December 1, 2014

United States Environmental Protection Agency
EPA Docket Center (EPA/DC), Mail Code 2822T
Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units (EGU).

Dear Sir or Madam:

The Public Utility Commission of Texas (PUCT), the Texas Railroad Commission (RRC), and the Texas Commission on Environmental Quality (TCEQ) appreciate the opportunity to comment on the United States Environmental Protection Agency's proposed Carbon Pollution Emission Guidelines for Existing EGUs. PUCT's and TCEQ's detailed comments, with which RRC joins, are enclosed; however, the PUCT, RRC, and TCEQ suggest the proposed rule be withdrawn due to the numerous technical, legal, and practical issues with the proposal.

If you have questions concerning TCEQ's comments on the proposed rule, please contact Mr. Steve Hagle, P.E., at (512) 239-1295 or by email at steve.hagle@tceq.texas.gov. If you have questions concerning the PUCT's comments, please contact Tom Hunter at (512) 936-7280 or by email at tom.hunter@puc.texas.gov.

Sincerely,

Richard A. Hyde, P.E.
Executive Director
TCEQ

Milton Rister
Executive Director
RRC

Brian H. Lloyd
Executive Director
PUCT

Enclosures:
TCEQ Comments
TCEQ Attachment 1
TCEQ Attachment 2
PUCT Comments
PUCT Appendix A

COMMENTS BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY REGARDING THE CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE; EPA DOCKET ID NO. EPA-HQ-OAR-2013-0602

I. Summary of Proposed Rule

On June 18, 2014, the United States Environmental Protection Agency (EPA) proposed a rule to establish carbon pollution emission guidelines for existing electric utility generating units (EGU) under §111(d) of the federal Clean Air Act (FCAA). The proposed rule (40 Code of Federal Regulations (CFR) Part 60, Subpart UUUU) would establish overall carbon dioxide (CO_2) emission performance goals specific to each state for the state's existing EGUs. Each state would have an interim goal over 2020 through 2029 and a final goal starting in 2030. Compliance with the interim goal would be based on a 10-year average and the final goal would be based on a rolling three-year average. States would be required to submit a state plan to the EPA to demonstrate how the state will achieve the interim and final state goals. States would also be required to track performance and submit annual reports to the EPA.

II. Comments

A. General Comments

1. The Texas Commission on Environmental Quality (TCEQ) does not support the proposed rule to establish carbon pollution emission guidelines for existing power plants. The EPA should withdraw the proposed rule due to the numerous flaws with the proposal. The disparate state goals proposed by EPA would result in inequitable treatment of the states and Texas will be severely and disproportionately impacted by the rule. Texas has made extraordinary efforts in developing a diversified energy generation mix and in becoming the nation's leader in renewable wind energy generation, yet the EPA's proposal actually penalizes the state for making these efforts.

The EPA's proposed rule to establish CO_2 emission guidelines for existing electric EGUs under FCAA §111(d) should be withdrawn due to the proposal's numerous legal, technical, and practical flaws. As discussed in TCEQ Comment C.1 (page 15), the EPA's approach would create tremendous disparity in treatment of the states as well as the affected individual EGUs. The proposed final goals range from 215 to 1,783 pounds per megawatt-hour (lb/MWh). States where the electrical generation is predominantly coal-based would be expected to make significantly less reductions under the proposal than states such as Texas that have a diversified portfolio of generation. Some states would receive credit for renewable energy generation in the state goal calculation, yet Texas, which actually produces more non-hydro renewable energy than any other state, is being penalized by EPA assuming the state can produce even more renewable energy without considering the costs and time necessary to do so. Section 111(d) does not allow the EPA to establish emissions guidelines on a state-by-state basis in such a disparate and inequitable manner. Texas encourages the EPA to abandon the proposed standards of performance. Texas further encourages the EPA to adhere to statutory limitations in proposing standards of performance for existing sources if the EPA decides to re-propose the standards of performance.

The proposed rule will have a severe and disproportionate impact on Texas. Based on EPA's Integrated Planning Model (IPM) projections of state CO_2 emissions from EGUs for the proposed rule, Texas would be required to make approximately 19% of all CO_2 reductions necessary for the United States. Comparing EPA's IPM projections of the 2030 base case CO_2

emissions with the 2030 policy case, Texas is expected to reduce its annual CO_2 emissions by approximately 114 million short tons, which is more than twice that of the state with next highest total mass of CO_2 reduction expected. While Texas does have more CO_2 emissions from electric generation than any other state, Texas' large electric generation is due in part to the state's large population. Texas is the second most populous state in the United States. Texas also has a large and diverse industry that relies on the state's electrical system. According to the United States Census Bureau's 2011 survey data, Texas' manufacturing sector had a total value of shipments of approximately $671 billion, more than any other state and approximately 12% of the total manufacturing sector for the United States. However, approximately 85% of Texas' electrical load is confined within Electrical Reliability Council of Texas (ERCOT) region. ERCOT is a finite grid with limited interconnections to other transmission regions within Texas. This constraint, coupled with the large residential, industry, and business electrical demand in the state, is another reason why Texas is disproportionately impacted by the proposed rule.

Texas has made significant efforts in developing a diversified and balanced energy generation mix. Texas is the nation's leader in wind generation. In 2012, Texas produced 23% of all wind energy produced in the United States and more than twice as much wind energy as the next highest wind energy producing state. The data EPA used for this proposed rule demonstrates Texas' efforts in developing a diversified clean energy fleet while simultaneously meeting the tremendous energy needs of the state. Yet, as detailed in the TCEQ's comments on the proposed rule, the EPA is using these efforts to impose a more stringent standard on Texas than other states that are predominantly coal or have implemented little renewable energy.

2. The EPA's proposed rule will not have the benefit that the EPA claims towards reducing global CO_2 emissions. Emissions of CO_2 in other countries, such as China, are growing so rapidly that the total annual reductions from the proposed rule in the United States by 2030 will barely offset a single year of CO_2 emissions increases from other countries.

The EPA's proposed rule will not have any significant effect on global CO_2 emissions. As illustrated by Figure 1, World Carbon Dioxide Emissions by Region, the reduction in CO_2 in the United States expected from this proposal will be greatly exceeded by the increases in CO_2 emissions from other countries, most notably China. The table in Figure 1, prepared by the United States Energy Information Administration, compares CO_2 emissions from countries that are members of the Organization of Economic Co-operation and Development (OECD) to CO_2 emissions from non-OECD countries. According to the United States Energy Information Administration, the United States, China, and India are the top three coal-consuming countries in the world. While United States CO_2 emissions from 2010 through 2040 are projected to increase less than 0.1% per year, CO_2 emissions from China and India are increasing at more than 2% per year. The average rate of increase in annual CO_2 emissions in China alone from 2010 through 2030 is more than 300 million metric tons of CO_2 per year. As shown in Figure 2, Projected CO_2 Emission Trends for OECD Countries vs. Non-OECD Countries, China's CO_2 emissions are projected to exceed the total CO_2 emissions of all OECD countries by 2030. The average annual rate of increase in annual CO_2 emissions per year for all non-OECD countries from 2010 to 2030 is approximately 500 million metric tons. The EPA projects that the proposed rule will reduce annual CO_2 emissions in the United States by between 545 – 555 million metric tons per year by 2030. The total increase in annual CO_2 emissions from non-OECD countries from 2010 to 2030 is projected to be 9,988 million metric tons per year, 18 times the total annual CO_2 reductions EPA expects from the proposed rule by 2030.

Table A10. World carbon dioxide emissions by region, Reference case, 2009-2040

(Million metric tons carbon dioxide)

	History		Projections						Average annual percent change, 2010-2040
	2009	2010	2015	2020	2025	2030	2035	2040	
OECD									
OECD Americas	**6,448**	**6,657**	**6,480**	**6,627**	**6,762**	**6,880**	**7,070**	**7,283**	**0.3**
United States[a]	5,418	5,608	5,381	5,454	5,501	5,523	5,607	5,691	0.0
Canada	548	546	551	574	593	609	628	654	0.6
Mexico/Chile	482	503	548	599	668	748	835	937	2.1
OECD Europe	**4,147**	**4,223**	**4,054**	**4,097**	**4,097**	**4,151**	**4,202**	**4,257**	**0.0**
OECD Asia	**2,085**	**2,200**	**2,287**	**2,296**	**2,329**	**2,341**	**2,365**	**2,358**	**0.2**
Japan	1,105	1,176	1,243	1,220	1,223	1,215	1,194	1,150	-0.1
South Korea	531	581	600	627	653	666	703	730	0.8
Australia/New Zealand	449	443	444	449	452	460	468	478	0.3
Total OECD	**12,680**	**13,079**	**12,821**	**13,020**	**13,188**	**13,373**	**13,637**	**13,897**	**0.2**
Non-OECD									
Non-OECD Europe and Eurasia	**2,421**	**2,645**	**2,750**	**2,898**	**3,065**	**3,250**	**3,420**	**3,526**	**1.0**
Russia	1,414	1,595	1,650	1,749	1,853	1,945	2,019	2,018	0.8
Other	1,007	1,050	1,100	1,149	1,212	1,304	1,401	1,508	1.2
Non-OECD Asia	**10,841**	**11,538**	**13,859**	**15,812**	**17,740**	**19,392**	**20,795**	**21,668**	**2.1**
China	7,347	7,885	10,022	11,532	12,951	14,028	14,771	14,911	2.1
India	1,621	1,695	1,856	2,109	2,397	2,693	3,009	3,326	2.3
Other	1,873	1,958	1,981	2,171	2,392	2,671	3,016	3,431	1.9
Middle East	**1,583**	**1,649**	**1,959**	**2,126**	**2,264**	**2,419**	**2,580**	**2,756**	**1.7**
Africa	**1,047**	**1,070**	**1,123**	**1,224**	**1,343**	**1,474**	**1,626**	**1,815**	**1.8**
Central and South America	**1,112**	**1,202**	**1,306**	**1,366**	**1,441**	**1,556**	**1,669**	**1,793**	**1.3**
Brazil	409	450	506	547	584	632	691	771	1.8
Other	703	752	800	819	857	924	978	1,022	1.0
Total Non-OECD	**17,004**	**18,104**	**20,996**	**23,426**	**25,853**	**28,092**	**30,090**	**31,558**	**1.9**
Total World	**29,684**	**31,183**	**33,817**	**36,446**	**39,041**	**41,464**	**43,727**	**45,455**	**1.3**

[a]Includes the 50 states and the District of Columbia.

Note: The U.S. numbers include carbon dioxide emissions from electricity generation using nonbiogenic municipal solid waste and geothermal

Sources: History: U.S. Energy Information Administration (EIA), International Energy Statistics database (as of November 2012), www.eia.gov/ies.
Projections: EIA, Annual Energy Outlook 2013, DOE/EIA-0383(2013) (Washington, DC: April 2013); AEO2013 National Energy Modeling System, run REF2013.D102312A, www.eia.gov/aeo; and World Energy Projection System Plus (2013).

Figure 1: World Carbon Dioxide Emissions by Region, United States Energy Information Administration, International Energy Outlook 2013.

