ELECTRIC POWER RESEARCH INSTITUTE

COMMENTS OF THE ELECTRIC POWER RESEARCH INSTITUTE ON

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2013-0602; FRL-9911-86-OAR]

Carbon Pollution Emission Guidelines for Existing Stationary Sources:

Electric Utility Generating Units

October 20, 2014

The Electric Power Research Institute, Inc. (EPRI) respectfully submits the enclosed comments[1] on the U.S. Environmental Protection Agency's (EPA's) proposed rule titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. EPRI thanks the EPA for the opportunity to comment on this proposed rule.

EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1986, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

More specifically related to this proposed rule, EPRI has been involved in global climate change-related research for more than 20 years, with economic and integrated assessment analyses and expertise related to emission projections, mitigation technologies, and climate economics. Technology assessment and technology innovation have been central to EPRI's activities since its inception. EPRI work spans nearly every area of electricity generation, delivery and use; management; and environmental responsibility. In assembling these comments, EPRI draws upon decades of experience and expertise in wide ranging research efforts associated with heat rate improvements, natural gas generation, and nuclear and renewable technologies as well as energy utilization across the electric sector.

These comments on the proposed rule reflect EPRI's research background in that they are technical rather than legal in nature. They are based upon EPRI's research and development experience over the last 40 years related to technology innovation, planning, and analysis of the electric power sector. EPRI comments focus principally on three areas of assessment: (i) technical engineering assessment; (ii)

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[1] This document is an EPRI Report # 3002004658.

economic assessment and analyses; and (iii) power sector system assessment. All comments contained in this letter reflect only EPRI's opinion and expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development.

EPRI comments are organized into five areas that parallel the proposed rule's structure.

1. Definition of Best System of Emissions Reduction (BSER) and the building blocks;
2. State Goals;
3. State Plans;
4. Impacts of proposed rule, including a technical assessment of the Regulatory Impact Analysis (RIA); and
5. Benefits of the proposed rule.

Summary comments for each of these areas are provided followed by more detailed comments. In addition, EPRI provided a variety of references and technical documents as appendices to the main body of comments.

EPRI hopes its comments and technical feedback will be valuable to EPA.

Sincerely,

Anda Ray
Vice President, Environment
And Chief Sustainability Officer

SUMMARY OF EPRI COMMENTS

This section summarizes EPRI's comments. The next section provides more detailed comments followed by various reference materials and technical documents in appendices. The abstracts and, in many cases, full copies of the referenced EPRI reports are available at EPRI.com.

BUILDING BLOCKS AND THE BEST SYSTEM OF EMISSIONS REDUCTION

Based on its technical research and evaluation of the proposed rule, EPRI suggests that U.S. Environmental Protection Agency (EPA) consider establishing the Best System of Emissions Reduction (BSER) centered on the following considerations:

- Utilize latest available technical knowledge so that the BSER accurately reflects the cost-effective mitigation potential of electric generating units (EGUs).
- Reduce uncertainty for EGU owners to provide clearer understanding of necessary operating conditions and investment planning needed to maintain reliable, affordable, and environmentally responsible electric generation and delivery.
- Better account for the heterogeneous nature of the existing electric system operating within differing state or regional characteristics.
- Consider the system dynamics of the power sector as building blocks are not necessarily additive and maintain varying degrees of interdependency.

Building Block 1: Heat Rate Improvements

- Estimates of heat rate improvements at existing coal EGUs are very dependent on individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal. In estimating mitigation potentials, EPRI recommends that the estimates should be based on current studies and data that take into account recent EPA environmental control regulations. Regional or state-specific research and data should be used as the basis for estimating potential heat rate improvements rather than use of a national average for all. States differ widely in the characteristics and operating performances of their respective generating fleets.
- While EPRI studies indicate there may be opportunities to achieve a variety of heat rate improvements at an EGU in the range of 0.5% – 5% on a net generation basis, these values may not be additive and their applicability and realized savings are highly dependent on the characteristics of an individual unit.
- Increased penetration of renewable power and greater use of natural gas combined-cycle (NGCC) units, as called for in the proposed rule, will lead to potential heat rate increases in coal units associated with lower utilization of these units, and the need for these units to engage more often in

flexible operations (e.g., load following, extended low output generation, cycling), rather than "baseload" operations. In addition, there are potential wastewater-related impacts that should be recognized as flue gas desulfurization (FGD) wastewater treatment may be negatively impacted with large swings in FGD water chemistry resulting from increasing flexible operations.

- EPA's use of gross heat rate data for estimating heat rate improvement-related carbon dioxide (CO_2) mitigation for building block 1 is inconsistent with the use of the net emission accounting used in the state goals computation. This leads to inconsistencies, confusion, and possible overestimation of the heat rate improvement-related mitigation potential. EPRI recommends that EPA use a consistent approach for net heat rate estimation and accounting through the proposed rule.

Building Block 2: Dispatch Changes

- EPRI comments focus on the critical question of whether there will be sufficient capability to handle flexible operations duties that are now principally handled by NGCCs. That is, flexibility and reliability could become primary concerns as many NGCCs may move to baseload while coal generation capacity is reduced and variable generation from renewable energy substantially increases.
- EPA proposes to increase capacity factors for NGCC units to 70% based on the premise that "…changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal." While EPRI sees no technical issue with individual NGCC units physically operating at a 70% capacity factor, there is little long-term operating experience with widespread and sustained operation of a majority of NGCC units at that level. In addition, the capacity factor of NGCC units has been highly influenced in the past by volatility in the price of natural gas and is therefore, likely to have a significant impact on capacity factors in the future. EPRI notes that achieving technically feasible capacity factor of 70% does not include other significant daily operating impacts on capacity factors, such as the market price of natural gas, availability of pipeline infrastructure, and firm pipeline capacity. Reinforcing the dependency of gas price to capacity factor; natural gas prices are currently forecasted to be relatively low, history has demonstrated the price of natural gas to be highly volatile, and multi-year forecasts have consistently been inaccurate. Establishing a mitigation goal based on an assumption of persistent low natural gas prices is not a reliable or dependable approach to estimating capacity factors for NGCC plants over a long period.
- Establishing a dispatch-based mitigation goal that impacts other existing generation types without thorough consideration of the impacts to resource adequacy may significantly degrade reliability. For example, during the extreme cold temperatures across most of the Southern and Eastern United States from January 6 to 8, 2014, natural gas fired generating plants did not perform as expected due to both plant outages and natural gas delivery system inadequacies.
- The changes in the utilization of the various generating plants driven by this proposal could have a significant impact on transmission reliability due to potential large changes in power flows across the system and retirement of generation that contributes to transmission system voltage and frequency performance. The change in generation will almost certainly require development of new transmission to ensure operational reliability, but scheduling outages of existing facilities will be difficult if simultaneous upgrades across many systems are needed such that time lines for

commissioning of new transmission facilities may be delayed. To understand the full reliability, economic, and financial impacts of the proposed rule, detailed transmission reliability evaluations should be conducted.

Building Block 3a: Renewable Generation

- EPA's "best practices" scenario for developing state-specific renewable energy targets assumes state equivalency for regional calculations of resource potential. This assumption is problematic when regions are large and encompass states with appreciably different renewable energy resources.
- Based on EPRI research, a more effective and comprehensive basis for state aggregation would be informed by the region-specific potentials for renewable energy development, which would include technology costs, fuel costs, network effects, and regulatory requirements. Investor response, regional competition for other resources, learning-by-doing and network effects, regulatory limitations, and public acceptance also should be considered.

Building Block 3b: Nuclear Generation

- In reviewing how EPA used this building block for state goal setting and in the Regulatory Impact Analysis (RIA), EPRI urges EPA to consider the lifetime of existing nuclear units where many units will reach their 60-year license limit by 2029. Three units with licenses scheduled to expire prior to 2030 are already in their extended period of operation and would need to obtain additional license extension to extend their operating lives to 80 years (known as subsequent license renewal). Though it is expected that many reactors will apply for and receive license extensions out to 80 years, there is no level of certainty at this time.
- There is significant uncertainty as to whether the Nuclear Regulatory Commission (NRC) will extend the operating licenses for each nuclear unit as assumed. License renewal is a long and multifaceted process which is based on submittals of complex studies to the NRC and its detailed review. EPRI encourages EPA to consider evaluating a lower bound case and develop a sensitivity analysis on the potential future of nuclear power generation capacity.
- EPRI has no specific technical comments to add on Building Block 3b.

Building Block 4: Demand Side Energy Efficiency

- The level of energy efficiency performance in this proposed rulemaking –1.5% annual incremental electricity savings as a percentage of retail sales– is greater than EPRI's assessment of energy efficiency program potential. EPRI research indicates that achieving this level of energy efficiency will required the addition of measures beyond energy efficiency programs and will occur over a longer period and at a higher cost than suggested in the proposed rule and accompanying RIA. While efficiency improvements in end-use devices and advances in controls technology can lead to energy savings; economic, market, and perceptual barriers can inhibit or curb customer adoption. The assumptions used to determine the economic viability of the proposed levels of energy efficiency should be reviewed to ensure that adverse economic impacts are avoided. Furthermore, evidence indicates that the adoption of financial mechanisms that encourage electric utility investment in energy efficiency, similar to those underway in several states, can facilitate the achievement of incremental energy efficiency.

- EPRI agrees with EPA that the link between energy efficiency and CO_2 intensity reduction is present. However, in quantifying the link between energy savings and CO_2 reductions, EPA would benefit from a modeling approach that considers the economic optimization of future generation fleet resources over time, as EPRI does. In addition, EPRI urges EPA to consider both the spatial effects of regional variation in the electric power generation mix, and temporal effects of changes in electric system load shapes resulting from changes in energy efficiency, and their associated impacts on marginal CO_2 emissions.

STATE GOALS

- EPA's definition and use of the BSER to set state goals, while granting flexibility in implementation, proposes a system of compliance that is intrinsically inflexible. The dynamics of compliance, under circumstances of any unplanned shortfall in the non-emitting resources required for compliance, force an additional curtailment of covered fossil output, creating a further reduction in supply and forcing states to increase imports or reduce exports. This creates the risk of multi-state compliance failures that could disrupt interstate power flows.
- Language on constructing mass-based greenhouse gas (GHG) emissions reduction targets is ambiguous. The proposed rule and supporting documents contain language that leave open a variety of possible interpretations on how to construct mass-based targets from the established rate-based targets. As part of its analysis of the proposed rule, EPRI examined three possible interpretations resulting in three different mass targets which can differ by as much as 30% from one another implying dramatically different CO_2 mitigation paths.
- The proposed rule considers only the resource adequacy perspective with regard to potential electric system reliability impacts and does not address the potential thermal, voltage, and frequency impacts. Nor does the proposed rule consider the associated potential transmission economic implications of additional facilities required to ensure operational reliability or financial implications of stranded transmission investments that become underutilized. EPRI encourages EPA to conduct detailed transmission reliability evaluations to understand the full reliability, economic, and financial impacts of the proposed rule.

STATE PLANS

- Establishing workable evaluation, measurement and verification (EM&V) requirements for energy end-use efficiency efforts will be critical to incorporating these efforts in state compliance plans and actions. EPRI suggests that the states consider establishing a set of generalized, process-oriented EM&V requirements that would apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches, as appropriate for different types of programs and measures, provided that EM&V meets the minimum standards established by EPA.

- While transmission and distribution (T&D) efficiency options do not have the benefit of widely accepted EM&V approaches that exist for end-use energy efficiency options, EPRI encourages the states to develop standards to measure and verify savings from T&D programs using the concepts, approaches, and terminology in practice today related to end-use energy efficiency efforts.
- As the electric sector decarbonizes and generates electricity with a lower carbon emissions intensity, electrification of more carbon-intensive sectors has the potential to cost-effectively reduce GHGs across the U.S. economy. Electrification has been long recognized in the energy-economics literature, technology studies, and the climate policy area as a cost-effective approach to mitigate GHGs. For example, while the implementation of an electrification strategy could cost-effectively reduce GHG across multiple sectors, the CO_2 emissions from the power sector could remain flat or even slightly increase. While it is understood that compliance for out-of-sector reductions is challenging, they should not be excluded if appropriate rigor and durability can be demonstrated. EPRI recommends that care should be exercised so that state plans do not to eliminate or dis-incentivize clean electrification.

IMPACTS OF THE PROPOSED RULE

Regulatory Impact Analysis

- EPA provided estimates of energy efficiency potential and cost by state as part of the calculations for Building Block 4 in computing the target rate. However, in the analysis with the Integrated Planning Model (IPM) energy efficiency is not adequately modeled as a resource in competition with other mitigation options which could lead to underestimating the associated costs.
- A related limitation of IPM is that this model does not represent unit commitment and electric power plant hourly dispatch in a detailed manner. EPRI research shows that important insights can be gained when electric sector models capture positive and negative correlations between load, renewable energy resource variability, and uncertainty across adjacent regions given that renewable resources are non-uniformly distributed in space and time. EPRI encourages EPA to consider enhancing the treatment of renewable energy in IPM and to complement the IPM analyses with more detailed, unit commitment modeling.
- While EPA recognizes "…that biomass-derived fuels can play an important role in CO_2 emission reduction strategies…" biomass as a renewable fuel is not treated as a non-emitting resource in the proposal's RIA. Biomass is therefore disadvantaged as a potential compliance option. EPRI encourages EPA to apply the latest peer-reviewed scientific research to develop with the states an appropriate GHG accounting framework for biomass as a renewable resource in state compliance plans.

BENEFITS OF THE PROPOSED RULE

Estimated Air Quality Reduction Benefits

- The limitations of the Environmental Benefits Mapping and Analysis Program (BenMAP) used to calculate benefits in the proposed rule should be recognized. These limitations include: (i) embedded options in the tool that are limited and inconsistent with the scientific literature; (ii) no simple way to consider uncertainty within its framework; and (iii) no provision for considering different species or components of fine particulate matter ($PM_{2.5}$) despite increasing evidence that some components of $PM_{2.5}$ may be more highly associated with health effects than others.
- EPRI also encourages EPA to address the appropriateness of calculating benefits associated with the additional air pollutant reductions in populations living in geographic regions that already meet the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ and ozone. The RIA estimates benefits of further reducing $PM_{2.5}$ levels from the proposed rule in the same populations even when the initial exposure is at or below the NAAQS. Given that the NAAQS are set at levels that will "protect the public health" with an "adequate margin of safety," there appears to be an inconsistency related to calculating benefits associated with reducing air pollutions below these levels.

Estimated Climate Benefits (USG Social Cost of Carbon)

- From a detailed EPRI technical assessment of the U.S. Government's Social Cost of Carbon (USG SCC) estimation approach, EPRI identified a set of fundamental issues and related concerns that suggest the need for EPA to revisit the estimation approach to develop scientifically sound results.
- The USG SCC estimates are the result of significant aggregation and therefore are vague and difficult to interpret, discuss, and evaluate. Greater technical clarity on what underlies and drives the estimates is needed to better understand the USG SCC estimates.
- EPRI suggests EPA revisit the overall USG SCC estimation approach because (i) the USG approach does not provide consistent, comparable, and robust analytic results; and (ii) the approach would benefit substantially from an external scientific peer review, similar to the peer review of other EPA regulatory models such as IPM. Given the importance of the SCC for regulatory benefits analysis, peer review would be appropriate to ensure the development and use of scientifically sound estimates and to ensure the public confidence in these estimates.
- There also are methodological issues related to the application of the USG SCC values in the proposed rule's benefit-cost assessment. For example, EPA applies the SCC values to estimated CO_2 reductions from the electric power sector when SCC values should only be applied to estimated net changes in global emissions.
- Lastly, the RIA compares levelized (or annualized) compliance costs to annual CO_2 benefits (in a particular year). This is an inconsistent comparison with an uncertain meaning. EPRI suggests that EPA's comparison of economic benefits and costs be based on the comparison between the net present value of compliance costs and estimated CO_2 benefits over time.

DETAILED EPRI COMMENTS

This section provides detailed comments and is followed by various reference materials and technical documents in the appendix.

1. DEFINITION OF BEST SYSTEM OF EMISSIONS REDUCTION AND THE BUILDING BLOCKS

1.1 Detailed Comments Building Block 1: Heat Rate Improvements

EPRI's research neither proves nor disproves that a 6% heat rate improvement could be attained in any given operating power plant. However, EPRI's research[2] does show that (i) heat rate improvements are not necessarily additive, (ii) they are very sensitive to operational issues - cycling, fuel type, etc., and (iii) they are very dependent on the type of equipment installed such as emissions controls. EPRI research has not yet developed data on the sustainability of most of the heat rate improvements discussed in these comments.

EPRI research identified potential unit-specific, heat rate improvements in the range of 0.5 – 5% on a net basis. However, the numerical values for separate heat rate improvements may not be additive. They also may not be achievable or justifiable at every coal-fired plant. In many cases, staff at many well-performing plants have been proactive and already implemented some of the possible improvements (e.g., steam turbine upgrades, remote monitoring centers, etc.), thus reducing the potential for further maximum heat-rate improvement. Estimates of heat rate improvements at existing coal EGUs are very dependent on the individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal.

In the last several years, older power plants with higher heat rates and no longer considered economically viable have been retired by plant owners. These retirements typically remove units with the most potential heat rate improvement from the fleet. Those units where investments have already been made to improve operations are less apt to be retired, but have less additional potential heat rate improvement.

More detailed discussion and the feasibility of achieving high, fleet-wide average heat rate improvements is addressed below for the following areas:

- Net heat rate is significantly affected by increased plant auxiliary power consumption due to the addition of environmental controls;
- Diverse individual unit designs lead to differences in potential heat rate improvement opportunities;

[2] See EPRI Report 3002003457, "Range and Applicability of Heat Rate Improvements", 2014 for a summary of recent research.

- Potential economic disincentive to implement heat improvements due to concerns about incurring costs resulting from the age of the unit or, potentially, New Source Review requirements; and
- Adverse impacts on unit efficiency when engaging in flexible operations (e.g. load following, cycling, prolonged low output operations).

Net Heat Rate Sensitivity to Additional Plant Auxiliary Power Consumption

Historically each set of emissions control regulation increases auxiliary power consumption by about 1% of gross generation.[3] If the trend (observed over 20 years) continues, additional air emissions control technologies will likely be required and as a consequence, additional auxiliary power consumption will result. All EPRI and other referenced estimates of heat rate improvements are reported on a net basis. Net heat rate reflects the cost of generating electricity including the cost of auxiliary power consumed as part of the process and thus net heat rates are affected by the addition of emissions controls. The use of gross heat rate data for determination of heat rate improvement-related CO_2 mitigation potential in Building Block 1 is inconsistent with the use of the net emission accounting used in the state goals computation. This may lead to inconsistencies, confusion, and possible overestimation of the mitigation potential. EPRI recommends that EPA use a consistent approach for net heat rate estimation and accounting through the proposed rule.

With respect to the effect of air emissions requirements, the Mercury and Air Toxics Standards (MATS) Rule[4] requires coal plant operators to pay more attention to tuning and improving combustion performance, thus potentially improving plant heat rate. But if the installation and operation of additional emission mechanical controls are required, net heat rate – not gross heat rate – will typically suffer. Since those controls increase the consumption of auxiliary power, less efficient plants may be required to operate to make up the difference consumed by the new controls. The incremental increase in those plants' operation will increase the average heat rate of the affected fleets.

Uniqueness of Unit Designs and Options for Heat Rate Improvement

Power plants are designed for an optimal heat rate. While that heat rate may not be the lowest achievable at any given point in time, trade-offs occur with respect to capital and operations and maintenance (O&M) costs, siting, and fuel. The average age of operating coal-fired power plants is 40 years. Over the course of the past four decades, these plants have been subject to physical modifications and repairs and

[3] EPRI report 1024651 "Program on Technology Innovation: Electricity Use in the Electric Sector", 2011.
[4] The MATS includes the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Electric Utility Steam Generating Units and the revised New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units. www.epa.gov/mats and ww.epa.gov/ttn/atw/nsps/boilernsps/boilernsps.html

suffered age-related degradation. Many of the modifications have been the addition of emissions controls, which typically have an adverse effect on heat rate. Since initial startup, many units have changed fuel supply and reduced staffing size, increasing operational challenges which create additional potential adverse heat rate effects.

The actual heat rate improvement achievable at any site is unit-specific, as shown in EPRI studies. The maximum potential improvement depends on the condition and operation of the unit. For example, those units where major modifications or replacements of the turbine have been recently completed will have much smaller potential for heat rate improvements, while those units that have not upgraded equipment or have been less well maintained will have a larger potential for heat rate improvement. The costs to improve heat rate are also unit-specific; factors that may affect the costs include the age of the unit, its location, its condition, and whether asbestos removal is required. Economy of scale also plays a role, as the expenditures are more easily justified for larger units with higher capacity factors.

