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

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Projecting EGU CO_2 Emission Performance in State Plans

U.S. Environmental Protection Agency
Office of Air and Radiation

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I. Introduction

As discussed in the preamble, in section VIII.F.7, all state plans will need to include a projection of the CO_2 emission performance by affected EGUs that will be achieved under a state plan (inclusive of plan measures that avoid CO_2 emissions from affected EGUs, such as end-use energy efficiency and renewable energy). Depending on the type of plan approach, this will include either a projection of the average CO_2 emission rate achieved by affected EGUs or total CO_2 emissions from affected EGUs.

The EPA is also proposing that a state may translate the state rate-based CO_2 emission performance goal for affected EGUs to an equivalent mass-based CO_2 emission performance goal. If this translation option is used, a state plan must also include a projection used to derive the mass-based CO_2 emission performance goal. This translation will involve a projection of CO_2 emissions from affected EGUs during the initial 2020-2029 plan performance period and in 2030, under a scenario that assumes the rate-based goal in the emission guidelines is met.

As discussed in the preamble, the EPA is striving to find a balance between providing state implementation flexibility and ensuring that the emission performance required by CAA section 111(d) is properly defined in state plans and that plan performance projections have technical integrity. The credibility of state plans under section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools, and assumptions for such projections is critical.

The preamble, at section VIII.F.7, seeks comment on options presented for how CO_2 emission projections might be conducted in an approvable state plan, and how different types of state plan approaches are represented in these projections. These options include the use of historical data and parameters for estimating the future impact of individual state programs and measures. Alternatively, a projection could be based on modeling, such as use of a capacity expansion and dispatch planning model, or a dispatch simulation model.[1] This latter approach would be able to capture dynamic interactions within the electricity sector, based on system

[1] In many cases, this approach will also require the development of parameters for estimating the effect of individual state programs and measures, for use as input assumptions for modeling.

operation and market forces, including interactions among state programs and measures and the dynamics of market-based measures.

In the preamble, the EPA further seeks comment on whether the EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as whether the EPA should provide technical resources for conducting projections.

This technical support document (TSD) elaborates these options and considerations. The TSD discusses possible analytic approaches for translating from a rate-based CO_2 emission performance goal to a mass-based goal, and projecting the CO_2 emission performance that will be achieved through a state plan. It discusses both modeling and non-modeling approaches, such as electricity sector capacity expansion and dispatch planning models, dispatch simulation models, and growth tools that base projections on historical data and algorithms. The TSD also discusses possible approaches for developing inputs that are used for emission projections and applied considerations for different types of state plans. Topics addressed include:

- *Section II* discusses analytic approaches for projecting CO_2 emissions from affected EGUs
- *Section III* discusses the concept and practice of translating from a rate-based CO_2 emission performance goal to a mass-based CO_2 emission performance goal
- *Section IV* discusses the concept and practice of projecting EGU CO_2 emission performance under a state plan
- *Section V* discusses applied considerations for projecting EGU CO_2 emission performance under different types of state plans, including:
    - Considerations that should be addressed in conducting projections of emission performance for different types of plans
    - Data needs and methods for developing inputs to EGU CO_2 emission projections, for different types of state plans
- *Section VI* discusses process considerations for conducting EGU CO_2 emission projections for state plans, including:
    - Regional coordination among states in conducting projections

- Whether the EPA should provide guidance and other analytic support for conducting projections in state plans and translation of rate-based CO_2 emission performance goals to mass-based goals

II. Analytic Approaches for Projecting CO_2 Emissions from Affected EGUs

This section surveys different types of methods and tools for projecting CO_2 emissions from affected EGUs, including modeling tools and other tools that base projections on historical data and use algorithms to extrapolate future CO_2 emissions performance based on past performance.

A. Electricity System Modeling Approaches for Projecting EGU CO_2 Emissions

1. National-scale capacity expansion and dispatch planning models

National-scale electricity capacity expansion and dispatch planning models are typically used for fundamentals-based projections of the power sector (i.e., projections of the expected response of the sector to factors such as electricity demand, fuel prices, and emission constraints) that may extend over a period of several decades. These models are built to evaluate the impacts of market, technical, and regulatory factors on the electric power sector and related markets. Typical outputs of such models include EGU dispatch, fuel consumption, fuel prices, wholesale electricity prices, emissions, EGU retirements, and infrastructure expenditures (e.g., addition of new EGU capacity and installation of retrofit pollution control technologies).

National-scale electricity capacity expansion and dispatch planning models have moderate spatial detail with broad scope, generally encompassing the entire country or transmission system interconnects (i.e. Eastern, Western, and ERCOT), which are subdivided into smaller areas, such as balancing authorities or control areas.[2] For computational efficiency, these models generally model several representative hours of the year, or aggregate hours into representative bundles with similar electricity demand profiles (i.e. peak, shoulder, off-peak). In these models, to reduce model size, existing EGUs may be aggregated into "model plants" to the extent that such EGUs share key unit characteristics, such as location, size, efficiency, operating costs, pollution retrofit control status, age, and fuel type use/availability. These types of models are well suited to project dynamic entry and exit (capacity expansion and unit retirement) to meet energy and capacity requirements while minimizing system costs, maintaining reliability criteria,

[2] A "balancing area" or "control area" refers to a specified portion of the transmission system where electricity demand and generation are balanced in real time by a system administrator to maintain grid reliability.

and following other constraints, such as minimum build times, transmission constraints, renewable energy availability, or emission limitations.

2. Utility-Scale Capacity Expansion and Dispatch Planning Models

Utility-scale capacity expansion and dispatch planning models are similar in concept to related national-scale models. However, utility-scale capacity expansion and dispatch planning models are typically used for evaluating narrower utility planning and investment decisions, such as procurement of a specific new electric generating facility and retirement or retrofit decisions for existing capacity within a specific utility's territory. Utility planning models typically project outcomes for periods of up to two decades. Utility-scale capacity expansion and dispatch planning models are an industry standard, used regularly in state electricity regulatory proceedings. Within the electricity sector there is broad familiarity with these models at state PUCs. Multiple vertically integrated utilities use capacity expansion and dispatch planning models to conduct forward planning and review the economics of specific EGU retrofit decisions. Utilities that submit integrated resource plans (IRP) typically use a utility-scale capacity expansion and dispatch planning model to examine long-term strategies and develop short-term action plans.[3] Utilities have experience using these models to examine CO_2 emission reduction strategies or CO_2 emission constraints, as IRP scenarios may include greater penetration of end-use energy efficiency or renewable energy, proxy CO_2 emission prices, emission trading, and limits on CO_2 mass emissions.

Utility-scale capacity expansion and dispatch planning models tend to have relatively high spatial detail with limited geographic scope, generally encompassing a utility service territory or a sub-regional scale. These models generally have better temporal resolution than the national-scale capacity expansion and dispatch planning models, with each model year typically

[3] See, for example: The Duke Energy Carolinas IRP (Annual Report), September 2012, available at http://www.energy.sc.gov/files/view/Duke_IRP 2012.pdf; PacifiCorp 2013 IRP (Vol 1), April 2013, available at http://www.pacificorp.com/es/irp.html; TVA IRP, March 2011, available at http://www.tva.gov/environment/reports/irp/archive/index.htm; Georgia Power Company 2013 IRP, January 31, 2013, available at http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=145981; 2011 Joint IRP of Louisville Gas and Electric and Kentucky Utilities Company, April 2011, available at http://psc.ky.gov/PSCSCF/2011%20cases/2011-00140/20110421_LG%26E-KU_IRP_Volume%20I.pdf; Great River Energy IRP, November 2012, available at http://www.greatriverenergy.com/makingelectricity/resourceplan/pdoc295631.pdf; Public Service Company of Oklahoma IRP, October 2012, available at http://occeweb.com/pu/PSO%202012%20IRP.pdf.

dispatched based on an annual hourly load duration curve.[4] Utility-scale capacity expansion and dispatch planning models typically represent individual EGUs, where each EGU has specific operational characteristics.

Due to the additional spatial and temporal resolution of these models as compared to the national-scale models, the number of technology options for capacity expansion is generally limited to reduce the runtime of the model. This can be done through an outside-the-model screening analysis to pre-select the resources most likely to be economic in a planner's area of interest, or by running the model iteratively to eliminate rarely chosen technology alternatives.

3. Electricity System Dispatch Simulation Models

Dispatch simulation models are regularly used by utilities, grid operators, and independent power producers (IPP) for short-term planning, ratemaking, dispatch decisions, and market intelligence. Dispatch simulation models are typically driven by near-term economics, system restrictions and market constraints, including a typically more detailed representation of an EGU's operational constraints (*e.g.*, ramp rates, heat input curves, and unit downtime for maintenance). These models typically do not add or retire generating capacity on an economic basis, although EGU additions and retirements may be exogenously input to these models. As a result, projections from these models tend to be considered more robust in the shorter term.[5] Grid operators, including utilities, and independent system operators (ISO) use dispatch simulation models in near real-time to match demand with electric generation from available generating units and dispatch EGUs on a least-cost basis. EGU owners and operators run dispatch simulation models to assist in fuel procurement, forecast revenues and costs, and calculate the avoided generation supply costs related to procurement of end-use energy efficiency and

[4] Load duration curves typically represent electricity load during a typical week for each month.
[5] Some planners use dispatch simulation models in conjunction with national or utility-scale capacity expansion and dispatch planning models, where the capacity expansion and dispatch planning model indicates the disposition of new and existing generating resources, and the dispatch simulation model is used to simulate operation of individual EGUs. In this case, these models can be used in the same time horizon as a capacity expansion and dispatch planning model (*i.e.*, decades).

renewable energy resources.[6] Other utilities use dispatch simulation models to forecast retail rates for ratemaking proceedings and other planning purposes.

