (T&D) Losses from End-Use Energy Efficiency Measures

In general, the difference between the amount of electricity input to the transmission system by an EGU and the amount ultimately delivered to an end-user constitutes transmission and distribution (T&D) line losses.⁷⁹ According to EIA data, nationally, annual electricity transmission and distribution losses are equivalent to about seven percent of the electricity that is input to the transmission system in the United States. For every unit of energy use avoided at the end-use site, energy efficiency also avoids the losses that would otherwise occur as electricity is

⁷⁸ This includes energy efficiency programs and measures for which there is significant experience with EM&V, a robust set of existing EM&V studies and reports, and relatively straightforward EM&V approaches.

⁷⁹ The T&D system includes all the power lines and related equipment used to deliver electricity from an electric generating plant to an end-use site. Along the way, some of the supplied by the generator is lost due to the resistance of the wires and equipment that the electricity passes through, as well as reactive power losses in alternating current systems due to inductance and capacitance. Most of this lost energy is converted to heat. The magnitude of losses in the T&D system depends on the physical characteristics of the system in question, as well as how it is operated.

delivered to consumers through the T&D system.⁸⁰ Many state PUCs are aware of this additional benefit of demand-side energy efficiency programs, and actively credit program energy savings results to account for program contributions to avoided line losses, albeit using a range of measurement approaches and calculations. A consideration for EM&V requirements and guidance for state plans is whether to account for avoided T&D losses, and how to do so in a consistent manner across states.

4.2.3 Reported Energy Savings Values

Energy savings results for energy efficiency programs are often expressed in terms of annual MWh of savings per year. However, for an assessment of the associated avoided CO₂ emissions impacts, it may be useful to utilize time-differentiated (i.e., hourly, seasonal) energy savings data.⁸¹ Information about the timing of energy savings has direct implications for estimating the avoided CO₂ emissions that result from an efficiency program or portfolio of programs. The temporal energy savings profile that results from the application of energy-efficient technologies and practices to different end-uses can vary significantly. For example, air conditioner programs save energy primarily on hot summer days, whereas a refrigerator program saves energy every hour of the year. Time-differentiated information related to electricity generation is useful in estimating avoided CO₂ emissions. In particular time-differentiated data is necessary to estimate the marginal avoided CO₂ emissions related to electric generation, as discussed above in section IV.C.3.

In practice, state PUCs around the country have substantially different requirements and recommendations for evaluating and reporting time-differentiated energy savings. Some energy efficiency program administrators report annual energy savings impacts, where savings are typically based on either tracking data (i.e., data used to estimate savings for planning purposes) or evaluated (i.e., ex-post) savings data. Other programs supplement reporting of annual energy savings with data on the timing of energy savings, which can be used to identify the marginal EGU or cohort of marginal EGUs that would have provided generation in the absence of the

⁸⁰ U.S. EPA, *Assessing the Multiple Benefits of Clean Energy: A Resource for States* (February 2010), available at: http://epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits_ch3.pdf

⁸¹ This is often referred to as the “load shape” of energy savings achieved through an energy efficiency measure.

energy savings. This supplemental data can be used to more accurately estimate avoided CO₂ emissions that result from program energy savings. Due to improved evaluation software and data availability, it is increasingly common for energy efficiency program EM&V plans to include calculation of estimated seasonal or even hourly energy savings as part of the program evaluation process. A consideration for EM&V requirements and guidance for state plans is the extent to which time-differentiated data on energy savings from energy efficiency programs is available, and whether states can readily acquire such data and information for use in implementing their state plans.

A related consideration is metrics reported for electricity savings. The primary metric required to understand the avoided CO₂ emissions impacts of energy efficiency programs and measures is annual MWh of energy saved. In addition, a secondary metric is MW demand reduction impacts, which may be desirable because it is helpful in identifying the marginal EGU or cohort of EGUs, in particular units on the build margin. This information is necessary to estimate the marginal avoided CO₂ emissions related to electric generation, when reporting on avoided CO₂ emissions achieved through energy efficiency programs and measures during a plan reporting period, as discussed above in section IV.C.3. Identifying EGUs on the build margin, based on estimates of MW demand savings that will be achieved through the implementation of energy efficiency programs and measures included in a state plan, may also be useful in projecting emission performance by affected EGUs that will be achieved under the state plan.

4.2.4 Savings Definitions: Net and Gross Savings

As described above, state PUCs typically specify whether energy efficiency program administrators are required to report either gross or net energy savings, or both. Gross savings are the change in energy use (MWh) and demand (MW) that results directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the change in energy use and demand that is directly attributable to a particular energy efficiency program.⁸² Reporting of net savings helps a PUC ensure that energy

⁸² Calculations of net energy savings involve excluding energy efficiency measures undertaken by "free riders" (i.e., EE program participants who receive a program rebate even though they would have taken the efficiency action anyway), or adjusting energy savings estimates to account for these effects. Free riders increase program costs

efficiency program budgets are being used to promote technologies and practices that are not otherwise being adopted in the marketplace. A consideration for EM&V requirements and guidance for energy efficiency requirements and programs included in state plans is whether required reporting of energy savings should be specified on either a gross or net basis, or both, to promote national consistency in measuring the impact of energy efficiency measures across state plans.⁸³

4.2.5 “Measure Life” and Persistence of Savings

Measure life and persistence of energy savings describe the ongoing effects of an installed energy efficiency measure, including the retention of the measure (*i.e.*, is it still in place) and the performance degradation of that measure, which reduces a measure’s achieved energy savings over time. Typically, program administrators estimate the impact of energy efficiency programs in terms of first-year savings (in MWh), plus the cumulative MWh savings realized from that program (or measure) over an assumed “measure lifetime”. Depending on the mix of energy efficiency measures and their assumed measure lives, these energy-savings benefits may extend from 10 to 15 years, or more into the future from the point of measure installation. In practice, evaluators determine measure lifetimes on the basis of engineering judgment, manufacturer specifications, and some empirical field studies. These values are frequently entered into PUC-managed state technical databases for ongoing and repeated use in evaluation studies. For state plans, a key consideration for EM&V is whether measure life and persistence values for energy efficiency measures documented by states are accurate, up-to-date, and consistent with those utilized in other states (after accounting for appropriate non-energy factors, such as weather and building occupancy type).

without producing additional energy savings impacts beyond what would have occurred in the absence of the EE program. Free ridership may also be addressed in the setting of baselines that are used to calculate energy savings. Estimates of net energy savings may also involve an assessment of "free drivers" (sometimes referred to as "spillover effects"). These are individuals who do not directly participate in an EE program, but who undertake efficiency actions in response to program activity (e.g., marketing/advertising, greater availability of energy-efficient equipment in a marketplace as the result of EE programs). Accurate estimation of free ridership and spillover effects is complex, especially in areas of the country with robust energy efficiency markets with multiple non-program influences competing for customers’ attention.

⁸³ If both gross and net savings were required to be reported, this would increase the transparency of reported energy savings estimates, but only one savings value would be used to evaluate the effect of energy efficiency programs and measures on CO₂ emissions from affected EGUs.

5. Options for EM&V Requirements and Guidance for State Plans

As EPA develops guidance on acceptable evaluation methods that can be incorporated in an EM&V plan included as part of an approvable state plan, the agency (as discussed in the preamble at section VIII.F.4) is seeking comment on the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols, as described in this section.

As summarized in the preamble, and discussed in more depth in this section, utilities and states have conducted ongoing evaluation of end-use energy efficiency and renewable energy measures and programs for several decades. These evaluations, which include quantification, monitoring and verification of results, generally rely upon a well-defined set of industry-standard practices and procedures. As a result, existing state and utility EM&V requirements and processes generally provide a solid foundation for minimum EM&V requirements that can be utilized by the EPA in the development of EM&V requirements and guidance for state plans. However, measurement approaches vary by state based on multiple factors, including the measure and program type being evaluated, the level and nature of regulatory oversight, the degree of state and utility experience with these measures and programs, and the overall magnitude of program impacts. Due to this variation in state EM&V approaches, as well as the specific objectives of a state plan under CAA section 111(d), harmonization of state EM&V approaches, or inclusion of supplemental EM&V actions and procedures, may be warranted in an approvable state plan.

As discussed previously, current state EM&V practices involve aligning the level of EM&V effort (i.e., rigor, reliability, validity, and uncertainty of energy savings estimates) with the appropriate level of certainty of evaluation results, while taking into consideration the magnitude of energy efficiency program impacts. This approach is consistent with the objective of achieving environmental results, ensuring minimum levels of cross-state consistency, and supporting and encouraging the use of energy efficiency requirements, programs, and measures

in state plans. To advance these objectives, the EPA could take several possible approaches for documenting energy efficiency savings from measures in state plans.

Options for EM&V requirements and guidance for state plans that incorporate energy efficiency requirements, programs, and measures include:

- Establishing specific EM&V requirements with a level of defined rigor – such as a required minimum level of precision and accuracy (see discussion of ISO forward capacity markets above) – for all energy efficiency programs and measures
- Establishing specific EM&V requirements for certain types of widely used energy efficiency programs and measures – such as those addressed by DOE’s Uniform Methods Project (UMP) – while establishing a generalized EM&V approach that states can apply to programs that are relatively new, innovative, or untested
- Establishing a set of generalized, process-oriented EM&V requirements that apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches, as appropriate for different types of programs and measures, provided that EM&V meets these minimum requirements

At one end of this spectrum, establishing program-specific EM&V requirements and an associated level of rigor for EM&V provides certainty to states in terms of required energy savings documentation, and does so in a manner that ensures a consistent level of EM&V rigor across all state plans. However, this approach may require significant effort by the EPA to establish such requirements, and could potentially duplicate state efforts currently under way to harmonize EM&V practices. This approach may also limit the variety of valid EM&V approaches applied at the state level, and by extension the types of energy efficiency programs and measures that could be included in a state plan. It could also inhibit the development of innovative EM&V approaches that improve the accuracy of energy savings estimates. At the other end of the spectrum, if only generalized, process-oriented EM&V requirements and guidance are established, then a state has maximum flexibility, but also faces somewhat greater uncertainty about whether the EM&V approach included in a state plan will be approved by the EPA. This could increase the transaction costs incurred by states during the development of their

plans, and could possibly delay the full implementation of energy efficiency programs incorporated in state plans.

Alternatively, a middle-ground approach involves a combination of specific EM&V criteria for common energy efficiency program and measure types, along with generalized guidance for emerging program designs and measures. Such an approach would provide some level of certainty regarding acceptable EM&V approaches in state plans, while maintaining a certain degree of flexibility for states to determine an appropriate mix of EM&V approaches, given the types of energy efficiency programs and measures included in their plan.

In addition, one option for supplementing either approach described above is to prescribe who can conduct EM&V activities and prepare energy savings documentation, and to specify their needed qualifications. This approach is analogous to professional certification requirements in the accounting and engineering fields, in which a minimum level of credibility, rigor, and accountability is imparted to the services provided by qualified individuals and firms. Criteria for eligible evaluators might include a demonstration of independence from those implementing or administering the energy efficiency programs and measures (*i.e.*, identification and mitigation of potential conflicts of interest) and required minimum levels of training, experience, or certification. This approach recognizes that the qualifications, integrity, and independence of those conducting EM&V of energy efficiency programs and measures, and preparing energy savings estimates, is critical to assuring best-practice EM&V. However, such requirements alone may not ensure sufficient evaluation rigor.

5.1 Use of EM&V Protocols

Establishing requirements and guidance for EM&V of energy efficiency programs and measures included in state plans may involve:

- Relying on existing EM&V infrastructure and protocols, most of which have been established for utility-customer funded energy efficiency programs overseen by state PUCs
- Establishing new protocols and procedures

Relying on existing approaches has the benefit of utilizing existing resources that can be relatively quickly ramped up for use in state plans. However, existing state and utility EM&V infrastructure and protocols may not be applicable to the full range of energy efficiency programs and measures that a state may want to include in its plan. In addition, because existing state and utility EM&V infrastructure and protocols were established to support the goals of state energy efficiency programs, in current form they may not adequately support the level of EM&V required for state plans under CAA section 111(d). In particular, this may include the form and precision of energy savings data and reporting necessary to evaluate avoided CO₂ emissions that result from energy efficiency programs and measure included in state plans.

5.2 EPA Review of EM&V Plans as Part of the State Plan Review Process

As discussed in the preamble, at section VIII.F.4, the EPA is proposing that a state plan must include an EM&V plan, which is subject to approval by EPA, as part of plan review and approval. Under this approach, the EPA would review these EM&V plans as part of its review of submitted state plans. One option is that an approvable EM&V plan could rely primarily on state- or utility-level EM&V plan review and approval processes, consistent with established EPA requirements and guidance for EM&V, with open public involvement and state lead-agency approval. Using existing state EM&V plan review processes may better ensure that energy savings estimates are transparent, peer reviewed, and address stakeholder input. Using state processes also minimizes duplication of state and the EPA requirements, and balances the need for EM&V credibility and rigor with an interest in encouraging the deployment of cost-effective energy efficiency programs and measures through incorporation in state plans.

5.3 General Quality Standards for EM&V Rigor and Accuracy

Since existing state EM&V process vary, EM&V guidance established by EPA may need to identify and establish minimum criteria for EM&V rigor, accuracy and reliability, and quality control. Requirements could be (a) a single set of requirements that apply to all energy efficiency programs and measures in all states or (b) a variable or flexible set of requirements with increasing levels of EM&V effort and rigor depending on the relative degree of uncertainty of energy savings from the energy efficiency programs and measures in a state plan. For example,

well understood energy efficiency measures with a higher degree of energy savings certainty might require a lower level of EM&V effort, while measures with greater complexity or uncertainty of energy savings effects would require greater EM&V effort.⁸⁴

For simple, well-understood and straightforward energy efficiency programs and measures, such as lighting retrofits, EPA guidance might specify only verification that measures were installed and the use of deemed energy savings values (i.e., lower EM&V effort level). In contrast, EPA guidance might specify more detailed EM&V (i.e., a higher level of EM&V effort) for less well-understood or more complex energy efficiency programs and measures, such as behavior programs and market transformation programs.

A prescriptive EM&V approach in EPA guidance for different types of energy efficiency programs and measures would provide states with certainty while supporting a consistent level of EM&V rigor across all states. A flexible EM&V approach, based on an individual assessment of the measurement uncertainty related to the energy efficiency programs and measures included in a state plan could provide states with greater flexibility when selecting energy efficiency programs and measures. However, the lack of a prescribed EM&V approach in EPA guidance could increase uncertainty about the approvability of different plan approaches.

6. EM&V Documentation in a 111(d) State Implementation Plan

EM&V documentation will be an important component of state plans that incorporate energy efficiency programs and measures, because transparency and reproducibility increase overall confidence in reported energy savings results. A crucial component of EPA's proposed approach for evaluating energy efficiency programs and measures included in a state plan is a requirement that state plans that include enforceable energy efficiency and renewable energy measures must include an EM&V plan for these measures. These EM&V plans would specify how achieved energy savings will be retrospectively evaluated at appropriate increments during

⁸⁴ For the purposes of this discussion, lower, medium, and high levels of "EM&V effort" are intentionally indeterminate. One possibility is that "lower EM&V effort" could refer to greater reliance on deemed savings values, smaller sample sizes for measured savings, fewer direct measurements, and proportionately greater reliance on ex-ante estimates. "Medium" and "high" levels of EM&V effort could require incrementally more effort in each of these areas. Other interpretations of this concept are possible.

the plan period. Decisions about the level of EM&V documentation that is necessary in a state plan must consider tradeoffs between provision of more information and greater transparency, and the level of EM&V effort required. Excessive documentation requirements may not add value in terms of transparency, but may discourage the inclusion of cost-effective energy efficiency options in state plans. However, two basic criteria for EM&V documentation should be applied in state plans:

- Energy savings documentation should be provided at a level of detail that allows for recalculation of program energy savings totals; and
- EM&V information in state plans should be provided in a consistent manner across states to allow for comparison, benchmarking, and more efficient review of plans by the public and EPA

6.1 Illustrative Example of an EM&V Plan for End-Use Energy Efficiency Programs Measures in a State Plan

The following is an example of a possible outline of the types of information that might be included in an EM&V plan for energy efficiency programs and measures included in a state plan. An EM&V plan would specify how EM&V activities will be conducted and reported for relevant energy efficiency programs and measures during a state plan performance period. An EM&V plan could apply to utility energy efficiency programs that are incorporated into a state plan on a stand-alone basis, and might also apply to such programs when used to meet mandatory energy efficiency requirements, such as an EERS, that are incorporated into a state plan.

Who Will Document Savings and When

- Name of the organization that will prepare evaluated energy savings reports
- Relationship of the organization to the subject energy efficiency program(s) and program administrator(s)
- Schedule of when the reports will be prepared and what period of time they will cover
- Name of the state or regional government entity, or non-governmental entity, which will review and certify the evaluated savings

- How evaluated energy savings reports will be made publicly available and what the primary use of the reports will be

Documentation Procedures

- List of energy savings metrics to be reported (e.g., annual MWh, monthly MWh, hourly MWh, average MW), and whether gross or net savings, or both, will be reported
- Name of impact evaluation protocols, guidance documents, and other methods that will be followed in preparing evaluated energy savings reports
- Description of the range of uncertainty for energy savings estimates indicated in evaluated energy savings reports, including sources of uncertainty
- Description of assumptions concerning availability of data and data collection methods
- Indicate how the following issues, if applicable, will be addressed in the claimed and evaluated savings estimates:
 - Inclusion of estimates of avoided electricity transmissions and distribution losses
 - Adjustment of gross savings estimates to net savings estimates (if applicable)
 - Sources of uncertainty

B. Quantification, Monitoring, and Verification for Renewable Energy Measures

For rate-based state plans, a key element of the plan is a demonstration of how the state, and related entities with enforceable obligations under the plan, will measure and verify electric generation that is achieved through the implementation of renewable energy measures incorporated in the plan.⁸⁵ This section discusses current state and utility quantification, monitoring, and verification practices for renewable energy measures, and discusses considerations related to possible acceptable quantification, monitoring and verification approaches for a state plan under CAA section 111(d).

States and utilities use a variety of policy instruments to increase the production and use of renewable energy. The principal mechanisms include: renewable portfolio standards (RPSs),

⁸⁵ In this section we use the term “renewable energy measure” to refer to a renewable energy requirement (such as an RPS), a renewable energy deployment program, or individual installed renewable energy measures, such as installation of a solar photovoltaic system through a renewable energy deployment program.

feed-in tariffs (FITs), tax incentives (e.g., property tax exemptions; production-based tax incentives; etc.), financial assistance programs (e.g., grants, loans, and other direct financial assistance based on generating capacity or investment level), and other policies (R&D support; manufacturing incentives; workforce training; net metering; etc.). Experience to date indicates that RPSs have led to the vast majority of the increase in renewable energy generating capacity and generation resulting from state policies. However, FITs and production-based tax incentives have been among the most important incentives used by states and utilities to help achieve RPS requirements, as well as to spur additional production and use of renewable energy. Further, these types of programs rely on measurable electric generation as the basis for compliance or incentive payments. As a result, the following discussion focuses on quantification, monitoring, and verification mechanisms related to these state policies. Other types of programs (e.g., certain grant and rebate programs) may not currently quantify electric generation output from funded renewable energy projects. However, if such programs were modified to require the collection of such data, many of the quantification, monitoring, and verification considerations discussed in this section would also generally apply.

1. Renewable Portfolio Standards

A RPS is designed to increase the amount of renewable energy a distribution utility or load-serving entity provides to retail electricity customers.⁸⁶ This increased customer demand in turn increases the production of renewable energy to meet demand. To achieve compliance with a RPS, an increasing share of a distribution utility's electricity retail sales is required to be produced or acquired from renewable energy resources and delivered to customers. To verify compliance, RPSs have been complemented by tracking systems for renewable energy generation and use. These tracking systems account for the growing amount of renewable energy

⁸⁶ In states that have restructured their electricity sectors and introduced retail competition, entities other than a utility may supply electricity to a retail customer. These entities use a regulated distribution utility's network to deliver electricity to a retail consumer. These entities either generate their own electricity or contract for supply from wholesale electricity market participants. In this section, we use the term "distribution utility" to refer broadly to both local distribution companies (LDCs) and other load-serving entities that supply electricity to retail customers.

that is produced for obligated retail sellers as well as large and small retail energy consumers that purchase renewable energy on a voluntary basis.⁸⁷

The point of regulation for state RPSs is typically investor-owned electric distribution utilities, because most RPS apply to entities under the jurisdiction of state PUCs. In a number of states, municipally-owned utilities and electric cooperatives are exempt from state RPS, have lower RPS requirements, or are required to develop their own renewable energy procurement targets. Additionally, some states have created separate renewable energy requirements for each of their affected distribution utilities.

The absolute amount of renewable energy that each distribution utility is obligated to deliver will vary, with requirements in the form of a fixed amount of renewable energy (either MWh or MW of capacity) or percentage of retail sales.

There are several pathways that affected distributed utilities typically have to meet state RPS requirements, including building and operating renewable energy generating capacity, purchasing electricity from renewable energy generators, and purchasing the attributes from renewable energy generation. Many state RPSs take this latter approach. Rather than requiring each distribution utility to generate electricity from its own renewable energy facilities or purchase electricity from a renewable facility owned by others, many states require distribution utilities to acquire renewable energy certificates (RECs) that represent the attributes of the unit of renewable electricity produced.⁸⁸

By allowing REC trading, many states have created markets for RECs based on specific state RPS requirements. Renewable energy generators can sell RECs as another product bundled with the underlying power they produce or sell RECs separately to different customers. Once the

⁸⁷ “Voluntary” renewable energy purchases, as used here, refers to renewable energy purchases in addition to the renewable energy required by RPSs.

⁸⁸ RECs are contractual instruments that convey ownership of the attributes of a unit of energy generated, but do not represent the energy itself. The attributes conveyed with RECs include information about the generator, such as: type of resource (e.g., wind), plant-level air emissions (if any), geographic location, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification.

RECs are separated from the power generated, the power has no attributes associated with it and is considered generic or “null” power.⁸⁹

There are a number of key aspects of RPS design and implementation that affect the quantification, monitoring, and verification of renewable energy generation used to meet a RPS:

- Eligible renewable energy resources. While most RPS-eligible resources in most states will result in avoided CO₂ emissions from fossil fuel-fired EGUs, some RPS-eligible resources in some states are responsible for greenhouse gas (GHG) emissions or do not meet common definitions of renewable energy (e.g., waste coal, coal-bed methane, and fuel cell operation using fossil-fuel feedstocks).
- Existing and new resources. RPS-eligible resources can include facilities that began operation prior to the enactment of the RPS and, more importantly, prior to the proposal of the emission guidelines by EPA.⁹⁰
- Scope of coverage. In some states a RPS applies to all retail sales in a state, but in others only a subset of retail sales (e.g., only investor-owned utility retail sales) are subject to a RPS.
- Credit multipliers. Some states provide additional incentives for specific eligible resources in the form of bonus credit toward compliance in their RPS accounting framework. For example, these states may favor certain resources (e.g., distributed solar PV), or locally-important resources or technologies. The MWh produced or renewable energy certificates (RECs) related to MWh production from such facilities may be counted twice or three times toward compliance with a RPS in such states. However, these credit multipliers and bonuses are not an accurate representation of the amount of

⁸⁹ These distinctions are typically made as part of utility disclosure to customers about the energy resource mix and emissions of the electricity used by a customer that was supplied from by the distribution utility. “Generic power” or “null power” refers to energy that has no generation attributes or descriptive information (*i.e.*, the remaining system mix of power, after assignment of specified power to different utility customers, through power purchase contracts or purchase of generation attributes through RECs). For electricity labeling, disclosure to customers, or other market claims, generic or null power is typically assigned the attributes of the remaining system mix of power, after the assignment of attributes as described above.