A 2014 National Coal Council[5] report includes a review of various options for improving the heat rate of existing coal power plants including coal switching, coal drying, steam turbine upgrades, condenser cleaning, instrumentation and controls improvements, low temperature heat recovery, auxiliary power use reduction, and cooling tower improvements. This report states:

> "In some cases the benefits are cumulative – such as those derived from minimizing auxiliary power, fuel drying, and improving heat rejection. Other actions that increase heat removal from the boiler – economizer modifications, improved air heater performance and low temperature heat recovery – do not provide cumulative benefits. All efficiency improving measures are unit and site-specific and will not always be technically and/or economically feasible. A detailed analysis would be required to assess the benefits of this set of measures, as well as its compatibility with new source review regulations. It is possible that a thermal efficiency improvement of up to 3-4 percentage points could be derived, if these actions can be proven to work together and do not compromise plant reliability."

The report also has a detailed list of reasons why cited heat rate improvements might not be applicable at a specific power plant. It also includes a list of factors which could lead to an increase in coal power plant heat rates including more operation at part-load, adding more environmental control equipment, switching from once-through to evaporative or air cooling, and switching from bituminous to lower sub-bituminous coal.

In 2014, EPRI completed a report "Range and Applicability of Heat Rate Improvements"[6] summarizing the results of recent EPRI projects focused on improving the heat rate of operating coal-fired power

[5] "Reliable &Resilient: The Value of Our Existing Coal Fleet ", May 2014, National Coal Council, http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf. The National Coal Council is A Federal Advisory Committee to the U.S. Secretary of Energy.

[6] EPRI Report 3002003457, "Range and Applicability of Heat Rate Improvements", 2014.

plants. The study identified examples—both demonstrated/realized and projected—of methods to improve heat rate or recover efficiency losses. Examples include:

- Production Cost Optimization (PCO). In EPRI's project, the units evaluated realized 3-5% net heat rate improvements through various means.[7]
- Sliding Pressure. By employing sliding pressure over a several-month period, a 2% net heat rate improvement was realized at part load.[8]
- Remote Monitoring. The use of remote monitoring centers was documented to improve net heat rate 2.5 to 4%.[9]
- Steam Turbine Steam Path Modifications. EPRI members reported steam turbine steam path modifications were worth 2% to 4% net heat rate improvements.[10]
- Cycle Alignment. Implementing a cycle alignment (isolation) program was documented to be worth at least 0.5% improvement in net heat rate.[11]
- Capital and Maintenance Projects. A list of 57 potential actions and modifications to improve efficiency was made and evaluated in detail. While the amount of gains would be unit specific, the projected net heat rate improvements ranged from less than 0.1% to more than 2% for the various actions and modifications. One utility applied the methodology and analyzed a number of these potential projects for its own specific fleet, resulting in a projected 5% improvement in net heat rates.[12]

<u>Economic Barriers to Heat Rate Improvement: New Source Review, Limited Remaining Life, High Costs for Additional Heat Rate Improvement</u>

Owners of many coal-fired plants may refrain from making improvements based on the financial risk associated with potentially triggering a New Source Review, which may result in the requirement to invest in additional emissions controls. EPRI does not take a position on New Source Review

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[7] EPRI report 1015734, "Production Cost Optimization Assessments", 2008; EPRI Report 1019704, "Production Cost Optimization Project 2010"; and EPRI report 3002002772, "Production Cost Optimization Project", 2014.
[8] EPRI report 1023912, "Methods to Mitigate the Effect of Increased Cycling and Load Following on Heat Rate", 2012.
[9] EPRI report 1023075, "Evaluation of Remote Monitoring Heat Rate Improvement", 2011.
[10] EPRI report 1018346, "Compilation of Results and Feedback Regarding Turbine Upgrades at Nuclear and Fossil Power Plants", 2008.
[11] EPRI report 1024640, "Cost Benefit Assessment of Cycle Alignment", 2011.
[12] EPRI report 1019002, "Capital and Maintenance Projects for Efficiency Improvements", 2009 and report #1021206 , Methodology for Fleetwide Energy Efficiency Analysis", 2010.

requirements; rather, EPRI notes that the requirements could increase costs of potential heat rate improvements and therefore are a potential impediment which should be recognized in the rule's calculations.

In July 2009, the National Energy Technology Laboratory (NETL) conducted a workshop [13] which reported that the largest barriers to heat rate improvement projects are the New Source Review provisions of the Clean Air Act and the lack of economic incentives exacerbated by the fuel adjustment clauses in utilities electrical rates permitting them to pass-through changes (increases) in fuel costs directly to consumers.

These conclusions are supported by the National Coal Council report previously cited which states the following about the potential impact of New Source Review

> "The New Source Review (NSR) permitting program unintentionally limits investments in efficiency. Some actions to improve efficiency at an existing power plant could lead to a designation of the change as a "major modification" subjecting the unit to NSR permitting requirements. These requirements usually entail additional environmental expenditures (that can reduce efficiency), as well as delays associated with processing the permit. In general, if a plant owner expects that an efficiency improvement would lead to such a designation, the efficiency project will not be pursued as the resulting permitting process would be extensive and the compliance requirements would be onerous and likely too stringent to be practicable."

The finances of power generating companies, both regulated and independent power producers (IPPs), require that any large expenditure must be justified, create a return on investment, or both. Often, smaller and/or older units operate less frequently, making a reasonable return on investment difficult to achieve for expensive modifications. In many cases, these units are old and may have a limited remaining life. Some heat rate improvement modifications and actions are costly and require a long period of operation to realize a return on investment. Thus some of these modifications may not be economically attractive for units with a few or unknown years of remaining projected lifetime.

In 2010, in collaboration with one of its member utilities, EPRI issued the results of a year-long study titled "Methodology for Fleetwide Energy Efficiency Analysis."[14] The focus of the research was the evaluation of power plant projects that would reduce CO_2 emissions by improving plant efficiency. A team of experts, including assistance from EPRI, developed a list of potential projects to improve power plant efficiency. The team developed estimates for each project including the cost to implement and the potential heat rate improvement. Next they determined which projects were applicable to each of their operating units. Those 174 capital projects were studied in detail to determine accurate, unit-specific

[13] "Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants Workshop Report", 2009, National Energy Technology Laboratory.
[14] EPRI Report 1021206, "Methodology for Fleetwide Energy Efficiency Analysis", 2010.

costs and heat rate improvement values. Of those 174 projects, 58 “top priority” projects were deemed as “no cost,” since fuel savings would eventually offset capital costs after 30 years. The initial cost to implement the 58 projects across this fleet was $61 million and the expected improvement in the heat rate of those plants was 2.5%. The remainder of the identified projects were estimated to cost $740 million to achieve an additional heat rate improvement of 2.5%.

Adverse Impacts due to Flexible Operations

Current operating conditions call on older coal plants for flexible operation, requiring load following and significant time at part load, again reducing plant efficiency. With the increased use of natural gas for electrical power generation and the proposal to increase it further, those coal-fired plants still in operation will be required to engage in flexible operations more frequently. These large coal plants were designed to be baseload and the near continuous variations in power level decreases both efficiency and reliability. EPRI completed a study in 2011 titled “Cycling and Load Following Effects on Heat Rate”[15] to determine the extent of the efficiency losses associated with increased load following. The report confirmed a substantial loss and identified the areas in the plant that suffered with the decreased load stability. Based on those results, both hardware and control systems were unable to maintain design operating values during portions of transient operation / non-steady state operation, (e.g. lower steam temperatures). Thus, the time that a unit spends operating at off-design conditions causes poorer heat rates.

In addition, there are potential wastewater-related impacts that should be recognized as FGD wastewater treatment –both biological as well as physical/chemical treatment approaches– may be negatively impacted with large swings in FGD water chemistry resulting from increasing flexible operations. For example, biological treatment is one of the proposed options under the effluent limitations guideline Best Available Technology (BAT) for FGD wastewater for selenium and nitrates. Initial EPRI research,[16] focused on FGD chemistry namely oxidation reduction potential, shows that FGD water chemistry can swing from high to low load.

1.2 Detailed Comments Building Block 2: Dispatch Changes

Technical assessment of NGCC 70% Capacity Factors

Based on EPRI and other known research, there are no technical reasons why individual NGCC units cannot maintain 70% capacity factors over the long term. Useful references for this technical assessment include:

[15] EPRI Report 1022061, “Cycling and Load Following Effects on Heat Rate”, 2011.
[16] EPRI Report 1022160, “Selenium Speciation and Management in Wet FGD Systems”, 2011.

- ASME paper GT2010-23182 "A Historical and Current Perspective of the Availability and Reliability Performance of Heavy Duty Gas Turbines: Benchmarks and Expectations"[17] which shows NERC GADS data for 2004-2008 timeframe. Average availability ranged from 86.9% to 90.2% depending on the unit size.

- Article in *Combined Cycle Journal*, 2nd Quarter, 2011,[18] showing combined cycle plants in the United States with F-class natural gas turbines achieved an average of 90.5% availability and 92.4% median availability based on NERC GADS data for 2005-2009 timeframe.

- Currently available NERC GADS Generating Availability Report shows average Availability Factor for 2010 and 2011 at about 87.7% (and an Equivalent Availability between 84.8%-85.8%).

It should be noted that capacity factors and availability factors are not the same thing. Availability factor indicates how often a power plant is capable of running (i.e., when it is not undergoing maintenance), while capacity factor indicates how often a power plant actually runs. Availability factor sets the upper bound on capacity factor. How often a power plant is dispatched when it is "available" will dictate its capacity factor. While EPRI sees no technical issue with individual NGCC units physically operating at a 70% capacity factor, there is little long-term operating experience with widespread and sustained operation of a majority of NGCC units at 70% capacity factor. Because maximum NGCC output is a function of weather conditions, assumptions regarding nameplate capacity should be re-examined to determine an appropriate assumption reflective of widespread NGCC operations at potentially high capacity factors across a wide range of weather conditions.

Based on maintenance guidance from natural gas turbine suppliers, EPRI concludes that increased capacity factors are not likely to cause decreased availability. Natural gas turbine suppliers recommend tracking both the number of starts experienced by a turbine and the number of operating hours. General Electric, for example, recommends natural gas turbines be taken out for inspection after 24,000 operating hours or 1200 starts, whichever comes first.[19] Consequently, a turbine which starts up and runs for only two hours every day would be taken off-line for inspection after 1,200 days (about three years and three months) while a turbine which operated 70% of the year (6,132 hours) and had one start per week would be taken off-line for inspection after three years and 10 months of service.

More critical questions than whether NGCCs can operate with higher capacity factors is whether there will be sufficient units to handle load-following duties that are currently handled by NGCCs if (i) most existing NGCCs move to baseload operation, or (ii) if economics drive reduced operation of the NGCCs

[17] ASME paper GT2010-23182 "A Historical and Current Perspective of the Availability and Reliability Performance of Heavy Duty Gas Turbines: Benchmarks and Expectations", ASME Turbo Expo 2010: Power for Land, Sea, and Air Volume 1: Aircraft Engine; Ceramics; Coal, Biomass and Alternative Fuels; Education; Electric Power; Manufacturing Materials and Metallurgy, ISBN: 978-0-7918-4396-3 | eISBN: 978-0-7918-3872-3
[18] See http://www.ccj-online.com/archives/2q-2011/commentary-ram-analysis/
[19] Balevic, David, Steven Hartman, and Ross Youmans, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations", GER- 3620L, GE Power Systems, Atlanta, GA, 2010.

(for example if natural gas prices are higher than expected by EPA). EPRI is concerned that today's coal fleet may not be able to provide adequate flexible operations capabilities for the overall fleet as most existing coal plants were not originally designed for such duty.

In the public inspection version of the preamble to the proposed rule, pages 186-7, it states: "We also conclude from our analyses that the extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. …delivered natural gas prices were projected to increase by an average of no more than ten percent…." In its evaluation of this section, EPRI found it difficult to identify EPA's modeling assumptions on the magnitude of exports of liquefied natural gas (LNG) from 2020 to 2029. The combination of increased LNG exports and increased consumption by the power industry could boost natural gas prices by more than EPA is anticipating, potentially leading to higher costs than estimated by EPA.

Further in that same section, Page 194, it states: "We invite comment on whether we should consider options for a target utilization rate for existing NGCC units greater than the proposed 70 percent target utilization rate." Given the approach in Building Block 3 to increase the amount of power generated from non-emitting sources, a capacity factor greater than 70% seems difficult to achieve. EPRI recognizes that 70% capacity factor may be incompatible with the desire to increase the contribution from renewable sources in certain regions of the country while at the same time noting that this is not related to the technical limitations of NGCCs. It is important to note that EPRI's assessment regarding technical feasibility of 70% NGCC capacity factor does not consider potential fuel availability or natural gas supply infrastructure issues.

Dispatch and system reliability

Establishing a dispatch-based mitigation goal that impacts other existing generation types without thorough consideration of the impacts to resource adequacy may significantly degrade reliability. During the extreme cold temperatures across most of the Southern and Eastern United States from January 6-8, 2014, natural gas fired generating plants did not perform as expected due to both plant outages and natural gas delivery system inadequacies. As an example, in the PJM footprint 9,700 MW of gas generation capacity was unavailable due to forced plant outages and another 9,300 MW unavailable due to natural gas supply constraints, such that approximately 36% of the natural gas generation capacity was effectively forced out.[20]

Sensitivity of NGCC unit capacity factors to natural gas prices

EPA used recent history to support the idea that NGCC units can increase capacity factors to 70% by stating in the proposed rule that "…changes in generation patterns have been driven largely by changes

[20] PJM Interconnection, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," May 8, 2014.

over time in *the relative prices of natural gas and coal"* (emphasis added, p. 175). However, history suggests that NGCC capacity factor is a sensitive function of natural gas prices; therefore, the assumption of high future NGCC capacity factors could be invalid if significant natural gas price volatility and increases were to be experienced in the future. This historical relationship is illustrated in Figure 1 by showing the trends in both the price of natural gas and resulting NGCC capacity factors from 2008 to 2013 from the most current U.S. Energy Information Administration (EIA) Electric Power Monthly.[21]

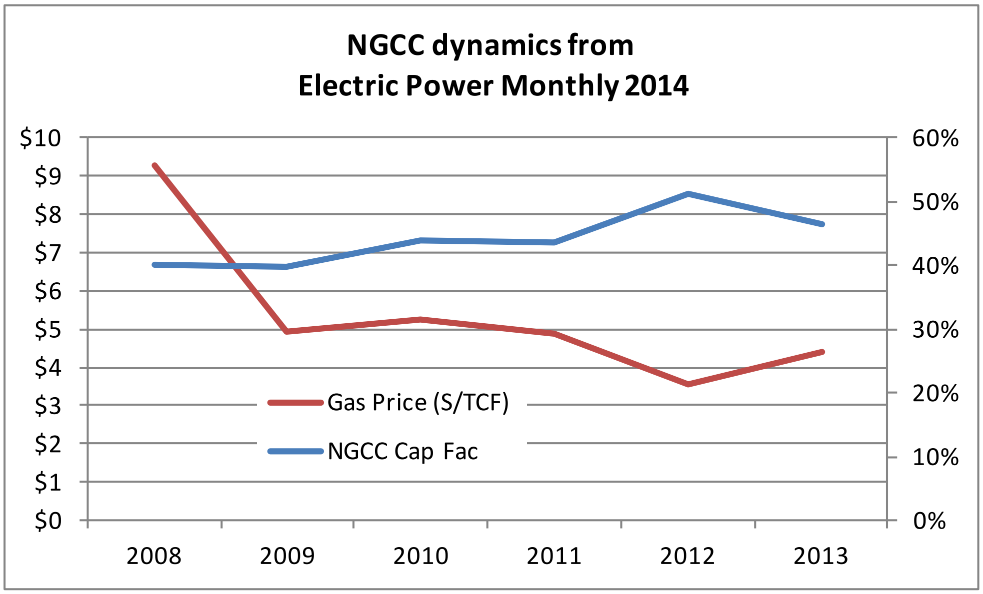

Figure 1: Natural gas price relationship to NGCC unit capacity factors

Specific Comments on Technical Support Document, "GHG Abatement Measures"

The following comments relate to specific sections and pages of the Technical Support Document (TSD), "GHG Abatement Measures" Chapter 3:

On page 3-5 under the heading "Historical Context" the CO_2 emission rate of U.S. coal power plants is stated to be 2,200 lb/MWhr and that of NGCCs is 907 lb/MWhr. Footnote 42 says this information comes from the "2012 eGrid data" file provided in the docket. On page 3-10, footnote 53 says the \$15/ton CO_2 "price signal" is based on CO_2 emission rates of 2,354 lb/MWhr for coal and 926 lb/MWhr for NGCC and also cites the 2012 eGrid data file. EPRI recommends EPA clarify or correct this discrepancy in the two sets of numbers cited as coming from the same data file.

The final sentence on page 3-10 cites an expected increase in natural gas production of 20% between 2012 and 2020 as a reason the United States can accommodate an increase in the average NGCC capacity

[21] http://www.eia.gov/electricity/monthly/

factor to 70%. EPRI suggests that it is important to evaluate what is expected to be consumed by the LNG export facilities which have recently been approved. For example, EPRI estimates 3.6 trillion cubic feet (TCF) per year have already been approved and another 3.6 TCF is under review by DOE.[22] EPRI recommends EPA clarify its assumptions for the potential magnitude of LNG exports to the potential price of natural gas.

Page 3-11: "Adding in the existing sources that were not yet online in 2012 (under construction) increases total NGCC generation calculated in the goal setting to 1,444TWh." This would represent a 50% increase over what was produced in 2012, which was a record year; however, in the "Building Blocks" memo TSD, EPA predicts NGCC power production in 2030 will be 1,743TWh, which is 178% of the 2012 value. That implies a significant increase in natural gas consumption versus today. For 2020 EPA predicts NGCC power production will be 1,369TWh, which shows a mismatch between what is in this reference document and what is in the cost-benefit calculation memo.

Page 3-12: "For comparison, NGCC generation growth of 450TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector." There is a miscalculation here based on what is stated in Footnote 69 where the heat rate of an NGCC is assumed to be 10,000 Btu/kWhr – EPRI believes this is too high. To get 3.5 TCF from 450TWh of electricity one has to assume a heat rate of 7,964 Btu/kWhr. However, EIA estimates the electric power sector consumed 9.1 TCF of natural gas in 2012.[23] Consuming an additional 3.5 TCF of natural gas would mean an increase of 38.5%, but that does not seem to match with the statement on page 3-11 that NGCC generation would increase by 50%. Although the amount of power produced by simple cycles might be large enough to account for this discrepancy, the modeling results in the cost-benefits memo show only a very small amount of power being generated by simple cycles.

The discussion on page 3-14 regarding the availability of NGCCs is confusing and seems to suggest that the availability of "advanced" NGCCs is higher than that of lower firing temperature NGCCs. EPRI recommends EPA clarify the discussion on page 3-14.

Page 3-20: In the discussion of the assumptions that went into EPA's IPM predictions they say they assigned a CO_2 charge to units that produced CO_2 at a rate greater than 1,100 lb/MWhr. Additional rationale for this charge and at this particular level would be useful.

Table 3-6: The base case has an NGCC capacity factor of 52% which is significantly higher than the value in 2012. It is uncertain whether this is due to the assumed impact of planned coal unit retirements and NGCCs taking up the slack or another reason.

[22] See table of proposed LNG export projects in N. Powell and S. Sullivan, "How LNG export projects could slot into DOE's reshuffled queue", SNL Data Dispatch, June 2, 2014.
[23] http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

Page 3-26: At the top of the page it is stated: "This is because only 29 state goals are premised on the existing NGCC fleet achieving an average capacity factor of 70 percent. Consequently, a 70 % utilization rate target for the existing NGCC fleet requires an average national capacity factor of 63 percent." This second sentence is confusing and should be clarified.

1.3 Detailed Comments Building Block 3a: Renewable Generation

Proposed Quantification

The EPA proposes primary and alternative approaches for quantifying target renewable energy generation levels for each state. The primary method divides contiguous states into six regions to define a "best practices" scenario. This approach begins by calculating a baseline renewable energy level for each region by summing 2012 levels of non-hydro renewable generation. Then, an aggregate renewable generation target for each region is calculated by averaging the existing Renewable Portfolio Standard (RPS) requirements currently adopted by states in the region. Finally, state-specific renewable energy targets are determined by applying a regional annual growth factor to the state's initial renewable energy level subject to the maximum generation target.