Electricity system dispatch simulation models (also called production cost models) utilize security constrained economic dispatch (SCED) algorithms to determine which EGUs operate on an hourly (or shorter) basis to meet electricity demand.[7] These models typically have a very broad spatial scope, generally covering multiple Regional Transmission Organization (RTO) regions, and often modeling entire interconnects (i.e. Western, Eastern, and ERCOT). While individual EGUs are modeled in detail, including fuel and variable costs and operational constraints, transmission is simplified to characterize thermal constraints between zones, which typically represent control areas or balancing authorities. Zones contain both load (electricity demand) and EGUs; EGU dispatch and electricity demand are balanced to maintain transmission system reliability while providing least-cost service on a variable cost basis. Some versions of these models operate at a "nodal" level, where transmission constraints between individual EGUs and load are modeled as well.[8] Dispatch simulation models typically operate chronologically, modeling either all 8760 hours of the year, or typical weeks of the year. These models contain substantially more detail about individual EGUs than regional or national capacity expansion and dispatch planning models, including EGU ramp rates, minimum outages, maintenance schedules, emission rates, fuel use constraints, and heat rate curves depicting expected efficiency changes at various levels of output.

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[6] For example, see Hornby, R., P. Chernick, D. White, et al., 2013. Avoided Energy Supply Costs in New England: 2013 Report. http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/AESC%20Report%20-%20With%20Appendices%20Attached.pdf

[7] The Federal Energy Regulatory Commission (FERC) defines security constrained economic dispatch as "the level at which each available resource should be operated, given actual load and grid conditions, such that reliability is maintained and overall production costs are minimized". SCED optimizes dispatch based not only on the marginal costs of all available generating resources, but also constraints on transmission availability and ancillary services. See FERC, "Security Constrained Economic Dispatch: Definition, Practices, Issues, and Recommendations" (2006), available at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf.

[8] "A "nodal" model represents the entire transmission network in a given area, without making the simplifying assumptions that load is served on a more aggregate "zonal" level." A caveat is that while a nodal model has more "links" and places where supply must meet demand, it is still an approximation in terms of the electrical operation of the transmission network (the network is represented as a DC flow network, not an AC flow network).

4. Multi-Sector Models

Multi-sector energy models are typically used to examine the effect of energy and environmental policies that affect multiple economic sectors, such as multi-sector emission trading systems. Multi-sector models are used to review trends in emissions, expected broad-scale resource use, and energy sector impacts under changing regulatory and economic conditions, and often review changes over a period of decades.

Multi-sector models cover a broad range of energy sectors beyond the electricity sector, and can better reflect energy demand and technology choices by energy end-users. Such models typically have relatively limited spatial detail with broad scope, generally encompassing the entire country subdivided into from one to 30 regions. Such models tend to have much more limited temporal resolution and treatment of EGU dispatch. EGUs are typically aggregated to a few broad technology types. A key strength of multi-sector energy models is the ability to provide multi-sectoral feedback between energy resource use and price (*i.e.*, tracking national fuel supplies and adjusting price to account for demand).

The range of national- and utility scale capacity expansion and dispatch planning models, and dispatch simulation models identified above all tend to focus on properly characterizing the electricity sector in order to answer sector-specific questions. Multi-sector energy models attempt to include many other energy-using sectors of the economy in order to better capture interactions between these sectors. The more aggregated representation of the electricity sector in multi-sector models may limit their use to providing input data for more specific analysis in an electricity sector model, and to better understanding variations in electricity load that may result from changes outside the electricity sector.

B. Growth Tools for Projecting EGU Utilization and CO_2 Emissions

Organizations use growth tools for a variety of reasons, including to estimate future emissions inventories for state and regional air quality modeling,[9] and to estimate the impact of load-reduction measures such as end-use energy efficiency and distributed renewable energy on

[9] See, for example, the ERTAC Load Growth Model, available at http://www.ertac.us/index_egu.html.

individual EGU emissions, and county, state,[10] and regional emissions rates.[11] Because these algorithms are generally based on publicly available data[12] and do not rely on economic data or proprietary information regarding individual EGUs, they provide a low-cost, simple, and often transparent framework for estimating how EGUs will respond to changing system conditions.

Non-modeling approaches, such as growth tools, approximate future emissions and generation from existing and new fossil fuel-fired EGUs under different assumed growth, retrofit, and load-reduction scenarios. These forecast tools do not simulate economic EGU dispatch, but could use demand growth rates and electricity production trends from other energy modeling forecasts as an input assumption.[13] The algorithms in these forecast tools assume that EGU dispatch behavior generally follows simple rules based on past operation. In the absence of significant shifts in fuel prices and electricity demand, EGUs may be expected to behave similarly in the future as they did in the past. Several common features of these forecast tools are that they (a) generally build on historical generation and emissions output from individual EGUs, (b) are insensitive to fuel and emission price forecasts, (c) do not solve for optimal economic EGU dispatch or EGU capacity expansion, and (d) do not capture transmission constraints or limits. The algorithms in these forecast tools generally divide the contiguous US[14] into regional power markets, following ISO boundaries, eGRID boundaries, NERC regional boundaries, or similar designations. These algorithms generally seek to examine how operation and emissions from individual EGUs could be expected to change with changes in environmental regulations or installed pollution control retrofits and additional or reduced hourly electricity demand. Some algorithms use the observed historical behavior of individual EGUs to approximate future behavior, while others add additional steps of differentiating EGUs into fuel groups and unit

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[10] See EPA's AVERT (Avoided Emissions and Generation Tool), available at http://epa.gov/statelocalclimate/resources/avert/index.html.

[11] See Flexibility Weighted Hourly Average Emissions Rate (FW-HAER) tool, available at http://nepis.epa.gov/Adobe/PDF/P1002UQO.pdf; Time Matched Marginal (TMM) emissions tool, a proprietary algorithm used to estimate avoided emissions; D. Jacobson and C. High, "U.S. Policy Action Necessary to Ensure Accurate Assessment of the Air Emission Reduction Benefits of Increased Use of Energy Efficiency and Renewable Energy Technologies," *Journal of Energy & Environmental Law* (2010).

[12] Hourly emissions and generation data for all fossil fuel-fired EGUs greater than 25 MW are available from EPA's Clean Air Markets Division (CAMD) through its Air Markets Program Data (AMPD).

[13] For example, EIA's AEO 2013 electricity load growth rates and EGU production trends are available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2013).pdf.

[14] Hawaii and Alaska do not report hourly generation and emission data from individual EGUs to EPA, and are therefore generally excluded from these forecast tools.

types, with implicit differentiation of economic outcomes for these different groups. Some of these algorithms may contain subroutines to add new generating capacity automatically to meet load requirements.

III. Translating from a Rate-Based Emission Performance Goal to a Mass-Based Emission Performance Goal

As discussed in the preamble, in section VIII.C.2, the EPA is proposing that the projected CO_2 emission performance by affected EGUs (taking into account the qualifying impacts of plan measures that avoid CO_2 emissions from affected EGUs) must be equivalent to, or better than, the required CO_2 emission performance level in the state plan. This required level of emission performance in the state plan is the rate-based goal for the state in the emission guidelines, or a translated mass-based goal if the state chooses to use this approach. State plans that are projected to achieve an average CO_2 emission rate (CO_2 lb/MWh) or tonnage CO_2 emission outcome by all affected EGUs equal to, or lower than, the required level of CO_2 emission performance in the state plan would be considered to meet this plan approvability criterion. States may demonstrate such emission performance by affected EGUs either by state or jointly on a multi-state basis.

This section of the TSD discusses the concept of a mass-based CO_2 emission performance goal, considerations for constructing projection scenarios for such a translation, methods for conducting such a translation, and key input assumptions for such a translation.

A. Concept

A mass-based CO_2 emission performance goal translates the application of a rate-based emission performance goal to an expected CO_2 emissions outcome in tons during a plan performance period. A mass-based CO_2 emission performance goal is calculated by projecting the tons of CO_2 that would be emitted during a state plan performance period (e.g., 2020-2029, 2030-2032) by affected EGUs in the state if they hypothetically were meeting the state rate-based CO_2 emission performance goal for affected EGUs established in the emission guidelines. The translation of a rate-based goal (expressed in lb CO_2/MWh of useful energy output from affected EGUs) to tons (expressed as total tons of CO_2 emissions from affected EGUs over a specified time period) is based on a projection of affected EGU utilization and dispatch mix. Importantly, this projection is conducted assuming the absence of qualifying state programs and measures contained in a state plan, and applying the rate-based goal in the emission guidelines as a proxy emission limit for affected EGUs. State programs and measures in the state plan are not included in this projection, because the purpose of this analysis is to determine the tonnage CO_2

emissions that corresponds to the state-specific rate-based CO_2 emission performance goal for affected EGUs in the emission guidelines, without the eligible state programs and measures that are included in the state plan.

Translation of a rate goal to a mass goal seeks to answer the question, "What would happen to EGU CO_2 emissions if one applied the rate goals in the emissions guidelines instead of the measures in the state plan?" Because the emission guidelines do not specify the emissions reduction measures that a state must use in its plan, only the level of emission performance that must be achieved through a plan, there is no specified "policy" or set of emission reduction measures in the emission guidelines to apply when conducting this projection. However, a proxy policy can be applied to project the emission performance in tons that would be achieved if the state plan were to include suitable measures to achieve the required level of emission performance established through the state rate-based CO_2 emission performance goals in the emission guidelines. This proxy involves applying the rate-based emission goal for a state as a rate-based average CO_2 emission limit for affected EGUs in a state and then projecting the CO_2 emissions that would occur if such a limit were applied.