⁹⁰ In the preamble, the EPA is proposing that, for an existing state requirement, program or measure, a state may apply toward its required emission performance level the emission reductions that existing state programs and measures achieve during the plan period due to actions taken after the date on which the emission guidelines are proposed (*i.e.*, from June 2014 onward).

renewable energy generation that is attributable to a RPS. For the purpose of quantifying the amount of renewable energy produced as a result of a RPS included as a measure in a state plan, only the actual renewable energy generation used to comply with an RPS is relevant.

- *Banking.* Some states permit the carryover of renewable energy produced in one year to satisfy RPS requirements in a subsequent year. Accounting for year-to-year carryover should be addressed in a state plan, in order to determine the renewable energy generation that occurred in a respective reporting year or compliance period.
- *Alternative compliance payments (ACP).* Many states allow a compliance alternative which requires obligated entities to pay a predetermined fee to the state for each MWh of RPS shortfall. Although these ACP payments may be directed to programs to promote the deployment of renewable energy technologies, these payments are not equivalent to renewable energy generation and should not be accounted as such.
- *Interstate issues.* While treatment of interstate emission effects is discussed in detail in section VII, for quantification, monitoring, and verification of renewable energy generation under a RPS it is important to note that most states allow use of eligible renewable energy resources located in other states to satisfy the state RPS requirements.⁹¹

Considerations related to the quantification, monitoring, and verification of renewable energy generation used to meet a RPSs depends on the design and implementation of the RPS. Distribution utilities subject to a RPS may meet their RPS obligations by building and operating their own renewable energy generating facilities, entering into bilateral contracts with other parties to purchase renewable energy, and participating in the REC market. Each compliance method has specific implications for the quantification, monitoring, and verification of renewable energy generation used to meet RPS obligations. Implications under these different pathways are discussed below.

⁹¹ This may also include international renewable energy resources, such as Canadian hydroelectric and wind energy resources, which may be used to comply with some state RPSs.

Build renewable generating facilities

In many states, utilities with RPS obligations may build, own, and operate their own renewable energy generating facilities. This pathway is often used by vertically integrated utilities subject to a RPS. For large renewable energy generating facilities, production is measured through a revenue-grade utility meter as it enters the grid at the point of interconnection. This meter is subject to the same verification standards as for any other generator participating in the wholesale market.

Some utilities with RPS obligations also build, own, and operate smaller distributed renewable energy generating facilities. Smaller generators, such as residential rooftop solar PV systems of less than 10 kW capacity, often don't have discrete metering of their total generation.⁹² State RPS requirements may permit these distributed generators to qualify for use in meeting utility RPS obligations based on an engineering estimate of their renewable energy generation output, provided the distributed generators are registered with a REC tracking system and the generation output is verified according to tracking system and RPS rules.

Bilateral contract model

Under the bilateral contract model, distribution utilities with RPS obligations contract with renewable energy generators for supply. These contracts typically specify a delivery amount in MWh over a specified contract period. These supply contracts may be short- or long-term, may specify generation from certain renewable energy EGUs, and may be solicited through an RFP or entered into through negotiation. Quantification of renewable energy generation (in MWh) is accomplished through the use of a revenue-grade meter that measures the flow of electricity from the generator into the transmission grid. A contract may also stipulate an adjustment to the metered MWh generation data to account for transmission losses that occur between the point of injection of electricity to the transmission grid and the point of receipt at a utility transmission or distribution system. A renewable energy supply contract also generally addresses the ownership of the RECs related to the renewable energy generation. Under such a

⁹² Metered data for these PV systems may only track net electricity supply to or from the grid, representing either surplus generation that is not used to serve on-site electricity load or additional net electricity supplied from the grid if the system does not meet a building's total electricity load.

contract, purchase of the RECs should accompany the purchase of the electricity, in order for the utility to satisfy its RPS obligations through the contract.⁹³

State RPS compliance processes may provide for PUC review of supply contracts, including inspection of meters and verification of electricity delivery from the generator to the utility distribution network through a specified contract path (e.g., through evidence of transmission rights held or scheduled). The purchasing utility also reports their purchase and delivery of RPS-compliant renewable energy pursuant to the contract to the state agency responsible for RPS enforcement, typically the state PUC or state energy office. Verification is accomplished by audit of electricity supply contracts along with REC tracking system reports of RECs held by the utility and submitted for retirement by the tracking system administrator. Some state RPS require that electricity from qualifying renewable energy sources be produced within the state or a specified grid region, or if outside the state or specified grid region, that electricity be delivered to the state or grid region. In such cases, the verification of electricity delivery is typically done by the REC tracking system administrator before issuing RECs for the imported energy. Verification can be provided, for example, by demonstration of scheduled delivery through the ISO or RTO serving the state or region, through demonstration that the seller holds transmission rights for delivery or possession of NERC tags for the energy.⁹⁴ Bilateral contracts also typically require certification by the seller that attributes related to the sold electricity have not been and will not be otherwise sold, retired, claimed, represented as part of energy sold elsewhere, or used to satisfy obligations in another jurisdiction.

⁹³ This ensures that multiple parties are not using the same MWh of renewable energy generation to comply with their RPS obligations.

⁹⁴ A NERC Tag, sometimes referred to as an E Tag, is an electronic tag that is used to track wholesale electricity transactions that involve the transfer of electricity across or through control areas. NERC Tags allow transmission system operators to track electricity transactions in real time in order to assess any potential reliability implications of scheduled power transactions. NERC Tags define the physical path of an electricity transaction from the point of generation to the point of receipt, and also define the financial path, including all parties to a transaction. All wholesale electricity transactions that will result in the transfer of electricity from one control area to another, or that involve transfers through a control area, must be accompanied by a NERC Tag. Based on a real-time assessment of NERC Tags, system operators can curtail transfers if reliability issues would arise as a result of the transfer. NERC tags are issued through an electronic system in accordance with specifications established by the North American Electric Reliability Corporation (NERC).

REC model

Under the REC model, renewable energy generators register their EGU with a renewable energy tracking system, which have been established by several regional groupings of states, as well as a few individual states.⁹⁵ The registration process collects data about the generator's attributes: type of resource (e.g., wind), plant-level emissions, geographic location, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification. After the generator is registered, revenue-meter data is transmitted to the tracking system. Meter accuracy is verified for renewable energy generators in the same manner as for any other generator participating in wholesale electricity markets.

Each MWh of renewable energy generation reported to the tracking system by a registered generator results in the issuance of a REC, with its own unique serial number and information about the generator, location, resource type, and the month in which the MWh was generated, and the month or quarter in which the certificate was issued. The renewable energy generator can then sell the renewable electricity as a bundle (both the commodity electricity and the associated REC) or unbundle the RECs from the electricity and sell the two products separately. Other market participants, such as brokers, REC marketers, and load-serving entities also maintain accounts with the tracking system so that REC electronic transactions can be recorded within the tracking system platform. The system tracks each REC through these transactions and ultimately "retires" the REC when the final purchaser designates it for retirement. Retirement could result from the REC being used to satisfy a state RPS, or as a result of a voluntary buyer retiring the REC to demonstrate that they had purchased and used renewable energy to meet their electricity demand.

⁹⁵ Currently, nine regional renewable energy certificate (REC) tracking systems operate in different regions of North America, including: Texas Renewable Energy Credit Program, run by the Electric Reliability Council of Texas (ERCOT), NEPOOL Generation Information System (GIS), PJM Generation Attribute Tracking System (PJM-GATS), Western Renewable Energy Generation Information System (WREGIS), Midwest Renewable Energy Tracking System (M-RETS), North American Renewables Registry (NARR), Michigan Renewable Energy Certification System (MIRECS), Nevada Tracks Renewable Energy Credits (NVTREC), and North Carolina Renewable Energy Tracking System (NC-RETS). For more information see <http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=3>.

Because the tracking system follows the REC from the point of issuance to retirement, including all interim transactions, it minimizes the opportunity for renewable energy to be double-counted across, for example, two different state RPSs, or between two voluntary purchasers. In recent years, the various tracking systems have developed interchange standards so that RECs generated within one tracking system can be transferred to and used within another tracking system.⁹⁶ Note that not every potential interchange possibility is currently supported, and that many states have additional eligibility restrictions within their RPS that may limit the use of RECs related to electric generation from distant locations. These include requirements in some state RPSs for the seller to hold firm transmission rights for delivery of the accompanying electricity from the renewable energy generator into the respective ISO/RTO system or grid system in which a state is located.

Small distributed generators

Smaller distributed generators, such as residential rooftop solar PV systems of less than 10 kW capacity, often don't have discrete metering of their total generation. State RPS requirements may permit these distributed generators to qualify for use in meeting utility RPS obligations based on an engineering estimate of their renewable energy generation output, provided the distributed generators are registered with a REC tracking system and the generation output is verified according to tracking system and RPS rules. Where such projects are third-party owned and operated, the project developer will own the RECs and factor their revenue value into their pricing offered to the site host for electricity supply. Note also that many utility-sponsored renewable energy incentive programs stipulate that all RECs resulting from the project must be transferred from the generation owner to the utility as a condition of participation in the incentive program. These RECs can then be used by the utility to meet its RPS obligations, or can be sold to other parties.

⁹⁶ Additional linkages between tracking systems are being established. More information can be found at <http://www.narecs.com/resources/registries/>

State agency role

In many states, the PUC or its equivalent is responsible for establishing the detailed rules and procedures that obligated parties must follow to comply with a RPS. The PUC is usually responsible for receipt and review of obligated parties' periodic compliance reports, imposing compliance penalties as needed, and for evaluating the impacts of the program on energy costs, generation diversity, and market operations. The list of eligible resources and MWh requirements are often set through state legislation, but these decisions may also be delegated to the PUC for study and promulgation through regulations of commission orders.

In some states the energy office may be responsible for certifying the eligibility of specific generators to participate in the RPS and for making siting determinations. In New York, for example, the New York State Energy Research and Development Authority (NYSERDA) is responsible for the centralized procurement of the renewable energy needed to meet the RPS for all of the state's investor-owned utilities.

2. Feed-in Tariffs

Feed-in tariffs (FITs) are offered by some individual electric distribution utilities and some states for renewable energy systems that meet eligibility criteria.⁹⁷ Under a FIT, the utility offers to purchase specific kinds of electricity (e.g., solar) from sellers at posted prices or under a published pricing formula for a specified period of time. FITs typically have caps on the amount of renewable energy that will be purchased by a utility (in MWh of energy or MW of capacity). FITs may also include customer impact caps for the tariff as a whole (in total dollars spent or in specified retail rate impacts allowable), and may also have limits on the size of any participating renewable energy generator from which the utility will purchase electricity through the FIT. FITs may also have pricing formulas that are differentiated by resource or that change through time as specified benchmarks are achieved (e.g., MW of renewable energy generating capacity subject to the FIT, amount of electricity purchased through a FIT as a percentage of utility sales, or retail

⁹⁷ There are several states that offer FITs, including California, Hawaii, Maine, Oregon, Rhode Island, South Carolina, Vermont and Washington, as well as numerous electric utilities.

rate impact level reached). Typically, the tariff treats all similarly-situated generators in a consistent manner.

Quantification of renewable energy generation output under a FIT is accomplished through the use of a revenue-grade meter to measure the generator's injection of electricity into the grid. The utility's tariff will typically specify the minimum performance characteristics and/or certifications that a meter must meet in order to be used on its system. Utilities retain the right to inspect and test the calibration of meters connected to their systems. As the utility will be paying the generator each month based on the meter reading, it is in the utility's interest to ensure that the meter is reading precisely and accurately through time.

Both the utility and the state will need to consider the ownership of the environmental attributes arising from the renewable energy generation purchased by a utility through a FIT, and whether the renewable energy can be counted toward RPS compliance. If renewable energy generation purchased by a utility through a FIT may be counted toward RPS compliance, then it should not be counted separately as another renewable energy program in a state plan.

State agency role

FITs are usually authorized by state statutes that specify which utilities must offer a FIT, eligibility criteria (e.g., renewable energy resource type, location, project MW generating capacity limits), and sometimes overall program targets (e.g., total installed MW of generating capacity subject to the FIT). State statutes may also specify whether the utilities offering a FIT will receive the RECs related to purchased electricity generation output for use in complying with a state RPS, and whether customers receiving FIT payments may also receive incentives under other utility and state programs. Typically state statutes leave implementation details to the PUC (or other utility governing body, if applicable, for municipal and cooperative utilities), but may provide guidance on what to consider in setting FIT payment levels. Based on this statutory authority, PUCs develop detailed rules governing implementation, which can include payment levels and contract length. PUCs may direct the affected utilities to develop standard contracts with all the terms and conditions spelled out, and these standard contracts must be approved by the PUC. As with state RPS, the PUC is responsible for receipt and review of the utility's

periodic status reports, approving changes to a tariff if needed, and evaluating the impacts of the tariff on retail prices, generation diversity, and electricity system operations.

Several FITs are offered by distribution utilities not overseen by PUCs, such as municipal utilities and rural electric cooperatives. These utilities have a variety of governance structures (e.g., municipal government, cooperative board of directors). The utility governing bodies in these situations will be responsible for receipt and review of the utility's status reports, taking corrective action if needed, and evaluating the impacts of the tariff.

3. State Tax Incentives

Several states offer a variety of tax incentives to promote the production and use of renewable energy. These currently include sales tax exemptions for certain kinds of equipment (e.g., PV panels), property tax abatement for improvements to a building or facility related to the asset value of the renewable energy generating system, and income tax credits for the installation of renewable energy systems based on capacity or investment level. Several states provide a renewable energy production tax credit based on the amount of renewable energy generated. This approach is useful because it results in a measureable quantity of renewable energy electricity generation.

With a production-based tax incentive, the renewable energy generator might claim a tax credit for each MWh of qualifying renewable energy generation within the state. One design consideration for a production-based tax incentive that affects quantification of renewable energy generation output is whether the electricity must be sold to a third party as opposed to being used by the site host. In the former case, a revenue-grade utility meter would be present at the point of interconnection to the electricity grid, which provides measurement of MWh generation output for tax compliance purposes. Site-host use might necessitate the installation of an additional meter within the project site to permit reliable measurement of the renewable energy generator's output.

State agency role

Currently, existing state tax policies are primarily under the authority of the state revenue agency. The state revenue agency might have the primary responsibility for establishing the rules

for production-based tax incentives, although it may seek advice from state energy agencies regarding the technical aspects of renewable energy generator operation and the behavior of energy markets. The renewable energy generator might claim the tax incentive through the state tax collection process and report MWh generation to claim the tax credit. The revenue agency could receive tax filings from the owner and operators of renewable energy generators and be responsible for determining whether the taxpayer's claim for tax incentives is supported by the MWh generation evidence. Assuming the state revenue authority retains its ability to audit the taxpayer's return, it could verify claimed MWh generation.

As with FITs, the renewable energy generation resulting from production-based tax incentives might be used for RPS compliance. If that were to become the case, then it should not be counted separately in a state plan from MWh generation used to comply with a state RPS.

4. Options for Quantification, Monitoring, and Verification of Renewable Energy Measures in State Plans

As summarized in the preamble, and discussed in more depth in this section, utilities and states have conducted ongoing evaluation of renewable energy measures and programs for several decades. These evaluations, which include quantification, monitoring and verification of results, generally rely upon a set of standard practices and procedures. In addition, states have designed and implemented REC tracking systems to facilitate compliance with state RPS. This resource provides the ability to track the location and attributes of renewable energy generators, and the electric generation from these generators, as well as the parties that use RECs for compliance with state RPS. As a result, existing state and utility requirements and processes for quantification, monitoring, and verification of renewable energy programs and measures generally provide a solid foundation for minimum requirements and guidance for EM&V for RE measures in state plans that are established by the EPA.

The programs discussed above (RPS, FIT, and performance-based tax incentives) all require quantification, monitoring, and verification of electricity generation from renewable energy generators, as well as provisions of other key information, to determine eligibility and

track program activity or compliance with regulatory requirements (if applicable). Quantification of electricity generation is typically through the use of revenue-quality meters,⁹⁸ or engineering estimates for small distributed generators. These data are essential to program management, verification of compliance or payments, budget control, and tracking progress toward goals. For example, PUCs overseeing compliance with state RPS receive compliance information from each obligated utility, including retail sales, compliance status based on MWh of electricity generated by eligible utility-owned renewable energy sources, or electricity or RECs purchased from eligible renewable energy generators, which may also consider application of multipliers or alternative compliance payments.⁹⁹ PUCs overseeing utility FIT and state agencies overseeing performance-based tax incentives managers receive reports containing MWh of electric generation from qualified electric generators that received payments under either a FIT or tax incentive. These data are essential for normal program management and accountability.

Current state data requirements under RPS, FIT, and production-based tax incentives are tailored to the objectives of these programs and facilitating effective regulatory oversight. Typically, avoiding CO₂ emissions, while considered a relevant co-benefit, is not a primary objective of these regulations and programs. As a result, additional information and reporting may be necessary to accurately quantify the avoided CO₂ emissions associated with the renewable energy generated through an RPS, FIT, or production-based tax incentive that is included in a state plan.

The following types of information will increase the accuracy and verifiability of avoided CO₂ emission estimates related to renewable energy requirements, programs, and measures included in a state plan. For example, information on the location of the renewable energy generation (e.g., in-by state or within a specified grid region) of the renewable energy generation used for compliance with state requirements and programs would be helpful in determining avoided CO₂ emissions. Information about the location of electric generators that supplied

⁹⁸ “Revenue-quality meter” refers to a meter used for billing purposes in wholesale electricity markets, which typically need to meet ISO or RTO precision requirements or other specifications.

⁹⁹ Compliance status will also consider the application of credit multipliers or alternative compliance payments, if relevant under an RPS.

electricity generation that was imported to a state or grid region, will also be important. Time-differentiated information related to electricity generation is also useful in estimating avoided CO₂ emissions. In particular time-differentiated data is necessary to estimate the marginal avoided CO₂ emissions related to electric generation. Such time-differentiated data could be based on metering or engineering estimates for a technology type that indicate the typical generation profile for the renewable energy resource. This could include time differentiation on an hourly, daily, or seasonal basis. If RECs can be banked and used for RPS compliance at a later time than the year in which the electricity generation related to the REC occurred, information about the quantity and vintage of RECs from prior year(s) generation that is used for RPS compliance will also be useful.

VI. Reporting and Recordkeeping for End-Use Energy Efficiency and Renewable Energy Programs and Measures

As discussed in the preamble, in section VIII.F.5, reporting and recordkeeping for end-use energy efficiency and renewable energy requirements and programs will be an important component of certain types of state plans. If a state plan incorporates renewable energy and demand-side energy efficiency requirements and programs under a rate-based approach or implements a mass-based portfolio approach with such measures, reporting and recordkeeping requirements for an approvable plan would differ from those applicable to an affected EGU. For example, these requirements may include compliance reporting by an electric distribution utility subject to an end-use energy efficiency resource standard (EERS) or renewable portfolio standard (RPS). They may also include reporting by a vertically integrated utility implementing an approved integrated resource plan. In the latter instance, the utility may also be the owner and operator of affected EGUs, but additional reporting of quantified effects of renewable energy and demand-side energy efficiency measures under the utility plan would be necessary to demonstrate emissions performance under the state plan. In other instances, a state agency or entity or a private or public third-party entity may be implementing programs and measures that support the deployment of clean energy technologies that are incorporated in a state plan. In each of these instances, reporting of program compliance or program outcomes is a necessary part of an approvable plan to demonstrate performance under the plan.

In the preamble, the EPA seeks comment on appropriate reporting and recordkeeping requirements for entities implementing end-use energy efficiency and renewable energy programs included as enforceable measures in a state plan, or for entities subject to requirements, such as an EERS or RPS, that are included as an enforceable state plan measure. This section provides examples of current reporting and recordkeeping under state energy efficiency requirements and programs, such as EERS, RPS, and utility and state deployment programs for energy efficiency and renewable energy. The section then examines the suitability of these reporting and recordkeeping practices as potential approaches in an approvable state plan.

A. Reporting for End-Use Energy Efficiency Programs and Measures

Reporting requirements and time frames (i.e. how often reports are required) for entities implementing energy efficiency programs and measures are key considerations for state plans. In a state-regulatory context with PUC oversight, impact reports are the mechanism by which utilities and other program administrators document energy (MWh) and demand (MW) savings. These reports serve as basis for PUC review of total achieved energy savings relative to program goals or regulatory requirements, as well as for determining financial performance incentives for utilities, where they exist.

In most states, impact reporting is initially conducted at the level of efficiency “programs” (each consisting of numerous “project” installations or efficiency measures occurring at individual homes, commercial buildings, or industrial facilities). Program level data are then aggregated to the “portfolio” level to capture the full impact of energy efficiency investments occurring under a PUC’s jurisdiction for the timeframe of interest.

Impacts reports are typically submitted annually, but in some cases program administrators also provide interim (e.g., quarterly) reports. This added step can help inform progress towards goals, as well as provide for corrections in cases where evaluated (ex-post) energy savings are not achieving projected or claimed (ex-ante) savings levels.

The information provided below presents a range of common reporting elements and common practices implemented by state PUCs. These reporting elements and practices – which raise important considerations for the reporting of energy-efficiency impacts in state plans – include:

- State EM&V guidelines, protocols, and/or framework utilized, where applicable
- Energy efficiency policy or program information reported to PUCs in annual reports:
 - Short description of the policies or programs implemented
 - Implementation schedules and timeframes
- Energy-savings impacts reported to PUCs in annual reports:

- Incremental annual and lifetime MWh savings for reporting (in the case of an energy efficiency program) or compliance years (in the case of utility compliance with a multi-year Energy Efficiency Resource Standard)
- Peak demand (MW) impacts (reported in many, but not all states)
- Verification documentation, which shows that installation of energy efficiency measures occurred, and the installed measures are capable of generating energy savings
- EM&V process followed:
 - Date and location of on-site facility visits and field observations
 - Description of public process for review of overall EM&V approach, EM&V plan, and EM&V results
 - Information about evaluators:
 - Name of firms and individuals performing EM&V activities, and qualifications
 - Certification that evaluators were selected through a public bid process, and are third-parties unaffiliated with efficiency program administrators or the state government
- EM&V methods used:
 - Deemed savings values - name, date, and public location of technical reference manual (TRM)¹⁰⁰ used for deemed savings values
 - Direct measurement approaches - description of the measurement approaches and reference to the EM&V protocols, standards, and guidance documents used
- Other documentation:
 - Data about the quantity of measures/projects on which the full program-level energy savings impacts are based (i.e., information describing the sample size and sampling procedures used)
 - Whether net or gross energy savings¹⁰¹ are estimated, definitions used for gross and net savings, and the basis for gross to net calculations, if applicable

¹⁰⁰ A technical reference manual (TRM) is a document consisting of predetermined savings values, assumptions, methods, and calculation approaches for conducting EM&V of state demand-side energy efficiency programs. Most states with robust efficiency programs rely on a TRM.