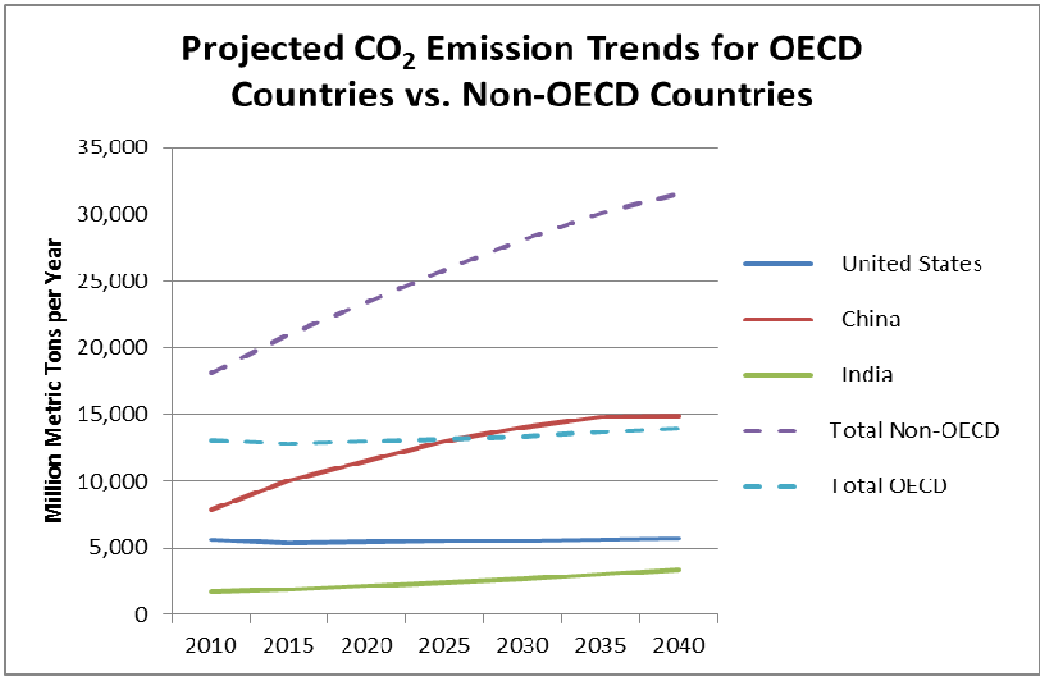

Figure 2: Projected CO_2 Emission Trends for OECD Countries vs. Non-OECD Countries.

According to statements made by Vice Premier H.E. Zhang Gaoli at the United Nations Climate Summit on September 23, 2014, China has decreased its carbon intensity since 2005 and plans to further reduce the nation's carbon intensity by 2020. China's improvement in carbon intensity in the electric power sector appears to be due to diversification of its electric generation fleet by expansion of generation through renewables, nuclear, and natural gas; however, China's installed electrical generation capacity is expected to more than double by 2040 (United States Energy Information Administration, http://www.eia.gov/countries/cab.cfm?fips=CH). Despite improvements in carbon intensity, China's actual CO_2 emissions are still projected to dramatically increase by 2040. China's large increase in CO_2 emissions is largely due to the country's drastic increase in coal consumption for electricity generation. Data from the United State Energy Information Administration, presented in Figure 3, China's Net Electricity Generation by Fuel, shows that China increasing use of coal for electricity generation is projected to continue well into the future. While the percent of China's total electricity generation from coal is expected to decrease, China's total consumption of coal for electricity generation is expected to more than double by 2040. China's increase in CO_2 emissions since 2005 from the combustion of coal exceeds the total United States CO_2 emissions from coal-combustion. As illustrated in Figure 4, China and United States Annual CO_2 Emissions from the Consumption of Coal, China's CO_2 emissions in 2011 from coal combustion were more than three times that of the United States. Additionally, the EPA's efforts to restrict coal usage for EGUs in the United States will have a significant impact on coal prices in the United States. The EPA acknowledges this fact in the Regulatory Impact Analysis (RIA). The EPA estimates that minemouth coal prices in the United States will decline 15.5 – 16.1% by 2020 (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Table 3-18, page 3-38).

However, the EPA has failed to consider the potential international consequences of the decline in domestic coal prices. The decreased price of coal in the United States coal mining sector may lead to increased exports and increased usage of coal internationally, further accelerating the already rapidly growing CO_2 emissions in other countries.

The Energy Information Administration's data also show that CO_2 emissions from the United States EGU fleet are relatively stabilized compared to emissions from China and other non-OECD countries. The EPA's own IPM modeling files in the base case demonstrate that this is expected to continue into the future. The IPM base case projections show that annual United States CO_2 emissions from fossil fuel-fired EGUs greater than 25 megawatts are projected to only increase approximately 181 million short tons from 2016 to 2030 without the EPA's rule in place. President Obama's recent announcement of an agreement with China on CO_2 emissions only maintains the pressure on the U.S. electric utility sector to reduce emissions while allowing China to continue to grow its emissions for 16 years. If the federal government wishes to have a real effect on reducing global CO_2 emissions, its efforts would clearly be better spent working with countries like China to gain binding commitments to reduce their increasing CO_2 emissions rather than attempt to force reductions on the United States electric power fleet, which is relatively stabilized compared to countries such as China and India.

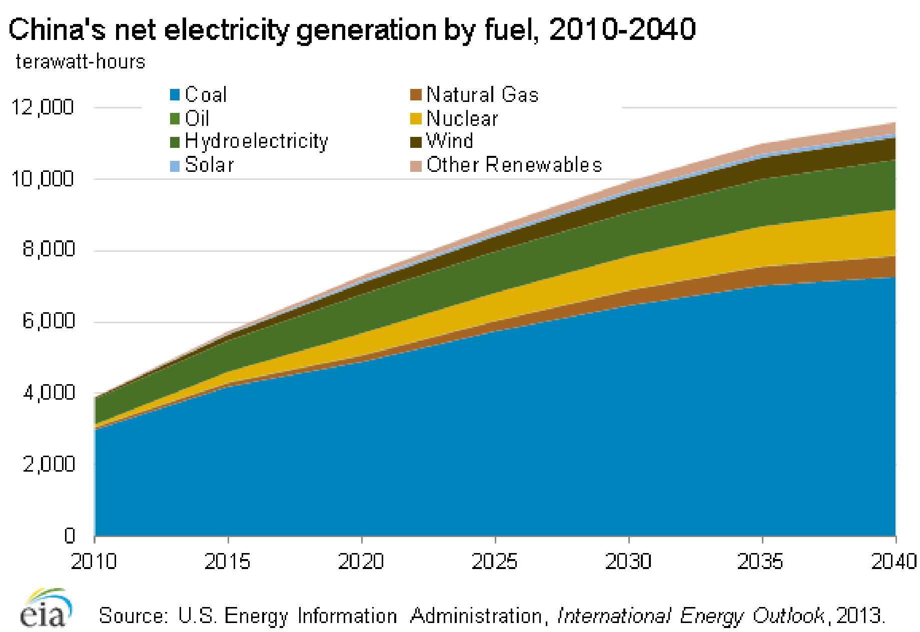

Figure 3: China's Net Electricity Generation by Fuel, United States Energy Information Administration, International Energy Outlook, 2013.

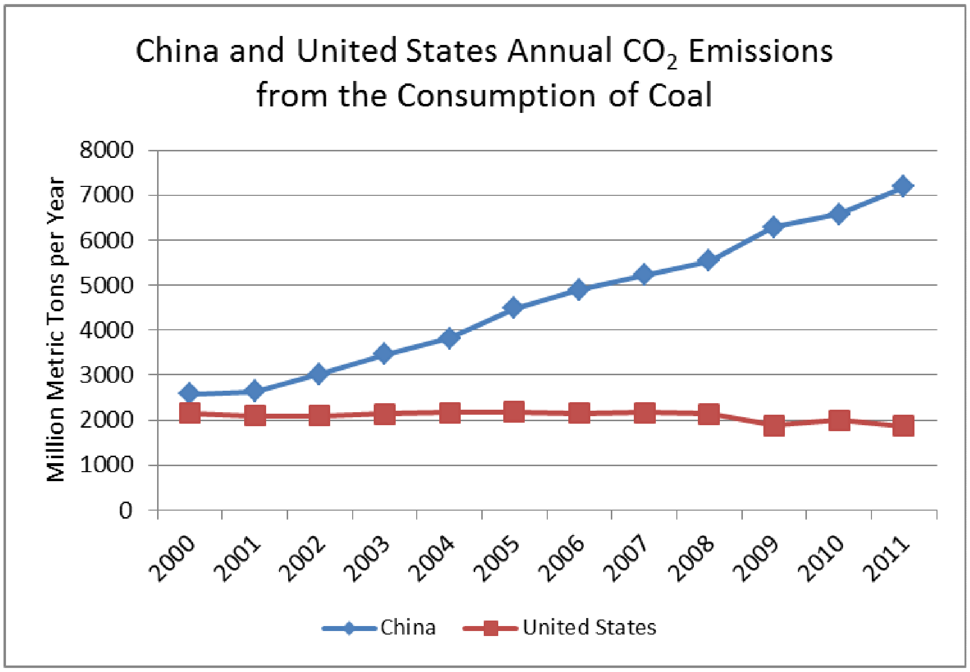

Figure 4: China and United States Annual CO_2 Emissions from the Consumption of Coal, United States Energy Information Administration, International Energy Outlook, 2013.

3. The EPA has not provided a single quantifiable climate benefit of the proposed rule. The EPA's purported climate benefits of the rule are based solely on the Office of Management and Budget's Social Cost of Carbon (SCC). Furthermore, the EPA used the global SCC yet did not consider the potential global impacts of the rule or other international changes in CO_2 emissions.

The EPA's only provided monetized climate benefits of the CO_2 reductions from the proposed rule using the SCC and has not provided a single real-world actual climate benefit. In fact, the EPA has not provided any data or other evidence that the proposed rule will even have any quantifiable effect on global climate. The EPA discusses at length it's assessment of climate change impacts in the RIA, e.g., global average temperature, sea level rise, and extreme weather and climate events (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Section 4.2.1). However, the EPA has not provided a single quantified effect to any climate parameter to demonstrate that the proposed rule would actually result in any impact on those climate events which the EPA cites as justification for the rule. The EPA has not even provided an estimated impact of the proposed rule on global atmospheric CO_2 concentrations. Furthermore, even though the EPA used the global SCC factor for calculating monetized benefits from the CO_2 reductions of the proposed rule, as discussed in TCEQ Comment A.2 (page 2), the EPA failed to consider global CO_2 emission trends. The EPA cannot claim benefits on a global basis while only taking into consideration changes in United States CO_2 emissions. As the EPA frequently points out, CO_2 emissions are a global issue and the EPA cannot legitimately claim any climate benefits from the proposed rule without taking into consideration global CO_2 emissions. Regardless of any particular position regarding anthropogenic CO_2 emissions and climate change, the SCC is founded on offsetting the impacts of climate change. The EPA is attempting to claim benefits of the rule and circumvent the burden of having to prove the rule would actually have any effect on the environmental issue the EPA has relied upon as the basis for the rule.