When demonstrating projected emission performance under a mass-based plan, a state would project the CO_2 emissions outcome that would be achieved under the suite of requirements, programs, and measures in its plan. The state plan requirements, programs, and measures substitute for EPA's application of the best system, which is represented by the rate-based goal in the emission guidelines. If the CO_2 emissions outcome, in total tons of CO_2 emissions over each plan performance period, is equal to or less than what would be emitted by affected EGUs through the application of the rate-based goal in the emission guidelines (*i.e.*, equal to or less than the translated mass-based goal), the plan would be deemed to achieve the required emission performance criterion.

B. Projection Scenarios

As described above, the projection scenario for translating from a rate-based CO_2 emission performance goal to a mass-based CO_2 emission performance goal does not include requirements, programs, and measures included in a state plan. Construction of this scenario must therefore carefully consider treatment of eligible "on-the-books" state requirements, programs and measures included in the state plan.[15]

Projection scenarios for translating from a rate-based CO_2 emission performance goal to a mass-based CO_2 emission performance goal, and comparing projected emission performance under a state plan to this goal, include the following:

1. *A Reference Case Scenario*. This scenario projects the average CO_2 emission rate and CO_2 emissions from affected EGUs in the absence of the EPA emission guidelines or any enforceable requirements, programs, and measures included in a state plan. This scenario does, however, include all current on-the-books state requirements, programs, and measures *that are not included* as enforceable measures in a state plan. These measures are complementary to the state plan. Because these measures will influence EGU CO_2 emissions, they should, however, be included in the reference case projection scenario.
2. *A Mass-Based CO_2 Emission Goal Policy Scenario*. This projection scenario is used to translate a rate-based goal to a mass-based goal. The scenario applies a rate-based CO_2 emission limit to affected EGUs that is equivalent to the state-specific rate-based lb CO_2/MWh emission goal in the EPA emission guidelines.[16] The CO_2 emissions from affected EGUs projected during the specified plan performance period in this scenario represents the translated mass-based CO_2 emission performance goal for the state plan.

[15] An "existing measure" refers to a state or utility requirement, program, or measure that is currently "on the books." For the purposes of this discussion, this may include a legal requirement that includes current and future obligations or current programs and measures that are in place and are anticipated to be continued or expanded in the future in accordance with established plans. Existing measures may have past, current, and future impacts on EGU CO_2 emissions.

[16] The proxy emission limit applied includes crediting for end-use energy efficiency, renewable energy, and nuclear generation included in building blocks three and four, which were used by EPA when calculating the state-specific CO_2 emission performance goals for affected EGUs in the proposed emission guidelines. In essence, these measures can be used by affected EGUs as "compliance" flexibility mechanisms when "complying" with the proxy emission rate limit in this projection scenario. As a result, the proxy rate-based emission limit is able to capture all four building blocks included by EPA when calculating the rate-based CO_2 emission performance goals.

To construct this scenario, this emission limit is added to the underlying reference case scenario described above.

3. *A State Plan Policy Scenario*. This projection scenario includes the enforceable requirements, programs, and measures included in the state plan, and is used to project CO_2 emission performance by affected EGUs under the state plan. To construct this scenario, the enforceable requirements, programs, and measures included in the state plan are added to the underlying reference case scenario described above.

An applied example is provided below in Box 1.

Box 1. Example Mass-Based Goal Translation and Projection of Plan Performance

***Example State Rate-Based CO_2 Emission Performance Goal Assumptions*:**

- State *interim* rate-based CO_2 emission performance goal for affected EGUs: 1,100 lb CO_2/MWh
- State *final* rate-based CO_2 emission performance goal for affected EGUs: 1,000 lb CO_2/MWh

***Reference Case Scenario*:**

- Under this scenario, the projected average CO_2 emission rate for affected EGUs is 1,500 lb CO_2/MWh during the 2020-2029 interim performance period and 1,500 lb CO_2/MWh in 2030.

***Mass-Based CO_2 Emission Goal Policy Scenario*:**

- A proxy emission rate limit is applied to affected EGUs (1,100 lb CO_2/MWh on average during 2020-2029; 1,000 lb CO_2/MWh in 2030 and subsequent years during the projection period).
- Under this scenario, the projected CO_2 mass emissions from affected EGUs during the 2020-2029 interim performance period are 100,000,000 tons of CO_2 (an average of 10,000,000 tons per year during this period) and 9,000,000 tons of CO_2 in 2030.
- **The mass-based *interim* emission performance goal for affected EGUs is 100,000,000 tons of cumulative CO_2 emissions during the 2020-2029 interim plan performance period.**
- **The mass-based *final* emission performance goal for affected EGUs is 9,000,000 tons of CO_2 per year, in 2030 and subsequent years.** During plan implementation, this final goal can be met on a three-year rolling average basis, beginning with the period 2030-2032, as discussed in the preamble at section VIII.B.2.c.

State Plan Policy Scenario:

- This scenario includes the suite of requirements, programs, and measures included in the state plan.
- **Under this scenario, the projected CO_2 mass emissions from affected EGUs during the 2020-2029 interim plan performance period are 98,000,000 tons of CO_2 and 8,800,000 tons of CO_2 in 2030.**
- **Based on this analysis, the state plan is projected to achieve both the translated interim and final mass-based CO_2 emission performance goals for affected EGUs.**

1. Constructing the Reference Case

A key consideration for translating from a rate-based CO_2 emission performance goal to a mass-based CO_2 emission performance goal is proper construction of a reference case scenario.

This includes assumptions for key variables that may drive EGU CO_2 emission projections,[17] such as:

- Electricity load growth projections (energy and peak demand)
- Fuel supply, delivery, and pricing assumptions
- Cost and performance of electric generating technologies
- EGU firm builds and retirements (e.g., those scheduled with a regional transmission organization or independent system operator (RTO/ISO))[18]
- Transmission capability and ISO/RTO transmission expansion plans
- Applicable federal regulations (other than the EPA emission guidelines)
- Applicable state regulations and programs (other than those that are included in the state plan)

It may be necessary in many instances to include assumptions about other state programs implemented by neighboring states in the same region. This would be especially relevant for states that are located within the same electric power pool (or adjoining power pools) that are administered by a common RTO/ISO.

2. Treatment of Existing State Regulations and Programs in the Reference Case

A key aspect of the reference case is proper treatment of existing state regulations, programs, and measures. As discussed previously, existing state regulations, programs, and measures that are not enforceable measures in a state plan are complementary to the state plan – as a result, they should be included in the reference case scenario rather than the state plan scenario. These state regulations, programs, and measures should not, however, be ignored altogether, as they influence EGU CO_2 emissions. Instead, these state actions are occurring in the background – either when a proxy rate-based CO_2 emission limit is applied in the *Mass-Based CO_2 Emission Goal Policy Scenario*; or when the state plan requirements, programs, and

[17] Process considerations related to constructing reference case scenarios are addressed in section VI of this TSD.
[18] ISOs and RTOs are independent organizations that administer a regional electric power pool (EGU dispatch and electricity transmission systems), and often also administer related wholesale electricity markets for electric energy and capacity.

measures are applied in the *State Plan Policy Scenario*. As a result, these state actions are properly addressed in the reference case scenario.

In effect, when evaluating whether a state plan will meet the mass-based CO_2 emission performance goal, the two policy scenarios described above, each of which involve adding a different CO_2 emission reduction policy on top of the reference case scenario, are compared to one another. If the *State Plan Policy Scenario* achieves projected tonnage CO_2 emissions equal to or lower than the projected CO_2 emissions in the *Mass-Based CO_2 Emission Goal Policy Scenario*, then the state plan can be deemed to meet the translated mass-based CO_2 emission performance goal.

As discussed in the preamble, the EPA is proposing that a state may apply toward its required emission performance level the emission reductions that are achieved by existing state requirements, programs, and measures during a plan performance period, due to *actions*[19] taken after the date of the proposal of the emission guidelines.[20, 21] In practice, this means that emission reductions that occur in 2020 and later due to actions taken pursuant to an existing state requirement, program, or measure could be applied toward meeting the required level of emission performance in a state plan if these actions occur after proposal of the emission guidelines (e.g., as of June 2014 and in subsequent years). For example, emission reductions during the initial plan performance period that result from end-use energy efficiency technologies and measures installed beginning in June 2014 could be applied toward meeting the required level of emission performance during the plan performance period. These investments might be made to meet requirements under an existing end-use energy efficiency resource standard (EERS).

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[19] An "action" as used here refers to an action taken pursuant to a state requirement, program, or measure. For example, the installation of an end-use energy efficiency measure, such as an energy-efficient refrigerator installed through a utility energy efficiency program to meet the utility's obligations under a state energy efficiency resource standard (EERS), would constitute an "action" taken pursuant to an existing state requirement.

[20] The preamble also takes comment on alternative dates for eligible actions, including: the start date of the plan period, the date of promulgation of emission guidelines, the end date of the base period for the EPA's BSER-based goals analysis (e.g., beginning of 2013 for blocks 1-3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date.

[21] As discussed in the preamble, at section VIII.F.2.b, the EPA is also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs, and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO_2 goals as part of BSER building block three.