- Avoided transmission and distribution (T&D) impacts assumptions, if applied

The energy savings EM&V reporting elements listed above vary from state to state in terms of type and level of documentation, and reports are provided in different formats from state to state. This significant variation among states in reporting contents and format raises several considerations for states utilizing demand-side energy efficiency programs in state plans. One is whether the reporting processes, timeframes, and documentation required by state PUCs, described above, are sufficient and appropriate in the context of state plans. Another consideration is whether lead state agencies that oversee energy efficiency programs should be required to certify reported energy efficiency savings impacts on behalf of the state, potentially including certification that the values are appropriate and conservative, and meet their approval. A final consideration is whether and how energy savings impact reports are made available for public input and comment prior to finalization, recognizing that impact reports in many states exist but are not easily located or widely accessible by the public, nor are they provided in consistent formats from state to state.

B. Reporting for Renewable Energy Programs and Measures

1. Typical Reporting and Compliance Requirements under State RPS

Each state has different reporting and compliance requirements for its RPS, but all states with mandatory RPS require obligated entities to provide compliance reports to the state PUC or equivalent state oversight agency. Compliance obligations are typically specified in authorizing legislation, regulations, or PUC orders. Compliance is typically on an annual basis, and includes a list of required reporting elements. Some states also require distribution utilities to provide an implementation plan describing how they will comply with the state RPS rules in the future.

Data requirements for reporting may vary based on the design and implementation of a RPS. However, for nearly all state RPS requirements, annual compliance report data is based on

¹⁰¹ Gross savings are the change in energy use and/or energy demand that results directly from program-related actions taken by program participants, regardless of why they participated in the program. Net savings refer to the change in energy use and/or energy demand that is directly attributable to a particular energy efficiency program.

measurable electric generation results and verified through tracking system data.¹⁰² In some states, compliance reports may also include state-level projections of renewable energy generation resulting from current or proposed state RPS policies.

The most common form of tracking system for RPS compliance is a regional or state REC tracking system or registry. These systems track RECs for both the compliance and voluntary markets. RECs are typically provided with a unique identification number and may be certified by a third-party verifier. Annual compliance reports containing REC data typically include the number of RECs the utility or load-serving entity procured and retired, what renewable energy generators supplied the RECs, and how much the utility spent on procuring the RECs.

2. Typical Reporting for Renewable Energy Deployment Programs¹⁰³

Renewable energy deployment programs involve the provision of a payment or credit for a renewable energy project, or for a quantified amount of electricity generation, in the case of performance-based incentives. Qualification of eligible projects and payment for qualifying electric generation (or related attributes) require reporting of electric generation and other project for each specific program. Program administrators use this information to track program progress and report to PUCs or other oversight entities. The summary below addresses typical reporting required for utility-administered programs, as well as programs administered by non-profit entities and state agencies and authorities.

Reporting for utility administered renewable energy incentive programs

Some utilities offer incentives to electricity consumers to accelerate the deployment of renewable energy technologies, such as rebates, feed-in tariffs, and net metering programs. As mentioned previously, it is easier to quantify the renewable electricity generation resulting from some programs than it is for others. Utilities administering FITs, for example, will track the

¹⁰² Some state RPS require electric utilities to procure a specified amount of renewable energy generating capacity, rather than supply a specified number of MWh or percentage of electricity supply from renewable energy generation to retail customers.

¹⁰³ In this section, “deployment programs” refers to incentive programs and market transformation programs designed to accelerate the market deployment of renewable energy technologies.

number of customer contracts, resource type, capacity of each contracted project, MWh generated, and utility expenditures for that generation under the tariff. In contrast, utilities administering a rebate or loan program are more likely to track the number of customer participants, the type and size of the projects, the cost of the projects, and the amount of rebates paid or loans provided. Measuring the electric generation output of these projects may not be necessary to evaluate program status.

Net-metering is a renewable energy incentive program that is based on performance, but where the total output of the net-metered device is often unknown. Utilities reporting on net-metering programs track the number of participating customers, the type and size of net-metered systems, and overall net-metered capacity. However, the gross amount of electricity generated may not be known if a single bi-directional meter is used. Such meters only record net electricity withdrawn from the grid or net electricity production supplied to the grid during an identified time period. Utilities and the customers where the renewable energy generating system is located may not necessarily know the total electric generation from the renewable energy system, unless two meters are installed – one to measure total output from the customer-sited system, and another to measure the total electricity purchased from the utility.

Many of these renewable energy deployment programs are developed as part of requirements by PUCs, and therefore utilities must provide reporting on a routine basis to the PUC about program expenditures and outcomes (typically quarterly or annually). These records should be readily accessible to states for estimating the impacts of their renewable energy deployment programs included in a state plan. However, some utility incentive programs are administered by distribution utilities that are not regulated by a state PUC (e.g., municipal and cooperative electric utilities). In these instances program reporting data may not be readily available to a state, unless separately required by a state if such programs are included in a state plan.

Renewable energy deployment programs may be designed and implemented under the auspices of a utility integrated resource plan (IRP).¹⁰⁴ IRPs document how a utility will meet forecasted annual peak and energy demand over a defined period of time through a combination of supply-side and demand-side resources. IRPs are typically mandated through state legislation or PUC orders and may include renewable energy generation planning, particularly as it relates to compliance with in-state requirements. IRPs are typically submitted on an annual basis to a state utility commission and/or other state entity, and address a multi-year period (e.g., 10 years is a typical period for an IRP). IRPs are a good resource for tracking and forecasting utility renewable energy developments within a state. Though they may not include renewable energy production data, data included in IRPs may help states project renewable energy generation trends in subsequent years, and are a good resource for the development of state plans.

Reporting for renewable energy incentive programs administered by non-profit or state entities

State renewable energy financial incentives are typically administered by a PUC, state revenue agency, other state agency (e.g., state energy office), or a private non-profit or for-profit entity contracted by a state agency. These programs may include an administrative process for pre-qualification, which in some instances may be competitive (e.g., performance-based contracts) or available on a first-come, first-serve basis (e.g., capped production tax incentive). Applications to incentive programs are good sources of data, and program administrators usually compile data from approved applications to track program status. Additional reporting data is also typically required to receive the incentive. For example, a production-based tax incentive is calculated based on the amount of electricity generated by a renewable energy installation, which may be tracked and verified through utility or third-party metering protocols. These reports, which are currently used for internal reporting for budgetary control and performance evaluation, and to track other performance metrics for regular public program reporting, could form much of the basis for reporting under state plans for such measures.

¹⁰⁴ IRPs are typically required in states with vertically integrated electric utilities, but are less common in states that have deregulated their electricity sectors and introduced competition for the supply of electricity to retail customers.

3. Considerations for Reporting Requirements for Renewable Energy Measures in State Plans

State renewable energy requirements, such as RPS and FITs, and incentive programs typically include robust reporting requirements. For nearly all state RPS requirements, annual compliance report data is based on measureable electric generation, using revenue-quality meters, and verified through tracking system data.¹⁰⁵ Other requirements and programs that provide performance-based payments and incentives, such as FITs, net metering, and performance-based tax incentives, also require reporting of metered generation output.¹⁰⁶ State and utility incentive programs where payment of incentives is not based on electric generation may not currently be sufficient for reporting under a state plan. Additional reporting requirements may be necessary if these programs are included as enforceable measures in a state plan.

In addition to the reporting states currently require for renewable energy requirements and programs, supplemental reporting information or adjustments may be necessary for state plans to demonstrate the avoided CO₂ emissions associated with these requirements, programs, and measures. States may need to require additional reporting detail, such as the location of renewable energy generating units that supplied output used to comply with a state RPS. Additional reporting detail about when renewable energy was generated may also be valuable for estimating the avoided CO₂ emissions from renewable energy generation, especially if a marginal avoided emission rate approach is used. This includes reporting of the typical generating profile of a renewable energy generating unit, group of units, or renewable energy resource type.¹⁰⁷ For distributed renewable energy resources, reporting of the MW capacity of generating systems that are installed as a result of state requirements or programs during a reporting period would also be useful for estimating avoided CO₂ emissions. These distributed

¹⁰⁵ Small distributed renewable energy systems, such as those below 10 kW in capacity, are often allowed to use engineering estimates to determine annual output.

¹⁰⁶ Some of these programs, such as net metering, may also require supplemental reporting in order to track total generation that avoids CO₂ emissions. In many instances, net metering programs only track the net electricity supplied to a customer or supplied to the grid by the renewable energy system, rather than total generation output.

¹⁰⁷ This might include information about the seasonal or daily generating profile of the generating unit or renewable energy resource type.

resources, since they are located “behind” the utility meter at a customer location, have a similar effect in reducing the demand for electricity supplied from the grid as end-use energy efficiency measures.

Example reporting requirements that provide sufficient data for estimating the avoided CO₂ emissions from renewable energy requirements and programs might include the following:

- Metered MWh generation, using a revenue quality meter, or estimates of annual output for small systems below 10 kW in capacity
- MW capacity of “behind-the-meter” distributed renewable energy generating systems added during a reporting period as the result of a state program
- For renewable energy resources reported, including through REC data, the typical generating profile of a renewable energy generating unit, group of units, or renewable energy resource type
- For REC data, information including the following generator attributes: type of resource (e.g., wind), plant-level emissions, geographic location, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification

VII. Treatment of Interstate Emission Effects

Programs and measures in a state plan, such as RE and demand-side EE measures, may affect the emission performance of the interconnected electricity system beyond a state border. In addition, many state measures allow for actions in neighboring states to meet the in-state requirement, or explicitly address CO₂ emissions in neighboring states. For example, many state renewable portfolio standards allow for generation by qualifying renewable energy sources in other states to count toward meeting the state portfolio requirement. Some states also apply CO₂ emission requirements related to the generation of power purchased by regulated utilities, including power imported from out of state.

As discussed in the preamble to the proposal, in section VIII.F.6, the EPA recognizes the complexity of accounting for interstate effects associated with measures in a state plan in a consistent manner, to minimize the likelihood of double counting. The EPA also realizes that interstate effects on CO₂ emissions from affected EGUs could be attributed in different ways in the context of an approvable state plan. This section discusses in more detail the options and alternatives for treatment of interstate CO₂ emission effects presented in the preamble. These options and alternatives could be applied to both projections of plan performance and demonstration of achieved emission performance under a plan. These options and alternatives may not be mutually exclusive – in some instances states could apply different approaches, without introducing the potential for double counting of emission effects. One option presented could lead to double counting of emission effects, and we highlight these aspects of this option in the discussion below.

In general, the options and alternatives address different possible state plan scenarios, and consider the range of interstate approaches that states are currently using to implement electricity sector policies, such as multi-state emission budget trading programs and regional renewable energy certificate markets for state RPSs. The options and alternatives reflect possible accounting approaches for interstate emission effects under CAA section 111(d) that could potentially align with these current state programs and measures that we anticipate states may want to include in a state plan.

A. Background

Electricity flows across state lines. Often electricity load centers (i.e., areas of high electricity demand) in one state are supplied in part by generating units in another state. As a result, some states are net exporters or importers of electricity on an annual basis. Reducing electricity load through improved end-use energy efficiency (e.g., through state energy efficiency programs) or deploying new renewable energy electric generating capacity (e.g., through a state RPS) therefore can result in CO₂ emission effects that are realized outside the state that implements the regulation or program that produces the effects. Reducing electricity demand or increasing available electric generating capacity also often impacts the economic dispatch curve and locational economics that are used to dispatch EGUs on a regional basis. As a result, state end-use energy efficiency and renewable energy regulations and programs often have regional effects on electricity generation and avoided CO₂ emissions. In addition, many state regulations explicitly address CO₂ emissions in neighboring states, or allow for actions in neighboring states to meet an in-state regulatory requirement. For example, many state RPS allow for generation in other states to count toward meeting a utility portfolio requirement.

End-use energy efficiency actions reduce electricity load, and ultimately impact electric generation. In some instances improving end-use energy efficiency will reduce electric generation nearby a load center (e.g., in the case of a load pocket with limited access to electricity transmission capacity). In such cases, it may be feasible to directly link in-state end-use energy efficiency programs and measures to avoided CO₂ emissions from specific in-state EGUs. More often, reduction of electricity load will impact EGU dispatch across a regional generation control area, based on factors such as power plant economics and electricity transmission capability, and could also impact flows between control areas.¹⁰⁸ In these cases, state end-use energy efficiency programs and measures will affect electricity generation in the state that reduces load, as well as in neighboring states.

¹⁰⁸ Often these dispatch economics differ by location, based on electricity demand, transmission constraints, and generation economics of individual power plants necessary for meeting demand (e.g., in competitive wholesale markets, these factors are represented through locational marginal prices (LMPs), which determine dispatch).

State RPS regulations also impact electricity generation at a regional level. Over time, state RPSs result in the introduction of new, incremental renewable energy generating capacity to regional generation control areas, which affects EGU dispatch at the regional level. State RPSs are typically applied to electric distribution utilities as a percentage of sales (e.g., a specified percentage of delivered electricity must come from qualifying renewable energy sources). Many state RPSs do not require the qualifying renewable energy electric generation to take place within the state, or even be delivered into the state, but instead require that the renewable energy be supplied within (or delivered into) the ISO/RTO in which the state resides. Often, utility compliance with state RPS is through the submission of renewable energy credits (RECs), which represent the attributes of renewable energy generation but not the actual electricity generated. As a result, in many cases the intent of the state policy is often to affect the characteristics of the *regional* electric generation mix, rather than the state generation mix.

The approach to implementing an RPS may differ in vertically integrated, cost-of-service states where the distribution utility also owns electric generating capacity and dispatches generation resources within its service territory. In such cases, the RPS may require a utility to increase its renewable energy generating capacity, rather than supplying a percentage of the electricity it delivers to retail customers from renewable energy sources to meet load. A number of state RPS also include “carve-outs” or “set-asides” where a portion of the renewable energy supplied to retail customers must come from renewable energy generating capacity located inside the state. Most of these carve-outs are for distributed solar photovoltaic generating capacity, which are located at the point of customer end-use (e.g., rooftop mounted solar PV on residential homes and commercial buildings).¹⁰⁹ Distributed solar PV capacity often provides benefits to the electric distribution system by improving distribution system reliability and avoiding the need for distribution system capacity upgrades. This type of distributed renewable energy generation has effects similar to end-use energy efficiency, as it reduces the customer electricity load that must

¹⁰⁹ A number of RPS also have carve-outs for other renewable energy resources, typically those where there is a significant renewable energy resource located in the state. An example is carve-outs for offshore wind energy in coastal states.

be met through large EGUs connected to the grid.¹¹⁰ Regardless of the approach taken, state RPS regulations typically have impacts on EGU dispatch, and related avoided CO₂ emissions, beyond the state border.

B. Summary of Possible Approaches for Treatment of Interstate Emission Effects

As discussed in the preamble, the EPA is proposing a set of approaches for addressing interstate emission effects that result from the implementation of state plans that incorporate end-use energy efficiency and renewable energy programs. The preamble also solicits comment on additional alternatives. The proposed approaches in the preamble include:

- For EE programs and measures:
 - A state may take into account in its plan only those CO₂ emission reductions occurring in the state that result from demand-side energy efficiency programs and measures implemented in the state.
 - States participating in multi-state plans would have the flexibility to distribute the CO₂ emission reductions among states in the multi-state area.
 - States could jointly demonstrate CO₂ emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution among states of emission reductions from demand-side energy efficiency measures would not be necessary.
- For RE programs and measures:
 - Consistent with existing state RPS policies, a state could take into account all of the CO₂ emission reductions from renewable energy programs and measures implemented by the state, whether they occur in the state and/or in other states.
 - States participating in multi-state plans would have the flexibility to distribute the CO₂ emission reductions among states in the multi-state area.
 - States could jointly demonstrate CO₂ emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case

¹¹⁰ Distributed solar PV is also typically peak coincident, meaning it provides its greatest electric generation output at times of peak system electricity demand. At many times of the day and year, solar PV systems supply electricity back to the grid, when PV system output exceeds building electricity demand.

attribution among states of emission reductions from renewable energy measures would not be necessary

This section surveys the range of potential approaches that could be applied for individual state plans, as well as approaches that could be applied on a regional basis. The surveyed approaches include those proposed, as well as alternatives. These basic approaches, including variants of some approaches, include:

- *State may only claim the impact of a measure in reducing in-state EGU CO₂ emissions*
For plan measures such as end-use energy efficiency and renewable energy regulations and programs, estimating the avoided CO₂ emissions from in-state versus out-of-state EGUs could be addressed through modeling, other analytical tools, or proxy metrics (e.g., net import factor).
- *State that implements the measure claims the emissions reduction benefit*
Under this approach, the state that implements the measure (e.g., end-use energy efficiency and renewable energy regulations or programs, or an emission limit that addresses out-of-state generation) claims the avoided CO₂ emissions, regardless of where they occur.
- *Cooperative multi-state accounting*
Multiple states are allowed to mutually agree to how they will distribute avoided CO₂ emissions from state plan measures (e.g., end-use energy efficiency and renewable energy regulations or programs, or an emission limit that addresses out-of-state generation) across their respective EGU fleets. Avoided CO₂ emissions are distributed among states by agreed formula they derive – an accounting “credit” in one state for out-of-state avoided CO₂ emissions is complemented by an accounting “debit” in the other state where the avoided CO₂ emissions occurred (i.e., through an increase in reported CO₂ emissions or CO₂ emission rate).
- *Tradable regional EE/RE credit market*
This is a variant of the multi-state accounting approach, which could be applicable where multiple states in a region are implementing rate-based state plans. Under this approach, state end-use energy efficiency and renewable energy regulations and programs that meet

EM&V guidelines or requirements are allowed to generate credits, based on MWh of energy savings or renewable energy generation. These credits, which are denoted in avoided tons of CO₂ or avoided MWh, could be used by affected EGUs toward demonstration of compliance with state rate-based CO₂ emission limits within a designated region. EE/RE credit issuance could be on a project and/or program basis. State accounting for interstate emission effects would be addressed through the credit market and determined based on credits held by affected EGUs.

- Regional demonstration by states of EGU emission performance

States are allowed to regionally demonstrate emission performance by affected EGUs. States jointly demonstrate emission performance for affected EGUs, in terms of total CO₂ emissions (under a mass-based multi-state plan) or weighted average CO₂ emission rate (under a rate-based multi-state plan).

- The EPA jointly assesses regional performance achieved in aggregate by all individual state plans in a grid region

The EPA assesses interstate effects on a regional basis during the plan review process. The EPA requires states to agree to an interstate attribution process only if necessary (i.e., if regional performance falls short of the aggregated identified performance levels for affected EGUs in individual state plans). Alternatively, the EPA requires plan revisions if regional performance falls short of the aggregated regional performance level (i.e., the aggregated identified performance levels for affected EGUs in individual state plans).

Table 3 includes illustrative examples of the application of some of the different approaches for addressing interstate emission effects summarized above. The table explains how these approaches might be applied in different state plan contexts. The illustrative examples consider the range of approaches states are currently using to implement electricity sector policies, all of which interstate effects, such as multi-state emission budget trading programs, regional renewable energy certificate markets used for state RPS compliance, and end-use energy efficiency programs.

Table 3. Applied Examples of Intersate Emission Effects Attribution Approaches

State claims reductions from in-state EGUs	State that implements measure claims reductions	Regional agreed-upon attribution process	Regional demonstration
<p>EE program in Virginia saves MWh</p> <ul style="list-style-type: none"> • VA is a 35% net annual importer of electricity. • VA estimates the effect that the reduction in MWh demand in VA has on generation in PJM and related avoided CO₂ emissions. • Could be done through modeling, other analysis tools (e.g., EPA AVERT tool), or proxy estimate (e.g., net import factor). • For example, using proxy estimate: <ul style="list-style-type: none"> • Energy: MWh savings x 0.65 (proxy net import factor) = avoided VA MWh generation • CO₂ Emissions: MWh savings x 0.65 (proxy net import factor) x PJM average or marginal CO₂ emission rate = CO₂ emissions avoided from EGUs in VA 	<p>New Jersey RPS yields new RE capacity and RE generation throughout PJM</p> <ul style="list-style-type: none"> • Utilities in NJ purchase RECs to meet RPS requirement. • RECs held by NJ utilities to meet RPS requirements represent MWhs of generation from RE in multiple states in PJM (e.g., wind turbines in PA and WV). • To demonstrate that the CO₂ emission rate requirement for affected EGUs in NJ is met, NJ applies MWh of RE generation used to meet NJ RPS (based on RECs held NJ utilities) to adjust CO₂ emission rates of affected EGUs in NJ. 	<p>States mutually agree to an accounting approach for interstate effects</p> <ul style="list-style-type: none"> • Assume a mix of states in a region, with different states using mass-based and rate-based portfolio approaches • States agree to attribute effects of RE through the existing regional REC market used for compliance with state RPSs; RE effects are attributed based on the party that holds RECs • States with a mass-based approach add CO₂ emissions to their reported emissions total, based on any out-of-state transfer of RECs • States with a rate-based approach reduce CO₂ emission rate based on amount of RECs held (including RECs from out-of-state RE generation) • As a result, a “credit” in one state is complemented with a “debit” in another state 	<p>RGGI states demonstrate emissions performance jointly on a multi-state basis</p> <ul style="list-style-type: none"> • A mass-based goal would be based on a translation from the aggregated rate-based goals for each of the 9 participating RGGI states • A weighted-average rate-based goal is calculated for the 9 RGGI states and then this is translated to a joint mass-based goal • State emissions may vary among states, provided the multi-state mass emissions level is met • This type of multi-state demonstration will be necessary for programs like RGGI, where state-by-state emissions may vary based on CO₂ allowance market prices and EGU marginal abatement costs

1. State May Claim the Impact of a Measure on CO₂ Emissions from Affected EGUs Within its Borders

Under this approach, the effect of a state measure could be applied to help demonstrate emission performance by affected EGUs in the state if it has the effect of avoiding CO₂ emissions from those in-state EGUs. This could be done regardless of whether the action taken to implement the state measure occurs within or outside the state. For example, renewable energy generation that occurs outside the state as a result of a state renewable portfolio standard obligation would still be a valid state plan action, provided the out-of-state renewable energy generation has the effect of avoiding CO₂ emissions from affected EGUs inside the state. As another example, for a state that is a net importer of electricity, improvements in demand-side EE and related reductions in electricity demand may reduce the need for generation from both affected in-state and out-of-state EGUs. These electricity demand reductions could be applied to help demonstrate emission performance by affected EGUs in the state if the reduction in electricity demand has the effect of avoiding CO₂ emissions from those in-state EGUs.

Estimating the effect of RE and demand-side EE measures on in-state versus out-of-state EGU CO₂ emissions could be addressed through modeling, other analytical tools, or proxy metrics such as a net import factor.