4. The EPA is misrepresenting the climate benefits of the proposed rule it claims will occur in 2020 through 2030 because the assumed benefits of the SCC are based on long term impacts. The costs of the proposed rule greatly exceed the claimed benefits by 2030. The EPA should not be claiming co-benefits from reductions in other pollutants such sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from the proposed rule.

The TCEQ contracted with NERA Economic Consulting (NERA) to perform a review of the monetized climate benefits and health co-benefits in the EPA's RIA for the proposed rule. NERA's final report is included with these comments in TCEQ Attachment 1, Technical Comments on the Regulatory Impact Analysis for the U.S. Environmental Protection Agency's Proposed Carbon Pollution Emissions Guidelines for Existing Power Plants. The TCEQ incorporates NERA's comments on the RIA into its comments on the proposed rule. The NERA report highlights a number of issues associated with the EPA's RIA on the proposed rule. In particular, the TCEQ notes NERA's comments regarding the EPA's claim of the near-term monetized benefits of CO_2 reductions using the SCC. Setting aside all the uncertainties of using the SCC to estimate climate benefits and assuming that the proposed rule will actually result in climate benefits, it is misrepresentative for the EPA to claim that the rule will result in climate benefits of $17 billion in 2020 and $31 billion in 2030. The SCC is in reality an estimated present value of an assumed future benefit that would not occur until long after 2030. According to NERA's analysis using the 3% discount rate SCC values, the estimated climate benefits from the proposed rule in 2020 would be less than $0.1 billion globally and the total accrued climate benefits by 2030 would only be $3.5 – 4.6 billion, far less than the values presented by the EPA for the same time period. In making any claim of the climate benefits of the proposed rule using the SCC, the EPA should acknowledge that the claimed climate benefits are not actual present benefits but are actually assumed future benefits occurring over a longer period of time. Additionally, the total costs of the rule from 2020 – 2030 will greatly exceed the claimed climate benefits during the same time period. NERA estimates the total payback period under the 3% discount rate scenario is actually more than 100 years. The EPA should properly represent the claimed benefits temporally in a manner similar to how NERA has presented in their attached report so that interested parties can fully understand the nature of the costs and benefits that the EPA claims will result from this proposed rule. The fact that the EPA is comparing claimed global climate benefits to United States costs is also misrepresentative. The Interagency Working Group that developed the SCC estimated that domestic benefits could be from 7% to 23% of the global SCC estimates (Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, February 2010, page 11). The EPA should further delineate its claimed climate benefits by separating the international benefits from United States benefits so that interested parties can properly compare the costs to the United States to the climate benefits that the EPA claims will result from the rule and understand where those benefits are expected to occur.

The analyses performed by NERA indicate that the maximum temperature increase that would be avoided by the amount of CO_2 reductions expected by the proposed rule is approximately 0.003 °C, calling into question any climate benefits the EPA claims will result from the proposed rule. According to the National Oceanic and Atmospheric Administration (NOAA), the world's globally averaged surface temperature increased by 0.85 °C from 1880 to 2012 (NOAA, http://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature). The estimated avoided temperature change that might result from implementation of the rule is less than 0.5% of the total average surface temperature increase reported by NOAA over more than 130 years. Natural variation in the globally averaged surface temperature on year to year basis from events such as El Nino and La Nina is exponentially greater than the maximum avoided temperature increase expected from this proposed rule. The EPA's use of the SCC effectively assumes linear benefits for any reduction in CO_2 emissions, regardless of whether the amount of that reduction would have sufficient effect on the world's climate to actually mitigate the impacts that the SCC is based on. This is an illogical and unfounded assumption.

The EPA should not be claiming co-benefits from possible changes in ambient concentrations of ozone and particulate matter with an aerodynamic diameter equal to or less than 2.5 micrometers ($PM_{2.5}$) from reductions in other pollutants such as NO_X and SO_2. Not only are criteria pollutants not the purpose of the proposed rule, the EPA's claimed co-benefits from the proposed rule are likely overestimated. As discussed in NERA's attached report, the majority of co-benefits are due to changes in ambient concentrations of ozone and $PM_{2.5}$ in areas that are already attaining the NAAQS for these criteria pollutants. It is irrational for the EPA to claim a health benefit from reduction in a pollutant in areas where the EPA has already determined that the current concentration of that pollutant is adequate to protect human health within an adequate margin of safety. The EPA is attempting to argue that any reduction in a pollutant will have a corresponding health benefit, regardless of the current ambient concentration, solely for the purposes of claiming health benefits for its rules. Additionally, for an area that is not attaining the NAAQS for these criteria pollutants, the state either has already or will be required to submit a state implementation plan (SIP) revision to bring that area into attainment with the NAAQS. In is inappropriate for the EPA to claim a benefit from a reduction in a criteria pollutant in a nonattainment area for this proposed rule when that reduction is already required to occur under separate FCAA obligations regardless of whether the EPA adopts the proposed carbon pollution emission guidelines for existing power plants.

5. The enhanced energy efficiency programs assumed by the EPA under Building Block 4 are based on a tremendous cost impact to electricity consumers, approximately $21.8 billion per year in first-year costs as early as 2024. The EPA should make this cost impact to consumers more clear in the RIA.

According to the EPA's analysis, the total first-year costs of the EPA's assumed energy efficiency enhancements will be approximately $30.8 billion in 2020 and approximately $43.7 billion in 2030 (GHG Abatements Measures Technical Support Document, pages 5-59 – 5-60 and Appendix 5-5). The EPA's total annualized cost estimates are approximately $10.2 billion in 2020 and approximately $42.7 billion in 2030. The EPA assumes that half of this cost for enhancing energy efficiency programs is on program administrators and the other half on program participants, i.e., electricity consumers. The EPA attempts to deflate this cost burden by claiming that the total power sector generating costs will decrease as a result of the decreased generation needs from the energy efficiency programs. However, the approach used by the EPA in an attempt to net-out the costs associated with the EPA's assumptions regarding expanded energy efficiency incorrectly adjusts the costs to energy efficiency program participants downward based on assumed savings in the electric utility sector. The EPA applies the difference in total power sector generating costs between the base case and policy case scenarios to the entire annualized costs of the energy efficiency programs (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Table 3-9, page 3-23). Even assuming the EPA's assumptions regarding savings to the electric power generation sector from reduced generation are accurate, these cost savings do not automatically translate to savings to the electricity consumers. Furthermore, the estimated cost impacts to electricity consumers associated with the EPA's assumed energy efficiency enhancements should be more clearly presented and explained in the preamble of the proposed rule as well as the RIA. The costs to electricity consumers under the aggressive energy efficiency programs envisioned by the EPA are approximately $21.8 billion per year in first-year costs by 2024. While the information is available in the RIA and in the GHG Abatements Measures Technical Support Document, the EPA does not make the tremendous cost impact to consumers associated with the enhanced energy efficiency assumptions readily available to the general public, the people most impacted by this cost burden.

Furthermore, the EPA acknowledges that electricity prices will increase as a result of the proposed rule but claims that average monthly electricity bills will decrease by 2030 through demand-side energy efficiency programs. However, the EPA fails to acknowledge the tremendous costs associated with these assumed energy efficiency programs in its discussion of the projected electricity bill impacts (79 FR 34934 and Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, page 3-43). The $21.8 billion per year in first year costs to electricity consumers should be presented in the context of the electricity price and monthly bill impacts to electricity consumers, rather than combining with projected operating costs for electricity utilities as the EPA has done for its net benefits claims.

6. The EPA should provide a more clear and consistent economic analysis of its rules. The preamble of the proposed FCAA §111(d) rule presents cost information as total costs while the RIA presents the same costs as annualized costs.

The EPA's cost information on the proposed rule is inconsistent in how the EPA refers to cost information. The preamble of the proposal (79 FR 34840) presents the compliance costs as total costs. The executive summary of the RIA refers to the same costs as annual incremental compliance costs (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, page ES-7). Chapter 3 of the RIA identifies these same costs as annualized costs (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Table 3-8, page 3-22). Total costs, annual incremental costs, and annualized costs are not equivalent; yet, in all cases with this proposal, the EPA is referring to the same cost values. It is particularly misrepresentative for the EPA to present annualized cost estimates as being total costs. The EPA should be providing total costs of its proposed rule over a defined period in addition to annualized costs so the public and other interested parties can properly consider the economic impacts of the EPA's proposed rule and make valid comparisons with their own cost estimates. Furthermore, the EPA should provide a clear explanation of exactly how cost estimates have been annualized.

7. The EPA's claim in the Regulatory Flexibility Act analysis that the proposed rule will not have a significant economic impact on small businesses is misrepresentative and contrary to the EPA's own economic analysis which identifies significant potential costs to electricity consumers.

The EPA claims under its Regulatory Flexibility Act analysis that the proposed rule will not have a significant economic impact on a substantial number of small businesses. The EPA's claim is based on the following assertion in the preamble of the proposed rule:

> "The proposed rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those state requirements that could potentially impact small entities." (79 FR 34946)

However, while the EPA interprets the Regulatory Flexibility Act to only apply to costs directly imposed by a proposed rule, the Regulatory Flexibility Act does not make this distinction. Section 605 of the Regulatory Flexibility Act only speaks to a significant economic impact on a substantial number of small entities and does not preclude indirect impacts on such entities. Furthermore, it is incorrect for the EPA to assert that the emission guidelines it sets under §111(d) do not result in direct costs to small entities through the application of the emission guidelines by states. In the EPA's economic analysis of the enhanced energy efficiency programs as part of Building Block 4, the EPA clearly expects a potentially significant economic impact on small entities. The EPA acknowledges that half of the costs associated with enhancing energy efficiency programs will fall to the electricity consumers, which will include the small entities that the Regulatory Flexibility Act is intended to address. The EPA's estimates for the costs to electricity consumers under its assumed energy efficiency programs are more than $15 billion per year in first-year costs in 2020 and exceed $21 billion per year by 2024. Additionally, the proposed §111(d) rule for existing power plants is fundamentally different from the prior NAAQS proposed rules which the EPA cites as precedent for the argument that the Regulatory Flexibility Act analysis is not required for the proposed §111(d) rule. The energy efficiency building block is a component from which the EPA has built the proposed rule and the EPA has already identified a potentially significant economic impact to small businesses through the assumed costs to energy efficiency program participants. It is irrational for the EPA to provide these estimated cost impacts to electricity consumers, which clearly will have a significant economic impact on small businesses, yet certify there is no significant economic impact on small entities for purposes of avoiding a Regulatory Flexibility Act analysis.

8. The EPA's RIA on the proposed rule underestimates the potential fiscal impact to the states. The EPA has underestimated the number of full time staff states will need to implement the proposed rule and has not accounted for all aspects of the proposed rule that have direct fiscal implications for the states.