Adequately accounting for the spatial and temporal distributions of renewable resources and their associated costs is an essential consideration in regulatory design. However, the primary approach for calculating state-specific renewable energy targets assumes state equivalency for regional calculations of resource potential. This assumption is problematic when regions are large and encompass states with drastically different renewable resources. Given the sizeable areas spanned by the six EPA regions, there is evidence of differing levels of renewable energy resource adequacy and availability across these proposed regions. Additionally, the EPA assumption that existing RPS targets are feasible across all states within a defined region does not adequately consider the varying definitions of 'renewable' across the states. Renewable resources physically located in one state are often used to satisfy RPS requirements in other states. Since these benefits are not allocated to the buyer's state, this raises questions regarding treatment of the environmental attributes of the renewable resource.

The primary approach assumes that RPSs are a reasonable proxy for quantifying renewable generation potential because: (i) states with RPSs "…have already had the opportunity to assess those requirements against a range of policy objectives including both feasibility and costs;" and (ii) "RPS requirements developed by the states necessarily reflect consideration of the states' own respective regional contexts." As shown in recent literature[24, 25, 26] however, motivations for RPS implementation and stringency are

[24] Lyon, T. P., & Yin, H. (2010). Why do states adopt renewable portfolio standards?: An empirical investigation. Energy Journal, 31(3), 133-157.
[25] Delmas, M. A., & Montes-Sancho, M. J. (2011). US state policies for renewable energy: Context and effectiveness. Energy Policy, 39(5), 2273-2288.

multi-faceted and include many state-specific factors that cannot be generalized to other contexts or assumed to be indicative of best practices over a multi-decadal horizon.

Section 4 of the GHG Abatement Measures TSD assumes that all states in each region can achieve by 2030 the average of the 2020 requirements of RPS states in that region. To accomplish this, the TSD assumes that states within each region exhibit similar levels of renewable resources, an inference made from state-level technical resource potential projections reported in a NREL GIS-based analysis. In fact, a review of this NREL report reveals a rather wide variation in renewable technical potential for specific regions and by renewable resource. For example, the technical potential for biomass varies significantly across virtually all regions. Additionally, in the NREL study, all biomass feedstock land resources were considered available for biopower use. Competing uses of available land and biomass resource, such as for biofuel production, were not considered. This could further affect the technical resource potential for biopower within a region. The variation of renewable resource technical potential is perhaps the most pronounced for the West region. Significant variability in renewable technical resource is indicated for hydrothermal, urban photovoltaic (PV), rooftop PV, concentrated solar power (CSP), and hydropower.

Even if renewable resources across states in a region had similar technical potentials, the primary renewable energy approach does not consider how these profiles may have dissimilar market potentials. Accounting for heterogeneous abatement cost functions for renewable resources across states is an important element in reaching specified emissions targets while minimizing abatement costs (or conversely in reducing more emissions for a given expenditure level). Identical standards for groups of states clustered by their technical potentials are not necessarily indicative of relative compliance burdens, especially in the presence of grid integration costs, siting concerns, and the provision of balancing flexibility from existing assets. Inadequately accounting for this cost information may overlook opportunities for lower-cost reductions in other states or building blocks, which would be exploited in an approach with broader coverage and greater flexibility.

A more appropriate and comprehensive basis for state clustering would be informed by the market potential for renewable energy development, which would include technology costs, fuel costs (e.g., for biomass), investor response, regional competition for other resources, learning-by-doing and network effects, regulatory limitations, and public acceptance. These externalities will influence regional renewable energy costs. EPRI assessed and reported the regional costs for deployment of renewable generation in two key reports.[27,28]

For a state where renewable generation (based on 2012 levels) already meets or exceeds the regional renewable energy target proposed under this quantification in Building Block 3, its obligation under the

[26] Carley, S., & Miller, C. J. (2012). Regulatory stringency and policy drivers: A reassessment of renewable portfolio standards. Policy Studies Journal, 40(4), 730-756.
[27] EPRI Report 1023993, "Renewable Energy Technology Guide: 2012".
[28] EPRI Report 1026656, "Program on Technology Innovation: Integrated Generation Technology Options 2012", 2013.

target is capped at its share of the regional renewable energy target. Similarly, once a state meets its share of the regional renewable energy target from 2017–2030, its obligation is capped. One alternative approach would be to incentivize states that have already met the renewable energy target to continue promoting renewable development and consider this 'added' renewable generation as an overall contribution to the regional renewable energy target. Such an approach could better account for the economic and market externalities that will impact individual state renewable energy deployment within a region.

Alternative Approaches to Quantifying Renewables

In addition to its primary approach for quantifying state-specific renewable energy targets, EPA proposes an alternate approach that determines available resources using a bottom-up methodology described in a TSD. This alternative approach relies on a metric that compares a state's renewable energy technical potential to its current renewable energy generation for different technology types and on IPM-projected market potentials at cost reductions of up to $30/MWh. For a given renewable technology, a state's target is defined as the lesser of the benchmark rate (based on the development renewable energy rate of the top 16 U.S. states) multiplied by state-specific technical potential (measured by NREL) or the IPM-generated development level.

In contrast to the primary approach, this metric attempts to incorporate information about technical and market potential simultaneously to inform renewable energy targets. Information on renewable energy technical potential is taken from the NREL GIS-based study. IPM modeling offers at least the possibility that development costs, grid limitations, and other considerations described above are taken into account.

However, the documentation associated with the alternative renewable energy approach does not present compelling justifications for many of its primary assumptions, including:

- Selection of the top one-third of states (16) in defining the average development rate;
- Selection of $30/MWh as a cost reduction target for IPM-projected market potential;
- Performing minimization of two metrics rather than maximization; and
- Selection and granularity of the technology choice set.

The TSD also does not illustrate robustness of targets to alternate specifications and does not provide a sense for how reasonable alternatives could bias flexibility and cost estimates.

EPA describes a different alternative method in the TSD that uses state-by-state assessments of technical and economic potential for different renewable energy technologies. The method compares the "…estimated cost of new renewable energy to the avoided cost of energy from implementing clean energy generation, by comparing the total cost of generation for each renewable energy technology by region to the estimated fuel, operating, and capital costs avoided by adding that generation." Since this approach uses detailed supply curve information from many locations, it broadly seems more consistent with cost-effective compliance than the primary and alternative methods. However, there is insufficient evidence about the precise methodology or its results to make definitive assertions about the relative merits and transparency of this approach.

1.4 Detailed Comments Building Block 3b: Nuclear Generation

EPRI has no specific technical comments on EPA's development of Building Block 3b on nuclear power generation. However, in reviewing how EPA used this building block for state goal setting and in the RIA, it's not clear if the Agency took into account the lifetime of nuclear units and that many units will hit the 60 year mark by 2029.

The current U.S. fleet of operating nuclear reactors stands at 100 units. These reactors were originally licensed for 40 years. License extension (for an additional 20 years) has been applied for and granted in many cases, although a number of plants have shut down prior to the end of their licensed lifetime.

The license expiration for each unit in the current fleet is shown in Table 1. There are 28 units that have licenses scheduled to expire before 2030. Of these, 18 units have pending applications submitted to extend their license from 40 to 60 years. Three units with licenses scheduled to expire prior to 2030 are already in their extended period of operation and would need to obtain additional license extension to extend their operating lives to 80 years (known as subsequent license renewal). Though it is expected that many reactors will apply for and receive license extensions out to 80 years, there is no level of certainty at this time.

Due to on-going economic pressures and the need for many plants to obtain license extensions, there is significant uncertainty as to the number of reactors that will be operating in 2030. Several nuclear plants have already shut down prior to their license end date. Looking beyond 2030, an additional 50 units have licenses expiring between 2030 and 2040.

There also is uncertainty that either companies will decide not to seek license extensions due to economic considerations, or that the Nuclear Regulatory Commission may not approve further extending the lifetimes of these units. As a consequence, the estimate EPA developed of available non-emitting nuclear power may be an overestimate. EPRI recommends that EPA consider a lower bound case and a sensitivity analysis on the potential nuclear power capacity.

Table 1: License expiration dates for current nuclear fleet

Plant Name, Unit Number	Operating License Expires
Indian Point Nuclear Generating, Unit 2	9/28/2013
Indian Point Nuclear Generating, Unit 3	12/12/2015
Davis-Besse Nuclear Power Station, Unit 1	4/22/2017

Plant Name, Unit Number	Operating License Expires
Sequoyah Nuclear Plant, Unit 1	9/17/2020
Sequoyah Nuclear Plant, Unit 2	9/15/2021
LaSalle County Station, Unit 1	4/17/2022
LaSalle County Station, Unit 2	12/16/2023
Callaway Plant	10/18/2024
Limerick Generating Station, Unit 1	10/26/2024
Byron Station, Unit 1	10/31/2024
Grand Gulf Nuclear Station, Unit 1	11/1/2024
Diablo Canyon Nuclear Power Plant, Unit 1	11/2/2024
Waterford Steam Electric Station, Unit 3	12/18/2024
Fermi, Unit 2	3/20/2025
Diablo Canyon Nuclear Power Plant, Unit 2	8/26/2025
River Bend Station, Unit 1	8/29/2025
Perry Nuclear Power Plant, Unit 1	3/18/2026
Clinton Power Station, Unit 1	9/29/2026
Braidwood Station, Unit 1	10/17/2026
Byron Station, Unit 2	11/6/2026
South Texas Project, Unit 1	8/20/2027
Braidwood Station, Unit 2	12/18/2027
South Texas Project, Unit 2	12/15/2028
Oyster Creek Nuclear Generating Station, Unit 1	4/9/2029
Limerick Generating Station, Unit 2	6/22/2029
Nine Mile Point Nuclear Station, Unit 1	8/22/2029
R.E. Ginna Nuclear Power Plant	9/18/2029
Dresden Nuclear Power Station, Unit 2	12/22/2029
Comanche Peak Steam Electric Station, Unit 1	2/8/2030
Seabrook Station, Unit 1	3/15/2030
H. B. Robinson Steam Electric Plant, Unit 2	7/31/2030
Monticello Nuclear Generating Plant, Unit 1	9/8/2030
Point Beach Nuclear Plant, Unit 1	10/5/2030
Dresden Nuclear Power Station, Unit 3	1/12/2031
Palisades Nuclear Plant	3/24/2031
Vermont Yankee Nuclear Power Plant, Unit 1	3/21/2032
Surry Nuclear Power Station, Unit 1	5/25/2032
Pilgrim Nuclear Power Station	6/8/2032
Turkey Point Nuclear Generating, Unit 3	7/19/2032
Quad Cities Nuclear Power Station, Unit 1	12/14/2032

Plant Name, Unit Number	Operating License Expires
Quad Cities Nuclear Power Station, Unit 2	12/14/2032
Surry Nuclear Power Station, Unit 2	1/29/2033
Comanche Peak Steam Electric Station, Unit 2	2/2/2033
Oconee Nuclear Station, Unit 1	2/6/2033
Point Beach Nuclear Plant, Unit 2	3/8/2033
Turkey Point Nuclear Generating, Unit 4	4/10/2033
Peach Bottom Atomic Power Station, Unit 2	8/8/2033
Fort Calhoun Station, Unit 1	8/9/2033
Prairie Island Nuclear Generating Plant, Unit 1	8/9/2033
Oconee Nuclear Station, Unit 2	10/6/2033
Browns Ferry Nuclear Plant, Unit 1	12/20/2033
Cooper Nuclear Station	1/18/2034
Duane Arnold Energy Center	2/21/2034
Three Mile Island Nuclear Station, Unit 1	4/19/2034
Arkansas Nuclear One, Unit 1	5/20/2034
Browns Ferry Nuclear Plant, Unit 2	6/28/2034
Peach Bottom Atomic Power Station, Unit 3	7/2/2034
Oconee Nuclear Station, Unit 3	7/19/2034
Calvert Cliffs Nuclear Power Plant, Unit 1	7/31/2034
Edwin I. Hatch Nuclear Plant, Unit 1	8/6/2034
James A. FitzPatrick Nuclear Power Plant	10/17/2034
Donald C. Cook Nuclear Power Plant, Unit 1	10/25/2034
Prairie Island Nuclear Generating Plant, Unit 2	10/29/2034
Brunswick Steam Electric Plant, Unit 2	12/27/2034
Millstone Power Station, Unit 2	7/31/2035
Watts Bar Nuclear Plant, Unit 1	11/9/2035
Beaver Valley Power Station, Unit 1	1/29/2036
St. Lucie Plant, Unit 1	3/1/2036
Browns Ferry Nuclear Plant, Unit 3	7/2/2036
Calvert Cliffs Nuclear Power Plant, Unit 2	8/13/2036
Salem Nuclear Generating Station, Unit 1	8/13/2036
Brunswick Steam Electric Plant, Unit 1	9/8/2036
Joseph M. Farley Nuclear Plant, Unit 1	6/25/2037
Donald C. Cook Nuclear Power Plant, Unit 2	12/23/2037
North Anna Power Station, Unit 1	4/1/2038
Edwin I. Hatch Nuclear Plant, Unit 2	6/13/2038
Arkansas Nuclear One, Unit 2	7/17/2038
Salem Nuclear Generating Station, Unit 2	4/18/2040

Plant Name, Unit Number	Operating License Expires
North Anna Power Station, Unit 2	8/21/2040
Joseph M. Farley Nuclear Plant, Unit 2	3/31/2041
McGuire Nuclear Station, Unit 1	6/12/2041
Susquehanna Steam Electric Station, Unit 1	7/17/2042
Virgil C. Summer Nuclear Station, Unit 1	8/6/2042
McGuire Nuclear Station, Unit 2	3/3/2043
St. Lucie Plant, Unit 2	4/6/2043
Catawba Nuclear Station, Unit 1	12/5/2043
Catawba Nuclear Station, Unit 2	12/5/2043
Columbia Generating Station, Unit 2	12/20/2043
Susquehanna Steam Electric Station, Unit 2	3/23/2044
Wolf Creek Generating Station, Unit 1	3/11/2045
Palo Verde Nuclear Generating Station, Unit 1	6/1/2045
Millstone Power Station, Unit 3	11/25/2045
Hope Creek Generating Station, Unit 1	4/11/2046
Palo Verde Nuclear Generating Station, Unit 2	4/24/2046
Shearon Harris Nuclear Power Plant, Unit 1	10/24/2046
Nine Mile Point Nuclear Station, Unit 2	10/31/2046
Vogtle Electric Generating Plant, Unit 1	1/16/2047
Beaver Valley Power Station, Unit 2	5/27/2047
Palo Verde Nuclear Generating Station, Unit 3	11/25/2047
Vogtle Electric Generating Plant, Unit 2	2/9/2049

Source: http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1350/

1.5 Detailed Comments Building Block 4: Demand Side Energy Efficiency

The level of energy efficiency performance in this proposed rulemaking –1.5% annual incremental electricity savings as a percentage of retail sales– is greater than EPRI's assessment of energy efficiency program potential. EPRI research indicates that achieving this level of energy efficiency will required the addition of measures beyond energy efficiency programs and will occur over a longer period and at a higher cost than suggested in the proposed rule and accompanying RIA.

EPRI's recently published study "U.S. Energy Efficiency Potential Through 2035"[29] indicates an achievable range of energy efficiency potential from programs equivalent to an annual incremental electricity savings of 0.5% to 0.7% of retail sales through 2035. Moreover, EPRI estimates the economic potential of energy efficiency – characterized by 100% adoption of all cost-effective energy efficiency

[29] EPRI Report 1025477, "U.S. Energy Efficiency Potential Through 2035", 2014.

measures as customers phase them in over time – as equivalent to 0.9% of annual retail sales through 2035. By these benchmarks, the goal of 1.5% annual incremental savings represents a target that may be beyond the scope of cost-effective energy efficiency measures in the context of energy efficiency programs. In EPRI's view, other mechanisms complementary to energy efficiency programs, including federal, state, and local energy efficiency building codes and energy efficiency product standards, would be needed to attain the target levels.

EPRI's Energy Efficiency Potential Model[30] uses an appliance stock turnover approach to estimate the potential for energy efficiency by sector, by region, and by end-use. The model utilizes base data on national and regional electricity consumption from the EIA Annual Energy Outlook (AEO)[31,32] and detailed information on the performance and costs of technologies and measures from multiple sources, including regional measure databases, engineering models, and EPRI's staff of technical experts. The results are adjusted to reflect market barriers and best practices for energy efficiency programs as seen today. This well-established approach provides an accurate and useful estimate of the potential for energy efficiency that has been used to inform electric utilities and other entities in developing and augmenting energy efficiency programs.

The levels of energy efficiency in the proposed rulemaking represent a realization of best-in-class performance as achieved or mandated by a select few states. While EPRI agrees that efficiency improvements in end-use devices and advances in controls technology can make the realization of electricity savings equivalent to 1.5% of retail sales technically possible, economic, market, and perceptual barriers can inhibit or curb customer adoption. These barriers can be overcome with federal, state, and local energy efficiency building codes and energy efficiency product standards. EPRI's energy efficiency potential study indicates it will be necessary to use these methods to achieve the levels EPA assumes as energy efficiency programs alone will not reach these levels. However, these methods can take longer to implement and produce results less than utility best-in-class programs. Moreover, there is a 'learning curve' associated with effective implementation of energy efficiency programs. States with more experience implementing energy efficiency programs are likely to have a higher proficiency at launching new energy efficiency programs, whereas, states with less experience may require more time bring their programs to market. In addition, while a small number of states are achieving electricity savings at level commensurate with the 1.5% incremental annual target, maintaining that level over decades has not been proven. These factors lead EPRI to question whether a level of 1.5% incremental energy efficiency can be achieved as quickly as EPA assumes.

Additionally, there are market considerations that can inhibit or curb the realization of energy efficiency measures, even when they are economically beneficial to consumers. For example, dislocations in

[30] EPRI Report 3002001417, "User Guide to the Utility Energy Efficiency Potential Calculator Version 2.0", 2013.
[31] Latest available version: U.S. Energy Information Administration (EIA). "Annual Energy Outlook 2014 with Projections to 2040". U.S. DOE EIA, Washington DC, DOE/EIA-0383(2014). April 2014.
[32] EPRI's most recent analysis for national and regional energy efficiency potential referenced: "Annual Energy Outlook 2012 with Projections to 2035," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2012), June 2012.

customer awareness of energy efficiency measures or the market availability of energy efficiency measures can hamper adoption. While such market considerations can be, and have been, overcome with federal, state, and local energy efficiency building codes and energy efficiency product standards, these methods will increase the customer's cost of energy efficiency implementation. This is because the consumer cost of energy efficiency measures implemented through codes and standards is not offset by energy efficiency program incentives. This introduces another risk of decreased or slower adoption rates than EPA's assumptions.

In addressing customer economics, EPA determines its proposed levels of energy efficiency to be economic based on estimates for levelized cost of saved energy (LCOSE). EPA's estimates for LCOSE that would be incurred by achieving the 1.5% incremental savings goal are based on available electric utility program costs and the historical relationship between program costs and participant costs. While EPA has taken a conservative approach by applying program costs at the higher end of the range of reasonable values, the assumption that the ratio of participant costs to program costs will remain fixed at historical levels in the future may understate participant costs and therefore understate LCOSE and thereby overstate energy efficiency potential.

EPA estimates the LCOSE for participants to be between $85/MWh and $90/MWh. This estimate is difficult to assess since EPA does not specify the composition and relative contributions of end-use measures towards the overall energy savings target. Each end-use has a unique load shape, and specific technologies within an end-use category may have distinct load shapes. Load shapes can have a significant bearing on the costs of energy efficiency. For instance, energy savings distributed over nighttime hours, such as from residential lighting technologies, may not be as cost effective as energy savings distributed primarily over summer on-peak hours, such as from energy-efficient air conditioning. Therefore, the LCOSE is difficult to estimate without some assumptions of the underlying load shapes of energy savings

EPA compares its estimated LCOSE of $85/MWh to $95/MWh to American Council for an Energy-Efficient Economy's (ACEEE's) LCOSE value of $54/MWh.[33] The ACEEE value is reduced by its assumed level of incentives of 20% of participant costs which were derived from the assumption of equal program costs and participant costs. The incentives are removed from these LCOSE estimates. These estimates are so tightly bound by the assumptions that any error or changes in the future may produce much higher cost and much less available efficiency. This could mean that achieving a level of 1.5% incremental energy efficiency will cost more than EPA assumes.

In looking further at the economics of energy efficiency, the use of an assumed level of incentives, 20% of estimated first participant costs, may produce distributional or subsidization effects between participants and non-participants if the impacts are not limited by the avoided cost savings. This is a consequence of the use of the Standard Practice Economic Tests for energy efficiency. The total resource

[33] ACEEE. "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. U1402. March 2014.

cost (TRC) test, used by EPA and standard in the industry, is not affected by incentive levels which are a transfer payment between constituent groups. EPRI cautions that if the use of the TRC in choosing and designing energy efficiency measures is not tempered with examination of appropriate incentive levels through the use of ratepayer impact measures or participant cost tests, then uneconomic cross-subsidies may result depending upon the load shape of the energy efficiency implemented.