Modeling could be used to assess the interstate effects of state measures on EGU CO₂ emissions, both for projections of emission performance under the plan and ex post demonstration of performance achieved. Under this approach, both projected plan performance and performance achieved is assessed on a state-by-state basis.

Ex ante projections of plan performance

To project the effect of EE/RE measures under a state plan, a dispatch model would be applied to a grid region to estimate the marginal or average avoided CO₂ emissions impact of the plan measures on a state-by-state basis within the region. To the extent that a state's EE/RE measures were projected to avoid CO₂ emissions from its own in-state EGUs, these effects could be applied to meet the required level of CO₂ emission performance for affected EGUs in the state plan. (See section IV.C of this TSD for a full discussion of using a dispatch modeling approach to projected avoided CO₂ emissions that will be achieved through a plan.)

Ex post demonstration of plan performance

To assess the state-by-state avoided CO₂ emissions that result from the implementation of a plan, a dispatch model would also be applied to a grid region, on a retrospective “look-back” basis. This modeling would assess the avoided CO₂ emissions resulting from reported MWh of energy savings and MWh of reported renewable energy generation, as a result of implementation of EE/RE measures in the plan. Under a rate-based plan approach, modeled estimates of avoided CO₂ emissions, based on reported EE savings and RE generation, could be applied through an administrative adjustment by the state program administrator or through the issuance of tradable EE/RE credits within the state. For ex post demonstration under a mass-based plan approach, performance would be determined based on reported stack CO₂ emissions from affected EGUs—no further analysis would be necessary. (See section IV.C of this TSD for a full discussion of using a modeling look-back approach to estimate avoided CO₂ emissions.)

Use of simplified proxy metrics to apportion effects among states

Simplified metrics, such as a net electricity import or export factor, might also be applied to assess the impact of state actions in avoiding CO₂ emissions from in-state affected EGUs. For example, in a state that imports 30% of electricity on average during a year, energy savings from EE measures might be multiplied by a factor of 0.70.¹¹¹ Avoided CO₂ emissions might then be calculated by multiplying this adjusted energy savings number by the average or marginal CO₂ emission rate for affected EGUs in the state. This type of approach could be employed in both projections of plan performance and ex post demonstrations of performance. However, this method would be subject to uncertainty, as electricity net imports may vary significantly on an annual basis, due to changes in system dispatch. (See section IV.C of this TSD for a discussion of dispatch dynamics that affect avoided CO₂ emissions.)

This approach would avoid double counting of emission effects of state measures among states. However, it could reduce incentives for states to employ measures that have a system-wide, regional effect in reducing EGU CO₂ emissions. In effect, because an adjustment factor would be applied to energy savings under this approach, a net importer state would need to achieve greater energy savings through end-use energy efficiency requirements and programs to achieve a ton of avoided CO₂ emissions under its plan than a state that is not a net importer.

2. State that Implements the Measure Claims the Emission Effects

Under this approach, the state that implements the measure (e.g., an EERS or RPS, or an emission limit that addresses the attributes of purchased electricity from out-of-state generation) claims the avoided CO₂ emissions, regardless of where they occur.

If the avoided CO₂ emissions from state plan measures at the regional level are greater than avoided emissions from affected EGUs within the state, these interstate effects would need to be accounted for and applied to affected EGUs within the state. This could be achieved through an administrative adjustment by the state, or through a tradable credit system that is limited to affected EGUs in the state.

¹¹¹ In this instance, it would be assumed that 30% of the reduction in electricity load resulted in avoided CO₂ emissions from out-of-state EGUs that serve electricity load in the importing state.

Under an administrative adjustment approach, out-of-state avoided emissions would be applied to the in-state EGU fleet by the state program administrator when determining average fleet CO₂ emission rate or tonnage CO₂ emissions. Under a tradable credit approach, credits would be issued for all avoided CO₂ emissions resulting from applicable state plan measures, without regard to where the avoided emissions occurred. Since the tradable credit system would be limited to affected EGUs in the state, use of the credits by affected EGUs when demonstrating compliance with a rate-based emission limits would functionally apply the avoided CO₂ emissions to the state that was responsible for the measure.

This approach provides a clear policy signal and incentives that reward state actions that reduce EGU CO₂ emissions on a system-wide, regional basis. However, this approach, absent cooperative accounting among states in a grid region, as described below, will likely lead to double counting of emission impacts among states, which could reduce the overall emissions reductions achieved through state plans on a national basis under CAA section 111(d). We also note below that other approaches could also provide incentives for a regional, system-based approach to achieving CO₂ emissions reductions from affected EGUs, without raising the prospect of double counting of emission effects among state.

3. Cooperative Multi-State Accounting of Interstate Emission Effects

Under this approach, multiple states would be allowed to mutually agree on how they will distribute avoided CO₂ emissions from RE and demand-side EE measures across their respective EGU fleets. Avoided CO₂ emissions would be distributed among states according to a formula that they specify. Based on this agreed formula, each state would adjust its demonstrated emission performance by affected EGUs accordingly. In effect, a “credit” for out-of-state emission effects in one state would be complemented by a “debit” for such effects in another state.

This approach provides states with discretion about how to attribute interstate effects, based on their situations and policy preferences in a grid region. Importantly, this approach also avoids the potential for double counting of interstate emission effects among states. However,

this approach is premised on regional collaboration among all states in a grid region. Not all states in a grid region may be willing to cooperate in implementing such an accounting approach.

4. Tradable Regional EE/RE Credit Market

Under this approach, RE and demand-side EE actions that meet applicable quantification, monitoring, and verification requirements would be issued tradable credits that could be applied by affected EGUs to their reported CO₂ emission rates when demonstrating compliance with an emission limitation in a state plan.¹¹² A credit issued in one state could be used by an affected EGU in another state toward meeting its respective rate limit.¹¹³

A regional credit market would be premised on agreement among states that credits issued throughout a region could be used in multiple states. The distribution among different states of usage of the credits would be determined by economic factors such as credit prices and EGU marginal emissions abatement costs. In effect, accounting of interstate effects would be allocated among states based on prices in the credit market.

This approach is applicable if multiple states are implementing rate-based state plans. Where states were implementing a mix of rate-based and mass-based state plans in a shared grid region, this approach would lead to double counting of emission effects among plans, unless this market-based EE/RE credit approach was also coupled with a cooperative accounting agreement among states. In this latter instance, for states implementing a mass-based approach, where credits for avoided CO₂ emissions are transferred to affected EGUs located in another state for compliance purposes, the state from which credits were transferred would adjust its reported CO₂ mass emission from affected EGUs when demonstrating achievement of the required CO₂ emission performance level by affected EGUs identified in the state plan.¹¹⁴

¹¹² These credits might be denoted in avoided CO₂ emissions or MWh of electricity savings or electricity generation, as described above in Section VI.E.3., incorporating RE and demand-side EE measures under a rate-based approach. Depending on a state's circumstances and its plan approach, these tradable credits might represent a new instrument created for use under a state plan, or a state might use an existing instrument, such as RECs.

¹¹³ Credits could be issued on a program or project basis. The types of measures for which credits could be issued and the basis for issuing credits would be an enforceable element of a state plan.

¹¹⁴ Note that in this example, *state reporting* of overall achieved CO₂ emission performance by affected EGUs under a state plan is distinct from *demonstration of compliance by affected EGUs* subject to a mass-based CO₂

5. Regional Demonstration by States of Emission Performance

Under this approach, multiple states would demonstrate CO₂ emission performance by affected EGUs on a regional basis.¹¹⁵ This could allow states in a contiguous grid region to implement a portfolio of RE and demand-side EE measures without the need for state-by-state attribution of avoided CO₂ emissions. Instead, states would assess the impact of state measures in avoiding CO₂ emissions from the fleet of affected EGUs in the multi-state region.

This approach creates incentives for the implementation of system-based approaches that collaboratively reduce EGU CO₂ emissions on a regional basis, while also avoiding the need to attribute interstate emission effects among states. However, regional collaboration will require more time for the development of multi-state plans. This approach is also premised on the willingness of all states in a grid region to participate in the development and implementation of a multi-state plan. Some states in a grid region may be unwilling to collaborate regionally.

6. Assessment of Interstate Effects by the EPA in the Course of State Plan Review

Under this approach, the EPA would evaluate interstate effects on a regional basis during the plan review process.¹¹⁶ The EPA would assess the emissions performance of affected EGUs on a regional basis, considering the measures contained in the group of state plans for a respective grid region. Under this approach, the EPA might conduct an analysis that considers all of the state program measures together on a combined basis and evaluates projected emissions performance achieved by affected EGUs in the region.

To the extent that all affected EGUs in a region are projected to achieve the required level of performance represented in individual state plans, or are projected to achieve an aggregate

emission limit. For EGU compliance, no adjustment would be made to CO₂ emissions reported by affected EGUs subject to the mass-based emission limit, even though emissions from these affected EGUs may have been reduced as a result of EE/RE regulations and programs implemented in a neighboring state. In this case, the state would adjust the overall CO₂ emissions from the affected fleet to account for the “export” of avoided CO₂ emission credits, in order to demonstrate the overall level of CO₂ emission performance that is assumed to have been achieved by the affected EGU fleet under the plan.

¹¹⁵ This approach could be applied for CO₂ emission performance on either a rate or mass basis.

¹¹⁶ For example, this assessment could be for a multi-state region that generally aligns with a contiguous grid region.

regional level of performance consistent with the level of required performance included in all state plans in the region, instances of double counting of interstate effects among states are less important. The EPA could indicate as part of plan approval that it will review actual emission performance achieved by affected EGUs during the plan period on a regional basis.

VIII. Appendix

Survey of Existing State Policies and Programs that Reduce Power Sector CO₂ Emissions

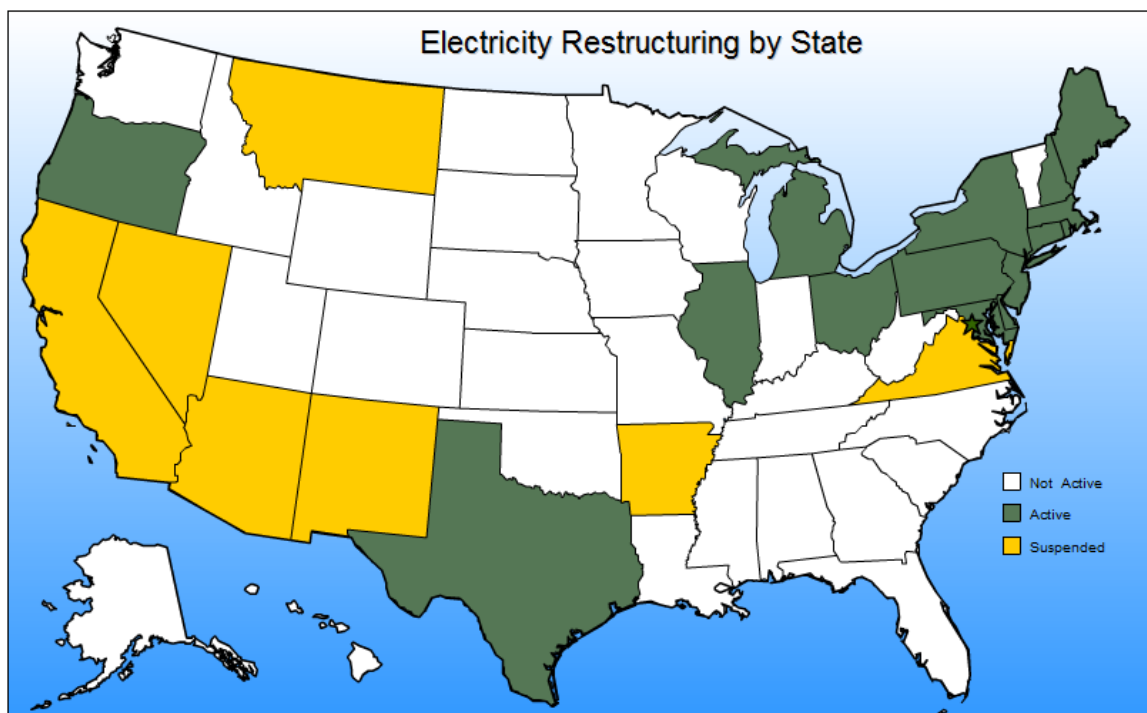
I. Overview of State Climate and Energy Policies and Programs that Reduce Power Sector CO₂ Emissions

Across the nation, many states and regions have shown strong leadership in creating and implementing policies, programs, and measures that reduce CO₂ emissions from the power sector, while achieving other economic, environmental, and energy benefits. These policies and programs can serve as a strong foundation as states develop plans to meet state goals for affected electric generating units (EGUs) under the proposed emission guidelines.

This document provides a survey of many of these activities. Policies and programs range from market-based programs and CO₂ emission performance standards that require CO₂ emission reductions from EGUs, to others, such as renewable portfolio standards (RPS) and energy efficiency resource standards (EERS), that reduce CO₂ emissions by altering the mix of energy supply and reducing energy demand. States have developed their policies and programs with stakeholder input and tailored them to their own circumstances and priorities. Their leadership and experiences provided the EPA with important information about best practices to build upon in the proposed rule.

States vary in their regulatory structures, electricity generation and usage patterns, while geography affects factors such as the availability of fuels, transmission networks, and seasonal energy demand. States have tailored their climate and energy policies and programs accordingly. For example, in some states, utilities are vertically integrated, meaning that the one company is responsible for electricity generation, transmission, and distribution over a given service territory. State public utility regulators have authority over these utilities. In other states, where the electric power industry has been restructured, ownership of electric generation assets has been decoupled from transmission and distribution assets, and retail customers have their choice of electricity suppliers. In states where restructuring is active (see Figure 1), state public utility regulators do not have authority to regulate the companies responsible for electricity generation, only the electricity distribution utilities. States rely upon and have access to different fuel types and have a variety of EGU types within state borders. States are part of regional electricity grids that usually do not align with state borders. Electricity is imported and exported by utilities across states throughout each regional grid.

Figure 1: Status of Electricity Restructuring by State



Source: “Status of Restructuring by State”, U.S. Energy Information Administration, accessed March 19, 2014, http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.

States also have different economic considerations, drivers, and approaches when implementing climate change, energy efficiency, and renewable energy policies, programs, and measures. State actions may be motivated by state environmental, energy and/or economic concerns. For example, ten states have passed legislation requiring GHG emission reductions and are using a combination of emission limits, performance standards, energy efficiency and renewable energy measures to achieve these requirements.¹¹⁷ Other state measures are motivated by public utility commission (PUC) requirements to achieve all cost-effective end-use energy efficiency improvements or by renewable energy generation requirements. Policies, programs, and measures vary from state to state in their implementation levels and administration. Some are administered by state agencies and others by utilities, with varying mechanisms for ensuring compliance with applicable requirements.

This appendix is not exhaustive and is only intended to provide background information about strategies states have used to achieve CO₂ emission reductions in the power sector, advance end-use energy efficiency, and increase the use of renewable energy resources. For example, states may also consider measures that states have used to support other low- or zero-emitting generating technologies beyond what is addressed here. State policies and programs

¹¹⁷ States include California, Connecticut, Hawaii, Maine, Maryland, Massachusetts, Minnesota, New Jersey, Oregon, and Washington. Targets are typically defined on a 1990 base year, aiming to achieve reductions of between 0 and 10 percent by 2020, although Maryland and Minnesota have chosen targets of 25 percent below 2006 levels by 2020, and 15 percent below 2005 levels by 2015 respectively.

included in this appendix are not necessarily approvable in the context of a CAA section 111(d) state plan. In order to be approvable, state requirements, programs, and measures included in a state plan must meet criteria laid out in the proposed emission guidelines.

II. Existing State and Utility Policies, Programs, and Measures that Affect EGU CO₂ Emissions

Some state and utility policies, programs, and measures directly target EGU CO₂ emissions by creating specific limits or standards for CO₂ emissions in the power sector. Other policies and programs, such as those that advance deployment of end-use energy efficiency and renewable energy, are designed to reduce energy demand or promote an increase of supply from low- or non-GHG emitting generating sources, which reduces CO₂ emissions from fossil fuel-fired EGUs. Many states that are aggressively pursuing climate change mitigation look to end-use energy efficiency and renewable energy first, recognizing the potential for low-cost GHG emissions reductions and the economic, reliability, and fuel diversity benefits these resources provide.

For example, according to California, “the integrated nature of the grid means that policies which displace the need for fossil generation can often cut emissions from covered sources more deeply, and more cost-effectively than can engineering changes at the plants alone, though these source-level control efforts are a vital starting point.”¹¹⁸ In working to meet its statewide goal of reducing GHG emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050, the California calls its energy efficiency standards “the bedrock upon which climate policies are built” and uses renewable energy to fill any remaining energy needs.”¹¹⁹ Compared to the costs of other climate policies, California finds that “energy efficiency provides substantial emissions reductions and should be an essential element of the BSER CO₂ reduction target.”¹²⁰ As another example, Connecticut has a law that requires the state to reduce GHG emissions to 10 percent below 1990 emissions levels by 2020 and 80 percent from 2001 levels by 2050.¹²¹ Connecticut considers energy efficiency investments, expanded renewable energy generation, and participation in the Regional Greenhouse Gas Initiative (RGGI) among its top ten strategies to reduce GHG emissions when considering cost-effectiveness and GHG emission reduction potential.¹²²

¹¹⁸ Mary Nichols (Chairman of California Air Resources Board), letter to EPA Administrator Gina McCarthy, December 27, 2013.

¹¹⁹ Ibid.

¹²⁰ Ibid.

¹²¹ Environment Northeast, *Connecticut House Bill No. 5600: An Act Concerning Connecticut Global Warming Solutions*, accessed March 19, 2014, http://www.environment.org/public/resources/pdf/CT_Global_Warming_Bill_Summary.pdf.

¹²² States’ Section 111(d) Implementation Group Input to EPA on Carbon Pollution Standards for Existing Power Plants, Joint comments from 15 states on Carbon Pollution Standards for Existing Power Plants sent to USEPA Administrator McCarthy on December 16, 2013. Signatories include: Mary D. Nichols, Chairman of California Air Resources Board, Robert B. Weisenmiller, California Energy Commission, Michael R. Peevey, Chair of California Public Utilities Commission, Larry Wolk, MD, MSPH, Executive Director and Chief Medical Offices of Colorado Department of Public Health and Environment, Dan Esty, Commissioner of Connecticut Department of Environmental Protection, Collin O’Mara, Secretary of Delaware Department of Natural Resources and

Beyond these specific policies and programs, some states implement utility planning requirements that can affect emissions both directly and indirectly. This section describes a range of existing state actions that fall into all of these categories.

a. Actions That Directly Reduce EGU CO₂ Emissions

Existing state actions that directly reduce EGU CO₂ emissions tend to fall in one of two categories: market-based emission limits or emission performance standards.

i. Market-based Emission Limits

Description

An emissions budget trading program is a market-based tool for reducing pollution. The basic approach, which involves the allocation and trade of a limited number of environmental permits, has been used across environmental media, including air pollution control, clean water regulation, and land-use applications.

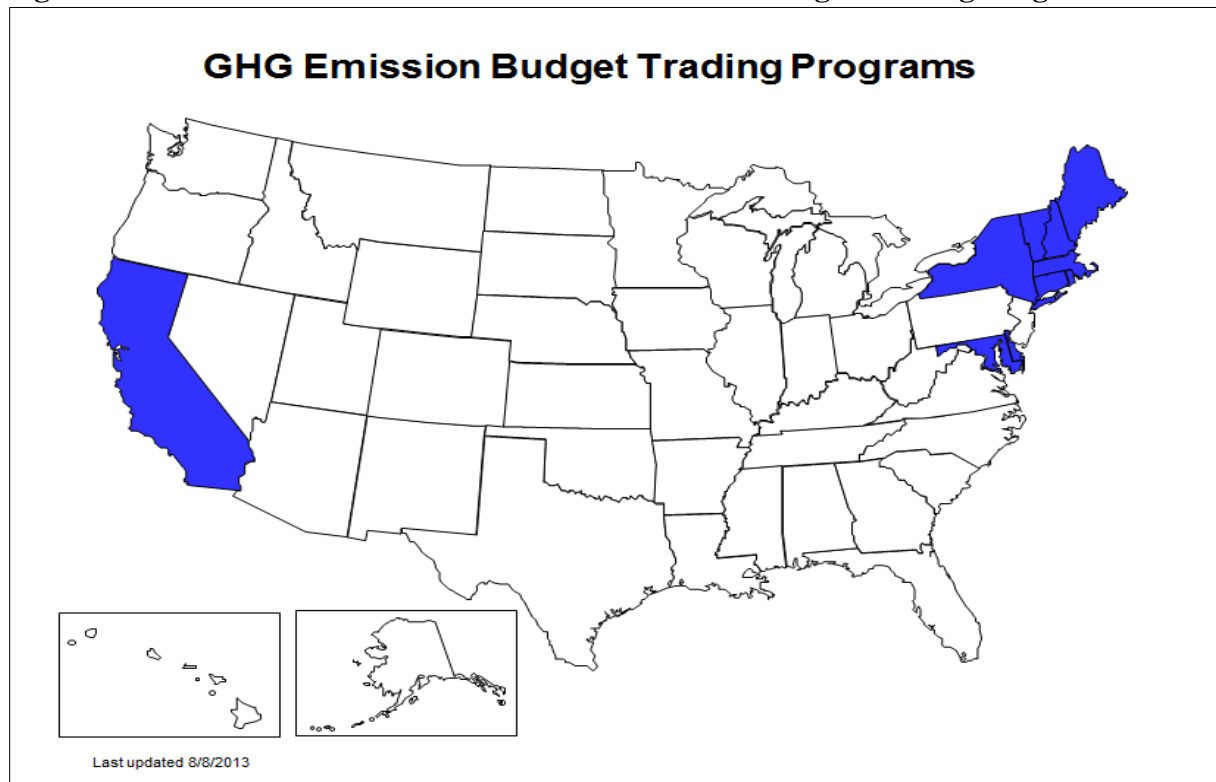
As shown in Figure 2 below, ten states have implemented emissions budget trading programs addressing CO₂ and other GHG emissions. These include California's emission budget trading program and the nine northeast and mid-Atlantic states participating in the Regional Greenhouse Gas Initiative (RGGI), consisting of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.^{123,124}

Environmental Control, Dallas Winslow, Chairman of Delaware Public Service Commission, Douglas Scott, Chair of Illinois Commerce Commission, David Littell, Commissioner of Maine Public Utilities Commission, Robert M. Summers, Secretary of Maryland Department of the Environment, Kelly Speakes-Backman, Commissioner of Maryland Public Service Commission, Ken Kimmell, Commissioner of Massachusetts Department of Environmental Protection, Mark Sylvia, Commissioner of Massachusetts Department of Energy resources, John Linc Stine, Commissioner of Minnesota Pollution Control Agency, Mike Rothman, Commissioner of Minnesota Department of Commerce, Thomas S. Burack, Commissioner of New Hampshire Department of Environmental Service, Joseph Martens, Commissioner of New York State Department of Environmental Conservation, Audrey Zibelman, Chief of New York State Public Commission, Dick Pederson, Director Oregon department of Environmental Quality, Janet Coit, Director of Rhode Island Department of Environmental Management, Marion Gold, Commissioner of Rhode Island Office of Energy resources, Deborah Markowitz, Secretary of Vermont Agency of Natural Resources, James Volz, Chairman of Vermont Public Service Board, Maia Bellon, Director of Washington State Department of Ecology. Letter hereafter referred to as "State environmental agency leaders from CA, CO, DE, IL, ME, MD, MA, MN, NH, NY, OR, RI, VT, WA, Open Letter to the EPA Administrator Gina McCarthy on Emission Standards Under Clean Air Act Section 111(d), December 16, 2013."