Under a rate-based plan, the approach described above would address the eligibility date for demand-side energy efficiency measures that, through MWh savings, avoid CO_2 emissions from affected EGUs. Measures installed after the eligibility date could generate MWh savings during the plan period, and related avoided CO_2 emissions, that could be applied toward meeting a required rate-based emission performance level. Under the proposed option, the eligibility date would be the date of proposal of the emission guidelines.[22]

Under a mass-based plan, the approach described above would be applied when establishing a reference case scenario projection that is used to translate a rate-based goal to a mass-based goal. For example, the assumed amount of energy savings from demand-side energy efficiency measures installed subsequent to the eligibility date that are used to meet an existing EERS would not be included in the electricity load forecast used in the reference case scenario. Energy efficiency measures installed prior to the eligibility date to meet an existing EERS would be factored into the electricity load forecast used in the reference case scenario. This treatment would represent in the reference case past actions taken under existing state programs and measures that are not eligible for inclusion in a state plan.

[22] Although such a limitation is not proposed for RE measures, we also describe here how such a limitation could be applied to RE measures under such an approach. For example, under this approach in the context of a rate-based plan, new renewable energy generating capacity installed in June 2014 or later to meet an existing, on-the-books RPS would be a qualifying measure in a state plan. However, only MWh generation beginning in 2020 and related avoided CO_2 emissions could be applied toward meeting a required emission rate performance level in a state plan. Similarly, under this approach in the context of a mass-based plan, the reference case might include the required MWh of renewable energy generation necessary to meet a state RPS as of the date of proposal of the emission guidelines (e.g., as of June 2014). Renewable energy generation that is used to meet a state RPS, but that is incremental to the amount of generation used to meet the existing RPS obligation included in the reference case as of June 2014, could be used toward demonstration of CO_2 emission performance under a state plan. This renewable energy generation would be incremental to the renewable energy generation already assumed in the reference case scenario.

IV. Projecting CO_2 Emission Performance under a State Plan – Overview

As discussed in the preamble, in section VIII.D.4, one of the required components of a state plan is a projection that a plan will achieve the required level of CO_2 emission performance by affected EGUs that is specified in the plan. (This identified level of performance must be consistent with either the state-specific rate-based CO_2 emission performance goals for affected EGUs identified in the emission guidelines, or an equivalent translated mass-based CO_2 emission performance goal.)

This emission projection is based on a scenario that includes the suite of requirements, programs, and measures in the state plan – the *State Plan Policy Scenario* described above. Depending on the plan approach, construction of this state plan scenario may be straightforward. For example, if the state plan consists solely of an emission limit, the state plan scenario would apply this emission limit to the underlying reference case scenario. Other types of state plan approaches are more involved, in particular when the use of end-use energy efficiency and renewable energy regulations, programs, or measures are included in a state plan. This could include a state plan that applies a rate-based CO_2 emission limit that provides credit for end-use energy efficiency and renewable energy measures that avoided CO_2 emissions, or the inclusion of such measures through a portfolio approach. These types of plans will require input assumptions for the amount of end-use energy efficiency and renewable energy resource (in MWh over the plan period) that will be realized through implementation of the plan. Utility-driven portfolio approaches may also include a diverse set of actions taken directly at affected EGUs that will need to be properly represented in the state plan scenario.

Considerations for developing estimates of energy savings and energy generation that will be achieved through end-use energy efficiency and renewable energy regulations, programs, and measures included in a state plan are discussed below in section VI.

V. Applied Considerations for Different Types of State Plans[23]

There are a number of considerations for properly representing different state plan approaches in CO_2 emission projection scenarios. This includes both accurate representation of the attributes of state regulations, programs, and measures in the scenario, as well as the methods and data sources used to derive certain input assumptions that are used in CO_2 emission projections. This includes:

- Estimating the future effects of end-use energy efficiency and renewable energy requirements, programs, and measures
- Properly characterizing flexibilities included in emission limits, such as emission budget trading programs
- Properly addressing characteristics of multi-state regulations and programs

A. End-Use Energy Efficiency and Renewable Energy

Evaluating the impact of a state end-use energy efficiency requirement or program included in a state plan, as part of a projection of CO_2 emissions from affected EGUs under a state plan, involves projections of the impact of the requirement or program on energy and capacity savings, and the impact of this reduction in electricity load and peak demand on EGU dispatch and CO_2 emissions from affected EGUs.[24] This involves projections of the level of current and future energy and capacity savings achieved through program investment or activities in each year, the distribution of those savings on a daily and seasonal basis (e.g., the load shape of the energy and capacity savings), and the effective useful life of those energy and capacity savings (e.g., the life of installed measures representing the persistence of energy savings). Such projections may also need to address net program energy savings after accounting for potential "free-ridership," which involves energy savings that were likely to have occurred in the absence of program incentives, and "spillover," which involves broader market

[23] Different potential state plan approaches are described in detail in the accompanying State Plan Considerations TSD.
[24] The evaluation discussed in this section is relevant for state plans that implement a rate-based CO_2 emission limit applicable to affected EGUs that provides for adjustment or crediting of the CO_2 emission rate of an affected EGU based on the effects of end-use energy efficiency and renewable energy. It is also relevant for state plans that take either a rate-based or mass-based portfolio approach. Descriptions of these plan approaches are provided in the accompanying State Plan Considerations TSD.

transformation impacts that result from the program. These energy efficiency program projections would then be used to adjust electricity load forecasts, as necessary, for modeling runs using an electricity sector dispatch and capacity expansion planning model. This modeling would evaluate the impact of the energy and capacity savings on the dispatch of EGUs, construction and retirement of EGUs, and related CO_2 emissions from affected EGUs.

Similar considerations apply for projecting the impact of renewable energy requirements and programs included in a state plan on CO_2 emissions from affected EGUs. The renewable energy generation and generating capacity in a state or region that results from renewable energy requirements, programs, and measures in a state plan will affect EGU dispatch and CO_2 emissions from affected EGUs. This section discusses these considerations in more depth, including approaches and data sources for estimating the impact of end-use energy efficiency and renewable energy requirements and programs as part of state plan projections of CO_2 emission performance by affected EGUs.

1. Potential Approaches for Estimating the Future Effects of State Energy Efficiency Requirements, Programs, and Measures

There are two basic approaches for developing a ten-year or longer forecast of end-use energy efficiency resources that will result from state energy efficiency requirements and programs: a bottom-up or a top-down approach. These forecasts would contain data that could be used to develop inputs to EGU CO_2 emission projections in a state plan, using modeling or an EGU growth tool, both of which are summarized above.

A bottom-up approach is based on annual evaluated and reported data from state and utility energy efficiency programs, and program-level utility compliance reports under state energy efficiency requirements, such as an end-use energy efficiency resource standard (EERS). One example of a bottom-up approach is the state-by-state end-use energy efficiency projection developed by ISO New England for use in its system planning process.[25] In simple terms, ISO

[25] Each year, ISO New England produces a Regional System Plan (RSP) that provides a comprehensive assessment of the New England bulk power system that is used as input data for evaluating the future reliability of the grid. One component of the annual RSP is a future estimate of peak loads and annual energy use that is modified (reduced) by the energy efficiency forecast. Information about the ISO New England energy efficiency forecasting method and assumptions is included in, ISO-New England (ISO-NE) Energy-Efficiency Forecast Working Group, *Draft Final*

New England develops production cost curves for energy efficiency measures based on historical performance of energy efficiency as documented in evaluation, measurement, and verification (EM&V) studies. ISO New England then applies those production cost curves (with adjustments for inflation and other factors) to future state or utility energy efficiency program budgets for each of the six New England states over a ten-year horizon. The ISO New England energy efficiency forecast includes both reductions in annual energy use (MWh) and peak demand (MW). ISO New England has produced an energy efficiency forecast for the last three Regional System Plans (2011, 2012, and 2013), and the near-term estimates in these forecasts have been validated by the actual quantity of end-use energy efficiency that has qualified for the annual capacity auctions conducted by ISO New England as part of its forward capacity market. Other approaches to projecting energy efficiency impacts, such as those used by New York ISO (NYISO), PJM Interconnection, and the California Public Utilities Commission (CPUC), estimate the effects of energy efficiency requirements and programs over a shorter time frame. In these cases, energy efficiency projections are typically consistent with the periods for which energy efficiency programs or program budgets have been approved by state PUCs, or consistent with the period for which energy and demand savings are acquired in ISO and RTO forward capacity markets.

Top-down projection methods analyze aggregate energy use changes resulting from end-use energy efficiency requirements or programs, often for a geographic region, entire industry, or economic sector. A top-down approach is determined on the basis of state energy efficiency policy requirements, and assumes that utilities and other parties implement efficiency programs necessary to achieve required energy and demand savings. In this way, a top-down approach is typically based on an estimated annual percentage reduction in energy use that results from state energy efficiency requirements and programs. One example of a top-down approach is the EPA's state-level projection of the impacts of "on-the-books"[26] energy requirements and programs. EPA's approach uses these state requirements and program commitments as the basis for

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Energy-Efficiency Forecast 2018-2023 (March 2014), available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/

[26] As used here, "on the books" refers to state energy-efficiency requirements and programs currently in place and specified in state legislation or administrative order. These requirements include energy efficiency resource standards (EERS) and dedicated sources of energy efficiency program funding.

adjusting national electricity load forecasts for use in electricity system modeling.[27] In this case, EIA Annual Energy Outlook (AEO) projections of future electricity use (MWh) and peak loads (MW) are modified to account for the reduction in energy sales due to state and utility programs and associated energy savings requirements.[28] These energy savings requirements are examined on a state-by-state basis and adjusted, as necessary, to reflect known increases or decreases in energy efficiency program budgets and other factors likely to affect whether state energy efficiency requirements are achieved. In addition to EPA's projections, a top-down approach is used to develop EE forecasts by LBNL[29], NREL[30], and some state energy offices and commissions.