Finally, in addition to using federal, state, and local energy efficiency building codes and energy efficiency product standards, evidence indicates that the adoption of financial mechanisms that encourage electric utility investment in energy efficiency, similar to those underway in several states, can facilitate the achievement of incremental energy efficiency. Such measures include allowance for recovery of energy efficiency program and administrative costs, the recovery of the lost contribution to fixed costs, and an incentive for shareholders or ratepayers to produce the desired "best practice" efforts.

Assumptions/basis for converting energy efficiency savings to CO_2 emissions reductions

EPA contends that there is a link between electrical energy efficiency and reductions in CO_2 emissions. The EPA's GHG Abatement document[34] refers to projected average 2020 Emissions Intensity across the U.S. Power Systems of 1,127 lbs/MWh saved. EPA describes this calculation as an average of the emissions reduced using IPM and from its base case.

EPRI research supports the assertion that the implementation of energy efficiency produced measurable, verifiable, and permanent emission reductions. EPRI has developed an emissions calculator based on its environmental analyses using the US Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN)[35]. As part of this analysis, EPRI estimates marginal emissions impacts of changes in load as a function of the characteristic load shapes of individual end-use measures.

EPRI and EPA models recognize that CO_2 emission impacts depend upon the spatial and temporal effects of changes in the load. EPRI agrees that using a model that captures the timing of energy efficiency implementation in relation to the generation dispatch stack allows for an energy efficiency portfolio to be optimized for CO_2 reduction.

EPRI research supports the link between energy efficiency and CO_2 intensity reduction and finds that EPA's approach for determining CO_2 intensity reductions of current energy efficiency measures is reasonable. However, EPA's approach and method may not be appropriate for long term forecasting; it does not account for evolution of the generation fleet over time. As the mix of generation in a given region changes, so does the average and marginal intensity of CO_2 emissions, which will in-turn impact the emissions reduction impact of specific types of energy efficiency interventions.

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[34] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: GHG Abatement, U.S. Environmental Protection Agency, Office of Air and Radiation, June 2014.

[35] EPRI Report 3002001410, "EPRI Energy Efficiency CO_2 Intensity Calculator, 2013 Edition".

2. DETAILED COMMENTS ON STATE GOALS

2.1 Form of the Goals, BSER Structure, and Compliance

The EPA proposed BSER, while granting broad flexibility in implementation, proposes a system of compliance that is intrinsically inflexible. The dynamics of compliance, under circumstances of any unexpected shortfall in the non-emitting resources required for compliance, creates the risk of multi-state compliance failures that would disrupt interstate power flows. To the extent levels of renewable energy, nuclear credits, and energy efficiency posited in EPA's target setting are not realized (i.e., the sum of Building Blocks 3 and 4 [BB3+4]), covered fossil generation will need to be curtailed below 2012 levels to satisfy compliance. While the specifics vary from state to state, at the national level, under delivery of a certain amount (X) of MWh from energy efficiency or renewable energy will require a 2.5 X MWh reduction in covered fossil generation for compliance. This dynamic will force states to seek increased imports, cut exports, or construct redundant new generation outside the jurisdiction of 111(d). If the shortfall occurs unexpectedly (i.e., within the lead time for securing new renewable energy, energy efficiency, or new NGCC capacity) the curtailed supply may force a choice between compliance and reliability. States that cut electricity exports (or ramp up imports) transfer the problem to neighboring states, forcing them to seek the power elsewhere; however, the BSER design cuts the short term response capability of the existing fleet to a minimum across all the states.

The BSER Building Blocks cover coal unit heat rate improvements (BB1), redispatch from coal[36] units to existing NGCCs[37] (BB2) and credit for non-emitting generation. The non-emitting generation includes an allowance for nuclear output[38] and renewable output (BB3) and certified load reductions from energy efficiency (BB4). The building blocks are combined into a CO_2 emission rate:

$$Rate^* = \frac{(Minimized\ Covered\ Fossil\ CO2\ per\ BB1\ and\ BB2)}{(2012\ Fossil\ MWh)\ +\ (EPA\ target\ BB3\ and\ BB4\ MWh)}$$

The proposal sets an annual target rate (*Rate**) for each state, starting with an interim target in 2020 that becomes tighter (lower) by 2029 and is constant thereafter. Compliance requires meeting the target rate over a three-year rolling average. EPA proposes target rates tailored to each state, mostly based on 2012 data. The resulting targets make near-maximum use of the opportunities for redispatching NGCCs for coal, and seek substantial increases in deployment of renewable energy and energy efficiency that may be unrealistically high (see comments above on renewable energy and energy efficiency). Nationally, the implied expectations in the state goals for nuclear credits renewable energy and energy efficiency sum to

[36] Also includes redispatch of oil and gas steam generation.
[37] Available redispatch MWH is NGCC output at a 70% capacity factor, minus 2012 generation.
[38] 6% of nuclear generating capacity as of May 2014 at a 90% capacity factor.

almost 1,000TWh in 2030, approximately 25% of current generation.[39] By comparison, total covered fossil generation in 2012 was about 2,50TWH (~60% of total generation).

States have flexibility in how they meet the target rate through varying mixes of non-emitting generation (nuclear, renewable energy, and energy efficiency) and different mixes and levels of fossil generation (coal and natural gas).

By the nature of the compliance equation, a shortfall in BB3+4 requires a reduction in covered fossil emissions. The two options for cutting covered CO_2 emissions are to redispatch more NGCC MWh for coal (which cuts the numerator), or by cutting the covered fossil output (which cuts both the numerator and the denominator).[40] Most states will have limited opportunity for additional redispatch beyond what was subsumed in the target setting. This is because the targets were set so that (i) either the existing NGCCs are at a 70% capacity factor, which leaves little room for additional output, or (ii) the coal generation has been fully displaced and is already at zero. As a consequence, for most states the bulk of any adjustment to maintain compliance in the face of a shortfall in renewable energy or energy efficiency deliveries will be made up by reducing the output of the covered fossil generation. However, the algebra of the compliance equation dictates a multiplier effect called the "Fossil Leverage Factor" (FLF). This factor dictates the reductions in fossil MWh induced per MWh of lower deliveries of BB3 or BB4. Roughly speaking, a 10% shortfall in displacing generation will require a 10% reduction in covered fossil generation. Given the 2.5:1[41] ratio between these two resources at the national level, this means that a 100TWh shortfall BB3+4 will require an additional 250TWh curtailment of covered fossil generation to maintain compliance. The total deficit becomes 350TWh.[42]

Each state has its own FLF and as can be seen in the Table 2 below; they vary widely. At the state level the FLF can be calculated as:

$$FLF = Rate^*/(r - Rate^*)$$

where Rate* is the state's target emission rate and r is the marginal emission rate for that state's fossil generation (i.e., the coal emission rate if coal has not been redispatched to zero, or if so the NGCC rate).

For 20 states, a one MWh shortfall in the sum of BB3 and BB4 deliveries must be made up by more than two MWh. As can be seen in the "Gen as a % of Sales" column, many of the high leverage states export large fractions of their generation (e.g., West Virginia, North Dakota, and Arizona). If they cut back exports to achieve compliance, trading partners will then be forced to find replacement power. Options

[39] Whether these goals are attainable at reasonable cost is not pertinent to this comment.
[40] The converse also applies; greater levels of displacing generation allow fossil sources to increase their output and their emissions while still meeting the target compliance rate.
[41] The ratio follows from the 2,500TWh of covered fossil generation to the 1,000 of Nuc, RE, and EE, summed across all the state in the EPA spreadsheet setting the rate targets.
[42] Note that for shortfalls in output from existing nuclear units would have a smaller multiplier, reflecting that only 6% of existing nuclear output is input to BB3, though shortfalls in output from new nuclear that is included in the target calculations would be similar to the 3.5 for RE and EE.

for making up the lower generation include increased output from new generation (NGCCs) or importing more power from out-of-state (or cutting exports to other states). This transfers the pressure to other states which will need to increase their generation, but their covered fossil generation is similarly tied to deliveries of BB3+4 displacing generation. The result risks creating a multi-state shortage of covered generation, forcing a choice between reliability and compliance.

Table 2: State Fossil Leverage Factors

Rank	State	2020 Fossil Leverage Factor	2030 Fossil Leverage Factor	Gen as % of Sales
1	Alabama	1.37	0.99	151%
2	Alaska	0*	6.87	96%
3	Arizona	6.37	3.55	143%
4	Arkansas	0.93	0.74	114%
5	California	2.13	1.63	71%
6	Colorado	1.47	1.13	89%
7	Connecticut	4.44	2	106%
8	Delaware	0.94	0.72	45%
9	Florida	0.67	0.54	90%
10	Georgia	0.81	0.63	88%
11	Hawaii	2.95	2.02	96%
12	Idaho	0.45	0.36	47%
13	Illinois	2.09	1.38	127%
14	Indiana	5.15	3.08	103%
15	Iowa	1.95	1.59	113%
16	Kansas	3.31	2.07	110%
17	Kentucky	18.9	6.45	97%
18	Louisiana	0.87	0.68	90%
19	Maine	0.96	0.8	133%
20	Maryland	3.18	1.41	61%
21	Massachusetts	0.61	1.85	75%
22	Michigan	1.62	1.21	104%
23	Minnesota	0.8	0.67	83%
24	Mississippi	12.07	4.42	99%
25	Missouri	6.71	3.72	99%
26	Montana	7.08	3.4	208%
27	Nebraska	5.28	2.59	113%
28	Nevada	5.86	2.75	97%

Rank	State	2020 Fossil Leverage Factor	2030 Fossil Leverage Factor	Gen as % of Sales
29	New Hampshire	2.65	1.24	195%
30	New Jersey	5.85	1.48	76%
31	New Mexico	1.19	0.91	150%
32	New York	0.54	0.36	93%
33	North Carolina	1.6	1.07	86%
34	North Dakota	4.96	4.03	259%
35	Ohio	3.66	2.03	86%
36	Oklahoma	0.85	0.7	114%
37	Oregon	1.24	0.78	111%
38	Pennsylvania	1.89	1.13	142%
39	Rhode Island	17	5.77	98%
40	South Carolina	0.83	0.61	115%
41	South Dakota	0.69	0.53	82%
42	Tennessee	1.79	1.23	72%
43	Texas	0.79	0.6	98%
44	Utah	2.89	2.12	127%
45	Virginia	0.87	0.61	58%
46	Washington	0.68	0.35	108%
47	West Virginia	23.35	5.17	233%
48	Wisconsin	1.63	1.18	84%
49	Wyoming	6.52	3.6	256%
*Mix of fuels makes calculation of Leverage Factor for 2020 ambiguous for Alaska.				

For states that have rate targets with zero coal output assumed (e.g., AZ, CA, NY, MS, MA), the only source of covered emissions is NGCC output. If state compliance planners believe that availability/deliverability of renewable energy and/or energy efficiency is below the expectations used by EPA to set state rate targets, then the only in-state option for compliance is adding *new* NGCCs to back-off existing NGCCs, clearly an inefficient solution.

Even if a state has abundant renewable energy and energy efficiency opportunities, there is still an operational issue due to multi-year delivery lead times. The displacing generation options have substantial lead times. For renewable energy, the lead time is taken up by integration studies, siting, permitting, construction, and possible transmission enhancements. Energy efficiency programs have lead times to set up, and the measurement and certification of results will likely mean that participation in the compliance accounting will lag substantially. The nuclear credits are even less flexible and face only downside uncertainty. This means that within the year, or even within a three year rolling average compliance period, the only flexible compliance option is redispatching NGCCs for coal, and as observed above, the state targets were set at levels that essentially fully utilize that option.

It is worth noting that these near-term dynamic issues will not show up in simulation models such as IPM that have perfect foresight. The models deliver the displacing generation by assumption or otherwise make up deficits by adding new generation. It is when resources do not become available as planned that the near-term operational issues identified here become important.

The basic challenge is that the BSER couples slow-moving long-lead time compliance options (e.g., nuclear, renewable energy, energy efficiency) to short-lead-time options (i.e., redispatch from coal to natural gas). The only "fast moving" option, redispatch, has by the BSER's design been largely maxed out. In the short term, any deficits will be transferred to other states through the power market. In the longer term, adding new NGCCs to back down existing NGCCs, though wasteful, can satisfy compliance obligations.

In consideration of the above challenges, EPRI offers the following alternatives to address them:

- Assure that the renewable energy and energy efficiency assumptions used to set state targets are realistic with little uncertainty in their attainment. This would help avoid shortfalls with multiplier effects, but would still be subject to risk from non-delivery in the short term. Allowing states to bank "over generation" of energy efficiency and renewable energy would help avoid future shortfalls and their negative consequences.

- Including safety values to limit the reductions in covered fossil output if/when there are shortfalls in BB3 + BB4 output could help keep compliance problems in one state from propagating to other states through the power market.

Longer averaging periods for compliance provide only limited value under most circumstances. Deficits in BB3+BB4 deliveries must be fully covered by subsequent "over deliveries" to comply with the target over the averaging period. Given the lead times for adding more renewable energy or energy efficiency, this is unlikely to be possible with a three-year averaging period, and in any case requires over investment creating an eventual surplus of energy efficiency or renewable energy in the long term.

2.2 Calculation Issues with Individual Building Block and State Goals

This section highlights a common point of confusion in analyzing the relative contribution of the individual Building Blocks used to create the EPA target rate by state. Because the EPA target rate is a fraction (i.e., lbs/MWh) the contribution of each Building Block to making up the target rate *depends crucially on the order in which the Building Blocks are added*. As a result, if the computation is performed by first removing heat rate improvement (BB1), then natural gas re-dispatch (BB2), renewables and nuclear (BB3), and energy efficiency (BB4) in that order, the results will be different than if the computation were performed by first removing BB4, then BB3, BB2, and BB1. Below is an example of this issue for the state of Pennsylvania.

For this reason, EPRI provides its own assessment of the impact of each Building Block by state that provides data that is comparable across Building Blocks and does not depend upon the ordering. This is done by removing one Building Block at a time from EPA's computation, calculating the new target rate (and hence the difference), then adding that Building Block back in, before removing the next. In this way, the impact of each Building Block on the target rate is computed from the same baseline (the EPA target rate), and are thus directly comparable. Any progressive one-by-one approach does not have this property and will tend to exaggerate the impact of the Building Blocks removed last in the calculations.

Example of How Building Block Ordering Affects Contributions to the Target Rate

From the EPA provided spreadsheet '20140602tsd-state-goal-data-computation.xlsx' the following can be computed for 2030 that make up the calculation for the target rate in Pennsylvania.

CO_2 emissions: 210,942.6 million lbs

Covered fossil generation (BB1&2): 142.52TWh

Expected renewables generation for Pennsylvania (BB3): 35.33TWh

Existing nuclear generation (at 6% credit – BB3): 4.48TWh

Energy efficiency (BB4): 18.19TWh

EPA's target rate can then be written down as

$$\text{Target rate} = \frac{210942.6}{142.52+35.33+4.48+18.19} = 1052 \text{ lb/MWh.}$$

Suppose you consecutively remove BB1, BB2, BB3, and BB4 in that order. As you remove each building block, the target rate changes as shown below

$$\text{Rate} - \text{BB1} = \frac{220849.4}{142.52+35.33+4.48+18.19} = 1101 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} = \frac{231891.6}{142.52+35.33+4.48+18.19} = 1156 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} - \text{BB3} = \frac{231891.6}{142.52+18.19} = 1443 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} - \text{BB3} - \text{BB4} = \frac{231891.6}{142.52} = 1627 \text{ lb/MWh.}$$

Now suppose you instead consecutively remove BB4, BB3, BB2, and BB1 in that order. As you remove each building block, the target rate changes as shown below

$$\text{Rate} - \text{BB4} = \frac{210942.6}{142.52 + 35.33 + 4.48} = 1157 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} = \frac{210942.6}{142.52} = 1480 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} - \text{BB2} = \frac{220881.4}{142.52} = 1550 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} - \text{BB2} - \text{BB1} = \frac{231891.6}{142.52} = 1627 \text{ lb/MWh.}$$

Now compare the incremental contribution of each building block to the target rate using the two methods.

Ordering	BB1	BB2	BB3	BB4
BB1-2-3-4	49	55	287	184
BB4-3-2-1	77	70	323	105
EPRI (single impact)	49	50	261	105

This example demonstrates that ordering is important. A change in ordering can change the impact of a single building block by more than 50%. Furthermore, calculating the numbers by removing Building Blocks in order like this creates a bias towards those Building Blocks removed last. The EPRI calculations are all computed off a common base – the EPA target rate – and are thus comparable.

2.3 Equivalency of State Rate and Mass-Based Targets

The EPA proposal and supporting documents contain language that leave open three possible interpretations on how to construct a mass-based target from the rate-based targets set by the EPA. The various interpretations imply significantly different CO_2 paths with one interpretation shown to be considerably more stringent than the ‘equivalent’ rate-based target. EPRI recommends EPA clarify the construction of mass-based targets, and clearly define the meaning of 'equivalence' between a mass-based and rate-based target.

The first interpretation is based upon the following paragraphs found in the '20140602tsd-projecting-egu-co2emission-performance.pdf' Technical Support Document.

> "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." (p13)

> *"A Mass-Based CO2 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. 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. To construct this scenario, this emission limit is added to the underlying reference case scenario described above." (p15-16)

Given this language, it appears that the mass-based target should be constructed by creating a model of the future which projects capacity and generation mix subject to the constraint that covered units meet the EPA rate-based target by state. From this model, the CO_2 emissions from covered units can be calculated, and this would form the mass-based target by state.

This first interpretation has the property of 'equivalence of CO_2 emissions from covered units', so that covered CO_2 emissions (as modeled) would be the same if the state were using rate-based compliance or mass-based compliance. (This does not imply that total CO_2 emissions, including emissions from new units, would be the same). However, the language of the proposal itself seems to imply more support for a second, more stringent interpretation.

The second interpretation can be inferred from §60.5770(3) of the proposal itself.

> "The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart." (Federal Register, Vol. 79(117) p34953)

Given this language, and from the example constructed in page 16 of the '20140602tsd-projecting-egu-co2emission-performance.pdf' Technical Support Document, the construction of the mass-based target can be interpreted as constructing a reference case, extracting generation from covered units, and simply multiplying that generation by the EPA target rate to get mass-based target emissions for covered units.

The second interpretation implies, for most states, a mass-based target that is strictly lower than the first interpretation. This is because the second interpretation applies the EPA target rate (which is the average of emissions from covered units + renewables + some nuclear + energy efficiency) only to generation from covered units (and *not* renewables, nuclear, or energy efficiency). The mathematics of this calculation imply that the resulting emissions target must be lower than if the target were achieved by running a model with the rate as a constraint (in which case capacity and dispatch from covered units *and* renewables *and* nuclear *and* energy efficiency could be modified to meet the constraint). The only exceptions would be for states for whom the economics are such that they would not build additional renewables or energy efficiency under a rate-based target.

Consider the hypothetical example of State Z. Assume State Z has been set a target of 334 lb/MWh by 2030. Now suppose that the state is projected in the reference case to generate 1,000MWh of NGCC generation at 500lb/MWh, and 500MWh of renewables in 2030, due to local RPS policies already on the books. The 2030 average emissions rate would then be:

$$(1000*500 / (1000 + 500)) = 333 \text{ lb/MWh}$$

which meets the target rate, so State Z is already in compliance with the Clean Power Plan. Note that emissions from covered units are 500,000 lbs. Under the second interpretation, however, the mass-based target for this state would be 1,000MWh * 0.334 = 334,000 lbs. In other words, the state meets the rate-based target in the reference case but would have to do more to reach compliance with the 'equivalent' mass-based target. It is unlikely that any state with significant potential for renewables, nuclear, or energy efficiency would consider a mass-based target under this interpretation.

The differences between mass-based and rate-based compliance are such that EPA's use of the word 'equivalent' seems incongruous. It may be that the second interpretation is incorrect due to the definition of 'covered units', and a third interpretation is in order.

The third interpretation is identical to the second, except that the term 'covered units' includes both existing fossil *and* renewables *and* covered nuclear *and* energy efficiency. In this interpretation, the mass-based target would be calculated by taking reference generation from covered existing fossil units, renewables, covered nuclear, and energy efficiency, and multiplying that by the target rate. This interpretation would resolve the paradox arising in the hypothetical example above, as State Z would now be compliant under both rate-based and mass-based targets. This third interpretation would have a stronger claim to equivalence, as the target rate is applied to the same set of units as was used to calculate the target rate in the first place.

EPRI has used data from the IPM reference case and Option 1 – State scenarios provided by the EPA to illustrate how these three interpretations lead to very different mass-based targets by state. Table 3 below illustrates the three interpretations' mass targets as calculated from IPM results. The first column is the first interpretation, in which the emissions target is simply the emissions from covered units in the IPM Option 1 – State scenario. The second column is the second interpretation, in which the emissions target is calculated by taking generation from covered units in the IPM Reference Case, and multiplying that by the EPA target rate. Note that the U.S. wide emissions from covered units in the second interpretation is 22% lower. The third column is the third interpretation, in which the emissions target is calculated by taking generation from covered units, renewables, and covered nuclear in the IPM Reference Case, and multiplying that by the EPA target rate.