¹²³ "RGGI Homepage", Regional Greenhouse Gas Initiative, accessed March 19, 2014, at <http://www.rggi.org/>.

¹²⁴ "Cap and Trade Program", California Air Resources Board, accessed March 19, 2014 <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>.

Figure 2: States with Active Greenhouse Gas Emission Budget Trading Programs



Policy Mechanics

Design

An emissions budget trading program establishes an aggregate limit on pollution through an emissions cap that specifies the total allowable emissions over a specified time period for all of the emission sources subject to the program. To comply with the emission limitation, each emission source must surrender emission allowances equal to its reported emissions at the end of each compliance period.

Allowances may be traded among both regulated and non-regulated parties, creating a market for emission allowances. In turn, the allowance market establishes a price signal for emissions (a market price for emitting a unit of pollution), which triggers broad economic incentives for reducing emissions across the covered sector(s) and encourages innovation in developing emission control strategies and new pollution control technologies.

There are several key design elements that may vary from program to program:

- Scope of coverage (e.g., sectors and types of facilities covered)
- Applicability (criteria for inclusion of emitting facilities and units in the program)
- Initial emission budget (i.e., the aggregate emission limitation for covered emission sources) and emissions reduction schedule

- Flexibility provisions, in addition to ability to trade emission allowances, including:
 - Multi-year compliance periods
 - Allowance banking
 - Offsets (e.g., project-based emissions reductions occurring outside the capped sector/sources)
- Additional provisions to mitigate price volatility and overall costs
 - Auction reserve price
 - Cost containment reserve of allowances provided for sale at set price thresholds; once the allowance price hits a threshold, an extra supply of allowances are made available.

Table 1 summarizes some of the key design elements of the RGGI and California programs.

Table 1: Comparison of RGGI and California Emissions Budget Trading Programs

Element	RGGI	California
Applicability	<ul style="list-style-type: none"> • All fossil fuel-fired EGUs with a capacity of 25 MW or greater.¹²⁵ 	<ul style="list-style-type: none"> • All facilities in covered sectors emitting at least 25,000 metric tons CO₂-equivalent (CO₂e) or greater.¹²⁶
Scope	<ul style="list-style-type: none"> • Facilities in electric power sector.¹²⁷ 	<ul style="list-style-type: none"> • Facilities in electric power and large industrial sectors (plus fuel distributors in 2015)¹²⁸
Emissions budget	<ul style="list-style-type: none"> • Recently reduced 45 percent to 91 million tons of CO₂ in 2014. Beginning in 2015, the budget will decline 2.5 percent per year to 2020.¹²⁹ 	<ul style="list-style-type: none"> • Set at 2 percent below expected 2012 emissions, declining by 2 percent in 2014 and 3 percent annually from 2015 to 2020.¹³⁰
Compliance period	<ul style="list-style-type: none"> • EGUs must demonstrate compliance every three years and hold allowances equal to 50 percent of reported CO₂ emissions at the end of the first two years of every three-year compliance period.¹³¹ 	<ul style="list-style-type: none"> • Facilities must demonstrate compliance every three years. On an annual basis, facilities must also hold allowances and offsets covering 30 percent of the previous year's emissions.¹³²

¹²⁵ RGGI, *Overview of RGGI CO₂ Budget Trading Program* (Regional Greenhouse Gas Initiative, 2007), accessed on March 19, 2014, http://www.rggi.org/docs/program_summary_10_07.pdf.

¹²⁶ CARB, *Cap and Trade Regulation Instructional Guidance, Chapter 2: Is My Company Subject to the Cap-and-Trade Regulation* (California Air Resources Board, 2012), accessed on March 19, 2014, <http://www.arb.ca.gov/cc/capandtrade/guidance/chapter2.pdf>.

¹²⁷ "Regulated Sources", Regional Greenhouse Gas Initiative Inc., accessed on May 14, 2014, http://www.rggi.org/design/overview/regulated_sources.

¹²⁸ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

¹²⁹ RGGI Inc., "RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants," Regional Greenhouse Gas Initiative Press Release (January 13, 2014), accessed on March 19, 2014, http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.

¹³⁰ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

¹³¹ "Compliance" Regional Greenhouse Gas Initiative Inc., accessed on May 30, 2014 <http://www.rggi.org/market/tracking/compliance>.

¹³² CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

Allowance allocation method	<ul style="list-style-type: none"> Each state distributes allowances from its established budget in an amount and manner determined by its applicable statutes and regulations. Approximately 90 percent of CO₂ allowances are distributed through auction.¹³³ 	<ul style="list-style-type: none"> Allowances are both allocated and auctioned off according to provisions established by the program. More information is available from CARB (see footnote).¹³⁴
Cost containment provisions	<ul style="list-style-type: none"> A Cost Containment Reserve (CCR) of CO₂ allowances provides a fixed additional supply of allowances that are only available if the auction price exceeds a set threshold (\$4 in 2014 rising to \$10 in 2017 and 2.5 percent per year thereafter).¹³⁵ An additional five million allowances became available March 2014 when market price exceeded the current price trigger of \$4 per ton.¹³⁶ Trigger price increases until 2020 when 10 million allowances become available if price per ton exceeds \$10.75¹³⁷ 	<ul style="list-style-type: none"> A strategic reserve is included, providing an Allowance Price Containment Reserve of one percent of allowances for 2013-2014, four percent of allowances for 2015-2017, and seven percent of allowances for 2018-2020. Shares of allowances held in the reserve will be released at three price trigger points; \$40, \$45, and \$50 per ton and rise by 5 percent per year including inflation.¹³⁸
Banking	<ul style="list-style-type: none"> Allows unlimited allowance banking.¹³⁹ 	<ul style="list-style-type: none"> Allows unlimited allowance banking.¹⁴⁰
Offsets	<ul style="list-style-type: none"> EGUs subject to RGGI are allowed to use offsets within the RGGI region to meet 3.3 percent of their compliance obligation.^{141,142} 	<ul style="list-style-type: none"> Facilities may use domestic offsets for up to 8 percent of their compliance obligation.¹⁴³ A framework has been established to include international offsets but these are currently

¹³³ “2013 Allowance Allocation”, Regional Greenhouse Gas Initiative, Inc., accessed on March 19, 2014, <http://rggi.org/design/overview/allowance-allocation/2013-allocation>.

¹³⁴ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

¹³⁵ “The RGGI CO₂ Cap” Regional Greenhouse Gas Initiative Inc., accessed on May 30, 2014 <http://www.rrgi.org/design/overview/cap>.

¹³⁶ RGGI, “CO₂ Allowances Sold at \$4.00 at 23rd RGGI Auction,” Regional Greenhouse Gas Initiative Press Release (March 7, 2014), accessed on March 19, 2014, http://www.rrgi.org/docs/Auctions/23/PR030714_Auction23.pdf.

¹³⁷ RGGI, *Summary of RGGI Model Rule Changes* (Regional Greenhouse Gas Initiative, Inc., 2013), Accessed on March 19, 2014, http://www.rrgi.org/docs/ProgramReview/FinalProgramReviewMaterials/Model_Rule_Summary.pdf.

¹³⁸ “California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions,” California Code of Regulations, Title 17, §95800-96023, accessed on May 30, 2014, <http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf>.

¹³⁹ RGGI, *Overview of RGGI CO₂ Budget Trading Program* (Regional Greenhouse Gas Initiative, 2007), accessed on March 19, 2014, http://www.rrgi.org/docs/program_summary_10_07.pdf.

¹⁴⁰ CARB *Proposed Regulation to Implement the California Cap-and-Trade Program* (California Air Resources Board, 2010), accessed on March 19, 2014, <http://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf>.

¹⁴¹ “CO₂ Offsets” Regional Greenhouse Gas Initiative, Inc., accessed on March 19, 2014, <http://www.rrgi.org/market/offsets>.

¹⁴² Eligible offsets under RGGI include: landfill methane capture and destruction, sulfur hexafluoride (SF₆) reduction from power transmission, U.S. forest projects (reforestation, improved forest management, and avoided conversion) or afforestation (in CT and NY only), end use energy efficiency, and agricultural manure management. “Offset Categories” RGGI, Incegional Greenhouse Gas Initiative, Inc., Accessed on May 30, 2014. <http://www.rrgi.org/market/offsets/categories>.

¹⁴³ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

Authority

State and regional GHG emission budget trading programs are authorized through individual state legislation and implemented through state regulations. For example, California implemented its emission budget trading program under the authority of its 2006 Global Warming Solutions Act, which requires the state to reduce its 2020 GHG emissions to 1990 levels.¹⁴⁵ Each RGGI state has separate authorizing legislation, and in some cases their legislation specifically directs the use of auction proceeds. For example, Maine authorized its participation in RGGI through Statute 580-A, Title 38 Chapter 3B: Regional Greenhouse Gas Initiative. This statute also requires that 100 percent of auction proceeds go towards carbon reduction and energy conservation efforts.¹⁴⁶ RGGI is implemented through individual state CO₂ budget trading program regulations.¹⁴⁷

The state regulatory authority issues individual authorizations to emit a specific quantity of emissions (“allowances”), which represent one (metric or short) ton of a pollutant, in an amount no greater than the established emission budget.

Obligated Parties

Obligated parties in emission budget trading programs are generally the covered emission sources. It is the emission sources that are responsible for surrendering emission allowances equal to their reported emissions at the end of each compliance period. For example, as stated above, RGGI covers fossil fuel-fired EGUs 25 megawatts or larger in size.¹⁴⁸ The California emission budget trading program covers electricity generators, importers of electricity and industrial facilities with annual emissions that exceed 25,000 metric tons CO₂-equivalent. Starting in 2015, the California program will also cover distributors of transportation, natural gas, and other fuels with emissions greater than 25,000 metric tons CO₂-equivalent.¹⁴⁹

Offsets are initially limited to forestry, urban forestry, livestock methane capture and destruction, and destruction of ozone depleting substances. However, rice cultivation and coal mine methane are proposed for inclusion in the program. See: CARB – Potential New Compliance Offset Projects:

<http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm> for more information.

¹⁴⁴ Ibid.

¹⁴⁵ Assembly Bill 32, California Global Warming Solutions Act of 2006, Division 25.5 (September 27, 2006), accessed March 19, 2014, http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.

¹⁴⁶ Maine revised statutes, Title 38, Chapter 3-B, section 580-B, the Regional Greenhouse Gas Initiative Act of 2007, accessed on March 19, 2014, <http://www.mainelegislature.org/legis/statutes/38/title38sec580-B.html>.

¹⁴⁷ RGGI, “State Statutes and Regulations,” <http://www.rggi.org/design/regulations>.

¹⁴⁸ “Regulated Sources”, Regional Greenhouse Gas Initiative Inc., accessed on May 14, 2014, http://www.rggi.org/design/overview/regulated_sources.

¹⁴⁹ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

Measurement and Verification

Emission budget trading programs include requirements for emission monitoring and reporting by affected emission sources, holding and transfer of allowances, and surrender of allowances (and offset allowances or credits) in an amount equal to reported emissions. Allowance surrender in an amount equal to reported emissions is often referred to, generally, as the program “compliance obligation”.

For example, EGUs subject to the RGGI program must report CO₂ emissions quarterly pursuant to state regulations, which are generally consistent with EPA regulations for reporting of CO₂ emissions from EGUs under 40 CFR 75.¹⁵⁰ Emissions are reported quarterly to EPA, using the Emissions Collection and Monitoring Plan System (ECMPS), and data is transferred to the RGGI CO₂ Allowance Tracking System (RGGI COATS). GHG emissions reporting for affected sources under the California program is addressed through the California mandatory GHG reporting regulations, using a modified version of the reporting platform administered through the EPA Greenhouse Gas Reporting Program.¹⁵¹ Affected emission sources must report emissions annually and provide third party verification of reported emissions.

Penalties for Non-compliance

Failure to submit allowances in an amount equal to reported emissions result in automatic emission penalties in the form of additional allowance submission requirements (e.g., three-to-one submission requirements to account for any shortfall in RGGI, and a four-to-one submission requirement for any shortfall under the California program). States may also apply other administrative fines and penalties, pursuant to their implementing regulations.

Implementation Status

The RGGI program was established in 2009. From 2009 through 2012, the nine current RGGI participating states invested auction proceeds of more than \$700 million in programs that lower costs for energy consumers and reduce CO₂ emissions, including approximately \$460 million in energy efficiency programs.¹⁵² The participating RGGI states estimate that those investments are providing benefits of more than \$1.8 billion in lifetime energy savings to energy consumers in the region.¹⁵³

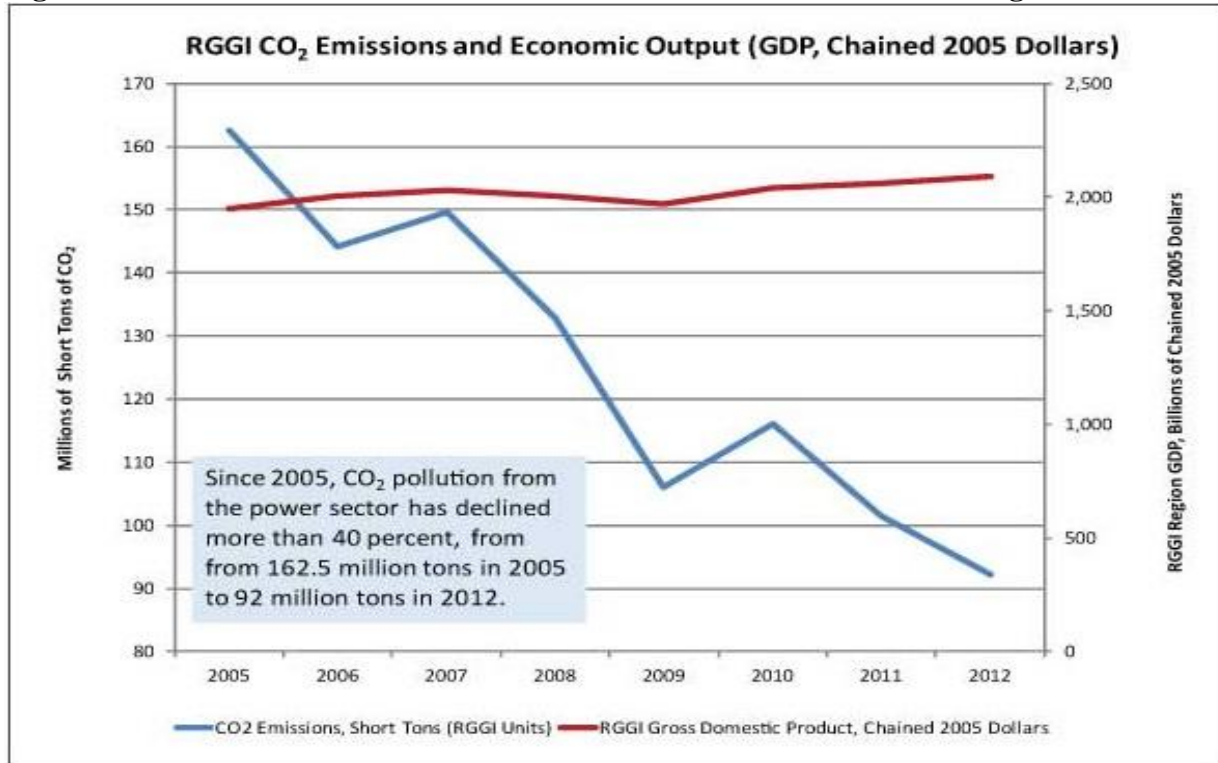
¹⁵⁰ RGGI, *Overview of RGGI CO₂ Budget Trading Program* (Regional Greenhouse Gas Initiative, 2007), accessed on March 19, 2014, http://www.rggi.org/docs/program_summary_10_07.pdf.

¹⁵¹ CARB, *Overview of ARB Emissions Trading Program* (California Air Resources Board, 2011) accessed on March 19, 2014, http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf.

¹⁵² RGGI Inc., *Regional Investment of RGGI CO₂ Allowance Proceeds, 2012* (Regional Greenhouse Gas Initiative Inc., 2014), accessed on March 19, 2014, <http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf>, Programs include residential, commercial, and industrial programs. Of the \$707 million in auction proceeds invested by RGGI participating states through 2012, 65 percent supported end-use energy efficiency programs.

¹⁵³ Ibid.

Figure 3: Historical GDP and Greenhouse Gas Emissions in the RGGI Region



Between 2005, when agreement to implement RGGI was first announced, and 2012, power sector CO₂ emissions in the RGGI participating states fell by more than 40 percent while GDP in the region grew (see Figure 3).¹⁵⁴ The RGGI program, which began in 2009, was not a primary driver for these emission reductions in RGGI states, but the lower emissions led participating states to adjust the multi-state CO₂ emission limit.¹⁵⁵ In January 2014, the RGGI participating states lowered the overall allowable CO₂ emission level in 2014 by 45 percent,

¹⁵⁴ Regional Greenhouse Gas Initiative, Open Letter to Gina McCarthy on Emission Standards under Clean Air Act Section 111(d), December 2, 2013, accessed on March 19, 2014, http://www.rggi.org/docs/RGGI_States_111d_Letter_Comments.pdf.

By contrast, total U.S. power sector CO₂ emissions fell by 16 percent during the same period of time. See 2014 U.S. Greenhouse Gas Inventory for more detail:

U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012* (U.S. Environmental Protection Agency, 2014), accessed May 14, 2014, <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

¹⁵⁵ Environment Northeast, *RGGI Emissions Trends* (Environment Northeast, 2011), accessed on March 19, 2014, http://www.env-ne.org/public/resources/pdf/ENE_RGGI_Emissions_Report_110502_FINAL.pdf.

The first three-year control period under RGGI, establishing CO₂ emission limits for EGUs, began on January 1, 2009. Low gas prices, increased renewables, decreased electric demand and weather are considered four primary drivers of the reductions through 2010, as reported by Environment Northeast in May 2011.

setting a multi-state CO₂ emission limit for affected EGUs of 91 million short tons of CO₂ in 2014 and 78 million short tons of CO₂ in 2020, more than 50 percent below 2008 levels.¹⁵⁶

The California economy-wide market-based GHG emission budget trading program, which addresses GHG emissions from multiple sectors, was implemented in 2012 with emission limits beginning in 2013.^{157,158} While California's emission budget trading program, like its state emission limit, is multi-sector in scope, the state projects that the emission trading program and related complementary measures will reduce power sector GHG emissions to less than 80 million metric tons of CO₂-equivalent by 2025, a 25 percent reduction from 2005 power sector emission levels.¹⁵⁹ Prior to the implementation of the emission trading program, California reports that it reduced power sector CO₂ emissions by 16 percent from 2005 to a 2010-2012 averaging period, a reduction of 16 million metric tons of CO₂-equivalent.¹⁶⁰

ii. CO₂ Emission Performance Standards

Description

CO₂ emission performance standards can apply either directly to EGUs or to the local distribution company (LDC) that sells electricity to the customers. (For more information about electricity is generated and distributed, see Chapter 2 of the Regulatory Impact Analysis).

As of March 2014, four states - California, New York, Oregon and Washington - have enacted mandatory GHG emission standards that impose enforceable emission limits on new and/or expanded electric generating units.¹⁶¹ Three states - California, Oregon and Washington - have enacted mandatory GHG emission performance standards that set an emission rate for

¹⁵⁶ RGGI Inc., "RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants," Regional Greenhouse Gas Initiative Press Release (January 13, 2014), accessed on March 19, 2014, http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.

¹⁵⁷ "Cap-and-Trade Program," California Air Resources Board, accessed March 19, 2014, <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>.

¹⁵⁸ The California program was developed in coordination with U.S. state and Canadian province WCI partners.

¹⁵⁹ State environmental agency leaders from CA, CO, DE, IL, ME, MD, MA, MN, NH, NY, OR, RI, VT, WA, Open Letter to the EPA Administrator Gina McCarthy on Emission Standards under Clean Air Act Section 111(d), December 16, 2013, accessed on March 19, 2014, http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf.

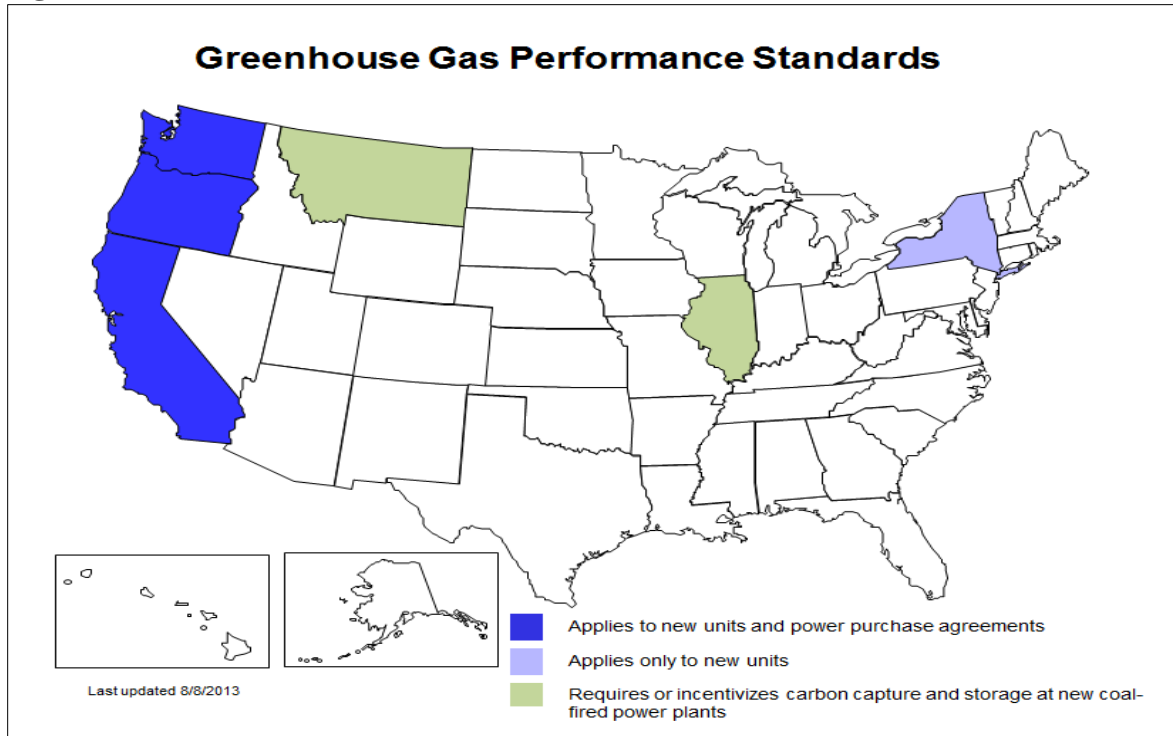
Preliminary California Air Resources Board analyses, based in part on CARB 2008 to 2012 Emissions for Mandatory GHG reporting Summary (2013), cited in this letter.