The EPA's RIA of the proposed rule assumes that each state would require two full time staff to implement the state plans and perform ongoing activities, such as assess progress and develop annual reports to EPA (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed

Power Plants, page 3-47). The exact number of staff needed to implement a state plan will depend on numerous factors, such as whether the state implements a cap and trade program or if energy efficiency and renewable energy measures are relied upon. However, the EPA has not considered the multiple state agencies impacted by the EPA's proposed rule. The TCEQ estimates that two to three full time staff would be needed for just the TCEQ obligations and that additional resources may be needed from other Texas state agencies, such as the Public Utility Commission of Texas (PUCT), ERCOT and the State Energy Conservation Office (SECO). Furthermore, significantly more resources will be needed by the state in the initial years during development the state plan for activities such as developing rules and guidance, creation of databases, and establishing new programs to implement the state plan. The EPA has also failed to include the fiscal implications of some of the proposed requirements that EPA is considering imposing on states, such as the state database for making records available to the EPA and the public, the requirements of the Evaluation, Measurement, and Verification (EM&V) Plan, and the possible need to contract out the EM&V activities to independent parties. If included in the final rule, these requirements will have fiscal implications for the states.

9. The EPA's proposed schedule for the rulemaking, state plan submittals, and compliance with the state goals is unreasonable and unworkable. The proposed rule's impact to state government is unique, even among EPA's prior utility sector rules and states need additional time for plan submittal and compliance.

Although the TCEQ acknowledges that the President, in a memorandum dated June 25, 2013, directed the EPA to require that states submit state plans no later than June 1, 2016, the schedule proposed by the EPA is unreasonable and unworkable for states. The EPA is not legally bound to comply with this directive, especially in light of the complex schema proposed by EPA. The Presidential Memorandum was not an executive order, and even if it was, it would not have the full force of law in this instance, particularly since authority to develop standards of performance was granted to the EPA under the FCAA, which controls in this instance. Furthermore, the proposed rule has a unique impact to state governments. While prior EPA rules targeting the electric utility sector may have had impacts to a state's electrical grid and reliability, the EPA's proposed CO_2 emission guidelines for existing power plants effectively establishes an emission performance standard for the state's entire electrical grid. Multiple state agencies must review the proposed rule and then assess the feasibility and impact of the proposed rule on the state's electrical grid as a whole in order to provide adequate comment to EPA. The proposed rule also raises significant and novel legal issues involving both state and EPA authority. The amount and complexity of planning involved in the development of state plans under the proposed rule is more similar to the SIP process and significantly more complicated than prior FCAA §111(d) rules and the EPA is not allowing adequate time for the states to develop and submit plans. As discussed in TCEQ Comment H.2 (page 33), the EPA's proposed provisions for granting extensions make it impossible for Texas and likely most other states to qualify for an extension.

Regarding the proposed implementation schedule, the EPA has not adequately considered the time for state legislative changes and subsequent rulemaking needed to implement many of the aspects of a state plan that would fundamentally change the states' energy policies. Legislatures in many states are not on-going bodies and only meet periodically and Texas is such a state. The Texas legislature only meets biennially unless a special session is called by the governor. Texas' upcoming 2015 legislative session will effectively be over before the EPA finalizes this proposed rule in June 2015 and is not scheduled to meet again until 2017. Neither did the EPA adequately consider the amount of coordination required between state executive agencies with independent authority over the different aspects of the electric market being regulated by the EPA through its assessment and application of BSER in the proposed rule. As discussed in TCEQ Comments C.2 and E.2 (pages 16 and 23), the TCEQ is particularly concerned about the EPA's interim goal for Texas which is heavily affected by the EPA's arbitrary assumption that a radical re-dispatching of the state's coal and natural gas combined cycle (NGCC) fleet can occur within a few years. While the TCEQ recommends the EPA withdraw the proposed rule, if the EPA decides to proceed with the rule then significantly more time needs to be provided to states for state plan development and implementation. At a minimum, the TCEQ recommends that the interim goals be removed from the final rule, compliance with the final goals is no earlier than 2030, and that states have until 2020 to submit state plans.

10. The EPA's open-ended comment solicitation on numerous issues associated with the proposed rule makes it impossible for states to assess the feasibility and potential impacts of the rule because the states cannot reasonably predict the possible outcomes in the final rule.

While the EPA has proposed specific state goals based on the four specific building blocks, the EPA has also requested comment on numerous issues on the proposed rule, such as alternate approaches to setting renewable energy targets not identified by the EPA and expanding BSER to include other strategies. The EPA's Notice of Data Availability (NODA) on the proposed rule, published in the October 30, 2014 *Federal Register*, only further expands the possible outcomes of the rule. The scope of the rulemaking is effectively open-ended. The states cannot assess the feasibility of the rule and the potential impacts on electric reliability without a clear understanding of the proposed rule requirements and a reasonable expectation of how the final rule is likely to be adopted. If the EPA intends to deviate substantially from the state goals included in the proposed rule, then the EPA should withdraw and repropose the rule to allow states and other affected parties adequate opportunity to provide meaningful comment on the substantive changes.

11. The TCEQ's review of the IPM files on the proposed rule indicates errors have been made in the EPA's assumptions.

The EPA's IPM files indicate that the CFB Power Plant in Calhoun County (ORIS Code 56708, IPM ID Numbers 56708_B_H1101 and 56708_B_H1201) would be subject to the rule and would even shut down as a result of the rule by 2020. However, the CFB Power Plant should not be subject to the rule. Based on the TCEQ's information, the CFB Power Plant is predominately a dedicated industrial power provider. While CFB Power Plant might have the capability of putting power to the electrical grid, the facility has not put sufficient power to the grid to trigger the applicability threshold the EPA used for the proposed rule. The EPA should not consider the CFB Power Plant as an applicable unit in the IPM files for this proposal.

Three of the coal-fired utility unit retirements in the 2018 IPM results for Texas have been announced by the companies, specifically Welsh Unit 2 and JT Deely Units 1 and 2. However, as the TCEQ commented on the EPA's 2018 emissions modeling platform (Docket ID. EPA-HQ-OAR-2013-0809), IPM also predicts that the San Miguel unit in Atascosa County will retire before 2018 even though the San Miguel Electric Cooperative has made no announcement of plans to retire their facility. Only announced shutdowns should be included in the IPM base case modeling. A company's decision to retire an asset as substantial as a coal-fired utility unit is based on many factors the EPA is not privy to and that cannot be factored into IPM.

B. State Energy Policy and Electric Reliability

1. EPA is attempting to establish the best system of emission reduction (BSER) by evaluating the electric grid and states' energy policies as a whole, instead of the individual sources which it has authority to regulate under §111(d). A state's energy generation mix and energy efficiency programs are not BSER as the EPA claims; they are the direct result of a state's energy policy.

The EPA supports the setting of state goals by its evaluation of four building blocks concerning heat rate improvements, re-dispatch of electricity from coal to natural gas, expected increases in renewable energy sources, and demand-side energy efficiency efforts. This is an unprecedented reach for an agency without authority to directly regulate in all but one of these areas. The EPA has no direct authority to regulate electric markets, require renewable energy generation, or to require energy efficiency efforts. The EPA's authority under §111(d) is limited to setting "standards of performance" for emissions of air pollutants from stationary sources. The EPA's proposed rule to require carbon pollution emission reductions under §111(d) is an attempt to require states to comply with the EPA's vision of national energy policy, without Congressional approval or endorsement. The EPA provides no rational basis for this unprecedented reach, particularly given the EPA's failure to document expected or actual health and welfare benefit from the anticipated carbon pollution reductions from the proposal, in light of other worldwide carbon emissions. A state's renewable energy standards, energy efficiency programs, and even the fuel mix of the fossil fuel-fired power generation fleet, are not a system of emission reduction but are actually energy policy decisions. The EPA is taking a mix of energy policies from the states, selecting the policies which it prefers, and imposing those policies onto the states by incorporating those energy policies into the state goal calculation under the guise of "BSER."

2. The EPA's claims that the states have broad flexibility in choosing which measures to use to satisfy the state goals are misleading. In reality, the EPA would be dictating energy policy to the states via FCAA §111(d).

The EPA has claimed that the states have broad flexibility in complying with state goals and are not required to use emission reduction strategies from the building blocks the EPA used to set the state goals. In webinars on the proposed rule, the EPA has even claimed that states could choose to do none of measures EPA used in setting the state goals. However, the EPA's claims of flexibility for the states are misleading. While a state is not legally obligated to include those specific measures in the state plan, the reality is that states have very little choice except to change their energy policies to implement the assumptions made by the EPA in its consideration of each building block. This is because the EPA has incorporated its assumptions regarding changes to state energy policy into the state goals. There are no economically and technologically feasible retrofit technologies to achieve the substantial CO_2 reductions needed to comply with the state goals in many cases, and in particular Texas' goal. EPA has admitted that carbon capture and storage (CCS) is not economically feasible for existing coal-fired EGUs. It would be impossible for the state of Texas to comply with its state goals without radically shifting generation toward its NGCC fleet and ramping up its renewable energy and energy efficiency. The EPA has provided no evidence to support that its overly optimistic assumptions for each individual building block, or its combination thereof, are independently achievable in each state to actually meet the stated goals. States such as Texas do not have the options or flexibility that EPA claims are available and it is misleading and disingenuous of the EPA to make such claims. Tying the state goal to the specific assumptions in the building blocks, the EPA effectively closes the door to state flexibility and choice.

3. According to the EPA's IPM predictions, the proposed rule under a state-by-state approach would result in the retirement of approximately 45% of Texas' coal-fired power generation capacity. However, retirements from the proposed rule may be greater and earlier than the EPA projects. Companies will be less likely to incur the expense of installing controls on a unit for an earlier compliance date for other rules, such as the Mercury and Air Toxics Standards (MATS) rule if the unit will have to be shut down a few years later due to the proposed §111(d) rule.

The EPA projects that approximately 45% of Texas' coal-fired EGU capacity will retire by 2020 as a result of the proposed rule under a state-by-state approach: 8,358 megawatts (MW) of coal capacity within ERCOT based on the EPA's Resource Adequacy and Reliability Analysis Technical Support Document; and approximately 2,800 MW of coal capacity outside of ERCOT based on the EPA's IPM data files. The TCEQ is concerned that the rule will actually prompt early, abrupt, and substantial shutdowns of coal-fired EGUs causing grid reliability problems and higher electric costs. The proposed rule requires existing coal-fired EGUs to improve efficiency by 6% employing measures that may trigger New Source Review (NSR) permitting and costly best available control technology for other pollutants. The EPA addresses the potential for triggering NSR permitting by suggesting utilities could avoid triggering NSR permitting by further reducing coal-fired EGU utilization. However, the EPA does not acknowledge the obvious problem that a unit must operate to produce a revenue stream and that continued reduction in its utilization diminishes a unit's economic viability. Additionally, utilities are faced with assessing the cost of additional controls that must be installed on existing coal-fired EGUs to comply with existing environmental regulations in the context of regulatory uncertainty created by the proposed rule.

4. A reliability "safety valve" provision should be included in the rule to address potential energy emergency situations.