Table 3: Hypothetical state mass targets (million short tons) in 2030

State	Interpretation One	Interpretation Two	Interpretation Three
Alabama	53.1	45.5	51.0
Arkansas	21.4	29.0	31.2
Arizona	14.4	15.3	19.5
California	57.7	31.5	58.6
Colorado	30.4	21.8	27.9
Connecticut	4.7	4.1	4.5
Delaware	0.8	1.8	1.9
Florida	47.9	56.3	58.0
Georgia	45.1	42.8	47.2
Iowa	31.4	19.5	28.7
Idaho	0.7	0.4	1.9
Illinois	80.5	56.2	71.3
Indiana	97.4	75.6	91.3
Kansas	38.2	27.0	34.6
Kentucky	95.4	71.0	74.0
Louisiana	29.2	21.6	22.6
Massachusetts	8.4	8.1	8.9
Maryland	16.1	10.1	13.0
Maine	2.0	1.5	3.1
Michigan	61.4	44.7	51.5
Minnesota	15.8	13.6	18.5
Missouri	88.2	67.8	74.0
Mississippi	10.3	13.1	13.4
Montana	19.8	15.3	26.1

State	Interpretation One	Interpretation Two	Interpretation Three
North Carolina	45.3	40.2	47.9
North Dakota	34.5	26.0	33.3
Nebraska	31.5	22.4	24.1
New Hampshire	2.0	2.2	3.1
New Jersey	6.4	5.8	6.6
New Mexico	12.5	8.0	10.5
Nevada	9.2	5.1	7.5
New York	19.4	10.1	19.2
Ohio	101.4	69.1	76.1
Oklahoma	31.8	29.5	35.4
Oregon	5.5	2.4	11.5
Pennsylvania	86.9	61.5	68.8
Rhode Island	5.2	2.6	2.8
South Carolina	20.8	10.3	13.1
South Dakota	3.3	2.0	4.8
Tennessee	35.5	27.7	33.4
Texas	126.7	116.7	131.3
Utah	24.7	24.2	25.9
Virginia	17.3	10.3	14.1
Washington	3.4	1.5	10.8
Wisconsin	32.5	30.1	33.7
West Virginia	69.8	69.9	72.5
Wyoming	37.7	36.2	40.5
US TOTAL	1667.9	1307.5	1559.3

Given the differences between these three sets of mass-targets and given the uncertainty around the context and use of the word ‘equivalence’ in the proposal, EPRI recommends that EPA define a consistent way to calculate ‘equivalence’ of the rate-based target and mass-based target.

2.4 Transmission Reliability Considerations

Power system reliability encompasses both adequacy of supply to meet demand and operational reliability of the transmission system. Power systems must be operated to ensure that supply and demand are balanced and that this balance is maintained respecting thermal, voltage, and frequency criteria for not only the present operating state but also for any single contingency and other credible contingencies beyond a single contingency. The proposed EPA rule considers only the adequacy perspective of the reliability impact of the rule and does not address the potential thermal, voltage, or frequency impacts. Nor does the rule consider the associated potential transmission economic implications of additional facilities required to ensure operational reliability or financial implications of stranded transmission investments that become underutilized as a result of the change in system power flows. To understand the full reliability, economic, and financial impacts of the proposed rule, detailed transmission reliability evaluations should be conducted.

Detailed reliability studies are conducted when any new generation plant interconnects to the bulk transmission system to ensure the deliverability of energy in a reliable and economic manner. If new transmission facilities are required, those facilities are planned and constructed. Constructing these new facilities will require outages on existing facilities, which are increasingly difficult to schedule. Coordinating outages across many systems that are attempting to simultaneously develop new transmission facilities to accommodate mandated generation changes will be challenging at best and likely result in increased congestion costs and longer lead times to commission the new facilities as sequencing of outages will be required.

Retirements of existing, conventional generation will require replacement generation to ensure continued supply to the loads. In situations where retiring conventional generation plant sites can be used to build new generation, the existing transmission infrastructure may potentially be utilized as is or with some minor upgrades. However, if new sites are needed for replacement generation new transmission infrastructure may be required to interconnect these generation resources with load pockets. For example, the retirement of an existing coal plant located near a load center and installation of replacement generation at a different, more remote location can change the power flow on the transmission lines leading into the load center and can lead to significant transmission congestion. Detailed transmission planning studies would be required to determine the extent of thermal impacts for a given large-scale generation replacement scenario, but significant investments in new transmission infrastructure may be required to ensure transmission reliability. Further, it is unlikely that sufficient lead times exist for actually building new transmission facilities that might be required to support the change in generation mix to meet the rules interim goals in 2020, especially considering the challenges scheduling outages of existing facilities noted above.

In addition to economic impacts associated with relieving congestion resulting from new generation, the retirement of a large number of conventional thermal generation plants may also impact transmission system voltage and frequency stability. Conventional thermal plants are traditional resources providing voltage and frequency support to the system. With respect to voltage performance, these plants provide dynamic reactive power to the system to control steady-state voltage levels and to ensure transient voltage stability of the transmission system. While most central station replacement generation technologies would likely have reactive support capabilities, some resources such as distributed solar PV and demand response may not be able to support transmission system reactive power and voltage control needs. Even for replacement technologies that do have reactive capabilities, the locational aspect of the replacement generation is critical in that reactive support is a local need. Replacing a large number of existing thermal generators with an equivalent capacity of generation or demand resources located elsewhere would not ensure voltage stability such that other transmission investments may be required.

Similarly, conventional thermal plants also provide frequency support to the transmission system through inertial and primary frequency response to oppose and arrest disturbance-driven frequency excursions. In fact, coal units have one of the highest inertia constant (H) among all synchronous units. As with reactive support, replacement resources may or may not have frequency support capabilities.

For example, under the proposed rule, many conventional thermal plants may be replaced by bulk or distributed connected variable generation (wind and solar). On-going and recently concluded EPRI research has shown potential frequency and voltage impacts of changing generation mix due to retirement of conventional thermal plants and increasing penetration of renewable generation. In terms of frequency performance, the report titled “Frequency Response Adequacy and Assessment”[43] showed that replacing conventional thermal units with transmission interconnected wind generation may adversely impact frequency performance if the replacement wind generation is not controlled to contribute to frequency response. Wind plants can certainly be equipped with these capabilities, but other replacement resources may not be as capable. In terms of voltage performance, the report titled “Evaluation of Potential Bulk System Reliability Impacts of Distributed Resources Frequency Response Adequacy and Assessment”[44] showed that high levels of distributed variable generation can impact system transient voltage performance.

Most of the transmission reliability considerations noted can be mitigated with additional investments in transmission infrastructure, but the impact of these costs and timing of these facility upgrades on reliability during transitional periods should be considered as part of the proposed rule.

[43] EPRI Report 1024275, “Frequency Response Adequacy and Assessment: Global Industry Practices and Potential Impact of Changing Generation Mix”, 2012.
[44] EPRI Report 1021977, “Evaluation of Potential Bulk System Reliability Impacts of Distributed Resources”, 2011.

3. DETAILED COMMENTS ON STATE PLANS

3.1 Evaluation, Measurement, and Verification for Energy Efficiency

EPA proposes three options to guide incorporating Demand Side Energy Efficiency in State Plans:

1. Establishing specific EM&V requirements with a level of defined rigor such as a required minimum level of precision and accuracy for all energy efficiency programs and measures

2. Establishing specific EM&V requirements for certain types of widely used energy efficiency programs and measures – such as those addressed by the U.S. Department of Energy 's (DOE's) Uniform Methods Project (UMP) – while establishing a generalized EM&V approach that states can apply to programs that are relatively new, innovative, or untested

3. Establishing a set of generalized, process-oriented EM&V requirements that apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches, as appropriate for different types of programs and measures, provided that EM&V meets these minimum requirements

EPA also suggests any of these options could be supplemented with a prescription of who can conduct EM&V activities and prepare energy savings documentation, and to specify their needed qualifications.

EPA thoroughly outlines the considerations necessary for a state to develop EM&V plans for consideration by EPA. However, the potential variation in methods and trade-off between cost and rigor identified by EPA are such that a state could invest considerable time and resources in developing a plan that may not be acceptable to EPA. Additionally, EPA also correctly identifies that EM&V protocols for many potential energy efficiency measures such as building codes and behavioral based approaches are not as advanced and widely implemented as other more common measures. EPRI suggests EPA outline minimum requirements for EM&V to ensure uniformity and provide guidance for EM&V plan development. However, these minimum standards should not be prescriptive. Flexibility is important to allow for customization to address state specific needs and incorporation of new efficiency measures as they are developed. EPRI believes EPA's third option could provide both minimum guidance and adequate flexibility to meet states' current and future needs.

EPA suggests that one option for guiding state plans is to limit the types of energy efficiency to pre-defined, well understood measures with straight forward evaluation methods. EPRI believes this would unduly limit the amount of energy efficiency available for implementation in a state plan and while in the short term this may not result in diminished energy efficiency levels, in the longer term as programs mature and energy efficiency implementation becomes more advanced, it may be difficult to find additional savings opportunities that fit within these defined measures. Further, limiting to well-recognized measures does not allow for innovation in the energy efficiency field that could further expand its effectiveness and impacts.

EPRI encourages EPA to adopt an adjustment of CO_2 emission rate based on avoided CO_2 emissions. EPA should consider a requirement for reporting of hourly energy efficiency savings to improve the estimation of avoided CO_2. EPRI encourages this approach while acknowledging that this is not currently practiced in most states. As EPA outlines, an average emission rate approach assumes that the dispatch of all EGUs will be reduced uniformly with the implementation of energy efficiency. However, this is not what actually happens. EGU's are dispatched on an economic basis, and marginal units will not have the same emission rates as the fleet average. If a calculation of avoided CO_2 is to be used in the determination of state compliance, then identification of savings on an hourly and unit specific basis is critical to accurately calculating avoided CO_2 emissions from energy efficiency.

3.2 Evaluation, Measurement, and Verification for Transmission and Distribution Energy-Efficiency

Energy losses across T&D networks typically represent around seven to nine percent of all electricity produced (approximately 284 million MWh of annual energy losses from 4,058 million MWh of total generation produced in the United States in 2013. That is roughly equivalent to the electricity needed to power 26 million homes, considering that the annual consumption of the average U.S. residential customer is approximately 11,000kWh.[45] If T&D systems were more efficient (i.e., reduced energy losses), the rate of CO_2 emissions per delivered MWh would be reduced. The amount of reduced energy losses represents an equivalent reduction in the amount of generation needed, and thus reduce CO_2 emissions equivalent to the system average CO_2 emissions rate.

Improving efficiency of T&D systems is one potential option to lower the total electricity sector emission rate while still ensuring the high reliability standards required by electric utilities and expected by customers. Contributions from distribution and transmission systems can be achieved through aggressive deployment of measures that directly reduce network losses, as well as measures that reduce CO_2 emissions via increased transmission system utilization. This allows greater throughput on existing transmission corridors and enables integration of higher levels of renewables such as wind and solar, as well as other less-carbon intensive generation resources.

EPRI has conducted extensive research on T&D efficiency. From 2008 to 2012, EPRI performed research to provide electric utilities and industry participants with tools to help assess energy efficiency opportunities to reduce losses and improve utilization of T&D systems, to choose and implement the most effective options, and to measure and verify results and ascertain the causes of possible deviations.

The effort was structured and implemented in two interdependent activities: (i) a suite of demonstration projects and case studies to understand efficiency improvements through real-life examples, and (ii) base research to set the basis for the demonstrations, including a comprehensive evaluation methodology for

[45] EIA http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3

quantifying the improvements as well as guidelines for project development and implementation. EPRI established collaborative research activities on energy efficiency for both distribution and transmission systems.

A total of 22 electric utilities participated in the distribution efficiency system collaborative. To evaluate distribution efficiency improvements, 66 circuit case studies were modeled and fine-tuned, based on field data. The options evaluated to reduce losses and energy consumption included voltage optimization, conservation voltage reduction, highly-efficient distribution transformers, low loss conductors, voltage upgrade, phase balancing, and reactive power compensation and control. Field trials of voltage optimization were implemented on nine circuits. Detailed advanced metering infrastructure (AMI) data from two circuits also provided information on transformers and secondaries.[46]

A similar number of electric utilities participated in the transmission efficiency collaborative. Seventeen transmission efficiency projects and case studies were conducted within this initiative.[47] The options studied to reduce transmission losses included voltage upgrade of transmission circuits, volt/var optimization, reduction of substation auxiliary power, low loss conductors, highly-efficient substation transformers, and reduction of shield wire losses and corona and insulator losses. EPRI also assessed options to reduce emissions through enhanced transmission capacity and system utilization, which included dynamic rating of transmission lines; use of high-temperature, low-sag (HTLS) conductors in congested corridors; power routers; and energy storage. In addition to these options, new technologies such as smart controls, wide-area monitoring, and high-performance computation clusters have the capability to dynamically mitigate conditions that may overload transmission infrastructure or imperil the security of system operation. This may enable transmission systems to operate safely close to the limits of the installed grid infrastructure and thereby improve system utilization and reduce emissions.

The outcomes of the various activities conducted throughout the EPRI T&D efficiency effort confirm that T&D systems can effectively contribute to reducing carbon emissions through aggressive deployment of measures to reduce losses and increase utilization. However, projects that improve T&D efficiency are seldom economically justified solely on the basis of reduced energy losses. Moreover, options that improve system efficiency can be economically sound in the context of projects undertaken for the purpose of system expansions, system upgrade, or component replacement and modernization. Hence, efficiency considerations should be included as part of a comprehensive energy-delivery resource plan.

One of the main challenges for T&D efficiency as a contributor of emission reduction is the measurement and verification (M&V) of the savings. Certainly as compared to end-use efficiency projects for which certain established measures have well-understood energy savings, efficiency projects in T&D systems do not have the benefit of widely accepted energy savings guidelines. Currently there is no industry-wide standard method to account for either electrical losses on the T&D system or the loss-reduction

[46] EPRI Report 1023518, "Green Circuits: Distribution Efficiency Case Studies", 2011.
[47] EPRI Report 1024345, "Transmission System Efficiency and Utilization Improvement: Summary of R&D Activity and Demonstration Projects", 2012.

opportunities for T&D upgrade projects. Further, there is no standard method for converting the energy savings to emissions reductions.

As part of its research, EPRI developed a framework to consistently assess benefits, cost, and performance of technologies to improve transmission efficiency and utilization, which it applied uniformly to the transmission efficiency demonstration projects to quantify impacts in a standardized manner. EPRI evaluated various tools and approaches for assessing energy and emission savings from measures to reduce losses as well as from measures to increase transmission capacity leading to higher integration of renewable generation.[48,49]

This body of EPRI research can serve as a foundation for continued efforts to develop a consolidated and widely accepted M&V methodology for T&D energy efficiency. Such an endeavor may be best undertaken under the auspices of a coordinated collaborative that brings together industry stakeholders including electric utilities, system operators, regulatory bodies, academic institutions, and research organizations.

As above for energy efficiency end-use options, EPRI also suggests that avoided T&D losses from energy efficiency measures be included in the inventory of possible options states may implement in their plans.

3.3 Electrification Strategies and State Goals

In the proposed rule, EPA has stated a nationwide goal, by 2030, of reducing CO_2 emissions from the power sector approximately 30% from 2005 levels. However, EPRI is concerned that the proposed rule would establish a mitigation approach that does not adequately recognize alternative methods of reducing emissions in an efficient and cost-effective manner across the U.S. economy. In the proposed rule, EPA cites the 2009 Endangerment Finding,[50] the recent Intergovernmental Panel on Climate Change report,[51] and the recently released National Climate Assessment[52] to establish impacts from GHGs and the reason for regulatory action on CO_2. According to EPA, all GHGs "cause and contribute" to the EPA identified impacts -- not only CO_2. Further, CO_2 is emitted from various sectors of the economy—not only from the electric sector. In terms of U.S. GHG emissions, the electric sector comprises 32% of total anthropogenic

[48] EPRI Report 1020142, "The Power to Reduce CO_2 Emissions: Transmission System Efficiency".

[49] A .Del Rosso and C. Clark, "Methods and Tools to Estimate Carbon Emission Savings from Integration of Renewable and T&D Efficiency Improvement", IEEE Power & Energy Society Meeting, July 2011 Detroit, MI.

[50] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496; Dec. 15, 2009.

[51] Intergovernmental Panel on Climate Change (IPCC) report, "Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change," 2007.

[52] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014.

emissions (excluding land use); the transport sector about 28%; and the combination of the commercial, industrial, and residential sectors comprises about 30%.[53]

A strategy that decarbonizes the power sector and increases the share of electricity used by energy end-use consumers has been long recognized in the energy-economics literature, technology studies, and the climate policy area as a cost-effective approach to mitigate GHGs and other air emissions; that is, as the electric sector decarbonizes and produces cleaner energy, electrification of more carbon-intensive sectors is an effective and economic action to reduce all GHGs.

A recently published study by Stanford University's Energy Modeling Forum[54] focused on the development and cross-model comparison of results from a new generation of comprehensive U.S. climate policy intervention scenarios focusing on technology strategies for achieving climate policy objectives. A robust finding from the study that a cost-minimizing approach to reducing GHGs across the economy is one that "increases electricity production as low carbon electricity substitutes for liquid, solid, and gaseous fuels in end-uses." This further confirms key conclusions and recommendations on near-term emissions reductions and technology choices in the U.S. National Academies most current multi-volume report titled *America's Climate Choices.*[55] Specifically, the report on *Limiting the Magnitude of Future Climate Change*,[56] Chapter 3 states:

"We conclude that the most substantial opportunities for near-term GHG reductions, using technology that is deployable now or is likely to be deployable soon, include the following:

- Improved efficiency in the use of electricity and fuels, especially in the buildings sector, but also in industry and transport vehicles.
- Substitution of low-GHG emitting electricity production processes, which may include renewable energy sources, fuel switching to natural gas, nuclear power, and electric power plants equipped to capture and sequester CO_2.
- Displacement of petroleum fuels for transportation with fuels with low- or zero- (net) GHG emissions."

EPRI defines this approach as an "Electrification Strategy for Emissions Reductions." This well-recognized, cost-effective strategy to mitigate GHG, that is, *Electrification*, requires consideration for flexibility in state plans. Moreover, strategies that employ an electrification approach should not be disadvantaged by too narrow an interpretation of compliance under the proposed rule. While it is

[53] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2012", Report EPA 430-R-14-003, United States, Environmental Protection Agency, April 15, 2014.
[54] Fawcett, A., Clarke, L., and Weyant, John. 2014. EMF24 Study on U.S. Technology and Climate Policy Strategies. The Energy Journal, Volume 35 (Special Issue 1).
[55] America's Climate Choices - Committee on America's Climate Choices. National Research Council of The National Academies, The National Academies Press, 2010. ISBN 13: 978-0-309-14585-5. www.nap.edu
[56] Chapter 3: Opportunities for Limiting Future Climate Change, In Limiting the Magnitude of Future Climate Change, Committee for America's Climate Choices, National Academies of Sciences. ISBN 978-0-309-14597-8.

understood that compliance for out-of-sector reductions is difficult, they should not be excluded if appropriate rigor and durability can be demonstrated; care should be taken not to eliminate or dis-incentivize clean electrification. For example, while the implementation of an electrification strategy could cost-effectively reduce GHG across multiple sectors, the CO_2 emissions from the power sector could remain flat or even slightly increase. Existing literature cited above, including EPRI analyses and reports,[57] has substantiated this. Therefore, EPRI recommends that care should be exercised so that state plans do not to eliminate or dis-incentivize clean electrification.

[57] EPRI Report 1020389, "The Power to Reduce CO_2 Emissions: The Full Portfolio", 2009 and Blanford, Merrick, and Young (2014). "A Clean Energy Standard Analysis with the US-REGEN Model," The Energy Journal, 35(1), pp. 137–164.