¹⁶⁰ Ibid.

¹⁶¹ California Energy Commission, California SB 1368, Chapter 598: Emission Performance Standards, September 29, 2006, accessed March 19, 2014, http://www.energy.ca.gov/emission_standards/; New York Department of Environmental Conservation, Part 251: CO₂ Performance Standards for Major Electric Generating Facilities, June 12, 2012, accessed March 19, 2014, <http://www.dec.ny.gov/regs/83094.html#83097>; Oregon Department of Energy, Oregon's Carbon Dioxide Emission Standards for New Energy Facilities (Oregon Department of Energy, 2010) <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>; Washington State Legislature, Chapter 80.70 RCW: Carbon Dioxide Mitigation, Accessed on March 19, 2014, <http://apps.leg.wa.gov/rcw/default.aspx?cite=80.70&full=true>

electricity purchased by electric utilities.¹⁶² In addition to these states, Illinois and Montana have policies to incentivize or require new coal plants to capture at least 50 percent of their CO₂ emissions (see Figure 4).¹⁶³

Figure 4: States with Greenhouse Gas Performance Standards



Policy Mechanics

Design

States have implemented three different types of CO₂ performance standards that affect EGUs and/or LDCs differently. The first requires power plant emissions per electricity generated to be less than or equivalent to an established standard and is directly applicable to EGUs. The second type places conditions on the emissions attributes of electricity procured by electric utilities. It consists of standards that are applicable to LDCs that provide electricity to retail customers. A third type requires that new coal-fired power plants must capture and store a specific percentage of CO₂ emissions. Table 2 provides state examples for each of the types of CO₂ performance standards.

¹⁶² Ibid.

¹⁶³ Illinois General Assembly, Public Act 095-1027, SB1987, Clean Coal Portfolio Standard Law, January 12, 2009, accessed March 19, 2014, <http://ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf>; Montana State Legislature, H.B.0025.05, An Act Generally Revising the Electric Utility Industry and Customer Choice Laws, May 14, 2007, accessed March 19, 2014, <http://leg.mt.gov/bills/2007/billpdf/HB0025.pdf>.

Authority

In some states, programs are regulated through the Public Utilities Commission (California, Oregon). New York's program is regulated through the Department of Environmental Conservation. Washington's program is regulated through two different sets of entities depending on the ownership of the utilities. The Washington Utilities and Transportation Commission regulate investor owned utilities, and the utility's governing board, Washington Department of Ecology, and the State Auditor oversees consumer owned utilities.

Obligated Parties

The emission performance standard can apply either directly to EGUs or to the local distribution company (LDC) that sells electricity to the customer.

Measurement and Verification

Obligated parties must measure and report on electricity generation and CO₂ emissions on a regular basis to verify their compliance with the standard. The reporting requirements and timing varies from state to state and are typically set by the agency that oversees the program as described under authority above.

Table 2 provides an overview of different CO₂ performance standards, while Table 3 provides examples regarding measurement and verification requirements across California, New York, Oregon, and Washington.

Table 2: Examples of State CO₂ Performance Standards

What It Does	State Examples
Requires power plant emissions per electricity generated to be less than or equivalent to the established standard; Applies to EGUs	<ul style="list-style-type: none">• <u>New York</u> (Part 251, 2012) - New or expanded baseload plants (25 MW and larger) must meet an emission rate of either 925 lb CO₂/MWh (output based) or 120 lbs CO₂/MMBTU (input based). Non-baseload plants (25 MW and larger) must meet an emission rate of either 1450 lbs CO₂/MWh (output based) or 160 lbs CO₂/MMBTU (input based).¹⁶⁴• <u>Oregon</u> (HB 3283; 1997, 2007) - New natural gas-fired power plants (baseload and non-baseload) must meet an emission rate of 675 lb CO₂/MWh. Cogeneration and offsets may be used to comply with the emission standard.¹⁶⁵• <u>Washington</u> (RCW 80-70-010; 2004) - New EGUs 25 MW and larger must have an

¹⁶⁴ New York Department of Environmental Conservation, Part 251: CO₂ Performance Standards for Major Electric Generating Facilities, June 12, 2012, accessed March 19, 2014, <http://www.dec.ny.gov/regs/83094.html#83097>.

¹⁶⁵ Oregon Department of Energy, *Oregon's Carbon Dioxide Emission Standards for New Energy Facilities* (Oregon Department of Energy, 2010) <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>.

	<p>approved CO₂ mitigation plan that results in mitigation of 20 percent of the total CO₂ emissions over the life of the facility. Includes modifications to existing EGUs that result in an increase in CO₂ emissions of 15 percent or more. The CO₂ mitigation plan may include one or more of a list of eligible measures (includes indirect measures, such as EE/RE and offsets).¹⁶⁶</p>
<p>Places conditions on the emissions attributes of electricity procured by electric utilities; Applies to LDCs</p>	<ul style="list-style-type: none"> • <u>California</u> (SB 1368; 2006) - Electric utilities may only enter into long-term power purchase agreements for baseload power if the electric generator supplying the power has a CO₂ emission rate that does not exceed that of a natural gas combined cycle plant. The California Energy Commission promulgated regulations establishing an emission rate of 1,100 lb CO₂/MWh.¹⁶⁷ By comparison, the average emissions rate of gas plants in the U.S. is 945 lb CO₂/MWh, while the average emissions rate of pulverized coal plants is 2,154 lb CO₂/MWh.¹⁶⁸ • <u>Oregon</u> (HB 101; 2009) and <u>Washington</u> (SB 6001; 2007) - Electric utilities may only enter into long-term power purchase agreements for baseload power if the electric generator supplying the power has a CO₂ emission rate of 1,100 lb CO₂/MWh or less.¹⁶⁹¹⁷⁰
<p>Requires that new coal-fired power plants must capture and store a specific percentage of CO₂ emissions</p>	<ul style="list-style-type: none"> • <u>Illinois</u> (SB 1987; 2009) Illinois utilities and retailers must purchase at least 5 percent of their electricity from Clean Coal Facilities in 2015 and beyond. To be designated a Clean Coal Facility, new coal-fired power plants must capture and store 50 percent of carbon emissions from 2009-2015, 70 percent for 2016-2017, and 90 percent after 2017.¹⁷¹ • <u>Montana</u> (HB 25; 2007). The Public Service Commission may not approve new plants constructed after January 2007 that are primarily coal-fired unless at least 50 percent of the plant's CO₂ emissions are captured and stored.¹⁷² These requirements apply to formerly restructured utilities in the state. Northwest Energy is the only utility subject to this requirement, which serves about two-thirds of Montana.¹⁷³

¹⁶⁶ Washington State Legislature, Chapter 80.70 RCW: Carbon Dioxide Mitigation, Accessed on March 19, 2014, <http://apps.leg.wa.gov/rcw/default.aspx?cite=80.70&full=true>.

¹⁶⁷ California Energy Commission, California SB 1368, Chapter 598: Emission Performance Standards, September 29, 2006, accessed March 19, 2014, http://www.energy.ca.gov/emission_standards/.

¹⁶⁸ U.S. EPA, *eGRID 2010 data files* (U.S. Environmental Protection Agency, 2014), accessed on March 19, 2014, <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html#>.

¹⁶⁹ Oregon Department of Energy, *Oregon's Carbon Dioxide Emission Standards for New Energy Facilities* (Oregon Department of Energy, 2010) <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>.

¹⁷⁰ Washington State Legislature, Chapter 80.70 RCW: Carbon Dioxide Mitigation, Accessed on March 19, 2014, <http://apps.leg.wa.gov/rcw/default.aspx?cite=80.70&full=true>.

¹⁷¹ Illinois General Assembly, Public Act 095-1027, SB1987, Clean Coal Portfolio Standard Law, January 12, 2009, accessed March 19, 2014 <http://ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf>.

¹⁷² Montana State Legislature, H.B.0025.05, An Act Generally Revising the Electric Utility Industry and Customer Choice Laws, May 14, 2007, accessed March 19, 2014, <http://leg.mt.gov/bills/2007/billpdf/HB0025.pdf>.

¹⁷³ Regulatory Assistance Project, *Emissions Performance Standards in Selected States* (Regulatory Assistance Project, 2010), accessed on May 30, 2014, <http://www.raponline.org/search/related/relation/project-document/id/10>

Table 3: Examples of Measurement and Verification Requirements for CO₂ Performance Standards

State	Measurement and Verification Details
California	<ul style="list-style-type: none"> The California PUC is responsible for approving any long term financial commitment by an electric utility and must adopt rules to enforce these requirements as well as verification procedures.¹⁷⁴
New York	<ul style="list-style-type: none"> CO₂ emission regulations require recordkeeping, monitoring and reporting consistent with existing state and federal regulations. Each applicable emissions source must install Continuous Emissions Monitoring Systems (CEMS) subject to Federal CO₂ reporting requirements for 40 CFR part 75, successfully complete certification tests, and record, report, and quality assure the data from the CEMS. The owner or operator must report the CO₂ mass emissions data and heat input data on a semi-annual basis to the Department of Environmental Conservation. On a quarterly basis, the owner or operator must report all of the data and information required in either 40 CFR part 60 or subpart H of 40 CFR part 75.¹⁷⁵
Washington	<ul style="list-style-type: none"> Mitigation projects must be approved by the appropriate council, department, or authority, and made a condition of the proposed and final site certification agreement or order of approval. Direct investment projects are approved if they provide reasonable certainty that the performance requirements of the projects will be achieved and that they were implemented after July 1, 2004. For facilities under the jurisdiction of a council, the implementation of a carbon dioxide mitigation project, other than purchase of carbon credits, is monitored by an independent entity for conformance with the performance requirements of the carbon dioxide mitigation plan. The independent entity shares the project monitoring results with the council. For facilities under jurisdiction of the department or authority, the implementation of a carbon dioxide mitigation project, other than a purchase of carbon credits, is monitored by the department or authority issuing the order of approval.¹⁷⁶
Oregon	<ul style="list-style-type: none"> It is up to the Council during the certificate application phase to determine the gross CO₂ emissions over a 30 year lifetime of the proposed facility to determine whether it meets the CO₂ performance standard. During the operation phase of approved facilities, there are CO₂ reporting requirements to the Oregon Department of Environmental Quality and US EPA. New facilities must pass a 100 hour test in their first year of operation to show they meet the performance standards.¹⁷⁷

¹⁷⁴ “SB 1368 Emission Performance Standards,” California Energy Commission, Accessed March 19, 2014, http://www.energy.ca.gov/emission_standards/.

¹⁷⁵ New York Department of Environmental Conservation, Part 251: CO₂ Performance Standards for Major Electric Generating Facilities, June 12, 2012, Accessed March 19, 2014, <http://www.dec.ny.gov/regs/83094.html#83097>.

¹⁷⁶ Washington State Legislature, Chapter 80.70 RCW: Carbon Dioxide Mitigation, Accessed on March 19, 2014, <http://apps.leg.wa.gov/rcw/default.aspx?cite=80.70&full=true>

¹⁷⁷ Oregon Department of Energy, *Oregon’s Carbon Dioxide Emission Standards for New Energy Facilities* (Oregon Department of Energy, 2010) Accessed on March 19, 2014 <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>.

Penalties for Noncompliance

For policies that affect target new electric generating units, utilities must prove any proposed units are in compliance at the time of permitting. In Oregon, if facilities do not meet the performance standard in their first year of operation during a 100 hour test¹⁷⁸, they must purchase offsets to account for any excess emissions.¹⁷⁹

Implementation Status

Since enacting the performance standard, California's carbon emissions rates have fallen from approximately 1,245 lbs CO₂e/MWh for fossil generation (considering both in-state and imported power) and 875 lbs CO₂e/MWh for all power in 2005 to an average of approximately 1,090 lbs CO₂e/MWh and 775 lbs CO₂e/MWh in the three years before 2012.¹⁸⁰

b. Energy Efficiency Policies, Programs and Measures

Demand-side energy efficiency policies and programs reduce utilization of EGUs and avoid greenhouse gas emissions associated with electricity generation. These electricity demand reductions can be achieved through enabling policies that incentivize investment in demand-side energy efficiency improvements by overcoming market barriers that otherwise prevent these investments, such as lack of information on energy efficient options, high transaction costs, split-incentives, lack of product availability, and perceptions of organizational risks. Reducing electricity demand also reduces the associated transmission and distribution losses that occur across the grid between the sites of electricity generation and the end use.

Demand-side energy efficiency is considered a central part of climate change mitigation in states that currently have mandatory GHG targets, accounting for roughly 35 percent to 70 percent of expected reductions of state's power sector emissions.¹⁸¹ For example, California expects to achieve reductions of 21.9 MMTCO₂e in 2020 from energy efficiency programs targeting electricity reductions. Taking into account expected reductions of 21.3 MMTCO₂e expected from California's RPS and 2.1 MMTCO₂e from the million solar roofs program, energy efficiency makes up 48 percent of power sector reductions based on California's Climate Change Scoping Plan.¹⁸² Another state, Washington, expects to reduce 9.7 MMTCO₂e from energy efficiency measures in 2020. Taking into account expected reductions of 4.1 MMTCO₂e from

¹⁷⁸ During the first year of operation new power plants test their equipment to ensure compliance with standards for commercial equipment. Initial CO₂ performance requirements can be validated during this test.

¹⁷⁹ Oregon Department of Energy, *Oregon's Carbon Dioxide Emission Standards for New Energy Facilities*, Accessed on March 19, 2014, <http://www.oregon.gov/energy/Siting/docs/Reports/CO2Standard.pdf>.

¹⁸⁰ State environmental agency leaders from CA, CO, DE, IL, ME, MD, MA, MN, NH, NY, OR, RI, VT, WA, Open Letter to EPA Administrator Gina McCarthy on Emission Standards Under Clean Air Act Section 111(d), December 16, 2013, accessed on March 19, 2014, http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf.

¹⁸¹ These reduction target ranges are based on a review of state GHG reduction laws in California, Connecticut, Hawaii, Maine, Maryland, Massachusetts, Minnesota, New Jersey, Oregon, and Washington.

¹⁸² California Air Resources Board, *Climate Change Scoping Plan*, accessed March 19, 2014, http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

Washington's RPS, energy efficiency makes up 70 percent of expected emission reductions from stationary energy within the state.¹⁸³

States have employed a variety of strategies to increase investment in demand-side energy efficiency technologies and practices, including (1) energy efficiency resource standards, (2) demand-side energy efficiency programs, (3) building energy codes, (4) appliance standards and (5) tax credits. Each of these strategies is described below.

i. Energy Efficiency Resource Standards

Description

Energy Efficiency Resource Standards (EERS) set multiyear targets for energy savings that utilities or third-party program administrators typically meet through customer energy efficiency programs but also through other approaches, such as peak demand reductions, building codes and combined heat and power (CHP). An EERS can apply to retail distributors of either electricity or natural gas, or both, depending on the state. To date, 23 states have mandatory EE requirements in place, two states have voluntary targets, and two more states allow EE to be used to meet part of a mandatory RPS, for a total of at least 27 states with some type of EE requirement or goal.^{184,185}

Policy Mechanics

Design

EERS design and implementation details vary by state, and may be expressed as a percentage reduction in annual retail electricity sales, as a percentage reduction in retail electricity sales growth, or as a specific electricity savings amount over a long-term period. A typical EERS sets multiyear targets for energy savings that drive investment in EE programs implemented by utilities or third party administrators. Over the compliance period, an EERS reduces electricity demand by a target amount that utilities must meet. As a result, an EERS indirectly affects utility CO₂ emissions by reducing the use of fossil-fuel-fired EGUs.

¹⁸³ Washington Department of Ecology, *Growing Washington's Economy in a Carbon-Constrained World*, Accessed March 19, 2014, <https://fortress.wa.gov/ecy/publications/publications/0801025.pdf>.

¹⁸⁴ "State Energy Efficiency Resource Standards (EERS)," (American Council for an Energy-Efficient Economy, April 2014), Accessed on May 23, 2014, <http://www.aceee.org/files/pdf/policy-brief/eers-04-2014.pdf>.

¹⁸⁵ Delaware and Florida were not included in the totals. Delaware has enacted legislation to create an EERS, but final regulations have not yet been promulgated (Database of State Incentives for Renewables & Efficiency, Accessed on May 29, 2014, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE17R). Florida has enacted an EERS, but program funding to date is considered to be "...far below what is necessary to meet targets" ("State Energy Efficiency Resource Standards (EERS)," American Council for an Energy-Efficient Economy, April 2014, Accessed on May 23, 2014, <http://www.aceee.org/files/pdf/policy-brief/eers-04-2014.pdf>).

Authority

Most state EERS policies are established through legislation. However, there are several instances in which they have been established by PUC orders under broader statutory authority, such as by setting quantitative targets consistent with the achievement of ‘all cost-effective energy efficiency.’¹⁸⁶

Obligated Parties

Retail electricity suppliers, which are utilities that sell electricity to customers for end-use purposes, are the obligated parties under an EERS.

Measurement and Verification

PUCs generally oversee EERS. Retail electricity suppliers comply with EERS requirements by developing a portfolio of end-use energy efficiency programs that encourage electric utility customers to invest in more energy efficient technologies and practices as described below. Transmission and distribution infrastructure improvements may also count towards EERS programs in some states.¹⁸⁷ PUCs typically rely on independent program evaluators to perform evaluation, measurement and verification (EM&V) activities that estimate the incremental annual and cumulative energy savings attributable to the programs.¹⁸⁸ These estimates are typically the basis for compliance reports submitted by retail electricity suppliers. See Table 4 for examples of penalties for program noncompliance. For more information about measurement and verification of energy efficiency policies or programs, see earlier in the State Plan Considerations Technical Support Document.

¹⁸⁶ Ernest Orlando Lawrence Berkeley National Laboratory, *Benefits and Costs of Aggressive Energy Efficiency Programs and the Impacts of Alternative Sources of Funding: Case Study of Massachusetts*, accessed on May 14, 2014, <http://emp.lbl.gov/sites/all/files/REPORT%20lbl-3833e.pdf>. An important policy driver for EE programs in six states is a statutory requirement for utilities to acquire "all cost-effective energy efficiency". This policy typically requires utilities and other program administrators to pursue energy efficiency up to the point at which it is no longer cost effective, as defined by cost-benefit tests and procedures REQUIRED by state PUCs. States with all-cost effective energy efficiency policies include: CA, CT, MA, RI, VT, WA. For MA, this goal has translated into achieving annual electric energy savings equivalent to a 2.4% reduction in retail sales from energy efficiency programs in 2012.

¹⁸⁷ For example, Ohio allows transmission and distribution infrastructure improvements to count towards their EERS. Database of State Incentives for Renewables & Efficiency, Accessed on May 29, 2014, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH16R&re=0&ee=0.

¹⁸⁸ Evaluation, measurement, and verification (EM&V) refers to set of techniques and approaches used to estimate the quantity of energy savings from an EE program or policy. Since energy savings cannot be directly measured, efficiency program impacts are estimated by taking the difference between: (a) actual energy consumption after efficiency measures are installed, and (b) the energy consumption that would have occurred during the same period had the efficiency measures not been installed (i.e., the baseline).

Table 4: Examples of Penalties for Noncompliance

State	Direct Financial Penalties
Pennsylvania	Failure to achieve the requisite reductions in electricity consumption and peak demand during Phase 1 results in one-time fines from \$1 million to \$20 million. Failure to file a plan with the public utilities commission is also punishable by a fine of \$100,000 per day. Costs associated with any such fines may not be passed on to ratepayers. ¹⁸⁹
Ohio	Failure to comply with energy efficiency or peak demand reduction requirements results in the state public utilities commission assessing a forfeiture upon the utility, to be credited to the Advanced Energy Fund. The amount of the forfeiture is either: an amount, per day per under-compliance or non-compliance, not greater than \$10,000 per violation; or an amount equal to the then existing market value of one renewable energy credit (REC) ¹⁹⁰ per megawatt hour of under-compliance or noncompliance. ¹⁹¹
Illinois	For both natural gas and electric utilities, failure to submit an energy reduction plan will result in a fine of \$100,000 per day until the plan is filed. This penalty is deposited in the Energy Efficiency Trust Fund and may not be recovered by rate payers. ¹⁹²

Penalties for Noncompliance

If the obligated parties do not demonstrate compliance with the EERS, they may face financial penalties. The existence and amount of penalties varies across the states. Table 4 provides examples of financial penalties in three states, Pennsylvania, Ohio and Illinois.

Implementation Status

As of April 2014, 23 states had an active EERS in place, while at least two have EE targets or goals that are voluntary at this time (see Figure 5). In addition, two states have renewable portfolio standard that allow the option for energy efficiency to meet requirements.¹⁹³

¹⁸⁹ “Energy Efficiency and Conservation Requirements for Utilities: Pennsylvania” Database of State Incentives for Renewables & Efficiency, accessed on March 19, 2014, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA14R&re=0&ee=0.

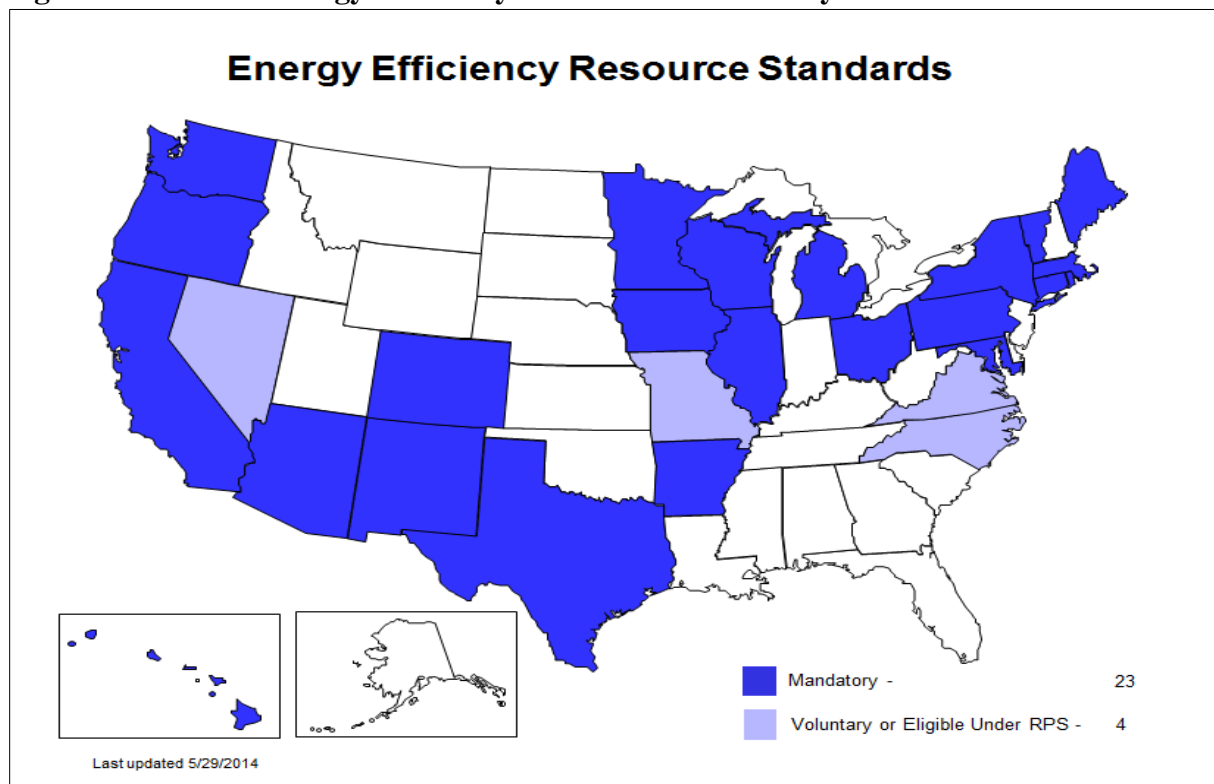
¹⁹⁰ RECs represent the non-energy attributes, including all the environmental attributes, of electricity generation from renewable energy sources. RECs are typically issued in single MWh increments. See the section on Renewable Portfolio Standards for more detail.