Prior to the EPA releasing the proposed rule, the TCEQ and PUCT commented that states may need to include a "safety valve" in their state plans (TCEQ Attachment 2, Comments on CO_2 Emissions for EGUs, Section 111(d) of the Clean Air Act, Letter from Richard A. Hyde, P.E., Executive Director TCEQ, and Brian H. Lloyd, Executive Director, PUCT to Gina McCarthy, EPA Administrator, January 14, 2014). As previously stated, the TCEQ maintains that the EPA should withdraw the proposed rule. However, if the rule is adopted, the EPA should include a provision in the rule itself that will allow states to suspend state plan requirements in the event of an energy emergency. While states and the EPA may exercise enforcement discretion in such events, entities subject to enforceable requirements under the state plan would still be subject to potential private citizen lawsuits for non-compliance with the FCAA.

5. The EPA should heed the comments and concerns expressed by Southwest Power Pool, Inc. (SPP) on the proposed rule.

The EPA should heed the reliability concerns raised by SPP in their comments submitted on the proposed §111(d) rule on October 9, 2014. SPP raised significant reliability concerns for six states, including parts of Texas that operate within the SPP region. According to SPP's evaluation, even if the generation capacity expected to retire is replaced, additional transmission infrastructure will be needed to maintain grid reliability. SPP stated that, based on their assessment, the proposed rule "will impede reliable operation of the electric transmission grid in the SPP region, resulting in violations of NERC's mandatory reliability standards and exposing the power grid to significant interruption or loss of load." SPP Comments on Proposed Carbon Pollution Emission Guidelines for Existing Power Plants, October 9, 2014.

6. The North American Electric Reliability Corporation (NERC) has expressed reliability concerns with the proposed FCAA §111(d) rule in a recent report.

On November 5, 2014, NERC issued a report entitled Potential Reliability Impacts of EPA's Proposed Clean Power Plan (http://www.nerc.com/news/Pages/Reliability-Review-of-Proposed-Clean-Power-Plan-Identifies-Areas-for-Further-Study,-Makes-Recommendations-for-Stakeholders.aspx). NERC indicated that essential reliability services may be strained by the proposed rule and that more time for implementation may be needed. NERC specifically recommended that the EPA consider a more timely approach that addresses reliability concerns and infrastructure deployments (NERC, Potential Reliability Impacts of EPA's Proposed Clean Power Plan, pages 2 – 3). The NERC report also lists numerous issues with the EPA's four building blocks used to calculate the state goals, many of which are discussed in the TCEQ comments. The TCEQ urges the EPA to review the NERC report and give serious consideration to the reliability concerns raised by NERC.

C. State Goals

1. EPA's state goals are very disparate from state to state, resulting in inequitable treatment of the states as well as individual EGUs.

EPA's conclusions for the individual and combined analysis of the building blocks have resulted in an outcome that disparately impacts states, in particular states like Texas that have a diversified electric market, implemented aggressive renewable energy policies, and have encouraged energy efficiency measures. The necessary CO_2 reductions and resulting compliance costs will be distributed unfairly amongst the states. Residents and businesses in states bearing higher compliance costs will also be disproportionately impacted economically as electricity prices increase as a result of the rule. Texas will also be disproportionally impacted due to the large presence of energy intensive industries in the state. Future economic development may also be impacted as potential future businesses weigh operating costs of locating a facility in one state versus another. Additionally, the disparate state goals will, by extension, necessarily result in comparative disparate treatment of EGUs depending on the state in which the EGUs are located. For example, instead of all coal-fired EGUs being required to meet BSER in a similar manner across the country, the emission limit that a particular coal-fired EGU may be required to meet will be vastly different depending on where the source is located. In states where electrical generation is predominately coal-based (e.g., Kentucky, North Dakota, and West Virginia), the state goals are significantly less stringent than in states that have diversified generation mixes including coal and other fossil fuel-fired sources (e.g., Texas and Florida). A state with a much more stringent goal, such as Texas, would be forced to require more CO_2 reductions from coal-fired EGUs within its jurisdiction than a state with coal-fired EGUs that has a much less stringent state goal. The EPA provides no justification for why EGUs within the same source and fuel category should be subject to wildly varying standards of performance and thereby varying costs and controls, including shutdowns, depending only upon the state in which they operate. As stated in TCEQ Comment I.3 (page 42), the EPA also has no legal basis for establishing state-specific standards of performance.

2. While compliance with the interim goal is demonstrated on a 10-year average from 2020 to 2029, Texas will still be forced to make the majority of CO_2 reductions by 2020 in order to comply with the interim goal. The EPA has not provided any quantifiable basis in terms of actual climate effects to justify the interim goals and the rule as a whole. The interim goals should be removed from the rule.

While the interim goals would be demonstrated on a 10-year average, Texas would still be required to make the majority of CO_2 reductions by 2020. The EPA's IPM runs support this conclusion. Using the EPA's IPM projection of base case versus policy case for Option 1 (the proposed state goals) and the state-by-state approach, approximately 77% of the necessary CO_2 reductions are expected to occur by 2020. This is largely due to the EPA's assumption that the re-dispatching under Block 2 can be implemented by 2020. However, as discussed in TCEQ Comment E.2 (page 23), this is an incorrect assumption by the EPA. In the October 30 NODA on the proposed rule, the EPA notes stakeholders concerns with the interim goals. The EPA states that it was their intent that the interim goals would provide "a reasonable glide path" to compliance with the final goals (79 FR 64548). The interim goals do not represent "a reasonable glide path" and would instead result a near-term extreme drop-off in the states' emission rates. The EPA has failed to consider the proximity of the interim goals to the final goals. Using the EPA's assumptions, and including Texas' renewable energy, Texas is starting at 1,284 lb/MWh. Texas' interim goal of 853 lb/MWh is only 62 lb/MWh higher than the final goal of 791 lb/MWh. The interim goal represents approximately 87% of the reduction from 1284 lb/MWh to 791 lb/MWh. Because Texas' interim goal is so close to the final goal, if the state delays making reductions during the 2020 – 2029 period then the state will be forced to over-control beyond the final goal in the later years of the interim period in order to meet the interim goal.

In the October 30 NODA, the EPA takes comment on ways to address concerns on the interim goals, such as using a phase-in of Block 2. While phasing-in the assumed implementation of Block 2 might provide some flexibility and reduce the stringency of the interim goals, as discussed in TCEQ Comment E.2 (page 23), the EPA is not qualified to determine what implementation rate is feasible for any particular state. The EPA also suggests that credit for early reductions might also be a means to decrease the reductions needed during the 2020 – 2029 interim period. However, the EPA has not explained in the NODA how such credit would be applied toward compliance with the interim goals or what early measures would be deemed creditable. Therefore, states have no basis for evaluating whether the credit for early action the EPA is contemplating would be sufficient to address their concerns with the interim goal. Furthermore, states would presumably have to make these early actions federally enforceable in order to receive such credit; however, the states would have no guarantee that the EPA will actually approve the early measures as creditable.

While the TCEQ does not believe the EPA has adequately justified the proposed rule in general, in particular, the EPA has no justification for imposing the interim goals. As discussed in other TCEQ comments on the proposal, the EPA's RIA on the proposed rule does not include any real world quantifiable climate benefits from the rule. The EPA only monetized the assumed benefits using the SCC. As discussed in TCEQ Comment A.4 (page 7), even the monetized climate benefits that the EPA claims for 2020 – 2030 are a misrepresentation because these estimates are actually the estimated current value of a claimed future benefit well beyond 2030. The EPA mentions in various part of the preamble the "urgency of addressing carbon emissions" but the EPA has not shown any quantified real world climate benefits from the rule. Given that the EPA has not shown a single quantifiable actual climate benefit from the rule, the EPA has not provided a rational basis for imposing interim goals in advance of the final goal. Section 111(d) of the FCAA does not mandate the schedule that the EPA has proposed. The EPA's only justification for the interim goals are vague statements of urgency and assumptions about what the EPA believes states are capable of doing within the schedule that the EPA has set. The TCEQ urges the EPA to remove the interim goals from the rule.

3. Section 111(d) of the FCAA requires the EPA to allow states to consider the remaining useful life of the existing sources that would be subject to this rule. However, the proposed rule's interim goals prohibit the states from making such considerations because the EPA's calculations used to set the interim goal rely on an assumed 50% reduction in Texas' coal-fired EGU generation by 2020. This specific provision in §111(d) also implies the emission guidelines that EPA issues under §111(d) must be on a source basis and not the overall electric grid basis that the EPA has proposed.

Section 111(d) of the FCAA clearly states that the EPA's rules "shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standards applies." The EPA attempts to satisfy this legal mandate by citing the "inherent flexibility" the EPA claims that the states have under the proposed rule (79 FR 34925). However, the states do not have the flexibility that EPA claims and the interim goals in particular undermine the states' authority granted under §111(d) to consider remaining useful life. The EPA has built into the interim goals its assumption that Blocks 1 and 2 can be implemented by 2020. For Texas, Block 2 assumes an approximate 50% reduction in generation at Texas' coal-fired EGUs can occur by 2020. On a lb/MWh basis, Block 2 accounts for 60% of the required reductions in Texas' overall CO_2 emission performance. These assumptions are made legally enforceable by EPA incorporating this shift in Texas' generation into the interim goal calculations. It would be mathematically impossible for Texas to comply with the interim goal while allowing additional time for consideration of the units' remaining useful life beyond what EPA has assumed in setting the interim goals. Given the manner in which EPA has calculated the state goals, the states' consideration of remaining useful life of existing sources would have to made prior to establishing the state goals, not afterward.

The EPA's circumvention of the FCAA §111(d) requirement allowing states to consider the remaining useful life of the units has a disproportionate impact on Texas because Texas' coal-fired EGU fleet is among the youngest in the United States. The average age of the coal-fired EGU fleet in Texas is approximately 30 years while the national average age is approximately 45 years. The oldest operating coal-fired unit in Texas has only been in service for 44 years, less than the national average age of coal-fired EGUs. Texas' coal-fired EGU fleet will only be reaching the current national average age by the end of the EPA's proposed interim goal period.

Additionally, this provision of §111(d) also does not support the EPA's interpretation that the standard of performance can be applied on a system basis. Section 111(d)(1) states that the EPA's rules shall permit the state "in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." This provision clearly states that any standard of performance established under §111(d) be applied to an existing discrete stationary source of emissions. The EPA has applied its standard of performance to the electrical grid itself including facilities that are not only not subject to EPA's regulatory authority under §111, but do not even meet the definition of a stationary source under the FCAA, i.e., "any building, structure, facility, or installation which emits or may emit any pollutant." Most forms of renewable energy, such as wind and solar energy generation, do not emit air pollution and therefore are not a stationary source and not subject to the FCAA. Nor are non-emitting wind and solar power generation facilities part of the fossil fuel-fired EGU source categories the EPA has identified as subject to this rule.

4. The EPA's use of 2012 as a base year is misrepresentative and improper due to the unusually low price of natural gas during that year. Using a recent base year also penalizes states that have been proactive on energy efficiency and renewable energy measures.