4. IMPACTS OF THE PROPOSED RULE

4.1 Energy Impacts in Regulatory Impact Analysis

Table 5, in the RIA, shows that in EPA's model for the "State" scenario in 2030 power production from natural gas will increase by 24.5% or 351TWh. The vast majority of the natural gas power would come from combined cycles rather than simple cycles (1743TWh vs 40TWh). Power production from coal would drop by 21% or 347TWh in the same scenario. The amount of power generation from combustion turbines (CTs) as opposed to combined cycles is quite low in the modeling results shown in Table 5 when compared to current experience. The results for the base case in 2020 show only 19TWh from CTs compared to 1,088TWh from combined cycles. The GHG Abatement Measures TSD, Table 3-3 says NGCCs in 2012 produced 981TWh in the United States. EIA's website states that 3% of the electricity produced in the United States in 2012 came from NGCCs.[58] Three percent would be 110TWh or about 11% of the output from NGCCs compared to about 2% in EPA's modeling results. Since CTs handle short-term load following and peak needs, it is unclear if EPA's model took into account for those duties. Given the relatively high heat rates of CTs compared to combined cycles, if EPA's model predicted that CTs produced on the order of 100TWh instead of 20, the percent reduction in CO_2 emissions from fuel switching would not be as great as the model currently shows. Alternatively, if CTs are going to operate less frequently than they do today, this implies that the coal power fleet will have to accommodate load following duties. That will increase the CO_2 emission rates of coal power plants.

The amount of power produced by coal in 2020 is estimated to be 1,395TWh; however, in EPA's state goal computation spreadsheet (20140602tsd_state_goal_data_computation.xlsx), the total amount of power produced from coal plants is 1,098TWh or 21% less than what was used in the cost-benefit analysis. This is an inconsistency which could impact the outcome of the cost-benefit analysis.

Table 6 shows that EPA's model predicts there will be 211GW of installed coal-based generation capacity nationwide in 2020. In 2012 there were 323GW of coal-fired capacity, which could be interpreted as a projection that approximately 35% of the existing coal fleet will be retired by 2020. The base case for 2020 calls for 244GW of coal capacity, which seems to indicated 33GW of retirements from the proposed rule. It is unclear if EPA has previously estimated the other 79GW of retirements occurring due to other current or pending regulations or additional factors. If 112GW of coal generating capacity is retired, it is unclear what capacity will replace it to ensure adequate reserve margins. Table 6 predicts there will be a total of 251GW of NGCC in 2020 which is only 4GW more than existed in 2012. Additional details from EPA on this issue would be useful.

Table 7 shows EPA's model is predicting an average capacity factor of 57% from the NGCC fleet in 2030. This is significantly less than the 70% capacity factor premised in the proposed rule preamble (line three of page 179), and less than the 64% used as the basis of the proposed state targets (page 190,

[58] http://www.eia.gov/todayinenergy/detail.cfm?id=13191 "Natural Gas-fired Combustion Turbines Are Generally Used to Meet Peak Electricity Load", October 1, 2013.

sentence before footnote 144). Table 15 shows EPA's model predicts natural gas prices will increase by 10.3% (or $0.66/MMBtu) in 2030 compared to the base case. This price prediction has an impact on the overall cost of implementing the fuel switching strategy of Building Block 2. EPRI suggests that EPA consider that prices may increase beyond 10% if, as predicted, the power sector's increase of natural gas increases by 25%.

4.2 Regulatory Impact Analysis and Use of the Integrated Planning Model

Modeling the Economics and Dispatch of Renewable Energy Resources

The spatial and temporal distributions of renewable energy resources are integral considerations in regulatory design. Adequately representing these factors in the modeling efforts to inform renewable energy targets is a challenging but necessary task in understanding the dynamics of investment and dispatch over time. In particular, selecting and weighting representative hours in piecewise approximations of load and resource duration curves can influence the economic attractiveness of renewable energy investments. Models must capture positive and negative correlations between load, renewable resource variability, and uncertainty across adjacent regions given that renewable resources are non-uniformly distributed in space and time. Representing periods of resource extremes is especially important in understanding capacity and generation needs across regions. EPRI research illustrates how incorporating these feedbacks can materially influence recommendations from modeling exercises (Blanford, Merrick, and Young 2014[59]).

EPA's applications of IPM use seasonal load duration curves with six segments for the summer and winter seasons (i.e., 12 segments per year) between 2016 and 2030. The model output only maintain eight representative annual segments for later model years. This assumption is especially problematic given that detailed dispatch becomes increasingly important as renewable energy deployment increases, which typically occurs in later decades of the time horizon. In contrast, standard US-REGEN runs require 87-segment load and resource duration curves to adequately sample the corners of the joint distribution.

A related limitation of IPM is that it does not represent unit commitment and dispatch in a detailed manner. Dispatch is based on variable generation costs alone and does not include operational constraints (e.g., ramp rates, startup and shutdown costs, minimum load limits). These omissions impact IPM's ability to offer insights about questions related to the operation of a fixed portfolio of capacity or to investment decisions related to capacity expansion. Consequently, the resource adequacy and reliability analysis TSD does not sufficiently demonstrate potential operational challenges associated with the

[59] Blanford, Merrick, and Young. 2014. A Clean Energy Standard Analysis with the US-REGEN Model. The Energy Journal, 35(1), pp. 137–164.

capacity mixes resulting from the proposed rules. The TSD states that "…the implementation of this rule can be achieved without undermining resource adequacy or reliability…," and IPM runs are used as supporting evidence for this claim. Detailed unit commitment modeling would be a prerequisite to a thorough assessment of the resource adequacy and flexibility needs induced by the proposed rule. Additionally, the IPM analysis focuses only on operational challenges in 2020 and does not examine how resource adequacy issues may change toward the end of the interim compliance period nearly a decade later.

Energy Efficiency Assumptions are not Resource-Based

EPA provided estimates of energy efficiency resource and cost by state, as part of the calculations for Building Block 4 in computing the target rate. In particular, EPA assumed that the first year energy efficiency improvements cost $550/MWh, if in total they reduce demand by 0.5% of sales or less, $660/MWh if in total they reduce demand 0.5% – 1.0% of sales, and $770/MWh if in total they reduce demand by more than 1.0% of sales.

This assumption leads to a contradiction. If a state invests in energy efficiency improvements that lead to .4999% reduction in sales year on year, then the cost is $550/MWh. If a state invests a little extra, so that total energy efficiency improvements lead to a .50001% reduction in sales, all the improvements now cost $660/MWh. Furthermore, there is no consideration of an upper limit in energy efficiency resource. A state is assumed to be able to add 1.5% or more of energy efficiency per year into the foreseeable future, regardless of the current state of the end-use capital stock and the state of technology.

This analytical contradiction points to a core issue with EPA's treatment of energy efficiency, that is, it is not modeled as a resource. EPRI suggests that EPA examine its model to take into account the cost and quantity assumptions used are based upon recent historical experience, and do not consider the quantity of end-use capital stocks in a state, do not consider the technical potential for technological improvements (and costs thereof) in the end-use capital stocks, and do not consider the different compositions of end-use capital stocks between states.

EPRI recommends that energy efficiency be treated as a resource, in the same fashion that renewable resources are computed by state in the Alternate Renewable Energy approach. This involves an estimate of end-use capital stocks by state, an explicit assessment of the available resource based upon those estimates, and a forecast of how technological improvements into the future could increase that resource.

Model Energy Efficiency Endogenously in Integrated Planning Model for Regulatory Impact Analysis

The IPM scenarios created in support of the RIA all assume that a fixed quantity of energy efficiency is deployed in all Clean Power Plan scenarios, at EPA assumed costs. Modeling energy efficiency in this way can lead to biased cost estimates, and would be much improved by an endogenous representation that allows the model to weigh energy efficiency against alternative technologies to meet load. This is relatively easy to do in a model such as IPM, and EPRI makes a suggestion as to one such implementation.

The current IPM modeling structure incorporates energy efficiency by subtracting it from demand and accounting for the costs of incorporating the energy efficiency ex-post (after the model has solved). This structure effectively forces the same amount of energy efficiency into the model in all scenarios – except the base scenario in which no energy efficiency is included (outside what is already included in the Annual Energy Outlook 2013 load forecasts).

In using this structure to model energy efficiency, EPA made three implicit assumptions:

1. Energy efficiency is so cheap that all available energy efficiency (at EPA limits) will be built in any scenario in which the Clean Power Plan is implemented.
2. Energy efficiency is so expensive that none will be built in the base scenario.
3. Energy efficiency is not the marginal technology for compliance with the Clean Power Plan (e.g., it is cheaper than new renewables or cheaper than coal-to-gas re-dispatching).

It seems implausible that all three of these assumptions could hold simultaneously. That would imply that energy efficiency is too expensive in the base case to deploy at all, and that the implicit subsidy granted to energy efficiency by the Clean Power Plan is enough to make it one of the cheapest compliance technologies. But there are several states, which, in the IPM scenarios have little or no compliance cost and therefore offer no subsidy to energy efficiency. Rhode Island is a case in point. In the Option 1 – States scenario, the shadow price to meet the EPA target rate is $0. This means that Rhode Island needs to do nothing to comply with the EPA target rate, and therefore offers no additional incentive to energy efficiency (or renewables). Yet under the IPM modeling of this scenario, energy efficiency appears in Rhode Island under the Clean Power Plan, but not under the Base Scenario. This is inconsistent with IPM's principle of meeting load at least cost and causes bias in the cost estimates.

As noted, it is unlikely all of the above implicit assumptions hold simultaneously. If any one of these assumptions is not true, then the method of forcing in energy efficiency exogenously leads to a bias in cost estimates.

1. If energy efficiency were expensive enough that cheaper compliance options existed, then the EPA technique of forcing energy efficiency in at EPA defined limits will overstate the total costs of compliance. In this case, compliance costs are biased upwards.
2. If energy efficiency is so cheap that it would be built in the reference case, then EPA's assumption that energy efficiency is not in the reference case biases compliance costs downwards. Because the benefits of energy efficiency outweigh the costs even in the reference case, adding exogenous energy efficiency to the model results in a net reduction in system costs. If the energy efficiency is only added to the scenario case, and not to the reference case, these net benefits are incorrectly counted as part of the compliance costs for the proposed rule, and will

reduce the reported compliance costs accordingly. In this case, the failure to include energy efficiency in the reference case biases compliance costs downwards.

3. If energy efficiency is the most expensive (utilized) compliance option, then the cost of the energy efficiency should drive the marginal price of CO_2. But the technique of forcing energy efficiency in exogenously implies the model treats energy efficiency costs as fixed – so the marginal cost is then computed by the next most expensive compliance option. This biases the compliance costs downwards.

It is not possible to gauge the scale of the potential bias without modeling energy efficiency endogenously. For the purpose of these comments, EPRI has utilized US-REGEN[60] to assess how energy efficiency, at EPA assumed quantities and costs, compares with other technologies. The US-REGEN model has many similarities to the EPA/IPM model. It is an inter-temporal regional model of the United States electric sector, focusing on the contiguous 48 states. For this analysis, EPRI added energy efficiency as an explicit technology that competed with other generation technologies to meet load. This was done as follows:

1. Create a new technology 'energy efficiency', and assume that 1MW of energy efficiency constructed in 2020 provides savings of 1MWh for every hour in 2020, 0.95MWh for every hour in 2021, 0.9MWh for every hour in 2022, and so forth until 2040 when the energy efficiency measure would expire. Then apply symmetric assumptions to other model years. This 20 year linearly decline in energy efficiency realized is taken directly from the 'GHG Abatement Measures' TSD. The assumption that the energy efficiency applies in every hour of the year was made by EPRI, and designed to maximize the value of energy efficiency while maintaining other EPA assumptions; thus weighting the model in favor of energy efficiency.)
2. Assign a cost to the energy efficiency. The paradox of EPA's energy efficiency costs assumption highlighted in Comment 2 above implies that energy efficiency cost is a non-linear function of quantity. For the purposes of this analysis, EPRI considered two boundary cases. One where all energy efficiency cost $550/MWh in the first year, and one where all energy efficiency cost $770/MWh in the first year. Using the assumptions stated above, this equated to $4641/kW for the $550/MWh cost, or $6497/kW for the $770/MWh. Energy efficiency deployment was limited to EPA assumed limits by year and state.

Using US-REGEN, EPRI created four scenarios (see Appendix A for more details). A reference case with energy efficiency priced at $550/MWh (Ref-EE550), a reference case with energy efficiency priced at $770/MWh (Ref-EE770), then the same cases with the constraint that average emissions rate meet the EPA target rate, in other words, an implementation of the Clean Power Plan. Denote these cases as CPP-EE550 and CPP-EE770 respectively.

[60] EPRI Report 3002000128, "US-REGEN Model Documentation", 2013.

Result 1: At $550/MWh, energy efficiency is competitive with other technologies even in the reference case. At $770/MWh, almost no energy efficiency is built in the reference case.

In the Ref-EE550 case, 6.41GWh of energy efficiency 'capacity' (equating to 56TWh in load reductions) was built in 2020 alone. This implies that 6.41GW of new energy efficiency was the least cost option amongst all the other technologies provided for in US-REGEN (such as new renewables, new NGCC, nuclear etc.) In the Ref-EE770 case, no energy efficiency was built until 2045, and then only 1GW of 'capacity' (8.7TWh). This suggests EPA's proposed costs span the range between energy efficiency being competitive with other technologies, and being uncompetitive with other technologies.

A significant portion of EPA assumed energy efficiency was priced at $550/MWh in IPM. This, combined with Result 1, suggests that EPA's estimated costs suffer from a downward bias due to energy efficiency not being modeled in the reference case.

Result 2: At $770/MWh, very little energy efficiency was built under the Clean Power Plan policy after 2020.

In the Clean Power Plan-EE770 case, a little under 2GW of energy efficiency capacity was built in 2020, and no more until 2040. This is well under the EPA proposed quantity of energy efficiency. A significant portion of EPA energy efficiency was priced at $770/MWh in IPM. If this result were replicated in IPM, it would imply total costs were likely overstated, but marginal costs understated for the Clean Power Plan scenarios.

To summarize, EPRI believes that the current modeling of energy efficiency as an exogenous input in IPM causes identifiable biases in the costs. EPRI recommends that energy efficiency be modeled as a technology option that competes against other technologies to meet load, both in the Clean Power Plan scenarios and the reference scenario. EPRI's own implementation may serve as a guide to how this can be done in a capacity investment model. By doing this, EPA would avoid three sources of potential bias in costs as outlined above.

Treatment of Biomass

While EPA recognizes "…that biomass-derived fuels can play an important role in CO_2 emission reduction strategies…" biomass as a renewable fuel is not treated as a non-emitting resource in the proposal's RIA and is therefore disadvantaged as a potential compliance option. This may be because EPA is revising its biogenic emissions GHG accounting framework in response to EPA Science Advisory Board comments (Khanna et al., 2012[61]). This exclusion of biomass-derived fuels as a low- or non-emitting CO_2 resource is inconsistent with the current scientific literature that suggests climate beneficial

[61] Khanna, Madhu, Robert Abt, Morton Barlaz, Richard Birdsey, Marilyn Buford, Mark Harmon, Jason Hill, Stephen Kelley, Richard Nelson, Lydia Olander, John Reilly, Charles Rice, Steven Rose, Daniel Schrag, Roger Sedjo, Ken Skog, Tristram West, Peter Woodbury, 2012. SAB Review of EPA's Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources, September 28, 2012.

U.S. biopower is possible (e.g., Miner et al., 2014,[62] Latta et al., 2013,[63] Daigenault et al., 2012,[64] Sedjo and Tian 2012[65]). EPRI encourages EPA to apply the latest science to develop, with the states, an appropriate GHG accounting framework for biomass as a renewable resource in state compliance plans.

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[62] Miner, Reid A., Robert C. Abt, Jim L. Bowyer, Marilyn A. Buford, Robert W. Malmsheimer, Jay O'Laughlin, Elaine E. Oneil, Roger A. Sedjo, and Kenneth E. Skog, 2014. Forest Carbon Accounting Considerations in US Bioenergy Policy 112.
[63] Latta, G.S., J.S Baker, R.H. Beach, S.K. Rose, B.A McCarl, 2013. "A multi-sector intertemporal optimization approach to assess the GHG implications of U.S. forest and agricultural biomass electricity expansion," Journal of Forest Economics 19(4): 361-383.
[64] Daigneault A, Sohngen B, Sedjo R 2012. Economic approach to assess the forest carbon Implications of biomass energy. Environmental Science & Technology 46(11): 5664–5671. http://dx.doi.org/10.1021/es2030142
[65] Sedjo, R. and X. Tian, 2012. Does wood bioenergy increase carbon stocks in forests? Journal of Forestry110:304 –311.

5. BENEFITS OF THE PROPOSED RULE

5.1 Detailed Comments on Estimated Air Pollution Reduction Benefits

The RIA for the propose rule describes the estimated human health co-benefits associated with reductions in SO_2 and NOx (ambient $PM_{2.5}$ precursors), directly emitted fine particles, and NOx as a precursor of ozone. The RIA quantifies the benefits of reductions in $PM_{2.5}$ and ozone using EPA's BenMAP. The RIA also contains a qualitative discussion of the potential benefits of direct reductions in exposure to NOx, SO_2, mercury, and CO.

EPRI's comments focus on two major topics: (i) limitations of BenMAP; and (ii) appropriateness of calculating benefits of pollutant reductions in populations already meeting the NAAQS for $PM_{2.5}$ and ozone.

Limitations of BenMAP

BenMAP is a complex tool used to evaluate many policy options and air quality planning scenarios in the United States and elsewhere. While it consists of a number of elements, or steps, to estimate benefits from changes in air quality, the focus of EPRI's comments is on the so-called "concentration-response function," or the function that statistically relates health outcomes to an incremental change in pollutant concentration. Specifically, EPRI identified three concerns with BenMAP, which extend to the use of BenMAP in the RIA benefits calculations for the proposed rule.

First, some of the embedded options are limited and inconsistent with the literature. For example, BenMAP includes three PM-mortality concentration-response functions: one each from Krewski et al.[66] and Lepeule et al.[67] for adult mortality, and one from Woodruff et al.[68] for infant mortality. These are taken from the literature, but they do not reflect the totality of the literature. For example, a recent analysis by Smith and Gans[69] surveyed the literature and identified 22 studies containing valid concentration-response functions and identified 59 appropriate risk estimates from these studies. A given study may have multiple valid risk estimates; for example, one can identify four different risk coefficients from Krewski et al. ranging from negative to 0.01. However, BenMAP includes only one of these coefficients (0.0058), which gives the impression of much more precise conclusions from that study than is the case. Overall, the estimates identified by Smith and Gans range from −0.0155 to 0.0255, as shown

[66] Krewski, D., Jerrett, M., Burnett, R., Ma, E., Hughes, E., Shi, Y., et al. 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. HEI Research Report, 140, Health Effects Institute, Boston, MA.

[67] Lepeule, J., Laden, F., Dockery, D., Schwartz, J. 2012. Chronic exposure to fine particles and mortality: an extended follow-up of the Harvard Six Cities Study from 1974 to 2009. Environ. Health Perspective. 120:965-970.

[68] Woodruff, T.J., Grillo, J., Schoendorf, K.C. 1997. The relationship between postneonatal infant mortality and particulate air pollution in the United States. Environ. Health Perspective. 105:608-612.

[69] Smith, A.E., Gans, W. 2014. Enhancing the characterization of epistemic uncertainties in PM2.5 risk analyses. Risk Analysis., online advance publication; doi: 10.1111/risa.12236.

below in Table 1 extracted from that publication. The impact of choice of risk estimate on resultant calculated benefits is illustrated by reference to a study that used BenMAP to estimate the premature mortality in the United States due to 2005 $PM_{2.5}$ concentrations (Fann et al[70]). This paper estimated an annual 130,000–320,000 premature deaths based on the lowest and highest of the BenMAP risk coefficients. If the range of risk coefficients identified by Smith and Gans is used, the same analysis produces risk estimates ranging from 0 to 516,000 deaths. This is not only much wider but also reveals a chance there is no risk at all.

Table I. Ranges of Epidemiologically-Based Mortality Risk Coefficients for Long-Term Exposure to $PM_{2.5}$: Our Literature Review Versus Contents of BenMAP's Main Library

Summary	Our Review	BenMAP
Year range	1993–2012	2002–2009
Number of estimates	59	3
Min	−0.0155	0.0058
Max	0.0255	0.0148
Mean	0.0068	0.0088

Note: Risk coefficients are stated as fractional change in annual risk of death per $\mu g/m^3$ of increase in annual average ambient $PM_{2.5}$ concentration.

Second, BenMAP has no simple way to consider uncertainty within its framework. While it does report ranges of benefits, these ranges reflect only the range of the two concentration-response functions used and does not consider any other sources of uncertainty. Sensitivity analyses are one way to address this issue, but they are limited for two reasons. First, alternatives not embedded within BenMAP are not easily considered as part of this analysis. Second, there is no clear way to consider the impacts of simultaneously varying more than one input or assumption into BenMAP at a time. The result of these two issues is that BenMAP can give a misleading impression about the uncertainty associated with a given analysis. In the existing applications, the limited sensitivity analyses give uncertainty ranges that are biased toward suggesting less uncertainty than there probably is. EPRI is currently supporting research to develop an integrated uncertainty analysis that is expected to illustrate the greater policy insights that can be obtained using this approach rather than a set of deterministic calculations as currently exists within BenMAP.