The LBNL and the EPA forecast models are useful for comparison with the bottom-up ISO/RTO approaches. Where discrepancies between the national top-down analyses of end-use energy efficiency savings and the more granular bottom-up energy efficiency forecasts conducted by ISOs and RTOs exist, review of key assumptions regarding state policies for the different approaches may be warranted. Ideally, using the two approaches as complementary analyses may provide for helpful comparison and reconciliation of energy savings estimates used in state plan projections of EGU CO_2 emission performance.

The electricity load forecasts developed by ISOs and RTOs are important because they are often the base case from which adjusted load forecasts that incorporate projected energy efficiency program savings are developed. For reasons described above, ISOs and RTOs are beginning to include some adjustments to their base case load forecasts to account for energy efficiency program impacts. In most cases, these efforts are focused on including the future anticipated impacts of existing "on the books" energy efficiency requirements and programs and

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[27] While EPA's approach utilizes AEO forecasts of electricity use and peak loads, other credible and long-term forecasts could be used in a similar manner. U.S. EPA, *Background and Draft Methodology for Estimating Energy Impacts of EE/RE Policies* (March 2014), available at: http://epa.gov/statelocalclimate/state/statepolicies.html.
[28] For example, annual incremental and cumulative energy savings requirements for utilities included in a state EERS.
[29] Lawrence Berkeley National Laboratory (LBNL), *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2015* (January 2013), available at: http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend.
[30] National Renewable Energy Laboratory, *State Energy Efficiency Resource Standards: Policy Design, Status, and Impacts* (May 2014), available at: http://www.nrel.gov/publications/.

adjusting load forecasts accordingly. However, in some cases there is also an effort to anticipate new incremental energy efficiency investments in the future that are not tied to existing energy efficiency requirements and programs.[31] When conducting a projection of EGU CO_2 emission performance as part of a state plan that includes energy efficiency requirements and programs, it will be important to know how the base electricity load forecast for the state or region was developed, whether it already includes the effect of state and utility energy efficiency requirements and programs, and whether and how it should be adjusted to account for the future effects of existing on-the-books and incremental (i.e., new) energy efficiency requirements and programs that are included in the state plan.

1.1 Potential Uses of Energy Efficiency Projections for State Plan Emission Projections

Whether developed through a bottom-up or top-down approach, projections of annual energy and peak load reductions that result from state energy efficiency requirements and programs included in a state plan are necessary inputs to projections of EGU CO_2 emission performance under the state plan. Energy and peak demand savings estimates included in energy efficiency projections are used as a decrement to future electricity load forecasts that are used in conducting EGU CO_2 emission performance projections. The energy efficiency projection is used as an input, or modifier, to various models or other tools used to project the impact of energy efficiency resources on state or regional CO_2 emissions. For example, capacity expansion and dispatch planning models are capable of incorporating energy efficiency program impact data, such as annual energy and peak load reductions, when projecting EGU dispatch and capacity additions, and the avoided CO_2 emissions that are projected to result from these requirements and programs.

[31] In New England states that have policies to pursue "all cost-effective energy efficiency," the ISO-NE energy efficiency forecast assumes that energy efficiency program investments will continue beyond the approved program funding period (typically documented three-year plans), either at a constant level or some discounted level based on assumptions about an increase in the cost of saved energy over time.

1.2 Data Issues and Considerations for Using and Developing Energy Efficiency Projections

Depending on what data sources and approaches are used to project the future energy and demand savings from energy efficiency requirements and programs, there are certain strengths and limitations regarding the approach and methodology used. Generally, these strengths and limitations relate to data availability and energy efficiency forecast assumptions, such as:

- Energy efficiency requirements and programs included
- Jurisdictions covered
- Planning timeframe
- Embedded energy and demand savings from energy efficiency requirements and programs in base electricity load forecasts
- Cost of saved energy for different energy efficiency measures
- Energy efficiency measure life and measure energy performance decay
- Time of energy and demand savings for energy efficiency measures (availability of hourly data necessary to derive a load reduction profile for an energy efficiency measure)

Bottom-up versus top-down forecasting approaches have different strengths and limitations related to the data and assumptions described above. In the case of bottom-up approaches, state energy efficiency requirements and programs can be fully addressed in the analysis. In top-down approaches, such as EIA AEO analysis, greater focus is placed on federal policies (e.g., codes and standards) but less data is incorporated to reflect state energy efficiency requirements and programs. Bottom-up approaches typically include state-specific data that are rolled up to a regional level, while top-down national electricity load forecasts do not have a comparable level of granular state data detail. ISO New England provides energy and demand savings forecasts for state energy efficiency programs (average annual and peak demand coincident with the ISO defined peak load periods). The ISO NE energy efficiency forecast is informed by data collected at the energy efficiency measure, individual program, program portfolio, sector, and state levels.

An important consideration with both top-down and bottom-up energy efficiency forecasts is the extent to which energy efficiency program effects have become embedded into the long-range economic forecasts used as an input in developing electricity load forecasts. In some cases the economic forecast includes the effect of historical energy efficiency policies, either implicitly or explicitly, while in other cases the economic forecast may also anticipate some limited quantity of future energy efficiency investment that is incremental to the anticipated effect of existing energy efficiency requirements and programs. An additional consideration is whether and how building energy codes and appliance standards (both current and future) are accounted for in the base electricity load forecast.

Another consideration, for all energy efficiency projections, is energy efficiency program spending. While "on the books" energy efficiency requirements and programs may include multi-year approved energy efficiency program budgets, actual program expenditures may differ. This has been the case in some of the New England states, for example, where ISO New England has made adjustments to "discount" the spending levels to reflect actual spending trends, and not used the state approved budgets identified through stakeholder discussions. Additionally, assumptions are made about how the overall cost of saved energy for a portfolio of energy efficiency programs will change over time. It is generally assumed in most energy efficiency projections that the cost of installing energy efficiency measures will become more expensive into the future as state programs move beyond "low-hanging fruit" and increasingly focus on achieving deeper and broader energy savings through whole-building, multi-fuel programs addressing new buildings and building retrofits).[32]

While many existing sources of energy efficiency projection data do not account for hourly savings, it is becoming increasingly possible for states to examine and incorporate information about the time dimension of energy efficiency impacts. Smart meters combined with data-sharing and analysis technologies are making it easier for utilities and other energy

[32] Evidence to date is mixed as to a relationship of larger scale energy efficiency programs and broader energy efficiency measure portfolios, and the associated deeper levels of energy savings, to increasing cost of saved energy. Economies of scale, and expertise gained by program administrators from managing larger programs for multiple years, can lead to cost reductions. However, at some point, as program administrators move away from initial low-cost strategies and end-use energy efficiency measures, it is assumed that the cost of saved energy will increase.

efficiency program administrators to more accurately determine how the total energy savings achieved in a calendar year are spread out across the hours of that year. These data can be applied to energy efficiency projections to provide a better estimate of the timing of energy and demand savings. Such time-differentiated data is valuable for identifying the marginal EGU or cohort of marginal EGUs that are affected by energy efficiency requirements and programs, which can be used to provide more refined estimates of avoided CO_2 emissions due to changes in EGU dispatch and the addition of new generating capacity.

2. Potential Approaches for Estimating the Future Effects of State Renewable Energy Requirements, Programs, and Measures

This section describes data and analytic considerations for the representation of renewable energy requirements and programs included in state plans, when conducting projections of EGU CO_2 emission performance that will be achieved under a plan. A range of data and analytic considerations are examined that may be relevant when using different modeling approaches, including use of capacity expansion and dispatch planning models, and less sophisticated statistical or top-down projection approaches. Examples of specific considerations are described for three renewable energy policies that may be used as enforceable measures in a state plan— renewable portfolio standards (RPS), feed-in tariffs (FIT), and performance-based tax incentives.

2.1 Renewable Portfolio Standards

RPS requirements are typically set at the state level with an increasing percentage of total retail sales over a set schedule. The RPS requirement defines the eligible resource types (e.g., wind, solar, etc.) and in some cases, may specify resource-specific requirements, such as a percentage of the overall RPS target that is set-aside for a specific resource. It also defines the allowable geographic boundary for obtaining renewable energy or RECs. With this context, the following issues may be important to consider when projecting the impact of state RPS on EGU CO_2 emissions.

2.1.1 RPS as an Input to Electricity Sector Modeling

Electricity sector modeling includes the use of dispatch simulation models and capacity expansion and dispatch planning models that simulate the operation of individual EGUs (or aggregations of EGUs) in the electric system over time based on a detailed characterization of those EGUs, engineering and market operating constraints, other market factors (e.g., fuel prices, transmission constraints), emission constraints, and the requirement to meet a certain level energy and peak demand. These models may be based on a small control area, but more likely are regional or national in scope. Some, such as capacity expansion and dispatch planning models, simulate EGU dispatch and also consider the impact of long-term generating capacity investment decisions when optimizing system operation and buildout over a long-term planning horizon. These are typically optimization frameworks that have as their objective meeting electricity demand subject to a broad range of operating, environmental and market constraints, including meeting RPS requirements.

When using these types of analytic tools to project EGU CO_2 emissions, a number of analytic and data considerations are relevant for analysis of RPS impacts on EGU CO_2 emissions. These analytic and data considerations are summarized below.