The EPA's use of 2012 as a base year for the state goals is misrepresentative because 2012 was an abnormal year due to the unusually low price of natural gas. Operation of natural gas EGUs, and natural gas combined cycle EGUs in particular, was higher than what normal economic conditions would typically allow. This skews the EPA's assumptions about the feasibility and impacts of re-dispatching under Block 2. Furthermore, using 2012 actually penalizes states such as Texas that have made significant efforts to develop renewable energy and energy efficiency. The TCEQ is also concerned about using 2012 as a baseline year, because it is not representative of coal-fired EGU dispatch. Dispatch of EGUs in a competitive least-cost electric market tends to reflect costs of fuels. Natural gas prices were unusually low in 2012, resulting in greater dispatch of natural gas-fired units and less dispatch of coal-fired EGUs. Dispatch of coal-fired EGUs over the last two summers has increased as natural gas prices have increased since 2012. Historic dispatch trends bear out the relationship between fuel costs and dispatch. In the October 30 NODA, the EPA takes comments on this issue and the use of data from 2010 and 2011. While using a multi-year baseline would partially address the concern with unusually low natural gas prices in 2012, it does not address the issue of penalizing states that have made early efforts such as Texas has with energy efficiency and renewable energy. The TCEQ recommends a more representative and earlier baseline year or a multi-year baseline average be used that takes into account the early efforts made by states.

5. The proposed rule should be based on gross generation rather than net generation. The EPA requirement to use net generation to demonstrate compliance with the state goals only penalizes facilities that have installed pollution control equipment that increase the facilities onsite parasitic load. The use of net generation is duplicative with Block 1 for coal-fired EGUs.

The EPA's proposed rule and state goals are based on net generation rather than total generation. The EPA's justification for the use of net generation states that improvements in the efficiency of auxiliary equipment and pollution control equipment represent opportunities to reduce carbon intensity at existing EGUs that would not be captured in measurements of gross generation. However, the EPA specifically requested comment on whether the goals and reporting requirements should be expressed in terms of gross generation instead of net generation (79 FR 34894). The TCEQ recommends that the rule be based on gross generation. The use of net generation only penalizes companies that have had to install controls for compliance with other regulations, such as MATS, that have increased parasitic loads due to installing pollution control equipment. Additionally, this requirement is particularly impactful on coal-fired EGUs because the EPA has already factored in such assumed efficiency improvements in Block 1. Effectively, EPA is at least partially applying Block 1 to coal-fired EGUs twice by requiring the use of net generation.

6. The EPA is attempting to restrict the states' ability to challenge the EPA's assumptions in developing the state goals by refusing to change a state's goals even if the state shows a particular block is not feasible unless the state also proves that additional reductions from the other blocks are not feasible. The EPA's interpretation of FCAA §111(d) is not correct. The EPA does not have the legal authority to require a state to go beyond BSER to meet a standard of performance in order to account for the EPA erring in its assumptions on one or more of the blocks.

The EPA indicates in the preamble that if a state demonstrates that a particular block is not feasible for the state to implement as the EPA assumed, the EPA would not adjust the state's goal to reflect that change unless the state also demonstrates that it could not get additional reductions from application of other building blocks, or in related, comparable measures (79 FR 34893). Effectively the EPA is requiring states to reprove BSER for all four of its building blocks and beyond before admitting that the EPA has erred in its assumptions on any of the building blocks. The EPA attempts to support this position by claiming that the building blocks do not represent BSER themselves and only represent what the EPA considers to be a reasonable overall level of reductions. The building blocks are used to directly determine the state goals. The EPA cannot sever the link from the building blocks to EPA's BSER determination in such an arbitrary fashion and the EPA's interpretation of FCAA §111(d) with regard to what represents BSER is flawed. The EPA's legal obligation under §111(d) is to establish standards of performance for existing sources through the application of BSER. While the TCEQ maintains the EPA does not have the legal authority to establish Blocks 2 – 4 as BSER, the clear application of §111(d) in the context of the EPA's proposed rule is that the state goals would represent the standard of performance and the building blocks are what the EPA assumes are the application of the technology to achieve that standard of performance, i.e., what the EPA considers to be BSER. The EPA cannot require a state to go beyond BSER under §111(d). Requiring a state to demonstrate that it cannot achieve additional reductions from the application of other building blocks requires states to go beyond BSER, since EPA represents each building block as an independent basis for emission reduction, that, when combined, result in an applied overall state goal. If, as the EPA contends, the building blocks do not represent BSER, then the EPA has not met its legal obligation to evaluate and apply BSER to set a standard of performance under the FCAA and the proposed rule is invalid and should be withdrawn.

7. The EPA's possible approaches to adjust the state goal calculation methodology for Blocks 3 and 4 discussed in the October 30 NODA would result in severe impacts on states, in particular the prioritized adjustment approach in which EPA would take generation and CO_2 emissions out of the calculation for coal-fired EGUs first before other sources. The prioritized adjustment approach would zero-out all of Texas' coal-fired EGU generation for purposes of calculating the state goal, further restricting the state's ability to consider the remaining useful life of the facilities and result in substantially more retirements of coal-fired EGUs.

In the proposed rule, the EPA's state goal calculation applies Block 2 differently from Blocks 3 and 4. In Block 2, the EPA shifted generation from coal-fired EGUs and other higher emitting sources to NGCC units without changing the total generation in the state. Under Block 3, EPA added renewable generation without taking away generation or the corresponding CO_2 emissions, increasing the total generation in the denominator. Similarly, under Block 4, the EPA added the energy savings to the denominator without removing generation or the corresponding CO_2 emissions. In the October 30 NODA, the EPA takes comment on ways to change the state goal calculation to make the adjustments for Blocks 3 and 4 similar to Block 2 (79 FR 64552). Specifically, the EPA would remove the amount of generation from fossil fuel-fired EGUs in the denominator of the equation, and the corresponding CO_2 emissions in the numerator, that is equivalent to the incremental renewable energy generation under Block 3 and incremental energy savings from Block 4. The TCEQ opposes any such adjustment, and in particular, the prioritized approached being considered by the EPA in which the adjustment would take away generation and CO_2 emissions from coal-fired EGUs first. Because the incremental increase in renewable energy and energy efficiency savings assumed by the EPA under Blocks 3 and 4 for Texas is greater than the residual coal-fired EGU generation assumed after re-dispatching under Block 2, the effect of the prioritized adjustment approach would be to zero-out all Texas' coal-fired EGU generation for state goal calculation purposes. All oil and natural gas steam EGU generation would also zero-out under this approach. The TCEQ estimates that such an adjustment would result in a final state goal for Texas of approximately 540 – 550 lb/MWh. Additionally, the TCEQ estimates that 21 other states would be similarly impacted by having all coal-fired EGU generation assumed to be removed by the prioritized adjustment approach discussed by the EPA in the October 30 NODA. Nationally, applying this adjustment would result in the state goals being based on an assumed reduction in coal-fired EGU generation across the country of approximately 60%, substantially more than the 26% that the proposed state goals are based on. Such a radical reduction in coal-fired EGU generation would result in substantially more retirements in the coal-fired EGU fleet and further endanger grid reliability. Furthermore, building such an assumption into the state goal would virtually eliminate Texas' ability to consider the remaining useful life of coal-fired EGUs because the state goal would be founded on an assumption that all coal-fired EGUs in the state would out-of-service by 2029, including EGUs which have only recently come online. Such a blatantly biased approach to establishing the state goals and BSER would be clearly contrary to the plain language of FCAA §111(d).

The TCEQ also opposes the proportional adjustment approach being considered by the EPA for adjusting the state goal calculations for Blocks 3 and 4. If based on a post-Block 2 re-dispatched generation mix, the TCEQ estimates the proportional approach would reduce the state goal for Texas to approximately 720 lb/MWh. While the proportional approach is expected to have a lesser impact on the state goal than the prioritized approach, the effect still makes the state goal more stringent and the TCEQ maintains the final state goal proposed for Texas is already infeasible.

8. The TCEQ's comments are based on the state goals and individual building blocks used by the EPA in the proposed rule, but these comments are equally applicable to the alternate state goals being considered by the EPA. The EPA's proposed alternate state goals do not lessen any of the TCEQ concerns with the proposed rule.

For the sake of brevity and due to the lack of sufficient time to develop comments, the TCEQ has focused its specific comments on the specific state goals included in the proposed rule and the building blocks used in their calculation. However, these comments are equally applicable to the alternate state goals which the EPA is considering. While the alternate state goals are slightly less stringent than the goals included in the proposed rule and would be implemented over a shorter time period, the TCEQ is equally concerned about the feasibility and impact of the rule should the EPA adopt the alternate state goals.

D. Block 1 – Heat Rate Improvement

1. The EPA's assumptions regarding the potential for heat rate improvement at existing coal-fired EGUs are flawed and fail to recognize the significant improvement in plant efficiency that has already occurred. The EPA has not taken into consideration the effects of other regulatory requirements on coal-fired EGUs that will increase on-site energy demands or the competing effects of the other building blocks on Block 1.

The EPA assumes that the heat rate of the existing coal-fired fleet in any given state can be improved by 6% with 4% of that improvement coming from applying recommended operation and maintenance conditions and 2% from equipment upgrades. The basis for the EPA's assumption that most coal-fired EGUs do not already apply recommended operation and maintenance programs or have not upgraded to more efficient equipment is not clear in the proposed rule. The EPA referenced a Sargent & Lundy (S&L) paper that lists potential methods of improving the heat rate at existing coal-fired EGUs as one of their bases for Block 1 BSER CO_2 reductions. However, the EPA acknowledges in its technical support document for Block 1 that, "…details of current actual unit configurations are unknown, and some units may have applied at least some of the upgrades…" (GHG Abatement Measures Technical Support Document, Section 2.5.10, page 2-35). Because of this admission, it was not rational for the EPA to conclude that a 6% heat rate improvement was possible at existing coal-fired EGUs. Also, given this acknowledgement, the TCEQ surveyed existing coal-fired EGUs in Texas to determine the extent of methods currently utilized to improve heat rate at coal-fired EGUs to ascertain the validity of the EPA's assumption. TCEQ discovered the majority of coal-fired EGUs in Texas currently already utilize many of the methods identified in the S&L paper. Survey results presented in Figure 5, Results of TCEQ's Survey of Existing Coal Fired EGUs Regarding Heat Rate Improvement Potential, indicate the percentage of units in Texas utilizing specific efficiency improvement or heat rate reduction measures at the five locations within their plants that were identified in the S&L paper. Most of the coal-fired EGUs in Texas utilize other specific measures identified in the S&L paper which are not listed in the table in Figure 5. The EPA inappropriately used the S&L study to assume that the types of improvements estimated by S&L either were not utilized or that they are equally applicable and achievable at each and every coal-fired EGU across the nation. This assumption is therefore based on invalid data, is inherently flawed, and does not support a rational basis for the emission reductions required by Block 1.