Third, BenMAP offers no provision for considering different species or components of $PM_{2.5}$ despite increasing evidence that some fractions of components of $PM_{2.5}$ may be more highly associated with

[70] Fann, N., Lamson, A.D., Anenberg, S.C., Wesson, K., Risley, D., Hubbell, B.J. 2012. Estimating the national public health burden associated with exposure to ambient PM2.5 and ozone. Risk Analysis. 32:81–95.

health effects than others. For example, Rohr and Wyzga[71] reviewed the epidemiological and toxicological evidence regarding PM composition and health effects and concluded that more scrutiny needs to be given to carbon-containing PM components (elemental and organic carbon), as growing evidence suggests these are most strongly associated with adverse health outcomes.

Benefits Calculated in Areas Meeting NAAQS

Figures 4-4 and 4-5 in the RIA depict, in different ways, the proportion of the U.S. population exposed to $PM_{2.5}$ at various concentrations in the modeling baseline. Both suggest that approximately 95% of the population experiences $PM_{2.5}$ levels that are already at or below the NAAQS of 12 $\mu g/m^3$ before implementation of the proposed rule. Nevertheless, these same populations are included in the benefits calculations, even when the initial exposure is at or below the NAAQS. It is not appropriate for health benefits to accrue at levels of PM that are already deemed to be protective of human health. NAAQS are set at levels that will "protect the public health" with an "adequate margin of safety." The increased use of epidemiological evidence in the NAAQS-setting process has made the determination of the preceding quoted concepts more difficult, since such evidence has not yet clearly identified a threshold below which the risk per concentration unit diminishes and thus could be assumed to be "safe." Thus, uncertainty about the association is the only consideration available for setting a standard above zero. In essence, the NAAQS is set at a level below which the uncertainty in the association becomes too large. However, in RIAs for a variety of regulations, including those which target $PM_{2.5}$ indirectly (such as this proposed rule), the same weights have been given to risks calculated for population exposures below the NAAQS as they do for exposures above this level. An inconsistency therefore exists, with RIAs assuming elevated risk with 100% certainty for all ambient pollutant exposure concentrations below the NAAQS, which is directly at odds with the rationale used to set the standard. Recent EPRI-supported research discusses this inconsistency in more detail (Smith, 2014[72]). Smith's paper provides several quantitative examples that show that, due to inclusion of risks calculated in areas in attainment with the NAAQS, the benefits estimates in RIAs are biased upward from the expected value that can be inferred from the rationale for the NAAQS. This upward bias is even larger for $PM_{2.5}$ co-benefits in RIAs for non-$PM_{2.5}$ regulations. Though not analyzed by Smith (2014), the proposed rule would be one such example.

5.2 Greenhouse Gas Reduction Benefits

This section addresses the development of the USG SCC[73] values and the application of those values in the RIA to estimate the benefits of reducing CO_2 emissions related to the proposed rule. The comments below are based on a recent EPRI report titled "Understanding the Social Cost of Carbon: A Technical

[71] Rohr, A.C., Wyzga, R.E. 2012. Attributing health effects to individual particulate matter constituents. Atmos. Environ. 62:130-152.
[72] Smith, A.E. Inconsistencies in risk analysis for ambient air pollutant regulations. Forthcoming in *Risk Analysis*, Fall 2014 with a pre-publication copy included in Appendix B.
[73] Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (November 1, 2013). http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

Assessment."[74] EPRI believes that its comments and recommendations on the USG SCC should be submitted related to this proposed rule because: (i) its research identifies fundamental issues with the USG SCC values, as well as how EPA applied those values, (ii) while USG SCC values already have been used in various federal regulatory proposals, this proposed rule is more significant in terms of estimated GHG reduction benefits, and (iii) EPRI hopes these comments can help improve the understanding of the SCC and transparency in its application.

Assessment of the USG SCC Development

The SCC estimates the monetary value of future incremental climate change impacts. The SCC is complex to compute, and the USG SCC estimates are the result of significant aggregation. Specifically, the USG SCC estimates are the culmination of global socioeconomic, climate, and damage modeling over 300 years and aggregation of results across three models (DICE, FUND, PAGE), over time, across scenarios, and across impact categories and regions. As such, the USG SCC estimates are difficult to interpret and evaluate. Making sense of the USG SCC estimates requires an understanding of these details. The EPRI study sets out to elucidate and assesses the modeling and raw detailed results underlying USG SCC estimation.

The EPRI study models and assess the raw SCC modeling and results—undiscounted and disaggregated to the underlying modeling elements. It evaluates each component of the SCC modeling causal chain — socioeconomics and emissions, climate modeling, and climate damage modeling —characterizing and assessing what was done with diagnostic modeling analysis, comparison, and consideration of alternatives. It also considers the overall USG SCC experimental design. The work aims to improve understanding of SCC modeling and estimates to inform public discussion and facilitate improved SCC analyses and climate change research broadly.

From the assessment, EPRI finds significant variation across models in underlying model structure, behavior and results, and identify fundamental issues and opportunities for improvements. Specifically, EPRI finds a number of issues with the current methodology that suggest the need to revisit the approach and estimates.

Consideration of uncertainty: Uncertainty is paramount when modeling global biophysical and socioeconomic systems for 300 years as is done in the USG SCC approach. Uncertainty is included in the USG SCC modeling via three elements: (i) uncertainties standardized across models (socioeconomics & emissions, climate sensitivity); (ii) model structure uncertainty via the use of multiple models; and (iii) model specific parametric uncertainties. EPRI's assessment suggests that the current approach for each should be re-considered. For the standardized uncertainties, the assessment identifies implementation issues and alternative specifications to consider. For model structure uncertainty, EPRI finds significant differences in responses across models (e.g., climate change, climate damages, and response sensitivity)

[74] EPRI Report 3002004657, "Understanding the Social Cost of Carbon: A Technical Assessment", 2014.

that need to be further evaluated to establish that they are legitimate reflections of uncertainty and, as such, useful information, and not arbitrary differences, or another dimension of uncertainty to formally model. For instance, observed modeling differences, such as sea-level rise formulation, temperature lag, climate feedback, non-CO_2 forcing, and damages included and formulations need to be reviewed to resolve or justify differences, and/or develop a new standardized uncertainty. For model specific parametric uncertainties, EPRI finds substantial inconsistency in the climate change and damage uncertainties considered across models. The models explore very different parametric uncertainty in both components and therefore represent different uncertainty spaces. The USG modeling uses the means from these uncertainties, yet these means do not appear to come from the same statistical population, which is required for averaging. Finally, EPRI finds that there are additional categories of uncertainty to consider in the modeling (e.g., socioeconomic structure, alternative climate modeling, alternative specifications for 2013 revisions, and alternative 2300 extrapolations).

Comparability of results across models: From a diagnostic analysis, EPRI finds significant variation in climate change and climate damage responses across the three models used in the USG SCC approach. Variation that is due to implementation inconsistencies, structural modeling differences, and differences in the uncertainties considered within each model. The substantial differences raise questions about the statistical comparability of the results across models, which is an issue for averaging results across models as is done in the USG SCC approach. Further assessment of the specifications and uncertainties and reconciliation or justification of differences is an essential future activity to insure comparable estimates in the USG's multi-model approach.

Robustness of the USG SCC estimates: Robustness of the USG SCC estimates is potentially an issue given the sensitivity of the models that EPRI observes in its assessment, and that EPRI identifies reasonable alternatives to the current modeling. Robustness was not evaluated in the USG SCC exercise, but would be a useful exercise to provide the public with greater confidence in final SCC estimates. Such an evaluation would test the sensitivity of results to alternatives and develop an experimental design that produces results that are robust to alternatives.

Multi-model approach: From its assessment, EPRI identifies a number of experimental design issues. One in particular is related to the multi-model approach. Averaging results across models requires that the differences in the models be equally legitimate, and results from the different models comparable and independent. However, EPRI's observations regarding differences in modeling, implementation, specification, and application suggest that the models may not be meeting these requirements. For instance, EPRI found a variety of issues that raise questions about the statistical comparability of the results across models. Also, the models are likely not independent given their use of the same climate impacts studies as inputs. Ensuring legitimately different, comparable, independent results across models could be challenging.

<u>*Application of USG SCC in the Regulatory Impact Analysis*</u>

EPRI also identified methodological issues regarding how the SCC is used within the proposed rule.

CO_2 reductions: The RIA estimates CO_2 benefits by multiplying the USG SCC values by estimated CO_2 reductions. The emission reduction benefits are estimates for CO_2 emissions changes within the power sector only. This is problematic because the SCC should only be applied to estimated net changes in global CO_2 emissions. The SCC is the marginal value of an incremental change in global CO_2 emissions. Therefore, regulatory analysis applications should be sure to estimate changes in net global emissions associated with a proposed rule, or justify why it is unnecessary. The proposed rule may have emissions implications beyond the boundaries of the power sector (i.e., "leakage"), and those effects should be accounted for to properly estimate CO_2 benefits.

Inconsistency in CO_2 benefit and cost calculations: EPRI notes two fundamental inconsistencies in the RIA's cost-benefit comparisons of estimated CO_2 benefits and compliance costs. These inconsistencies need to be corrected for proper comparison of benefits and costs.

- <u>Levelized costs vs. annual CO_2 benefits</u> – The RIA compares levelized (or annualized) compliance costs to annual CO_2 benefits. This is an inconsistent comparison with no practical meaning. The proper comparison is a comparison of the net present value streams of fixed and variable compliance costs and estimated benefits (both for CO_2 and air pollution reductions).

- <u>Reference scenario assumption inconsistency</u> – The proposed rule's base case is inconsistent with the socioeconomic/emissions scenarios used in the SCC calculations. Specifically, the U.S. CO_2 emissions, energy system, and economic condition underlying the estimated CO_2 reductions and compliance costs are inconsistent with the socioeconomic and emissions futures underlying the USG SCC estimates used to value the proposed rules CO_2 reduction benefits. The SCC estimates are computed using five alternative global socioeconomic and GHG emissions futures designed to span a range of possible global futures, with each future considered equally likely. Compliance costs and CO_2 reductions in the RIA, on the other hand, assume a single, U.S. power sector projection (based on the AEO 2013 Reference Case). This is an issue because the underlying USG modeling shows that SCC values vary across socioeconomic and emissions assumptions (USG, 2014). Therefore, one would want the same reference case assumptions for the SCC, CO_2 reductions, and compliance costs, or an argument for why it is unnecessary. Comparing the USG SCC and AEO2013 Reference Case socioeconomic and emissions projections, EPRI finds that the AEO2013 projections do not compare well with any of the USG SCC input scenarios, with lower projected U.S. energy sector CO_2 emissions and higher GDP that are based on much lower assumptions regarding the emissions and energy intensity of output (CO_2/GDP and Btu/GDP respectively). This is just for the U.S., so it is difficult to speculate on the implications of using consistent reference assumptions without a global context.

Guidance on use of the different SCC values: The USG SCC technical documentation recommends using all four of the USG time profiles of SCC values. The four have meaningful differences in discounting and what they represent probabilistically. However, there is no USG guidance on how agencies should apply the different SCC values jointly and consistently in rulemaking.

Recommendations regarding the USG SCC and CO_2 benefits estimates

Based on EPRI's technical assessment of the USG SCC modeling and estimates and evaluation of the application of the SCC in the proposed rule CO_2 benefits estimates, EPRI finds that there are a number of opportunities for improving the proposed rule's CO_2 benefit and overall cost-benefit analyses and offer the following recommendations:

SCC estimation

- Internal review of modeling – A detailed review of modeling differences, alternatives, and uncertainties represented would be beneficial to resolve or justify differences, improve comparability and uncertainties represented, and enhance robustness.

- Revisit experimental design – EPRI finds a number of experimental design improvement opportunities related to implementation inconsistencies, standardized uncertainties, model specific uncertainties, and multi-model application. Given the challenges associated with a multi-model approach, including inconsistencies, comparability, and independence, a new framework would also be a practical consideration.

- Peer review of application and models – The USG SCC approach to estimating SCC values is novel. The approach utilizes estimates from three models with specific specifications for standardized and model specific uncertainties and a results aggregation scheme. External peer review of the modeling framework (models, runs, aggregation); uncertainties (standardized, model specific, and specifications); and other elements would lead to improved methods and provide the public with greater confidence in the resulting estimates. Explicit peer review of the individual models would also be practical as is commonly done for other models used for regulatory processes, for example IPM used in the proposed rule's RIA.

- Evaluate robustness – It would be useful to evaluate the robustness of the USG SCC estimates to alternatives to establish confidence in the final estimates. In particular, a fuller characterization and discussion of uncertainty, and a subsequent analysis of robustness, would provide the analysts, and the public, with greater confidence in the estimates produced and the stability of those estimates.

SCC application in the proposed rule

- Calculate global CO_2 changes – Estimates of global CO_2 changes associated with the rule are required for proper use of the SCC for CO_2 reduction benefits calculations.

- Resolve inconsistencies in cost and CO_2 benefit comparison – Inconsistencies in the estimated compliance costs and CO_2 benefits need to be resolved for proper comparison.

- Provide application guidance – Guidance regarding use of the four USG SCC estimates is needed.

APPENDIX A

Example analysis of endogenous energy efficiency with the US-REGEN Model.

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Modeling Endogenous Energy Efficiency in US-REGEN

David Young & Victor Niemeyer
Energy and Environmental Analysis Group

September 30, 2014

Introduction

- Goal of this slide deck is to demonstrate how the modeling endogenous energy efficiency impacts the potential deployment of energy efficiency under a reference scenario, and under a scenario that approximately mimics the Clean Power Plan – Option 1
- EPA assumes no energy efficiency appears in the reference scenario versus a 1.5% per annum penetration after 2020 in the CPP scenario
- US-REGEN modeling results suggest this is not a cost minimizing outcome at the range of costs assumed by EPA, when energy efficiency is modeled endogenously

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Reference Assumptions

- Starting point for this analysis is EEA 2014 reference case, which includes
  - AEO2014 demand and fuel prices
  - No forced retirements for existing coal units
  - Limitations on new transmission and nuclear builds
  - Technology costs per EPRI Generation Options report
  - Includes state RPS, MATS, CWA § 316(b), RCRA CCR, and CAA § 111 (b) CO_2 performance standards for *new fossil units* but not for modified and reconstructed units
  - CA AB32, RGGI, WA/OR state CO_2 policies

Energy Efficiency Assumptions

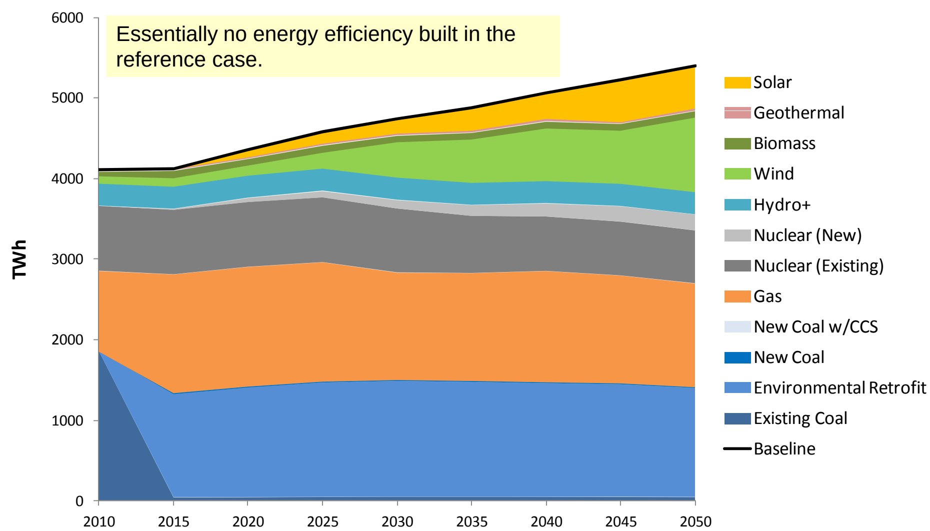
- EPA target rates assume a certain level of EE by state, at a first-year cost of between \$550-\$770/MWh
  - EE investment made in one year will endure for 20 years, with associated <u>annual</u> MWh reductions linearly declining to zero over that time

- We assume EE costs either all \$550/MWh or all \$770/MWh and let the model choose whether to use it, or to use other technologies
  - Also fix maximum quantity of EE by year at EPA target setting assumptions

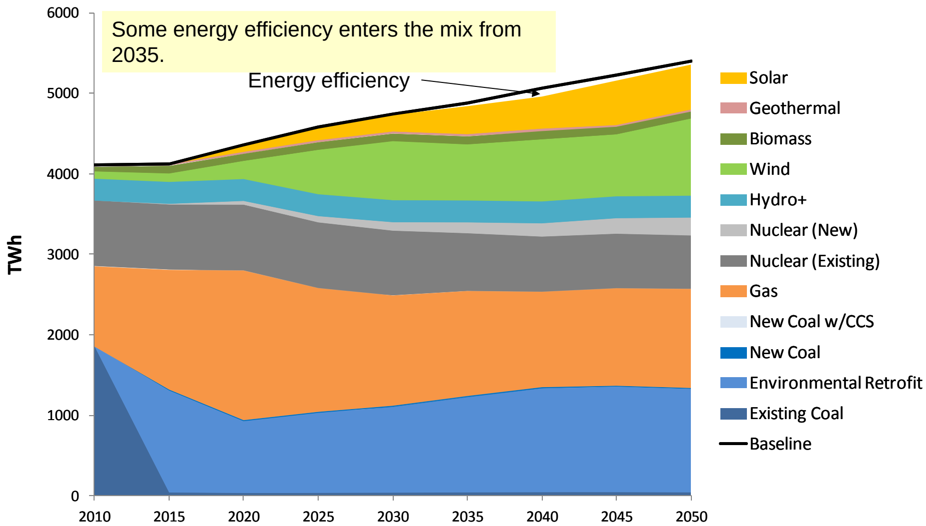
CPP Assumptions

- Rate-based targets by US-REGEN region
  - EPA state targets recalculated for US-REGEN regions using EPA's formula and data
  - Target rates must be met from 2020 onwards – no averaging assumed in this analysis
- Analysis looks for the least cost path to meet the EPA BSER emissions rate target given technology options implemented in the model – actual state implementation may be very different

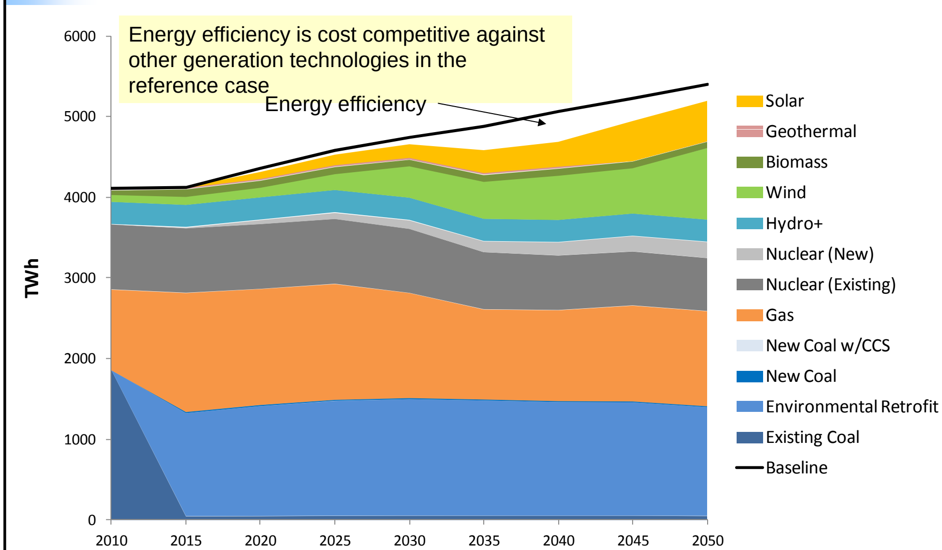
Generation: Reference with EE @ $770/MWh



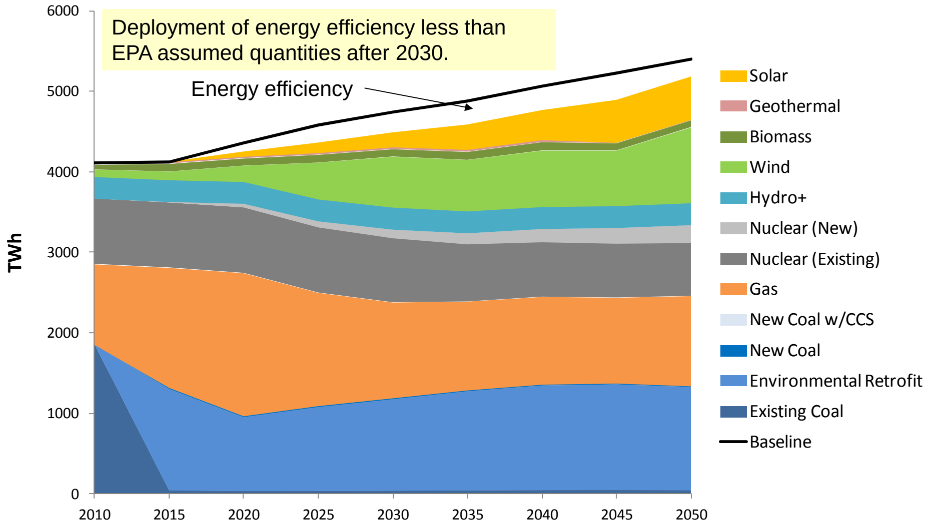
Generation: CPP with EE @ $770/MWh



Generation: Reference with EE @ $550/MWh



Generation: CPP with EE @ $550/MWh



Observations

- Little deployment of energy efficiency at the $770/MWh cost mark in either the reference or CPP scenarios
- Greater penetration of energy efficiency at the $550/MWh cost mark, both in the CPP scenario and the reference scenario
- Results suggest that an assumption of no energy efficiency in the reference and large scale deployment of EE in the policy case are not cost-minimizing outcomes at either cost point

Further Reading

- US-REGEN Homepage

  http://eea.epri.com/models.html
- US-REGEN Documentation
  http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000128

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APPENDIX B

Submitted manuscript: Smith, A.E. Inconsistencies in risk analysis for ambient air pollutant regulations. Forthcoming in *Risk Analysis*, Fall 2014.