Translation of RPS Requirements to Renewable Energy Generation Requirements

Most RPS are retail sales-based requirements, while most electricity sector analytic tools are generation-based models. When projecting CO_2 emission performance by affected EGUs using a generation-based analysis tool, it is necessary to translate the RPS sales-based requirement to a generation requirement using a transmission and distribution loss rate to "*gross up"* the sales estimate. For example, if an RPS requires 100 MWh of *sales* be met with eligible renewable energy resources, then the required renewable energy generation necessary to meet the RPS is 100 MWh / (1 + T&D loss rate).[33]

[33] 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.

RPS-Eligible Resources vs. State Plan-Eligible Resources

Some RPS rules define a broad range of eligible renewable energy generating resources. These could include renewable energy EGUs that emit CO_2, and EGUs that were constructed and began operation recently or many years ago. Some of these specific EGUs may not be eligible for use in a plan, in particular units that began operation prior to eligibility dates for actions that may be included in a state plan (if such limitations were applied to renewable energy measures in state plans).[34] Thus, the RPS requirement would need to be adjusted to reflect the use of only those resources eligible for use in state plans. This would be addressed through the treatment of existing RPS in the analysis base case, as described above in section III.B.2.

RPS Vintage Rules

Some RPS requirements provide that only renewable energy EGUs that began operation after a certain date are eligible. To the extent these renewable energy EGUs are eligible under a state RPS but not under the state plan, the analysis should explicitly address these resources. This could be done either through an adjustment of the MWh needed to meet the RPS, to account for renewable energy resources that are not eligible for use in a state plan, or through the use of two modeled RPS requirements for each class of renewable energy resource, with the RPS that addresses resources not eligible in a state plan addressed in the modeling reference case.

In/Out-of-State Contribution

Some RPS allow some of the requirement to be met by out-of-state resources. Some modeling frameworks may allow the user to explicitly specify the source region of eligible renewables. From a modeling perspective, this means a state would allow a broader supply area and model a broader area generally. If the renewable energy resources have different characteristics across the relevant geographic area, then data is needed on the characteristics of these resources by region (e.g., resource availability, performance, and capital and production

[34] As discussed in the preamble, and explained in section III.B.2 of this TSD, EPA is proposing that emission reductions that occur in 2020 and later due to actions taken pursuant to an existing state requirement, program, or measure could be applied toward meeting the required level of emission performance in a state plan if these actions occur after proposal of the emission guidelines (e.g., as of June 2014 and in subsequent years). As discussed in the preamble, at section VIII.F.2.b, the EPA is also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO_2 goals as part of BSER building block three.

costs). EIA (for NEMS), EPA (for IPM), and NREL (ReEDS) provide information on the characteristics and performance of renewable energy resources by region.[35]

Characteristics of Renewable Resources

In a dispatch modeling framework, better emission projections will result when the source of renewable energy is known and the energy profile is modeled. Renewable energy resources, such as wind or solar PV, may differ substantially in generation profile, as the supply of electricity to the grid from the EGU is based on availability of the renewable energy resource. The time during which electricity generation is supplied will influence the marginal fossil fuel-fired EGU (or cohort of EGUs) that is displaced by renewable energy generation. Understanding the renewable energy resource base, including the energy profile of the relevant renewable energy resource types will improve the modeling of EGU dispatch and projections of avoided CO_2 emissions that result from renewable energy generation. Data may include a detailed 8760-hour energy output profile for renewable energy resources, or at a minimum, a seasonal diurnal profile for such resources. If no state-specific data is available, generic output profiles for different renewable energy resources are available from NREL.[36]

Renewable Energy Resource Availability and Economics

Emission projections will be enhanced by a representation of the new renewable energy EGUs that are likely to be brought online as a result of a state RPS, based on an analysis of available renewable energy resources and economics. This requires understanding the relative economics (e.g., capital costs, fixed operation and maintenance (FOM) costs, variable operation and maintenance (VO&M) costs, and fuel costs) and operating conditions for different types of renewable energy generators, as well as renewable energy resource availability (e.g., MW

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[35] EPA's Integrated Planning Model generation profiles for wind and solar in the EPA IPM v.5.13 base case are available at http://www.epa.gov/powersectormodeling/BaseCasev513.html.

[36] NREL's datasets are intended for use by energy professionals, such as transmission planners, utility planners, project developers, and university researchers who perform wind and solar integration studies and need to estimate power production from hypothetical wind and solar plants. The Eastern Wind Dataset (http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html) contains modeled wind farm data points for the eastern United States for 2004, 2005, and 2006. The Western Wind Dataset (http://www.nrel.gov/electricity/transmission/western_wind_methodology.html) includes information about the methodology used to develop the dataset, the accuracy of the data, site selection, and power output. The Solar Integration Datasets (http://www.nrel.gov/electricity/transmission/solar_integration_methodology.html) are solar photovoltaic (PV) power plant five-minute and hourly day-ahead forecasts of generation output for approximately 6,000 simulated PV plants in the United States for the year 2006.

capacity available at different wind classes, solar insolation levels, and the characteristics of biomass). Having this information allows for better projections of the level and quality of renewable resources likely to be brought forward as the result of a state RPS. This will result in better emissions projections.

NREL has a suite of tools that can be used to estimate the potential costs of renewable energy under various assumptions.[37] For example, the CREST model is a cost-of-energy analysis tool intended to assist policy makers evaluating the appropriate payment rate for a cost-based renewable energy incentive policy. The model aims to determine the cost-of-energy, or minimum revenue per unit of production, needed for a sample (modeled) renewable energy project to meet its investors' assumed minimum required after-tax rate of return. [38]

Retail Rate Impacts

Many state RPSs have cost containment mechanisms or effective caps on the allowable impact on retail rates or on customer bills that can result from implementation of an RPS. If these caps are triggered, it will delay further increases in the RPS targets, depending on RPS implementation rules. This would lower estimates of renewable energy generation needed to satisfy the RPS requirements. Likewise, to limit rate impacts, many state RPS include an alternative compliance payment (ACP) provision, 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.

[37] NREL's Energy Analysis web site (http://www.nrel.gov/analysis/models_tools.html) has links to tools such as the Cost of Renewable Energy Spreadsheet Tool (CREST) and the System Advisor Model (SAM). CREST (https://financere.nrel.gov/finance/content/crest-cost-energy-models) makes performance predictions and cost of energy estimates for grid-connected power projects based on system design parameters that the user specifies. The SAM cash flow model (http://sam.nrel.gov/) helps assess solar, wind, or geothermal projects, design cost-based incentives, and evaluate the impact of tax incentives or other support structures on renewable energy projects.

[38] The CREST model is a product of a 2009-2010 partnership between the National Renewable Energy Laboratory (NREL), the U.S. Department of Energy (DOE) Solar Energy Technologies Program (SETP), and the National Association of Regulatory Utility Commissioners (NARUC). The model was developed by Sustainable Energy Advantage (SEA) under the direction of NREL. The report, user manual, and CREST models are free and available for download at: https://financere.nrel.gov/finance/content/crest-cost-energy-models.

Market Impacts – Multiple State Players

One important issue is to account for actions of others. Modeling results that consider the RPS-related actions of other states could differ substantially from those that consider a state's actions in isolation. This requires having at least a regional, if not national, modeling framework. A broader framework captures competition for renewables (and increased prices, greater reliance on poorer resources), as well as market-wide impacts on EGU dispatch and capacity expansion.

2.1.2 Data Needs for Estimating Generation Resulting from State RPS

Projections of renewable energy generation will require assembling the following data:

- Resource availability, resource performance, and resource costs will be necessary for the more sophisticated modeling approaches described above.
- Projections of retail sales, by year, adjusted to account for any exclusions from the RPS obligation (e.g. small utilities, cooperatives, municipalities, or perhaps certain large industrial loads). These covered sales must be calculated and projected using forecasts of annual retail demand.
- RPS requirements by year, so the annual forecast of covered retail sales can be multiplied by these percentages.
- The extent to which credit multipliers are used for compliance. Credit multipliers reduce the number of MWh needed for RPS compliance, and a downward adjustment should be made based on the percentage of compliance achieved by credit multipliers.
- Representation of alternative compliance payment (ACP) provisions, if applicable, and other relevant compliance flexibility provisions provided through the RPS.
- Estimates of transmission and distribution (T&D) losses, so that retail sales can be "grossed up" as described above. T&D losses estimates are available at the national level and can also be obtained for various grid regions from the appropriate regional grid operator.
- If an electricity sector capacity expansion and dispatch planning model is not used, estimates of the geographic origin, by state and grid-region, of generation used to satisfy the RPS will be necessary. If generation to satisfy the RPS is expected to come from out of state, the basis for these assumptions should be documented.

- CO_2 emission rate associated with renewable energy generation, by resource type (if applicable).
- Generation profile, by renewable energy resource type

2.2 Feed-in Tariff and Other Performance-Based Incentives

A feed-in-tariff (FIT) is a performance-based incentive (similar to production tax credits) that typically guarantees utility customers who own a eligible renewable electricity generation system (e.g., roof-top solar PV system) will be paid a specific amount by their utility for the electricity the system generates and provides to the grid over a fixed period of time. Such tariffs usually offer a fixed payment amount per kWh, but variations may require competitive bids. In some cases, FIT payments may be in addition to other incentives (such as a production tax credit). With a FIT, the amount of renewable energy that will be generated is not specified in the tariff schedule. A similar uncertainty about the amount of renewable energy generation that will occur exists for production-based tax credits. In the case of an RPS, the amount of renewable energy generation necessary to meet the RPS is known given the required RPS level and a utility sales projection.[39] In the case of FITs the response to the program may be more uncertain. The remainder of the discussion focuses on estimating these impacts.