¹⁹¹ “Energy Efficiency and Conservation Requirements for Utilities: Ohio” Database of State Incentives for Renewables & Efficiency, accessed on March 19, 2014, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH16R&re=0&ee=0.

¹⁹² “Energy Efficiency and Conservation Requirements for Utilities: Illinois” Database of State Incentives for Renewables & Efficiency, accessed on March 19, 2014, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL19R&re=0&ee=0.

¹⁹³ See footnotes 184 and 185.

Figure 5: Status of Energy Efficiency Resource Standards by State



Most states are meeting or on track to meet their incremental savings goals, which typically range from an annual reduction in electricity of about 0.25 - 2.5 percent.¹⁹⁴ In 2011, across the 50 states, incremental savings were equivalent to 0.62 percent of retail electricity sales.¹⁹⁵ For those states with EERS policies in place for more than two years as of 2011, thirteen of twenty states are achieving 100 percent or more of their goals, three states are achieving over 90 percent of their goals, and only three states are realizing savings below 80 percent of their goals.¹⁹⁶

ii. Demand-side Energy Efficiency Programs

Description

Demand-side energy efficiency programs are programs designed to advance energy efficiency improvements within a state or utility service area. They are typically implemented to help meet state policies, standards or objectives, such as energy efficiency resource standards

¹⁹⁴ Ibid.

¹⁹⁵ “The 2013 State Energy Efficiency Scorecard”, American Council for an Energy-Efficient Economy, Accessed on March 19, 2014, <http://www.aceee.org/research-report/e13k>.

¹⁹⁶ Michael Sciortino, Seth Nowak, Patti White, Dan York, and Martin Kushler. “Energy Efficiency Resource Standards: A Progress Report on State Experience.” *American Council for an Energy Efficient Economy* (2011).

(EERS), ‘all cost effective’ energy efficiency goals, integrated resource planning, and other demand-side management program and budget processes.

Policy Mechanics

Design

Demand-side energy efficiency programs include financial incentives to use energy efficient products, make energy efficiency upgrades to improve the performance of residential, commercial, and industrial buildings, and provide technical assistance and information programs to address market and information barriers. Funding for these programs typically comes from charges added to customer utility bills and from revenues raised through emission allowance auctions, such as under RGGI. The RGGI auction proceeds go to a variety of sources with the authority to run demand-side energy efficiency programs, including those also funded via independent trusts, DOE’s Weatherization Assistance Program (WAP), and state-run energy efficiency grant programs for municipalities.¹⁹⁷

States are also funding energy efficiency programs using revenues from “forward capacity markets” operated by regional electricity operators. Forward capacity markets allow energy suppliers to bid against each other for the amount of capacity they can supply into the electricity market in a future year. Demand-side management programs have been allowed to bid into these markets as an energy source, demonstrating that energy efficiency programs can compete with more traditional forms of electricity supply in meeting the needs of the power grid.

Authority

Demand-side programs that are a part of EERS programs are typically established through legislation or PUC authority. Other demand-side management programs can arise as a result of utility planning processes and state and local government efforts to ensure all cost-effective energy efficiency and other policy goals are met.

Obligated Parties

Energy efficiency programs can be administered by investor-owned, municipal or cooperative utilities; third party administrators; or state and local government agencies.

Measurement and Verification

PUCs generally oversee demand-side energy efficiency programs. Program administrators typically rely on independent evaluators to perform evaluation, measurement and verification (EM&V) activities that estimate the incremental annual and cumulative energy savings attributable to the programs. These estimates are typically the basis for annual

¹⁹⁷ RGGI, “Regional Investment of RGGI CO₂ Allowance Proceeds, 2012”, Regional Greenhouse Gas Initiative (February 2014), accessed on March 19, 2014, <http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf>.

performance reports submitted by retail electricity suppliers or third party administrators to the PUCs. In the case of state and local government agency run programs that are not overseen by the PUC, energy savings are typically estimated to assure proper use of grants or other funds. For more information about the evaluation, measurement and verification of energy efficiency policies and programs, see earlier in the State Plan Considerations Technical Support Document.

Penalties for Noncompliance

As discussed above, some states with an EERS levy direct fines for missing energy efficiency targets or failure to submit an energy efficiency plan. For some programs under PUC oversight, failure to reach certain performance levels may result in an inability to receive an incentive payment or recover all incurred costs. Demand-side programs funded by RGGI proceeds or grants typically do not have penalties for noncompliance. However, state agencies play a role in evaluating these programs and deciding whether funding should continue to flow to them.

Implementation Status

Well-established state demand-side energy efficiency programs have demonstrated their ability to reduce electricity demand.¹⁹⁸ For example, data reported to the U.S. Energy Information Administration (EIA) show that in 2012 California avoided 35,482 GWh of electricity consumption through its demand-side efficiency programs, while Illinois avoided 3,084 GWh and Maryland avoided 1,528 GWh.¹⁹⁹ These reductions are equivalent to 13.7 percent, 2.1 percent, and 2.5 percent of total 2012 retail electricity sales in those states, respectively.²⁰⁰ According to data and analyses from sources including Lawrence Berkeley National Lab (LBNL), the U.S. Department of Energy's Energy Information Administration, and the American Council for an Energy Efficient Economy (ACEEE), as well as the EPA's own analysis, 12 leading states have either achieved – or have established requirements that will lead them to achieve - annual incremental savings rates of at least 1.5 percent of the electricity consumption that would otherwise have occurred.²⁰¹

In 2011, utilities in 48 states implemented demand-side energy efficiency programs.²⁰² State demand-side energy efficiency programs are estimated to have reduced CO₂ emissions by 75 million metric tons in 2011, or 3.5 percent of national power sector emissions.²⁰³²⁰⁴

¹⁹⁸ “The Future of Utility Customer-Funded Energy Efficiency Programs in the United States”, Lawrence Berkeley National Laboratory, Accessed on March 19, 2014, <http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend>.

¹⁹⁹ “Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files”, Energy Information Administration, Accessed on March 19, 2014, <http://www.eia.gov/electricity/data/eia861/>.

²⁰⁰ “Electricity: Detailed State Data”, Energy Information Administration, Accessed on March 19, 2014, <http://www.eia.gov/electricity/data/state/>.

²⁰¹ See the Greenhouse Gas Abatement Measures TSD for more information.

²⁰² “The 2013 State Energy Efficiency Scorecard”, American Council for an Energy-Efficient Economy, Accessed on March 19, 2014, <http://www.aceee.org/research-report/e13k>.

²⁰³ The Edison Foundation: Innovation, Electricity Efficiency, *Summary of Customer-Funded Electric Efficiency Savings, Expenditures, and Budgets (2011-2012)*, March 2013, Accessed on March 19, 2014,

iii. Building Energy Codes

Description

Building energy codes establish minimum efficiency requirements for new and renovated residential and commercial buildings. These measures are intended to eliminate inefficient technologies with minimal impact on up-front project costs. This can reduce the need for energy generation capacity and new infrastructure while reducing energy bills. Energy codes lock in future energy savings during the building design and construction phase, rather than through a renovation.

Policy Mechanics

Design

Codes specify “thermal resistance” improvements to the building shell and windows, minimum air leakage, and minimum efficiency for heating and cooling equipment.

Mandatory building energy codes establish minimum efficiency requirements for residential and commercial construction. The International Energy Conservation Code (IECC) is the prevailing model code for the residential sector. ASHRAE 90.1-2010 is the model commercial code.

By locking in efficiency measures at the time of construction, codes are intended to capture energy savings that are more cost-effective than retrofit opportunities available after a building has been constructed. Energy code requirements are also intended to overcome market barriers to efficient construction in both the commercial and residential sectors, such as the complexity of advanced codes, lack of local-level implementation resources, and a shortage of empirical data on the costs and benefits of codes.

Authority

Model building codes are typically developed at the national or international level, adopted at the state and/or local level, and implemented and enforced locally.

Obligated Parties

Local parties, such as developers and property owners requiring building permits, are the most common obligated parties.

http://www.edisonfoundation.net/iei/Documents/FINAL_IEE%20Whitepaper_2012_US%20Energy%20Efficiency.pdf.

²⁰⁴ EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 Executive Summary*, (Environment Protection Agency, 2013), accessed on March 19, 2014.

<http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-ES.pdf>.

Measurement and Verification

Program implementation steps, including builder training, compliance assurance, and enforcement, are typically the responsibility of state and local governments. These steps, however, are often not fully or uniformly implemented for numerous reasons, including an emphasis on health and safety issues over the proper functioning of mechanical equipment, a lack of trained staff to review building plans and conduct onsite inspections, and limited funding to carry out key implementation activities. As a result, most jurisdictions do not have the capacity to analyze code compliance and to identify the measures and strategies that should be targeted for improved implementation. For more information about measurement and verification of energy efficiency, see earlier in the State Plan Considerations Technical Support Document.

Penalties for Noncompliance

In order to get building permits approved, the relevant developer or property owners must show they are in compliance with standards. Since permitting is done at the local level, the use of penalties and the ability to enforce standards vary significantly by region. DOE has been working with states and localities to improve compliance practice

Implementation Status

To date, 28 states have adopted IECC 2009 while four states have gone further by adopting the IECC 2012. In the commercial sector, 33 states have adopted ASHRAE 90.1-2007 and five states have adopted ASHRAE 90.1-2010. Currently, 11 states have outdated or no state-wide residential energy code, and 9 states have outdated or no state-wide energy codes for commercial construction.²⁰⁵ The current status of state residential and commercial energy codes are shown below in Figure 6 and Figure 7, respectively. The State of Oregon, which has adopted residential and commercial codes based on the IECC 2009, estimated total savings in 2009 from building energy codes of 1.17 GWh and 2.3 GWh in the residential and commercial sectors, respectively.²⁰⁶ This was equivalent to more than 7 percent of total retail electricity sales in Oregon in 2009.²⁰⁷

²⁰⁵ “Code Status”, Online Code Environment & Advocacy Network, Accessed on March 19, 2014, <http://energycodesocean.org/code-status>.

²⁰⁶ Oregon Department of Energy, *2011-2013 State of Oregon Energy Plan*, Accessed on March 19, 2014, http://www.oregon.gov/energy/docs/reports/legislature/2011/energy_plan_2011-13.pdf.

²⁰⁷ “State Electricity Profiles: Oregon Electricity Profile 2012”, Energy Information Administration, Accessed on March 19, 2014, <http://www.eia.gov/electricity/state/oregon/>.

Figure 6: Residential State Energy Code Status

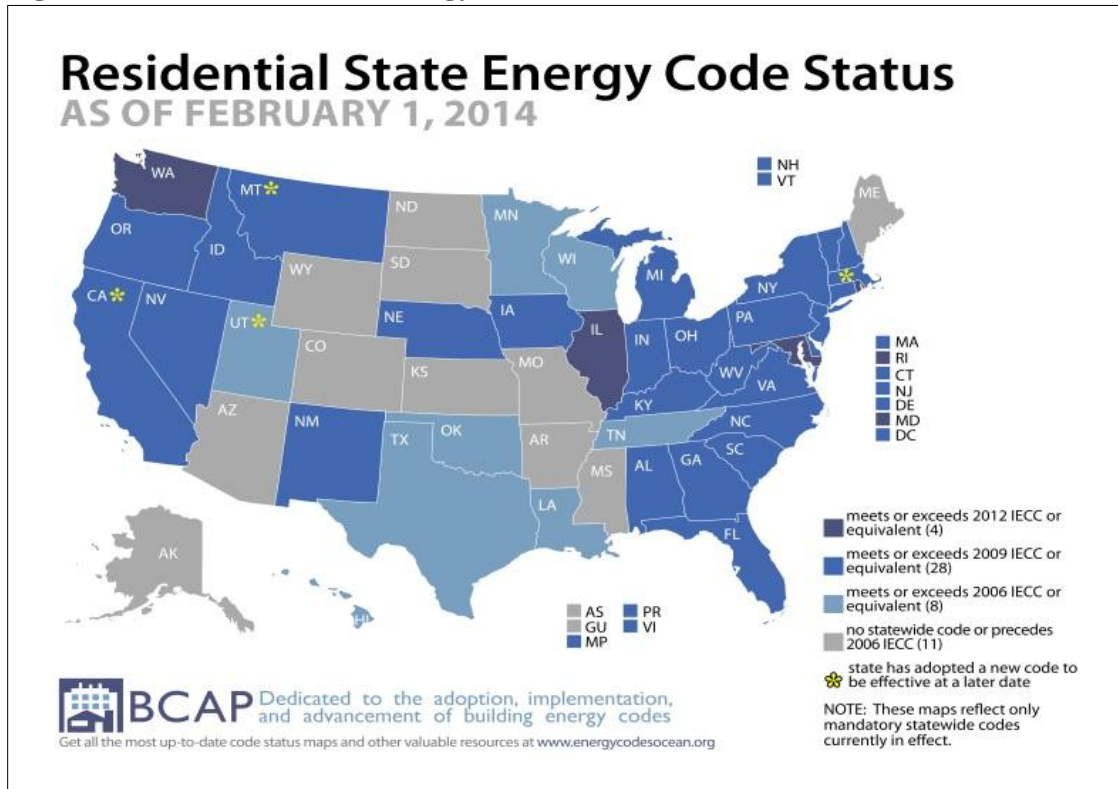
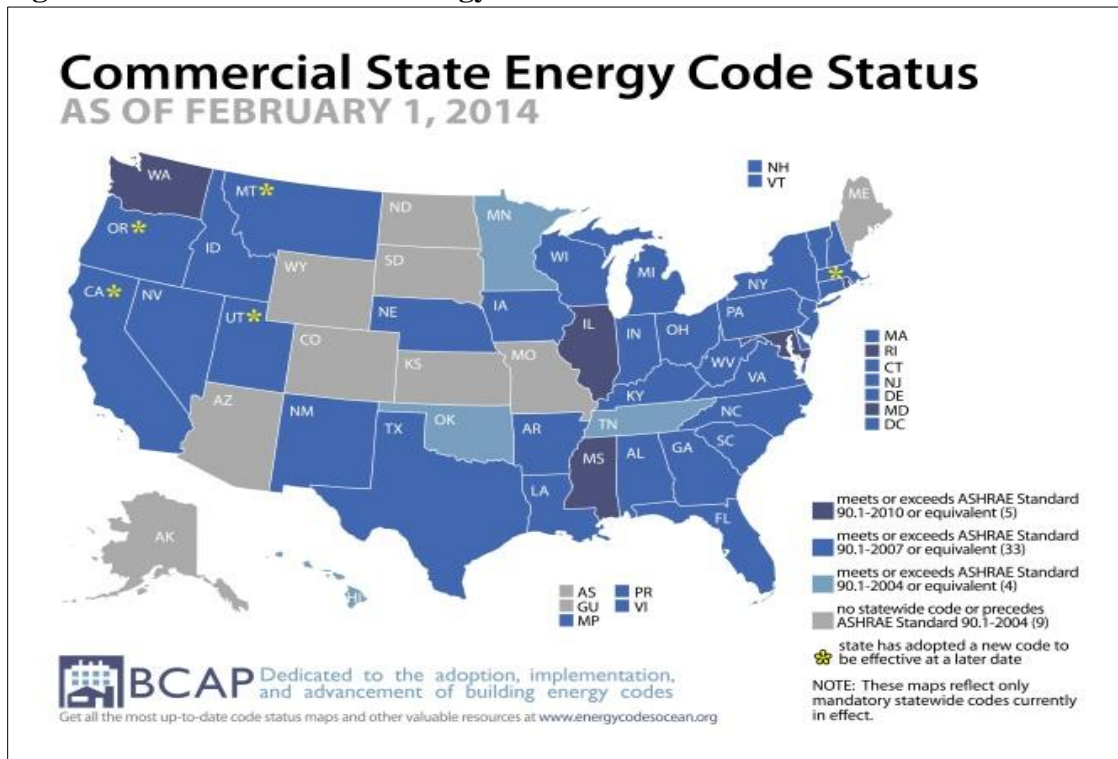


Figure 7: Commercial State Energy Code Status



iv. Appliance and Equipment Efficiency Standards

Description

State appliance standards establish minimum energy-efficiency levels for those appliances and other energy-consuming products that are not already covered by the federal government. These standards typically prohibit the sale of less efficient models within a state. States are finding that appliance standards offer a cost-effective strategy for improving energy efficiency and lowering energy costs for businesses and consumers, though these standards are superseded when Federal standards are enacted for new product categories.

While state appliance standards can be useful in testing and exploring the effectiveness of standards for new products, states cannot preempt or supersede existing Federal standards. States may apply to DOE for a waiver to implement more stringent standards. This is sometimes granted if a certain period of time has passed since the federal standard has been updated.

Policy Mechanics

Design

When states implement appliance and equipment standards, they are establishing a minimum efficiency for products, such as refrigerators or air conditioners, thereby reducing the energy associated with using the product. Standards prohibit the production and sale of products less efficient than the minimum requirements, encouraging manufacturers to focus on how to incorporate energy-efficient technologies into their products at the least cost and hastening the development of innovations that bring improved performance.

Authority

State energy offices, which typically administer the federal state energy program funds, have generally acted as the administrative lead for standards implementation. In contrast, inspection and enforcement of appliance standards regulations has typically involved self-policing. Industry competition is such that competitive manufacturers usually report violations.

Obligated Parties

Manufacturers of products being sold in a given state are typically obligated to ensure their appliances meet the appropriate energy efficiency standards.

Measurement and Verification

Evaluating the benefits and costs of the standards is important during the standards-setting process. Once enacted, however, little field evaluation is performed. For more information about measurement and verification of energy efficiency, see earlier in the State Plan Considerations Technical Support Document.

Penalties for Noncompliance

Appliances and equipment found in violation of the minimum energy performance standards are not allowed to be sold or manufactured in the state.

Implementation Status

Currently, fifteen states and the District of Columbia have enacted appliance efficiency standards. However, most of these standards have been superseded by federal standards. Still, nine states (AZ, CA, CT, MD, NV, NY, OR, RI, WA) and the District of Columbia have either enacted standards for equipment not covered federally or obtained waivers to enact tougher appliance standards where the federal regulations have become outdated. California currently leads all states in active state standards, covering 13 products, including consumer audio and video products, pool pumps and hot tubs, vending machines, televisions, battery chargers, and various lighting applications.²⁰⁸

v. Incentives and Finance Mechanisms for Energy Efficiency

Description

States offer a diverse portfolio of financing and incentive approaches that are designed to address specific financing challenges and barriers and incentivize specific markets and customer groups to invest in energy efficiency. These programs include revolving loan funds, energy performance contracting, tax incentives, rebates, grants, and other incentives.

Policy Mechanics

Design

Revolving loan funds provide low-interest loans for energy efficiency improvements. The funds are designed to be self-supporting. States create a pool of capital that “revolves” over a multi-year period, as payments from borrowers are returned to the capital pool and are subsequently lent to other borrowers. Revolving loan funds can be created from several sources, including public benefits funds (PBFs),²⁰⁹ utility program funds, general state revenues, or federal funding sources. Revolving funds can grow in size over time, depending on repayment interest rates and program administrative costs.

²⁰⁸ “Appliance Efficiency Regulations: California”, Database of State Incentives for Renewables & Efficiency, Accessed on March 19, 2014,

http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA48R&re=0&ee=0.

²⁰⁹ Public benefit funds (PBFs) are dedicated funds used for supporting research and development of energy efficiency and renewable energy projects. Funds are normally collected either through a small charge for every electric customer or through specified contributions from utilities.

Energy performance contracting allows the public sector to contract with private energy service companies (ESCOs) to provide building owners with energy-related efficiency improvements that are guaranteed to save more than they cost over the course of the contracting period. ESCOs provide energy auditing, engineering design, general contracting, and installation services, and help arrange project financing.²¹⁰ The contracts are privately funded and do not involve state funding or financial incentives.

State tax incentives for energy efficiency are available as personal or corporate income tax credits, tax exemptions (e.g., sales tax exemptions on energy-efficient appliances), and tax deductions (e.g., for construction programs). Tax incentives aim to spur private sector innovation to develop more energy efficient technologies and practices and increase consumer choice of energy-efficient products.²¹¹

Rebates (also known as “buy-downs”) are used to promote demand-side energy efficiency reductions by providing direct incentives to customers who purchase or make upgrades to approved efficient appliances or retrofit their homes (e.g., a utility may refund part of the cost for a homeowner to improve attic insulation or purchase a high-efficiency furnace). Funding for rebates may come from PBFs, direct grants, or utility program funds.

Grants from the federal government, state government, regional agency, or private source may be used to start or finance energy efficiency programs. A grant may be used to provide funding for a specific construction project (e.g., retrofit of a school), finance a rebate program, initiate a revolving fund, conduct a behavior change campaign (e.g., educate public about the benefits of off-peak energy use), or any other type of program that meets the specific grant requirements.

Authority

Financial mechanisms and incentives for energy efficiency are run by utilities and state and local governments. Utilities primarily offer rebates, grants, and loans. Personal, corporate, sales, and property tax incentives are mainly offered by state and local governments.²¹²

Implementation Status

Financial mechanisms and incentives for energy efficiency exist in all 50 states, with the most prevalent financial mechanisms and incentives for energy efficiency are rebates and loan programs. There are 43 tax incentives and over one-thousand rebate, grant, and loan programs.²¹³ In the first 3 years of Alaska’s Home Energy Rebate Program, the State provided an estimated

²¹⁰ EPA, *Integrating State and Local Environmental and Energy Goals: Energy Performance Contracting. Fact Sheet* (EPA, September 2004).

²¹¹ Elizabeth Brown, Harvey Sachs, Patrick Quinlan, and Daniel Williams. “Tax Credits for Energy Efficiency and Green Buildings: Opportunities for State Action.” *American Council for an Energy Efficient Economy* (2002).

²¹² “Financial Incentives for Energy Efficiency” Database of State Incentives for Renewables & Efficiency, accessed on March 19, 2014, <http://www.dsireusa.org/summarytables/finee.cfm>.

²¹³ Ibid.