Location of Heat Rate Reduction Method Applied Within Plant	Percentage of Units in Texas Utilizing Specific Methods Identified in S&L Paper (%)	Specific Method from S&L Paper
Boiler Island	71	Intelligent Sootblower (ISB) System
Turbine Island	61	Turbine Improvements
Flue Gas System	38	Forced Draft (FD) and Induced Draft (ID) Fan Improvements
Air Pollution Control System	64	Particulate System Air Pollution Control Equipment Improvements
Water Treatment System	82	Boiler Water Treatment Improvements

Figure 5: Results of TCEQ's Survey of Existing Coal Fired EGUs Regarding Heat Rate Improvement Potential

Additionally, coal-fired EGUs in the Texas fleet tend to already operate efficiently for the reasons identified below, which make a 6% heat rate improvement less achievable. Texas has a total of 41 operating coal-fired EGUs. The average age of the Texas coal-fired EGU is 15 years newer that the national average coal-fired EGU fleet and newer units tend to be more efficient. Texas has five units that are less than six years old and would otherwise be considered new units. The average size of coal-fired EGU in Texas is larger than the national average-sized unit and efficiency tends to increase with size of the unit. Texas coal-fired EGUs operate in a competitive de-regulated energy market that already incentivizes efficiency improvements. As previously mentioned, Texas has five units that are less than six years old and would otherwise be considered new units. New coal-fired EGUs are not capable of achieving a 6% heat rate improvement, because these units are already operating at very low heat rates. Texas also notes efforts already undertaken to improve efficiency of existing coal-fired EGUs are not given credit under the proposed rule, but are instead penalized, because actual emission in the baseline year include efficiency improvements already realized, upon which an additional 6% reduction is added.

The EPA's assumption that the heat rate of the existing coal-fired fleet in any given state can be improved by 6% does not appear to take into consideration the energy penalties associated with additional controls that must be added to existing coal-fired EGUs to comply with existing environmental regulations like the MATS rule, the Cross-State Air Pollution Rule (CSAPR), Clean Air Interstate Rule (CAIR), regional haze, and the new National Ambient Air Quality Standards (NAAQS) for ozone and sulfur dioxide. Furthermore, the effect of the EPA's other blocks actually compete with improving onsite efficiency at existing coal-fired EGUs, most notably the re-dispatching under Block 2. The EPA's assumed 6% heat rate improvement for coal-fired EGUs also does not take into consideration that EPA's other three proposed building blocks actually create an unintended effect of increasing the average heat rate of EGUs and making existing coal-fired EGUs less efficient. The other three blocks are intended to decrease the utilization or capacity factor of existing coal-fired EGUs; however, efficiency decreases as the capacity factor decreases. The result of the EPA not taking into consideration both the future penalty of additional environmental controls and capacity factor decreases caused by the rule will make the 6% heat rate improvement an unachievable standard of performance.

E. Block 2 – Re-dispatching

1. The EPA's selection of 70% as a reasonable capacity factor for NGCC units as BSER is arbitrary and capricious. The EPA did not consider any site or regional specific factors that would affect the operation rates or dispatching of the units.

The EPA attempts to justify its selection of 70% as a reasonable capacity factor for NGCC as BSER, by evaluating historic NGCC utilization data. The EPA states, "Of 464 NGCC plants generating in 2012 and greater than 25 MW, the EPA observed that 50 plants (more than 10% of NGCC plants) had a net generating value that was greater than or equal to its nameplate capacity x 8784 hours * 70%. That is, a capacity factor that was 70% or greater…" (GHG Abatement Measures Technical Support Document, page 3-7). However, the EPA did not adequately evaluate why 10% of the NGCC units were operating at or above a 70% capacity factor. Equally important, the EPA did not evaluate why 90% of the existing NGCC units did not operate at or above the 70% capacity. Numerous site and regionally specific factors affect how utility units are dispatched and at what operational rates the individual units may be able to be deployed, such as economics, regional grid restrictions, and regulatory restrictions. For example, environmental regulatory requirements specific to a particular region, such as SIP rules, may restrict the facility's ability to operate at the level assumed by the EPA. The EPA only briefly considered the effect of the low price of natural gas. The EPA stated that "the increase in the NGCC utilization was in large part driven by the decrease in natural gas prices to historic lows." (GHG Abatement Measures Technical Support Document, page 3-10). However, even at these historically low natural gas price levels in 2012, only 10% of the NGCC units ran at the 70% capacity factor that EPA claims is economically reasonable. Market forces that actually determined NGCC dispatch in 2012 relative to other electrical generation production processes do not appear to agree with EPA's assessment of economic reasonableness for high NGCC dispatch. Instead EPA says, "…the cost effectiveness of high NGCC utilization demonstrated later in this TSD all supported the notion of a NGCC fleet capacity factor of 70% as a reasonable ceiling in the EPA's BSER approach." (GHG Abatement Measures Technical Support Document, page 3-11). The EPA only considered the result of 10% of the NGCC fleet operating at a 70% capacity factor and not the factors that caused these units to operating at higher rates than the remaining 90% of the NGCC units. In other words, the EPA's decision is essentially based only on the effect and not the cause, and therefore is arbitrary and capricious.

2. The EPA's assumption that re-dispatching under Block 2 can be feasibly implemented by 2020 is arbitrary and flawed. It is not possible for Texas to implement such a significant shift in generation in the short time period assumed by the EPA. While a phase-in of the re-dispatched generation assumed in Block 2 might mitigate the impacts of Block 2, the EPA does not have the necessary expertise to decide what implementation rate is appropriate for each state.

The EPA assumes that the re-dispatching from existing coal-fired EGUs to NGCC EGUs under Block 2 can happen by 2020. However, the EPA does not consider that legislative changes, and in particular, ERCOT market changes would be necessary to effect such a re-dispatching change. The shift in generation assumed by the EPA for Texas' NGCC units is the largest of all states, approximately 19% of the total MWh increase assumed for the entire United States NGCC fleet. In fact, the net increase in generation at Texas' NGCC units assumed by the EPA, approximately 83 million MWh, is greater than the total NGCC generation in every other state except for Florida. Yet, the EPA assumes that Texas can effect such a change in less than four years. The EPA assumes that the states can force such a shift by imposing a cap-and-trade program such as Regional Greenhouse Gas Initiative (RGGI) or otherwise exercise its permitting authority to restrict operation of units. However, the EPA's arbitrary assumption is flawed. Neither the TCEQ nor the EPA has the legal authority to call the permits for the affected units to implement such a change through permitting actions. In citing RGGI as an example of how states might cause such a change, the EPA fails to acknowledge the significant amount of time required to implement RGGI. According the RGGI program design history webpage, discussions to create the program began in 2003. RGGI was first established in 2005 and includes two control periods, spanning from 2009 to 2014. From the initial concept to the final phase, the RGGI program encompasses more than ten years.

Furthermore, while the EPA might argue that they are not requiring the re-dispatching to be implemented by 2020, the EPA has incorporated this assumption into the calculation of the interim goals. The effect of the EPA's flawed assumption is that the interim goal for Texas is substantially reduced which forces the state to make significant reductions prior to the start of the 2020 – 2029 interim period. As discussed in TCEQ Comment C.3 (page 17), approximately 60% of Texas' required reductions on a lb/MWh bases are derived from Block 2 and the majority of reductions for Texas will be required to be made by 2020. Given the legislative, regulatory, and implementation factors, it is not possible for Texas to implement such a drastic shift in energy policy in the time period assumed by the EPA.

Incorporating a phase-in of the re-dispatching as discussed in the October 30 NODA (79 FR 64548) would mitigate some of the near-term impacts of Block 2. However, the EPA is not qualified to determine the feasibility of such a fundamental shift in a state's energy policy. Only the state public utility commissions are in a position to evaluate the feasibility of shifting generation from one fuel source to another on the scale that the EPA is assuming under Block 2. Furthermore, what may be feasible in one state is not necessarily feasible in another state. Therefore, as discussed in TCEQ Comment C.2 (page 16), the TCEQ maintains that the EPA should remove the interim goals from the rule.

3. The EPA has not considered local constraints which may prevent NGCC EGUs from operating at the EPA's assumed 70% capacity factor. In addition to local electrical grid considerations, local environmental regulatory requirements may limit NGCC operation.

The EPA's blanket assumption that a state's NGCC fleet can operate at 70% capacity factor fails to consider numerous local constraints. In addition to local electrical grid constraints such as transmission, local environmental regulations may already be in place that would conflict with increased operation at NGCC units. The EPA did not consider any environmental regulatory constraints on NGCC units other than potential NSR permitting requirements. Control strategies for NO_X in ozone nonattainment areas that are already incorporated into a SIP may directly conflict with increased operation of NGCC units. For example, the TCEQ has implemented a system cap requirement on EGUs located in the Houston-Galveston-Brazoria (HGB) eight-hour ozone nonattainment area that establishes a 30-day rolling average system cap based on historical operation. System owners in the HGB area whose system is comprised mostly or entirely of NGCC units may not have sufficient operational flexibility under their system cap to operate at the 70% capacity that EPA assumes.

4. The EPA has not provided adequate notice and information for the states to consider the feasibility of incorporating co-firing of natural gas at existing coal-fired EGUs as BSER. The modifications associated with co-firing natural gas at a coal-fired EGU will likely trigger applicability under EPA's proposed FCAA §111(b) rule for modified and reconstructed facilities.

In the original proposed rule published on June 18, 2014, the EPA took comment on the concept of co-firing natural gas in existing coal-fired EGUs as BSER. The EPA also discussed the concept of co-firing natural gas as BSER in the October 30 NODA. However, while the EPA provided some information regarding co-firing in Chapter 6 of the GHG Abatement Measures Technical Support Document, the EPA has not provided any specific information regarding what level of co-firing might be considered as BSER. The information presented ranges from 10% co-firing to 100% fuel switching. Furthermore, the EPA has not explained how co-firing would be incorporated into the EPA's building block structure for BSER. Therefore, the states have no basis for commenting on co-firing natural gas as a BSER determination. If the EPA wished to consider co-firing natural gas as BSER, then the EPA should have proposed a specific level of co-firing that might be considered as BSER to allow states and other interested parties adequate information and opportunity to comment. Additionally, the TCEQ notes that co-firing natural gas at a coal-fired EGU will likely trigger applicability under the EPA's proposed FCAA §111(b) rule for modified and reconstructed facilities. Installing natural gas co-firing capability will increase the overall firing capacity of the unit unless the company makes a corresponding decrease in the coal firing capacity of the unit.

F. Block 3 – Nuclear Energy and Renewable Energy

1. The EPA's approach for estimating potential future renewable energy in Block 3 is arbitrary and flawed. The EPA has not justified the rationale for dividing the country into the specified regions for renewable energy. Some of the regions have multiple state renewable portfolio standards (RPS) included in the average while the South Central Region and the South Eastern Region only have one state RPS used for each region. The EPA's assumption that Kansas' renewable energy goal is applicable to the entire South Central Region is flawed and without any technical merit, especially considering that Texas' total generation is ten times that of Kansas and represents the majority of generation in the South Central Region. Furthermore, the EPA's growth rate approach penalizes states with more renewable energy in 2012 and rewards states that have little renewable energy in that year. EPA's approach actually rewards some states by giving credit under Block 3 while Texas is assumed to be able to more than double the state renewable generation, even though Texas produces approximately 11% more non-hydro renewable energy than the combined total of the states that received credit for their renewable energy.