The key information required to estimate the generation that will occur as a result of a FIT includes:

- An estimate of the renewable energy generation that will be provided by year for the FIT, along with estimates of payments to be made. These should capture the impacts of interactions with other policies, including RPS requirements, net metering, and federal investment and production tax credits. If generators receiving FIT payments are also eligible to satisfy an RPS, states should ensure their estimates of renewable electricity generation are not double-counted. For analysis using a detailed capacity expansion and dispatch planning model, market penetration of renewable energy generation to meet an RPS may be an output of the model. In this case, information is required on the capital

[39] Most state RPS schedules are established as a percentage of utility sales in a given year, although some include specified MWh amounts or are based on MW of generating capacity.

costs, FOM costs, and VOM costs of the renewable energy generating technology. This is the same information required for modeling an RPS; however, the modeling or analysis mechanism may differ. For example, these costs may be reduced directly in a modeling framework to reflect the FIT payment (e.g., reducing VOM to reflect the FIT in the years it is available).

- Information on the types of renewable energy resources, including their location, output levels, energy output profiles (across all 8,760 hours of the year or seasonally), and operating life of the EGU (by technology, so that they can be included in an electric dispatch model or mapped to an appropriate load shape or marginal avoided emission rate if using simpler analytical methods.
- An estimate of whether the projected retail price impacts of the FIT will lead to lowering the amount paid to eligible renewable energy generators, if a FIT includes caps on generation subject to the tariff based on rate impacts. If retail electricity rate impacts or budgetary impacts become unsustainable, the projected generation resulting from the FIT will be overstated.

2.2.1 Data Needs for Estimating Generation Resulting from Feed-In Tariff and Performance-Based Tax Incentives

Projections of renewable generation that will occur as the result of FITs and other performance-based incentives will require assembling the following data about the specific incentive programs that will support renewable energy generation:

- Caps on generating capacity, if any, by year, because such caps will limit the amount of renewable energy generation resulting from the tariff or tax incentive.
- Capacity amounts by renewable energy resource type that will be subject to a FIT or other performance-based incentives, and the capacity factors for these resource types, so that total generation in MWh can be calculated.
- Payment levels per kWh or MWh for each year of the FIT or other production-based incentive.
- Budget amounts, if known, by year, which may be expended to support renewable generation. When divided by the incentive payment levels, on a per-kWh or per-MWh

basis, these budget amounts will yield an estimate of the total electric generation that will be supported by the FIT or other production-based incentive.

- State experience and trends with FITs and other production-based incentives. Lacking budget or capacity limits, prior experience in the state, or the experience of other states and utilities, normalized for state or utility size, could be the basis for estimated renewable energy generation at a given incentive level.
- Because performance is metered at the busbar (i.e., the point of interconnection to the electricity transmission or distribution system), no adjustments would be needed for T&D losses.
- Estimates of the geographic origin, by state, of generation that receives support from these programs. In most cases, eligible generation will be in-state, but if generation is expected to come from out of state, the basis for these assumptions should be documented.
- CO_2 emission of renewable energy generation, by resource type (if applicable).

B. Emission Budget Trading Programs

Emission budget trading programs establish an emission limit for a group of emission sources and establish a budget of tradable emission allowances equal to the emission constraint for the group of sources. An emission allowance typically represents a limited authorization to emit one ton of a regulated pollutant. These programs also typically include a number of additional flexibility mechanisms beyond the ability to trade allowances. These include multi-year compliance periods, the ability to bank allowances issued in a previous compliance period for use in a subsequent compliance period, the use of out-of-sector project-based emission offsets, and cost-containment allowance reserves that make additional allowances available to the market if pre-established allowance price thresholds are achieved.[40] As a result, annual emissions from affected sources subject to an emission budget trading program often differ from the established annual emission budget for affected sources. In addition, these programs may be multi-sector in nature, regulating emissions for source categories in addition to EGUs. As a

[40] Depending on the program, these cost containment allowance reserves make additional allowances available from within the base emission budget (i.e., from "within the emission cap"), or add to the base emission budget (i.e., increase the emission cap).

result, state plan emission projections will need to accurately account for and represent these compliance flexibilities, as well as the scope of affected sources if they are broader than EGUs affected under CAA section 111(d).[41] In general, most electricity sector capacity expansion and dispatch planning models can be configured to evaluate these program flexibilities and project CO_2 emissions from affected sources, considering these compliance flexibilities.

1. Addressing the Sectoral Scope of Emission Budget Trading Programs

Some existing state emission budget trading programs addressing GHG emissions regulate emission sources in addition to EGUs, such as industrial sources.[42] We refer to these here as multi-sector emission budget trading programs. All existing state emission budget trading programs addressing GHG emissions include out-of-sector project-based emission offsets, which may be used to cover a portion of the compliance obligation of affected sources.

For multi-sector emissions budget trading programs, state plan emission projections would need to evaluate projected CO_2 emissions across all source categories covered by the state or multi-state program. This would be necessary to project the CO_2 emissions performance of affected EGUs under the multi-sector emissions budget trading program.

For emission budget trading programs that regulate EGUs and include offsets, which we define here as emissions reductions from sources not regulated by the trading program, emissions reductions from offsets would not be counted when evaluating CO_2 emission performance of affected EGUs, because those reductions would not come from those affected EGUs. However, state plan emissions projections would need to evaluate the use and impact of offsets, because the availability of offsets would affect the amount of CO_2 emissions from affected EGUs.

Addressing Multi-Sector Emission Trading

A state or regional emission budget trading program could potentially regulate sources from multiple emissions sectors beyond the electric generating sector that is the focus of the EPA emission guidelines. For example, the California GHG emission budget trading program is a

[41] For example, the Regional Greenhouse Gas Initiative (RGGI), which is an emission budget trading program limited to EGUs, includes EGUs that are not subject to CAA section 111(d).
[42] The California GHG emission trading program also includes large industrial sources and as of 2015 will include distributors of transportation, natural gas, and other fuels.

multi-sector emissions trading program that address emission sources outside the scope of the EPA emission guidelines for EGUs. If a multi-sector emission budget trading program is included in a state plan, CO_2 emission projections provided as part of the state plan will need to evaluate projected CO_2 emissions across all covered emissions sectors under the program. This would be necessary to project the CO_2 emissions or weighted average CO_2 emission rate of affected EGUs that will be achieved under the multi-sector emission budget trading program included in the state plan.

Evaluating the projected impact of a multi-sector emission budget trading program on the CO_2 emission performance of affected EGUs introduces an additional level of analytical complexity to emissions projections. For example, additional modeling capabilities may be necessary to adequately evaluate CO_2 emission performance across sectors in a multi-sector emission budget trading program.

Adequately projecting the CO_2 emissions of affected EGUs subject to a multi-sector emissions budget trading program may require modeling using a multi-sector energy model.[43] The use of an electricity sector dispatch and capacity expansion planning model, might also be required, as a complement to a multi-sector model. Some multi-sector models, include an electricity sector dispatch and capacity expansion planning module. However, use of a stand-alone electricity sector model, might also be necessary as a supplement to a multi-sector energy model, in order to project CO_2 emissions or the weighted average CO_2 emission rate from affected EGUs at a sufficient level of resolution for state plan emission projections. Under this approach, a multi-sector energy model might be used to project the level of CO_2 emissions abatement achieved across the multiple emission sectors covered by the program. This multi-sector projection could be used to develop a CO_2 marginal abatement cost curve representing cost-effective, non-electricity sector emission reduction opportunities at increasing cost levels. The marginal abatement cost curve would then serve as an input assumption for the electricity sector capacity expansion and dispatch planning model, which would be used to project the CO_2

[43] For example, the Energy 2020 model was used by California to evaluate the impacts of its multi-sector GHG emissions budget trading program. Other multi-sector models are available with similar capabilities, such as the National Energy Modeling System (NEMS) developed and implemented by the U.S. Energy Information Administration (EIA).

emission performance of affected EGUs (e.g., the CO_2 emissions or CO_2 emission rate of individual affected EGUs, or the total CO_2 emissions or weighted average CO_2 emission rate across multiple affected EGUs).[44]

Multi-sector emission budget trading programs also often address GHGs beyond CO_2. If this is the case, emission projections in a state plan would need to account for emissions abatement opportunities for each of the GHGs regulated under the program, and project emissions reductions for each of the regulated GHGs. This would be necessary to project the extent to which affected emission sources in different industrial sectors reduce emissions of non-CO_2 GHGs, which could impact projected CO_2 emissions from affected EGUs.

Addressing Emission Offsets

Emission offsets in CO_2 or GHG emission budget trading programs represent project-based GHG emissions reductions outside the sector or sectors regulated by the program.[45] Emissions reductions achieved through eligible offset projects are awarded allowances or "credits" that may be used by an affected source to meet a portion of its allowance compliance obligation. For example, under the RGGI program "CO_2 offset allowances" awarded for GHG emissions reductions achieved through approved offset projects may be used by affected sources to meet up to 3.3 percent of their CO_2 allowance compliance obligation.

The ability to use GHG emission offsets for compliance means that CO_2 emissions from EGUs regulated under the emission budget trading program may exceed the base CO_2 emissions budget established for the program. Offset allowances or credits are awarded in addition to the existing CO_2 emission budget, in exchange for CO_2-equivalent emissions reductions achieved

[44] This marginal abatement cost curve would be applied in a similar manner as marginal abatement cost curves are applied for GHG emission offsets in modeling analyses of emission budget trading programs. Form a modeling perspective, emission reductions from other sectors could be used by affected EGUs to demonstrate compliance with the emission limit. When economic to do so, emission reductions from affected EGUs would be foregone and replaced by emission reductions from emission sources in other sectors that are also subject to the multi-sector emission budget trading program.