\$110 million to help finance energy efficiency retrofits for 16,500 homeowners. Retrofitted houses are currently saving an estimated 1.6 trillion BTUs of energy annually, or 5 percent of the Alaska's total annual energy demand for residential space heating.²¹⁴

c. Renewable Energy Policies and Programs

States have adopted a range of requirements and programs to advance the deployment of renewable energy technologies, including renewable portfolio standards, performance-based incentives and public benefit funds.²¹⁵ These renewable energy policies and programs reduce GHG emissions by increasing the use of renewable energy and altering the mix of energy supply.

i. Renewable Portfolio Standards

Description

A renewable portfolio standard (RPS), also known as a renewable electricity standard (RES), is a mandatory requirement for retail electricity suppliers to supply a minimum percentage or amount of their retail electricity load with electricity generated from eligible sources of renewable energy.²¹⁶ An RPS indirectly affects EGU CO₂ emissions by reducing the utilization of fossil-fuel-fired EGUs. As of June 2013, 29 states and Washington, DC have adopted a mandatory RPS (see Figure 8), although designs vary (e.g., applicability, targets and timetables, geographic and resource eligibility, alternative compliance payments) and an additional nine have voluntary renewable goals.²¹⁷

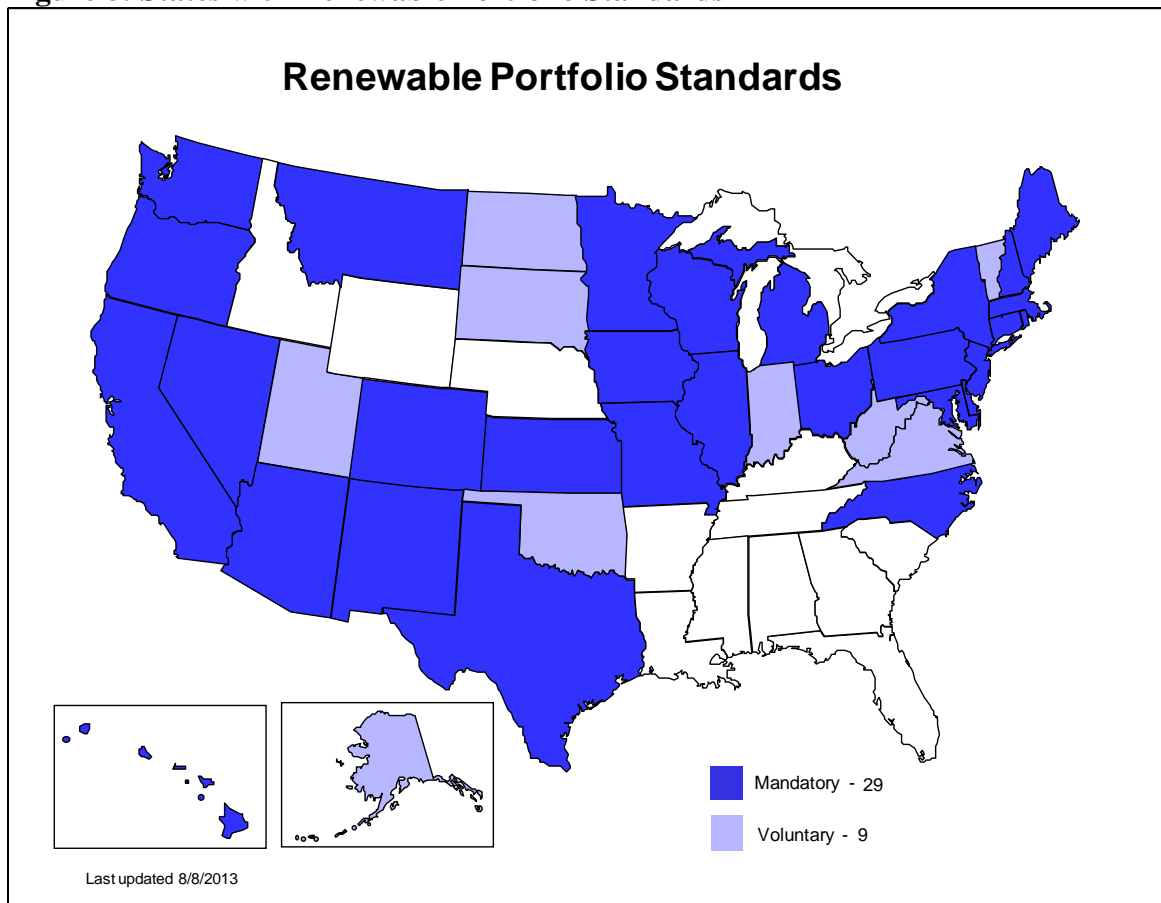
²¹⁴ Scott Goldsmith, Sohrab Pathan, and Nathan Wiltse, *Snapshot: The Home Energy Rebate Program*, (Cold Climate Housing Research Center, May 2012), Accessed on March 19, 2014, http://cchrc.org/docs/snapshots/HERP_snapshot.pdf.

²¹⁵ Feed-in tariffs, a performance-based incentive, offer long-term purchase agreements to renewable energy electricity generators. Public benefit funds are typically created by levying a small fee as a part of retail electricity rates and are used to support rebate, loan, and other programs that support renewable energy deployment. For more information, see *Database of State Incentives for Renewables and Efficiency*, available at <http://www.dsireusa.org/>.

²¹⁶ In some state Renewable Portfolio Standards (alternatively called “Alternative and Renewable Energy Portfolio Standards”), selected non-renewable sources such as coal bed methane or gasification are eligible for credit.

²¹⁷ Database of State Incentives for Renewables and Efficiency, March 2013, accessed on May 23, 2014, <http://www.dsireusa.org/>; Alaska House Bill 306, Signed by Governor Sean Parnell June 16, 2010, http://www.legis.state.ak.us/basis/get_bill_text.asp?hsid=HB0306Z&session=26.

Figure 8: States with Renewable Portfolio Standards



Policy Mechanics

Design

RPS requirements typically start at modest levels and ramp up over a period of several years. An RPS relies on market mechanisms to increase electricity generation from eligible sources of renewable energy.

Retail electricity suppliers can comply with RPS requirements through several mechanisms, which vary by state, including:

- Ownership of a qualifying renewable energy facility and its electric generation output,
- Purchasing electricity bundled with renewable energy certificates (RECs)²¹⁸ from a qualifying renewable energy facility, and

²¹⁸ RECs represent the non-energy attributes, including all the environmental attributes, of electricity generation from renewable energy sources. RECs are typically issued in single MWh increments.

- Purchasing RECs separately from electricity generators. Unlike bundled renewable energy, which is dependent on physical delivery via the power grid, renewable energy certificates (RECs) can be traded between any two parties, regardless of their location. However, state RPS rules typically condition the use of RECs based on either location of the associated generation facility or whether it sells power into the state or to the regional grid.

Authority

Most state RPS are established through legislation and administered by state PUCs.

Obligated Parties

RPS applicability varies by state. All state RPS apply to investor-owned utilities, while some state RPS obligate municipal utilities, rural cooperatives, and/or other retail providers, often depending on a minimum number of customers served.

Measurement and Verification

Some state RPS include an alternative compliance payment (ACP) option, where a retail electricity supplier may purchase compliance credits from the state at a known price, which acts as a de facto price cap, if it has not procured sufficient electricity from renewable energy sources or RECs to meet the RPS compliance requirement. State PUCs typically require annual compliance reports from retail electricity suppliers subject to a RPS. Most states use regional tracking systems (e.g., Western Renewable Energy Generation Information System, PJM Generation Attribute Tracking System) to issue, track, and retire RECs for RPS compliance purposes.²¹⁹ For more information about measurement and verification of renewable energy, see earlier in the State Plan Considerations Technical Support Document.

Penalties for Noncompliance

States have developed a range of compliance enforcement and flexibility mechanisms. As of 2007, despite the fact that several states had not achieved the RPS targets, only Connecticut and Texas had levied fines. A \$5.6 million penalty was incurred in Connecticut in 2006. In 2003 and 2005, two competitive electricity service providers in Texas were penalized a total of \$4,000 and \$28,000 respectively. Flexible enforcement and opportunities to “make-up” shortfalls in subsequent years or ACPs that are recycled to support other renewable and efficiency measures have helped other states avoid penalties for noncompliance.²²⁰

²¹⁹ For a summary of REC tracking systems, see: U.S. Department of Energy Renewable Energy Certificates (RECs)

National REC Tracking Systems. <http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=3>

²²⁰ Ryan Wisner and Galen Barbose, *Renewables Portfolio Standards in the United States – A Status Report with Data Through 2007*, (Lawrence Berkeley National Laboratory, 2008), Accessed March 19, 2014 <http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-154e-revised.pdf>.

Implementation Status

States with RPS policies have demonstrated higher levels of renewable energy capacity development. From 1998-2012, 67 percent (46 GW) of all non-hydro renewable capacity additions occurred in states with active or impending RPS requirements, although other factors may contribute to the growth in renewable capacity.²²¹

ii. Performance-Based Incentives and Finance Mechanisms for Renewable Energy

Description

States offer a diverse portfolio of financing, performance based incentive and state utility ratemaking approaches that are designed to address specific financial challenges and barriers and help specific markets and customer groups produce clean energy.

Policy Mechanics

Design

States support the advancement of clean generation technologies through performance-based incentives, including feed-in tariffs and other payments, or tax incentives. Performance-based incentives are paid based on the actual energy production of a system. Feed-in tariffs establish temporarily elevated price per kWh in order to encourage renewable energy innovation using high cost technologies. Tax incentives are used to lower financial barriers to renewable energy production.

A major source of funding for renewable energy activities comes from PBFs, but states also fund these activities through alternative sources including direct grants, rebates and generation incentives provided by utilities.

State tax incentives for renewable energy and Combined Heat and Power (CHP) take the form of personal or corporate income tax credits and tax exemptions. State tax incentives for renewable energy are a common policy tool, mainly using credits on personal or corporate income tax and exemptions from sales tax, excise tax, and property tax.

Authority

Financial mechanisms and incentives for renewables are run by utilities, non-profits, and state and local government. Personal, corporate, sales, and property tax incentives are mainly offered by state and local government.²²²

²²¹ Ibid.

²²² “Financial Incentives for Renewable Energy”, Database of State Incentives for Renewable Energy, accessed March 19, 2014, <http://www.dsireusa.org/summarytables/finre.cfm>.

Implementation Status

Financial mechanisms and incentives for renewable energy of some form exist in most states. According to the Database of State Incentives for Renewable Energy (DSIRE), there are over 200 tax incentives. In addition, nearly a hundred performance based incentives are offered from state and local governments, as well as utilities and non-profits.²²³

There are currently 18 states that have state-wide performance-based policies, and in several other states utilities have adopted programs based on performance-based incentives, including feed-in tariffs, standard offer payments, and payments in exchange for RECs.²²⁴ In many cases, however, PBI is limited to customer-sited projects or limited by size eligibility.

Financial incentives, working in concert with a strong RPS and net metering policies, have contributed to the rapid growth in solar power deployment in New Jersey. The state's RPS includes a minimum carve-out for solar sources, and allows solar energy generators to earn Solar Renewable Energy Certificates (SRECs) that can then be sold to electricity suppliers trying to meet the minimum solar production and/or purchase requirement. As a result of these interdependent policies, solar photovoltaic facilities are increasing, with installations more than doubling from 2010 through 2011.²²⁵ New Jersey ranks second only to California in terms of total installed capacity.²²⁶

d. Utility Planning Approaches and Requirements

Description

Some public utility commissions require utilities to conduct portfolio management or integrated resource planning (IRP) to ensure the supply of least cost and stable electric service to customers over the long term. Portfolio management refers to energy resource planning that incorporates a variety of energy resources, including supply-side (e.g., traditional and renewable energy sources) and demand-side (e.g., energy efficiency) options. The term "portfolio management" typically describes resource planning and procurement in states that have restructured their electric industry and may be required for default service providers (the backup electric service provider in areas open to competition). IRP is generally used by vertically integrated utilities and is a long-range planning process to meet forecasted demand for energy within a defined geographic area through a combination of supply-side resources and demand-side resources and considering a broad range of perspectives. The goal of an IRP is to identify

²²³ Ibid.

²²⁴ Ibid.

²²⁵ Solar-New Jersey.org, "Why has New Jersey become a Leader in Solar in the U.S.?" *Solar-New Jersey.org*, August 15, 2012, Accessed March 19, 2014, <http://www.solar-new-jersey.org/2012/08/15/why-has-new-jersey-become-a-leader-in-solar-in-the-us/>.

²²⁶ "Open PV State Rankings", National Renewable Energy Laboratory, Accessed March 19, 2014, <https://openpv.nrel.gov/rankings>.

the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.

In addition to energy resource planning, two states have policies or requirements for utilities to specifically factor pollution reduction requirements into their planning. In Colorado, the Clean Air Clean Jobs Act (CACJA), signed into law on April 19, 2010, required utilities to submit a plan to the PUC showing how they would meet EPA standards for a variety of pollutants.²²⁷ The law was passed because the state was out of compliance with the national Ambient Air Quality Standard for Ozone, and the EPA threatened to propose more stringent standards for the state.

In 2001, Minnesota enacted Minnesota Statute 216B.1692, which encourages utilities to make voluntary emission reductions and provides them with a mechanism to recover the costs through customer rate increases outside of the normal rate review cycle.²²⁸

Policy Mechanics

Design

- Portfolio Management and IRP - Portfolio management emphasizes diversity in fuels, technologies, and power supply contract durations. Portfolio management includes energy efficiency and renewable generation as key strategic components. Portfolio management typically involves a multi-step process of forecasting, resource identification, scenario analysis, and resource procurement.

Several states and vertically integrated utilities rely on an IRP process for long-term planning. Since these utilities own generation assets, they use their IRPs to evaluate a broad range of options for meeting electricity demand over a 20- or 30-year time frame. The IRP considers new supply-side options (including renewable resources) and demand-side options, and purchased power (including transmission considerations). A broad range of plans are considered, reflecting a range of objectives and capturing key uncertainties. Plans are evaluated against established criteria (e.g., costs, rate impacts, emissions, diversity, etc.) and are ranked. The IRPs detail fuel and electricity price information, customer demand forecasts, existing plant performance, other plant additions in the region, and legislative decisions. The following examples show how various states have designed their programs:

- Montana is a deregulated state that has established least cost planning rules and policy guidelines for default electricity suppliers. These rules and guidelines

²²⁷ RAP, *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses, and Administrative Processes* (Regulatory Assistance Project, 2013), Accessed March 19, 2014, www.raponline.org/document/download/id/6455.

²²⁸ Minnesota PUC, *Report To The Legislature On Emissions Reduction Projects Under Minnesota Statutes 216B.1692* (Minnesota Public Utilities Commission, 2008), Accessed March 19, 2014, http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000661.pdf.

target long-term electricity supply and are slightly different for vertically integrated utilities and restructured utilities. Vertically integrated utilities are required to submit electric supply resource plans every two years with the aim of providing a balanced, environmentally responsible electricity portfolio. Meanwhile, restructured utilities must file updates to their portfolio action plans every three years.²²⁹ These plans must include supply-side and demand-side resources, and they must address the need to supply power in a way that minimizes the environmental cost by estimating the cost to the environment of alternatives. In addition, utilities must account for the costs of complying with existing and future environmental regulations. When considering various resource options, Montana requires a competitive solicitation process, allowing resource operators and developers to submit their proposals to the default electricity supplier for consideration. Montana also requires the portfolio management plans to be subject to an advisory committee review and a public review.²³⁰

- Oregon electric utilities submit IRPs every two years, covering a 20-year timeframe. The goal of these plans is to consider the acquisition of resources at least cost while keeping the public interest in mind. Potential risk factors must be considered, including price volatility, weather, and the cost of meeting existing and future federal environmental regulations. Quantifiable environmental externalities are included, as are less quantifiable developments such as changes in market structure and the establishment of a renewable portfolio standard. As for energy efficiency requirements during the planning process, Oregon determines these on a utility-by-utility basis.²³¹
- **Multi-Pollutant Utility Planning** – Two states, Minnesota and Colorado, have worked collaboratively with their investor-owned utilities to develop multi-pollutant emission reduction plans on a utility-wide basis. This multi-pollutant, collaborative approach enables utilities to determine the least cost way to meet long-term and comprehensive energy and environmental goals.
 - The Colorado CACJA requires investor-owned utilities (IOUs) with coal plants to submit a multi-pollutant plan to the PUC to meet the EPA standards for NO_x, SO₂, particulates, mercury, and CO₂. Utilities were not required to adopt a specific plan set by the state, but had to meet with Colorado Department of Public Health and

²²⁹ Wilson, Rachel and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning* (Regulatory Assistance Project, 2013), Accessed March 19, 2014, <http://www.raponline.org/document/download/id/6608>.

²³⁰ U.S. EPA, *Clean Energy-Environment Guide to Action* (U.S. Environmental Protection Agency, 2006), Accessed March 19, 2014, <http://epa.gov/statelocalclimate/resources/action-guide.html>.

²³¹ Ibid.

Environment (CDPHE) and PUC approval. Xcel Energy's plan was submitted and approved in 2010.²³²

- The Minnesota Emission Reductions Rider allows utilities to submit plans for projects that reduce emissions and go beyond federal requirements outside of a general rate case. It allows them to recover the costs of those actions as an incentive.²³³ The specific design and process of the projects vary by utility, but typically involve installing additional pollution control equipment at coal-fired power plants, or repowering them with natural gas.

Authority

State utility commissioners oversee utilities' and default service providers' procurement practices in their states. Typically, the commissions solicit comments and input as they develop portfolio management practices from a wide variety of stakeholders. The utility regulator may also play a role in reviewing and approving utilities' planning procedures, selection criteria, and/or their competition solicitation processes.

Obligated Parties

Vertically integrated utilities are often obligated under integrated resource planning, while in restructured markets, the default utility service provider may be obligated to conduct portfolio management.

For multi-pollutant planning, Colorado IOUs, Xcel Energy and Black Hills Energy were required to file plans with the Department of Public Health and Environment and the PUC in order to be compliant with the CACJA. Plans needed to meet the National Ambient Air Quality Standards for a number of air pollutants.

As the Minnesota multi-pollutant legislation is voluntary for state utilities, there is neither compliance nor reporting requirements.

Measurement and Verification

Regulatory oversight aims to ensure utilities are following through with their plans. Regulators often require utilities to submit portfolio management plans and progress reports at regular intervals. These plans and reports describe in detail the assumptions used, the opportunities assessed, and the decisions made when developing resource portfolios. Regulators then carefully review these plans and either approve them or reject them and recommend

²³² RAP, *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses, and Administrative Processes* (Regulatory Assistance Project, 2013), Accessed March 19, 2014, www.raponline.org/document/download/id/6455.

²³³ Minnesota Office of Revisor of Statutes, 2013 Minnesota Statutes, §216B, 1692 Emissions Reduction Rider, 2013, Accessed March 19, 2014, <https://www.revisor.mn.gov/statutes/?id=216B.1692>.

changes needed for approval. California, for example, requires utilities to submit biennial IRPs and quarterly reports on their plans.

Penalties for Noncompliance

There are no penalties for noncompliance, however there is usually significant interaction with the regulator during the planning and implementation process as is described above.

Implementation Status

Currently more than half of the states have integrated resource or other long-term planning requirements,²³⁴ while Minnesota and Colorado have multi-pollutant planning policies or requirements (see Figure 9).

In Montana, for example, the 2011 Electric Supply Resource Plan for NorthWestern Energy calls for:

- Shortening the length of power supply contracts from seven years to a more competitive, staged process of between three to five years.
- Diversifying Montana's resource mix with the recent addition of a 150 MW gas-fired power plant.
- Improving the integration of intermittent power sources into the power supply as new wind turbines play a larger role in the state's resource mix.
- Meet state RPS requirements.
- Acquire cost-effective demand side management resources, targeting 6 MW of additional energy conservation per year.
- Monitor market, regulatory, and technology changes to better manage risks and opportunities.²³⁵

²³⁴ Wilson, Rachel and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning* (Regulatory Assistance Project, 2013), Accessed March 19, 2014, <http://www.raponline.org/document/download/id/6608>.

²³⁵ NorthWestern Energy, *Electric Supply Resource Plan* (NorthWestern Energy, 2011), accessed March 19, 2014, <https://www.northwesternenergy.com/our-company/tariffs-and-rates/montana-tariffs-and-rates/electric-supply-resource-procurement-plan>.

MW natural gas turbine. It plans to add 100 MW of capacity by 2017, Black Hills Energy will use competitive bidding to meet the remaining 60 MW.²³⁸

In Minnesota, projects currently implemented under the multi-pollutant legislation include the Minnesota Power's Arrowhead Regional Emissions Abatement (AREA) Project, Minnesota Power's Boswell 3 Emissions Reduction Plan, Xcel Energy's Mercury Reduction Plan, and Xcel Energy's Metropolitan Emissions Reduction Proposal (MERP). MERP, authorized in 2002, has shown a 93% reduction in SO₂, 91% reduction in NO_x, 81% reduction in mercury, 55% reduction in particulates, and 21% reduction in CO₂ from 2007-2009.²³⁹

²³⁸ Black Hills Energy, "Black Hills Energy Files Plan for Ongoing Reliable, Cost-effective Energy for Years to Come in Colorado" accessed on March 19, 2014, <http://www.blackhillsenergy.com/node/34671#.UzHkuIXYhIt>.

²³⁹ Xcel Energy, "Minnesota Metro Emissions Reduction Project – Environmental Benefits," accessed March 19, 2014, https://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/MN_MERP.

List of Acronyms

ACEEE - American Council for an Energy Efficient Economy
ACP - Alternative Compliance Payment
BSER – Best System of Emission Reduction
CACJA - Clean Air Clean Jobs Act
CCR – Cost Containment Reserve
CHP – Combined Heat and Power
CEMS – Continuous Emissions Monitoring System
CO₂ – Carbon Dioxide
CO₂e – Carbon Dioxide Equivalent
CDPHE – Colorado Department of Public Health and Environment
DOE – Department of Energy
DSIRE - Database of State Incentives for Renewable Energy
EERS – Energy Efficiency Resource Standard
EGU – Electricity Generating Unit
EIA – Energy Information Administration
EM&V – Evaluation, Measurement, and Verification
EPA – Environmental Protection Agency
ERP – Electric Resource Plan
ESCO – Energy Service Company
GDP – Gross Domestic Product
GHG – Greenhouse Gas
GW – Gigawatt (1 GW = 1,000 MW)
GWh – Gigawatt-hour (1 GWh = 1,000 MWh)
IECC - International Energy Conservation Code
IOU – Investor-Owned Utility
IRP – Integrated Resource Planning
kWh – Kilowatt-hour
LBNL – Lawrence Berkeley National Laboratory
LDC – Local Distribution Company
MERP - Metropolitan Reduction Proposal
MMBTU – Million British Thermal Units
MW – Megawatt
MWh – Megawatt-hour (1 MWh = 1,000 kWh)
NO_x – Nitrogen Oxides
PBF – Public Benefit Funds
PBI – Performance-based Incentives
RGGI – Regional Greenhouse Gas Initiative
REC – Renewable Energy Certificate
RES – Renewable Energy Standard
RPS – Renewable Portfolio Standard
PUC – Public Utility Commission
SO₂ – Sulfur Dioxide
VEIC – Vermont Energy Investment Corporation
WAP – Weatherization Assistance Program