INCONSISTENCIES IN RISK ANALYSES FOR AMBIENT AIR POLLUTANT REGULATIONS

Journal:	*Risk Analysis*
Manuscript ID:	Draft
Wiley - Manuscript type:	Perspective
Key Words:	risk analysis, PM2.5, epidemiology

INCONSISTENCIES IN RISK ANALYSES FOR AMBIENT AIR POLLUTANT REGULATIONS

ABSTRACT

This paper explores a conceptual issue fundamental to the risk analyses that the U.S. Environmental Protection Agency (EPA) uses to support its decisions on revisions to primary National Ambient Air Quality Standards (NAAQS). Quantitative risk estimates are prepared as part of the NAAQS-setting deliberations, using inputs derived from epidemiological studies of statistical associations between criteria pollutant concentrations and health effects incidences. These quantitative risk estimates are not directly used to set a NAAQS, but are incorporated into a broader risk-based rationale for the standard that is intended to conform to the legal requirement that a primary NAAQS "protect the public health" with "an adequate margin of safety." In a separate process, EPA staff relies on the same epidemiologically-based risk calculations to prepare its estimates of the benefits of the rulemaking that are provided in its Regulatory Impact Analyses (RIAs) for the NAAQS standard. This paper describes a logical inconsistency between the risk-based rationale used to set each primary NAAQS and the estimates of the benefits from that NAAQS that appear in the RIAs for that rulemaking. The paper provides quantitative examples based on the 2012 revision of the fine particulate matter ($PM_{2.5}$) primary NAAQS, and the 2011 Mercury and Air Toxics Standards. The examples show that, due to inclusion of risks calculated in areas that are already in attainment of the $PM_{2.5}$ NAAQS, RIAs' benefits estimates are biased upward from the expected value that can be inferred from the rationale for the NAAQS. The upward bias is even larger for $PM_{2.5}$ co-benefits in RIAs for non-$PM_{2.5}$ regulations.

Keywords: Risk Analysis, $PM_{2.5}$, Epidemiology, Co-benefits

1. BACKGROUND

When the first $PM_{2.5}$ NAAQS was established in 1997, the principal basis for it was epidemiological evidence and quantitative risk analyses based on that evidence. Quantitative risk analyses based on epidemiological evidence have continued to be a central feature of the review process for revisions of the $PM_{2.5}$ NAAQS since then, and have also been incorporated into revisions of NAAQS for ozone, nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). This paper focuses on a logical inconsistency between the rationale that EPA Administrators use for setting a NAAQS when relying primarily on epidemiologically-based risk evidence, and the estimates of benefits from those rules that EPA staff produces in its RIAs.[1]

2. THE RATIONALE FOR SETTING A PRIMARY NAAQS

The Clean Air Act requires EPA[2] to set a primary NAAQS for each criteria pollutant at levels that will "protect the public health" with an "adequate margin of safety."(1) This determination must be made without regard to cost of meeting the standard.(2) Prior to the 1997 $PM_{2.5}$ NAAQS rules, the rationale for choosing the NAAQS involved a balanced consideration of size of affected population, severity of effect, and certainty of effect. However, the evolution since 1997 to greater use of epidemiological evidence in setting a NAAQS forced a change in how the rationale could be constructed. This was because the available epidemiological evidence for several clearly adverse types of health effects due to $PM_{2.5}$ (such as premature death) did not identify any level of pollutant concentration where the risk per increment of concentration

[1] A separate point of discussion regarding the quantitative risk estimates is whether the full body of scientific evidence is sufficient to give confidence that these epidemiological associations reflect a causal relationship between the pollutant and health endpoint studied. This article notes but does not attempt to add to that discussion.

[2] Formally under the Clean Air Act, the responsibility for deciding where to set a NAAQS is vested in the Administrator. In this article, I use "EPA" to refer to the EPA Administrator, and "EPA staff" to refer to actions or analyses of the agency staff.

appears to diminish – colloquially called an effects "threshold."[3] This situation eliminated two of the three considerations that had typically been incorporated into NAAQS-setting rationales: the severity of effect is unchanging and the entire U.S. population is implicated as at-risk as the potential NAAQS level is lowered.

As a result, uncertainty about the reliability of the association became the only consideration available for setting a primary NAAQS anywhere above zero that can be argued to be adequately protective of the public health as required by the statute. Although the evidence developed for the NAAQS review includes quantitative estimates of health effects that continue without diminution down to zero concentration levels, EPA makes a case that expanding scientific uncertainty about the quantitative assumptions employed in those risk calculations ultimately becomes so large that one can consider the public health to be adequately protected, albeit not "risk-free," at a non-zero level. That non-zero level is then set as the NAAQS. This rationale for dealing with the no-threshold situation was deemed legally valid by the Supreme Court in 2001.[(2)]

Thus, the rationale for the $PM_{2.5}$ primary NAAQS decision (and for several other criteria pollutants set since 1997) has been *ad hoc* reasoning about where within the range of observed exposure levels the continued existence of the statistical association becomes too uncertain to represent a public health concern. Although the written rationale does not use the terminology of probability or expected values, it is readily interpreted as the expression of a subjective judgment

[3] Even if one is confident that the association is causal over some part of the range of data studied, the types of epidemiological studies in use have very limited ability to reliably discern the shape of a potential concentration-response relationship, and thus to inform the question of where or whether the association may end. Indeed, it is theoretically established that unavoidable inaccuracies in measurement of the explanatory factor variable (i.e., the pollutant) will make it difficult to statistically detect a threshold or other non-linearity at low concentrations that may actually exist (see Ref. 3).

regarding the probability that the apparent mortality relationship ceases to exist at different levels of ambient pollutant concentrations. Given that the size of the affected population and the severity of the effect are maximal in the case of all-cause mortality risk, the implied subjective probability that the relationship exists at the selected NAAQS level must, logically, be essentially zero. Indeed, the probability that the health effects association is present must fall to nearly zero at an ambient concentration somewhere above the selected NAAQS level, because that level needs to include a margin of safety below the point of no further expected risk to the public health.

3. THE RESULTING LOGICAL INCONSISTENCY IN BENEFITS ESTIMATES FOR A NAAQS

Thus, in setting a NAAQS using epidemiological evidence, quantitative estimates of health risks for concentrations below the NAAQS are deemed far less reliable and more inaccurate than the numerical precision with which they are reported. In essence, the quantitative risk estimates at levels below the selected NAAQS are given zero weight in EPA's judgment. However, this lack of confidence in such risk estimates has not made its way into the RIAs that accompany the release of the rule.

RIAs are documents that report on the benefits and costs of each major new regulation, such as a revised NAAQS. Federal regulatory agencies are required to prepare RIAs;[4,5] however, they have no connection to the legal requirements of the statute that motivates the regulation, such as the Clean Air Act in the case of air pollutant regulations. Nevertheless, as the NAAQS review process shifted towards use of quantitative risk analyses, the same epidemiologically-based method of quantifying health risks from ambient $PM_{2.5}$ to produce benefits estimates was adopted in $PM_{2.5}$ RIAs.[4] However, at the same time that EPA was setting NAAQS at levels where there is minimal confidence that the public health is affected at lower concentrations, the RIAs have been giving the same weight to risks calculated for population exposures below the NAAQS level as they do to risks calculated for population exposures above the NAAQS level. That is, RIAs assume elevated hazards exist with 100% certainty for all ambient pollutant exposure levels down to a zero concentration, inconsistent with the judgments formed in regulating those pollutants.

The fact that RIAs calculate risk reductions below the NAAQS, and effectively down to zero, is widely known. Using quantitative examples, this paper illustrates the extent to which this practice results in upward-biased risk and benefits estimates relative to the logic on which the various NAAQSs are set. This author recommends that that EPA staff more clearly communicate uncertainty in its risk estimates, and report central benefits estimates that are consistent with the subjective judgments of the standard setting process.

4. OVERSTATEMENT OF EXPECTED BENEFITS OF THE 2012 $PM_{2.5}$ PRIMARY NAAQS REVISION

The implications of this inconsistency are illustrated using as an example the RIA for the 2012 PM NAAQS rulemaking.[(6)] In this rulemaking the annual primary standard for $PM_{2.5}$ was tightened from an annual average of 15 $\mu g/m^3$ to 12 $\mu g/m^3$. In the associated RIA, a range of 460 to 1000 fewer premature deaths per year was estimated from tightening the standard to 12 $\mu g/m^3$ by applying two different concentration-response functions to the Agency's standard risk calculation formula. The concentration-response coefficient for the lower end of the range was

[4] While the "benefits" in an RIA are stated as a monetary value to be compared to the regulation's costs, they are directly derived from quantitative estimates of physical health effects.

derived using a coefficient from Krewski *et al*. (2009),[7] and the upper end of the range was derived using a coefficient from Lepeule *et al*. (2012).[8] A wider range of uncertainty than this range in potential mortality risk reductions exists,[9] but the following discussion addressed only how the Agency's selected range changes when the assumptions of the RIA's risk analysis are reconciled with the logic for the setting of the standard.

Calculations were performed using the BenMAP model.[10] We obtained from Agency staff the air quality input files that had been used for the RIA's calculations. Using those data, we confirmed that BenMAP does indeed produce the RIA mortality reduction estimates. We then used the data to assess the portion and location of the RIA's premature mortality estimates that are associated with reductions in baseline $PM_{2.5}$ below the selected NAAQS. We found that 70% of the benefits for the standard of 12 μg/m^3 were due to reductions in $PM_{2.5}$ from baseline levels that were already below the selected NAAQS level.

Given that the choice of a NAAQS level of 12 μg/m^3 meant that EPA assigned too little confidence in the continuation of health effects below 12 μg/m^3 to warrant setting the NAAQS at a lower level, standard risk analysis would assign negligible probability to calculations of benefits from reductions that would be occurring from levels below that NAAQS. That is, the *expected* values for 70% of the Agency's risk calculations should be approximately zero. When reductions from $PM_{2.5}$ levels already below 12 μg/m^3 are given zero weight in the expected benefits calculation, BenMAP calculates that the expected benefits of that NAAQS would be 138 to 313 reduced premature deaths per year, considerably lower than the 460 to 1000 deaths reported in the RIA.

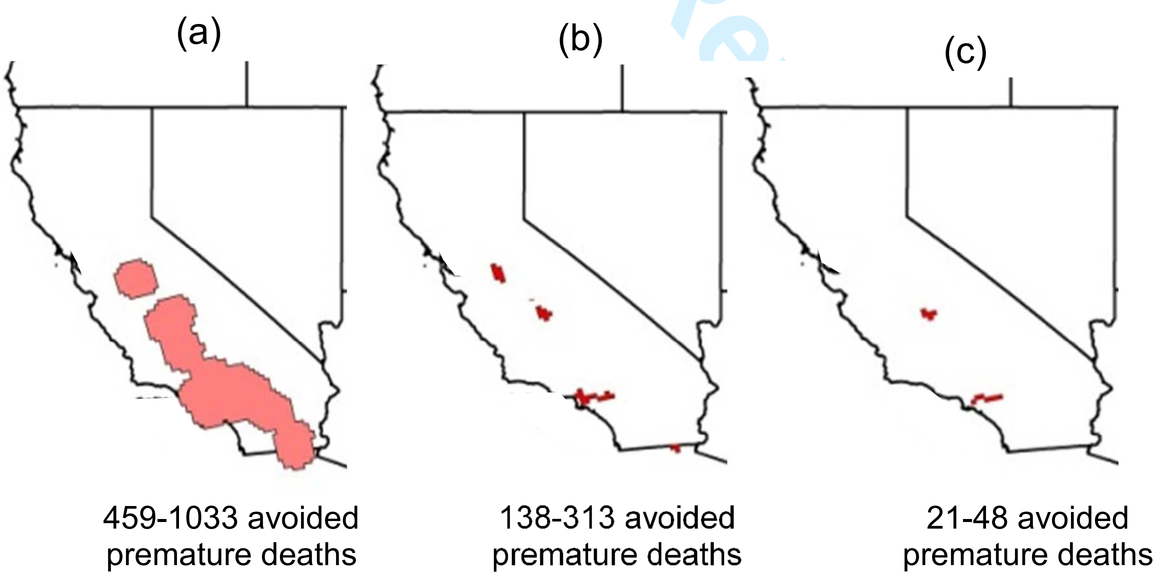
As noted above, the rationale for the NAAQS arguably implies that some of the benefits derived from areas with concentrations just above 12 μg/m^3 also should be given less than 100% weight, taking into account EPA's assurance that exposures to annual average concentrations of 12 μg/m^3 are protective *with an adequate margin of safety*. If, for example, the margin of safety is taken to be about 1 μg/m^3, and risks calculated for pollutant reductions occurring in areas below 13 μg/m^3 are also given zero weight, BenMAP calculates the expected benefits associated with the selected NAAQS of 12 μg/m^3 are only 21 to 48 deaths, less than 5% of the RIA's estimate of benefits from that standard.

Whether the particular probability weights used in this analysis are correct, or should be refined, the point of this analysis is that the RIA's benefits estimates are extremely sensitive in the downward direction to any such weighting.

Geographical representation of where these health benefits are expected to occur is also interesting to explore. The reductions in premature mortality were calculated only for areas that were within 50 km of a monitor that the RIA's air quality analysis projected would not attain each alternative standard under baseline conditions in the year 2020. Figure 1 shows the areas in which the RIA's estimate of 460-1000 avoided premature deaths occur. It is notable that all of those benefits occur in California, a point discussed later. Figure 2 zooms in on California to show: (a) the areas in Figure 1 where benefits are attributed to reductions in $PM_{2.5}$ at any level; (b) the more limited areas projected to experience a health benefit when only reductions in $PM_{2.5}$ that start above the 12 μg/m^3 NAAQS are considered; and (c) the even more limited areas if a 1 μg/m^3 margin of safety is assumed to be associated with the selected standard of 12 μg/m^3. That is, Figure 2(c) only gives weight to risks below 13 μg/m^3.

Figure 1. Areas Projected to Experience Health Benefits under the Selected NAAQS of 12 μg/m^3 in the $PM_{2.5}$ NAAQS RIA (459-1033 avoided premature deaths, rounded to nearest death)

Figure 2. Sensitivity Analysis of Areas Projected to Experience Health Benefits under the 12 μg/m^3 NAAQS: (a) Assuming benefits for all baseline $PM_{2.5}$ levels; (b) Assuming risks exist only if baseline $PM_{2.5}$ is above 12 μg/m^3; (c) Assuming risks exist only if baseline $PM_{2.5}$ exceeds the selected standard by more than 1 μg/m^3.



This example from the $PM_{2.5}$ NAAQS RIA brings to light another important uncertainty in its mortality benefits. All of the benefits estimates for the NAAQS of 12 $\mu g/m^3$ are based on $PM_{2.5}$ changes in California. The risk calculations for changes in $PM_{2.5}$ in California are performed using relative risk estimates derived from the entire U.S., yet the epidemiological evidence that an association between $PM_{2.5}$ and all-cause mortality risk association exists in California is tenuous.[5] Hence all of the risk estimates above, even if one does not wish to discount risks in areas already below the NAAQS, might actually be zero. The new $PM_{2.5}$ NAAQS was set on the basis of projected mortality reductions that occur only in a part of the U.S. where the evidence of heightened mortality risk from $PM_{2.5}$ appears to be weaker than for associations in other parts of the U.S.

5. OVERSTATEMENT OF $PM_{2.5}$ CO-BENEFITS IN NON-$PM_{2.5}$ RULEMAKINGS

Epidemiologically-based estimates of co-benefits from coincidental reductions of ambient $PM_{2.5}$ have also driven statements about regulatory benefits for a majority of non-$PM_{2.5}$ air rulemakings in recent years.[(11)] The upward bias in RIA benefits estimates becomes even more pronounced when co-benefits are calculated from coincidental $PM_{2.5}$ reductions from regulations that do not relate to the PM NAAQS or regulations to help attain that NAAQS. A prominent example is the Mercury and Air Toxics Standards (MATS) for electricity generating units.[(12)]

[5] The $PM_{2.5}$ RIA [(6)] cites seven California-specific $PM_{2.5}$ cohort studies with all-cause risk estimates and notes that four have insignificant associations while three have larger coefficients (at p. 5.A-13). However, one of the three positive findings cited (i.e., Ostro, et al, 2010) was erroneous, according to an erratum published the following year (Ostro et al., 2011), and the corrected estimate of association was found to be insignificant. The remaining two positive findings cited were from the same cohort, but with an updated analysis. Thus, the evidence for an all-cause mortality association in California alone consists of four null findings and one cohort with a positive finding.

Promulgated in December 2011, the MATS RIA projected $PM_{2.5}$ co-benefits in the hundreds of billions of dollars per year, based almost entirely on estimates of reduced premature mortality from reductions in $PM_{2.5}$: 4,200 to 11,000 deaths per year. The reductions in $PM_{2.5}$ in the MATS RIA are projected to occur when generating units are forced to install controls to reduce acid gas emissions, which will also reduce SO_2 emissions, a precursor to ambient $PM_{2.5}$ formation. A figure in the MATS RIA reveals that over 99% of those projected benefits are projected to occur in areas where the $PM_{2.5}$ levels will already be below the $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$ (Figure 5-15 on p. 5-105 of Ref. 12). If the MATS rule's co-benefits are calculated probabilistically, accounting for the very low subjective probability that EPA assigned to the existence of the $PM_{2.5}$-health effects relationships at levels below the NAAQS, the resulting estimate of expected benefits from the MATS rule becomes nearly zero.

It is notable that the fraction of $PM_{2.5}$ co-benefits calculated below the NAAQS is much higher than the already-high level of 70% that we have found for the benefits calculated for the NAAQS rule itself. This is due to the fact that benefits in the RIA for the NAAQS rule were calculated only in areas within 50 km of a monitor that was projected to be out of attainment. By letting projected non-attainment constrain the geographical area over which benefits will be calculated, one ensures that a larger fraction of the resulting benefits will indeed be from areas above the NAAQS. However, when co-benefits of some other rule are assessed using $PM_{2.5}$ risk relationships, no such constraint is applied. In the MATS rule, co-benefits were calculated across the entire nation, and furthermore, the units where acid gas controls were incremental to baseline controls were more likely to be in areas already attaining the NAAQS. As a result, nearly all of the $PM_{2.5}$ co-benefits are projected in NAAQS-attaining areas. For these reasons, the bias in $PM_{2.5}$ co-benefits estimates in RIAs for non-$PM_{2.5}$ rulemakings will tend to be much greater than the bias in the direct benefits estimates in RIAs for $PM_{2.5}$ regulations.

6. CONCLUSION

In conclusion, we find that a large majority of the Agency's estimated health benefit from the 2012 $PM_{2.5}$ NAAQS are attributable to reductions of $PM_{2.5}$ in areas that are already in attainment of the $PM_{2.5}$ NAAQS. RIA calculations of risk reduction in areas already attaining the new NAAQS are given the same weight (i.e., implicit subjective confidence level) as projected benefits from areas that would be exceeding the NAAQS. This RIA calculation is based on assumptions that are inconsistent with the rationale for that NAAQS. The above sensitivity analyses show that the upward bias in RIAs' benefits estimates is large compared to estimates of expected benefits. The upward bias is even larger for co-benefits from $PM_{2.5}$ in RIAs for non-$PM_{2.5}$ regulations.

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