[45] "Offsets" as used in the context of CO_2 or GHG emissions budget trading programs are distinct from offsets in the NSR permitting context under the CAA, where in certain instances emissions of a criteria pollutant from a proposed new facility must be offset with creditable emissions reductions at an existing facility, if the state or jurisdiction where the proposed facility would be located is in non-attainment status for the pollutant.

outside the capped emissions sector.[46] Consequently, the use of offsets by affected sources to meet a portion of their compliance obligation under an emission budget trading program could result in higher projected CO_2 emissions from affected EGUs in a state plan, because the use of offsets functionally expands the CO_2 emission budget for affected EGUs. This allows affected EGUs to emit more CO_2 while meeting their compliance obligation under the emission budget trading program, in exchange for CO_2-equivalent emissions reductions achieved outside of the affected source category. As a result, to properly project the CO_2 emissions from affected EGUs in a state plan that includes an emissions budget trading program that allows for the use of offsets, it is necessary for modeling to also project the extent to which offsets are used by affected EGUs for compliance.[47]

Under this approach, state plans would ignore the CO_2-equivalent emissions reductions projected to be achieved through offsets, when projecting the CO_2 emissions performance that will be achieved by the affected EGU source category through implementation of the state plan. This does not mean that an emission budget trading program included in a state plan could not include an offset component. Rather, when demonstrating emission performance by affected EGUs, the projected CO_2 emissions or weighted average CO_2 emission rate for affected EGUs under the state plan would not incorporate a credit for the CO_2-equivalent emissions reductions represented by offset allowances or credits used by affected EGUs for compliance with the emission budget trading program.[48]

2. Multi-State Emission Trading Programs

Emission budget trading programs may be multi-state in nature. For such programs, emissions reductions are achieved on a regional, rather than a state-by-state basis.

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[46] A key criterion that must be met for the award of offset allowances or credits is a demonstration that the offset project is "additional" (i.e., that it would not have occurred absent the incentive provided through the award of the offset allowance or credit).

[47] Existing capacity expansion and dispatch planning models can project the use of offsets for compliance based on specified offset marginal abatement supply curves, which represent the amount of offset credits/allowances assumed to be available from different categories of offset projects at different GHG emissions abatement costs.

[48] In other words, the projected CO_2 emissions or weighted average CO_2 emission rate for affected EGUs would be based on the direct emissions from these EGUs alone, with no calculation of "net" EGU CO_2 emissions that factor in the CO_2-equivalent emissions reductions represented by offset credits or allowances used by an EGU to meet a portion of its compliance obligation.

For example, in the multi-state Regional Greenhouse Gas Initiative (RGGI) emission budget trading program, individual participating states have established CO_2 emission budgets in state regulations. However, there is no requirement limiting total CO_2 emissions from affected sources in an individual state. State regulations include reciprocity provisions allowing emission sources to use CO_2 allowances issued by another participating state for compliance with the state program. This provides for state-to-state CO_2 allowance flows (and the potential for differences in state-by-state CO_2 emissions relative to state emissions budgets) based on where emission sources determine it is most economical to achieve CO_2 emissions reductions. However, in aggregate, the CO_2 emission budgets in each of the participating state regulations establish a regional cap on CO_2 emissions from affected EGUs. As a result, while a multi-state emission budget trading program may be projected to result in CO_2 emissions from affected EGUs consistent with a multi-state mass-based CO_2 emission performance goal, the CO_2 emissions outcomes may vary by state. This necessitates evaluating a multi-state emission budget trading program as a whole, because the individual regulations of participating states function together as single integrated program.

To address these issues, states participating in a multi-state emission budget trading program would jointly demonstrate that the multi-state program is achieving the required level of CO_2 emission performance on a multi-state basis, based on the CO_2 emission performance of all affected EGUs in the multi-state group implementing the program.

Some state emission budget trading programs also include international partner jurisdictions.[49] In such instances, the program could be treated in a similar fashion as a multi-state program that involves only U.S. states. In this instance, emission projections evaluating an international program would include all jurisdictions participating in the program, but emission performance for state plans would be assessed based only on the CO_2 emission performance of affected EGUs in the subset of the program represented by U.S. states. Although the CO_2 emission performance of EGUs (or other emission sources) in a foreign country would not be addressed in the state plan, the entire international program would be evaluated as part of the

[49] Currently, the EPA is only aware of one such instance, which is the linkage of the California GHG emission budget trading program with a similar program in Quebec.

emission projection included in the state plan. This would be necessary in order to project international allowance flows and CO_2 emissions across all participating jurisdictions, as these cross-jurisdictional flows would impact projected CO_2 emissions from affected EGUs in U.S. states.

VI. Process Considerations

As discussed in the preamble, in section VIII.F.7, the credibility of state plans under section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools, and assumptions for such projections is critical. Furthermore, considerations for projecting emission performance under a state plan will differ depending on the type of plan. This includes differences in how inputs to projections are derived; how projections are conducted, including tools and methods; and how aspects of a plan are represented in these projections.

In the preamble, the EPA seeks comment on whether the EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as provide technical resources for conducting projections. This section of the TSD elaborates on these considerations.

A. Provision of the EPA Guidance

One approach to address these considerations is for the EPA to provide guidance for EGU CO_2 emission projections included in state plans. Such guidance could include default modeling assumptions, or data sources for key assumptions. State modeling projections included in a state plan could include assumptions that deviate from the EPA's recommended default assumptions, but a state plan would justify the reason for using alternative assumptions. The EPA technical guidance could specify recommended reference case assumptions for use with modeling or EGU utilization growth tools, for example:

- Electricity load growth projections (energy and peak demand)
- Fuel supply, delivery, and pricing assumptions
- Cost and performance of electric generating technologies
- Cost and performance of pollution control equipment

- EGU firm builds and retirements (those scheduled with a regional transmission organization or independent system operator (RTO/ISO)[50]
- Transmission capability and ISO/RTO transmission expansion plans
- Applicable federal regulations (other than the EPA emission guidelines)
- Applicable state regulations and programs (other than the alternative standards that are included in the state plan)

It would be necessary in many instances to include assumptions about other state programs implemented by neighboring states in the same region. This would be especially relevant for states that are located within the same electric power pool (or adjoining power pools) that are administered by a common RTO/ISO. To address this need, the EPA technical guidance could provide documentation of state programs and policies included in a reference case, as well as those that are eligible for inclusion in a state plan as alternative standards. The guidance could compile information about state programs and provide model input assumptions related to these programs (e.g., MWh of electric generation needed to meet a state renewable portfolio standard).[51] The EPA might also play a role in facilitating coordination among states as they develop their plans, to harmonize regional assumptions.

ISOs and RTOs, in discussions with the EPA have also offered to support states in evaluating the emission performance of state plans on a regional basis. The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an RTO or ISO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements

[50] ISOs and RTOs are independent organizations that administer a regional electric power pool (EGU dispatch and electricity transmission systems), and often also administer related wholesale electricity markets for electric energy and capacity.

[51] EPA's manual, *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State Implementation Plans/Tribal Implementation Plans* (July 2012), could potentially support and be expanded upon to develop this component of EPA technical modeling guidance. In particular, see Appendix I: EPA's Draft Methodology for Estimating Energy Impacts of EE/RE Policies. The draft manual is available at http://www.epa.gov/airquality/eere.html. State environmental regulations addressing EGUs are itemized in the modeling documentation for the EPA IPM Base Case v.5.13.

its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans.

B. Party that Translates the Rate-Based Goal to a Mass-Based Goal

In the preamble, in section VIII.F.7, The EPA seeks comment on whether it should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as provide technical resources for conducting projections.

One consideration for state plans that use a mass-based CO_2 emission performance goal is the party that conducts the translation of the rate-based CO_2 emission performance goal in the emission guidelines to a mass-based goal—either the EPA or the state. In the preamble, in section VIII.D.3, the EPA seeks comment on whether to assist states that seek to translate the rate-based goal into a mass-based goal.

One approach is for the EPA to provide a presumptive translation of the state-specific rate-based CO_2 emission performance goal to an equivalent mass-based goal for all states, for those states that request it, and/or for multi-state regions. This could include default modeling assumptions and results of modeling runs for a *Reference Case Scenario* and an *EPA Mass-Based CO_2 Emission Goal Policy Scenario*, as described above in section III.B. A state could utilize the presumptive mass-based CO_2 emission performance goal for the state or multi-state region identified through these EPA modeling runs. If a state proposed modifications to EPA default modeling assumptions, it would need to justify these modifications as part of the CO2 emission projection included in its state plan, and present an emission projection that supports a proposed modified mass-based CO_2 emission performance goal.

Another approach is for the EPA to provide guidance for states to use in translating a rate-based goal to a mass-based goal. This could include information about acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. Under this approach, the EPA might also provide a coordinating function in addressing the assumptions applied by multiple states within a grid region, acknowledging that assumptions about state programs across a broader grid region that are included in an analysis scenario will influence projections of CO_2 emissions by affected EGUs in any particular state.

Under this approach, states could deviate from these default methods and assumptions with justification. Following the guidance could provide a streamlined path for the EPA approval of emissions projections, but states would still have flexibility to use other approaches, which the EPA would review.