The EPA's approach to set renewable energy targets for Block 3 is arbitrary and severely flawed. The EPA claims that by using the average of state RPS goals for each region the approach considers what states have already determined feasible, but does not address why regional averages have any validity in any one state, or why any particular state's renewable energy achievements are therefore valid in any other state. The EPA also neglects to acknowledge that its approach of separating the states into different regions has resulted in significant disparity in how many state RPS were used to set the regional targets. The renewable energy targets for the East Central, North Central, Northeast, and West Regions were determined using between five and eight different state RPS per region. However, the South Central Region and the Southeast Region were each determined using a single state RPS for each region. The EPA provides no basis for the difference in treatment of the South Central and Southeast Regions from the other regions. In the South Central Region, where Texas is located, the EPA used Kansas' RPS and arbitrarily excluded Texas' RPS from consideration in their analysis. Kansas' total electrical generation is one tenth that of Texas. Furthermore, Texas' total generation in 2012 represents approximately 57% of the South Central Region. Texas' 2012 non-hydro renewable generation represented approximately 64% of the South Central Region's total. It is not rational for the EPA to assume that a state the size of Kansas can be representative of the entire South Central Region, particularly when the region's total generation and total renewable generation is so heavily weighted towards Texas, the state with the largest total electrical generation and largest renewable energy generation in the region.

The EPA did not provide a rational explanation for why the Texas RPS was excluded from EPA's consideration in this Block 3 analysis for the South Central Region other than a footnote in the GHG Abatement Measures Technical Support Document stating that the EPA did not include targets that were capacity-based (GHG Abatement Measures Technical Support Document, page 4-10, Footnote 107). This unsupported conclusory statement cannot support the EPA's exclusion of Texas' RPS. Additionally, the Kansas Renewable Energy Standards Act is in reality a form of a capacity-based RPS. According to Kansas Statutes Annotated (K.S.A.) 66.1258, Kansas' renewable energy portfolio requirement is for net renewable generation capacity as a percent of peak demand. Furthermore, Kansas' Renewable Energy Standards Act established an exception in K.S.A 66-1261(b) to exempt a utility from administrative penalties if the utility can demonstrate that the retail rate impact for the utility has reached or exceeded the 1% level set in K.S.A 66-1260 and the utility has not achieved full compliance with the renewable portfolio requirement in K.S.A 66-1258. This stop-gap measure to avoid excessive costs that might result from the Renewable Energy Standards Act was not considered by EPA.

Additionally, the 8% growth rate EPA has applied has a disproportionately large impact on Texas because Texas produced more non-hydro renewable energy in 2012 than the other five states in the South Central Region combined. Texas renewable energy target under Block 3 reaches the 20% cap and results in an assumption that Texas can increase its renewable generation by 52 million MWh by 2029. However, Arkansas, Louisiana, and Nebraska are expected to increase their renewable energy far less than Texas because their renewable generation in 2012 was a very small percent of their total generation. In fact, the total increase in renewable generation assumed for all five other states in the South Central Region is less than half what EPA assumed for Texas only. EPA's approach actually rewards other states for implementing less renewable energy and penalizing Texas for implementing more renewable energy in 2012.

Finally, four states are receiving credit for their 2012 renewable energy generation: Iowa, Maine, Minnesota, and South Dakota. The EPA's block-by-block calculations for these four states show that their state goals become less stringent at Block 3. Texas produces approximately 11% more non-hydro renewable energy than these four states combined. Despite the tremendous efforts Texas has made to become the nation's leader in wind energy, the EPA is not only not giving Texas credit for its 2012 renewable energy generation, EPA assumes that Texas can more than double its renewable energy generation by 2029. The EPA's arbitrary approach in evaluating renewable energy potential is rewarding these four states and penalizing Texas.

2. The proposed alternate regional approaches discussed in the October 30 NODA are unclear and too open-ended to allow states adequate opportunity to comment. While the EPA's possible regional approaches to allocating renewable energy targets for the states might mitigate some of the disparate treatment of states under Block 3, the use of any regional approach does not address the underlying problem with the EPA's proposed Block 3 approach of assuming one state's RPS can be used to assign renewable energy targets to other states.

The discussion in the October 30 NODA (79 FR 34551) regarding alternate regional approaches to setting state renewable energy targets is unclear as to exactly how these alternate approaches would affect any specific state. The EPA has not provided adequate information for the states to evaluate the possible changes to Block 3 and provide meaningful comment. The EPA's proposed alternate regional approaches discussed in the NODA might mitigate the disparate impact of the growth rate approach in Block 3 to some degree by presumably raising the renewable energy targets of the other states that had lower renewable energy generation in 2012. However, these possible modified approaches do not address the underlying problem with Block 3, i.e., the EPA is assuming that just because one state has set a renewable energy target that another state is capable of meeting that same target. The EPA has provided no evidence demonstrating the validity of this underlying assumption about the feasibility of Block 3.

The EPA also appears to be contemplating combining the alternate renewable energy approach discussed in the Alternate RE Approach Technical Support Document with a regional approach (79 FR 64551). As discussed in TCEQ Comment F.3 (page 27), the EPA's alternate approach to determine state renewable energy targets is also flawed and using a regional approach to apportion the renewable energy generation will not address these flaws. Additionally, the EPA suggests as an example criterion using the state's share of total electricity sales within the region to allocate renewable energy targets to individual states. Using electricity sales as a criterion would be fundamentally flawed because the EPA used generation data, not electricity sales, in developing renewable energy targets. Furthermore, electricity sales in a state do not demonstrate the feasibility for increased renewable energy in that state.

3. The EPA's alternate approach to determine renewable energy targets for the states relying on the 2012 National Renewable Energy Laboratory (NREL) report and IPM predictions is flawed. The approach is biased in favor of states with very low technical potential for renewable energy and allows EPA to default to its IPM predictions for states like Texas. The EPA cannot use IPM to set federally enforceable state goals without making the data, calculation steps, assumptions, and all other aspects of IPM transparent and accessible to the public.

The alternate renewable energy approach described in the EPA Alternate RE Approach Technical Support Document is fundamentally flawed. The NREL report only considered technical feasibility and did not consider factors such as: economics; availability of existing or planned transmission infrastructure; relative reliability or time-of-production of power; local, state, regional, or national polices; or the location or magnitude of current and potential electricity loads (U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis, National Renewable Energy Laboratory, NREL/TP-6A20-51946, July 2012). These factors are critical to evaluate a state's true potential for development of renewable energy. The EPA's attempt to resolve this lack of consideration was to rank states based their actual renewable generation as a percent of their technical potential in the NREL report. EPA then arbitrarily selected the top 16 states and averaged the percentages to derive a benchmark level for each type of renewable energy. This approach is biased towards states with small technical potential and generates absurd results for large states like Texas. The benchmark for wind generation using this alternate approach was 9.0%. Applying the 9.0% benchmark to Texas' 5.5 million gigawatt-hour (GWh) potential that the NREL estimated for Texas results in approximately 500 million MWh of possible renewable energy generation, an unrealistically large number that is greater than the total electrical generation for the entire state. The EPA attempts to resolve the unrealistic results generated by the benchmark approach by using the lower of the benchmark approach or what IPM predicts as economical potential renewable energy for the state.

The reason the benchmark approach is producing unrealistically large potential renewable energy results for some states is because the EPA has failed to recognize the drastic difference in the development rate of renewables between states with very low technical potentials versus states with very large technical potentials. All 16 states that EPA used to set the benchmark for wind renewable energy have technical potentials in the NREL report less than 100,000 GWh. However, there is a clear distinction in the development rates for wind between states with very low technical potentials versus states with technical potentials greater than 1,000,000 GWh. The development rate for states with a technical potential for wind greater than 1,000,000 GWh averages only 0.32% and the maximum rate is only 0.81%. There is no rational basis for the EPA's assumption that states with the lowest technical potentials can or should set the benchmark for other states with very large technical potentials. The EPA's arbitrary and flawed decision to take the top 16 states does not consider the wide variation in the amount of the technical potential, electrical generation, or any other regional or state-specific factors that will affect a state's ability to implement renewable energy. The EPA also fails to consider a fundamental fact: a small amount of generation in a state with a very low technical potential will result in a larger percent development rate. Yet, the EPA has just arbitrarily averaged the percent development rates without any regard to this fact. The table in Figure 6, EPA's Alternate Renewable Energy Benchmark Approach, shows the states' NREL technical potential, 2012 wind generation, and development rate from the EPA's data file on the alternate renewable energy approach. The states have been sorted by technical potential and the yellow highlighted states represent the states that EPA used to set the benchmark for wind energy. The EPA appears to have even included Delaware in the benchmark average despite the fact that the state has the third lowest technical potential for wind generation in the entire country, only 22 GWh. Texas' actual wind energy generation in 2012 was almost 1,500 times greater than Delaware technical potential. It is irrational for the EPA to believe that a state such a Delaware is appropriate to be used even in part to set a benchmark for states with exponentially larger potential for renewable energy.

Alternative RE Approach Data File - Wind Only

All values expressed are GWh, unless otherwise noted

State	RE Technical Potential (NREL)	EIA 2012 Net Generation	Development Rate (%)
TX	5,552,400	32,214	0.58%
KS	3,101,576	5,195	0.17%
NE	3,011,253	1,284	0.04%
SD	2,901,858	2,915	0.10%
MT	2,746,272	1,262	0.05%
ND	2,537,825	5,275	0.21%
IA	1,723,588	14,032	0.81%
WY	1,653,857	4,369	0.26%
OK	1,521,652	8,158	0.54%
MN	1,428,525	7,615	0.53%
NM	1,399,157	2,226	0.16%
CO	1,096,036	5,969	0.54%
MO	689,519	1,245	0.18%
IL	649,468	7,727	1.19%
IN	377,604	3,210	0.85%
WI	255,266	1,558	0.61%
MI	143,908	1,132	0.79%
OH	129,143	985	0.76%
CA	89,862	9,754	10.85%
OR	68,767	6,343	9.22%
NY	63,566	2,992	4.71%
WA	47,250	6,600	13.97%
ID	44,320	1,891	4.27%
UT	31,552	704	2.23%
ME	28,743	887	3.09%
AZ	26,036	532	2.04%
AR	22,892	-	0.00%
NV	17,709	129	0.73%
PA	8,231	2,129	25.86%
NH	5,706	209	3.66%
WV	4,952	1,286	25.97%
VA	4,589	-	0.00%
MD	3,632	322	8.86%
MA	2,827	90	3.17%
NC	2,037	-	0.00%
LA	935	-	0.00%
TN	766	47	6.20%
SC	428	-	0.00%
GA	323	-	0.00%
NJ	317	12	3.65%
AL	283	-	0.00%
KY	147	-	0.00%
RI	130	1	1.06%
CT	62	-	0.00%
DE	22	4	16.75%
FL	1	-	0.00%
MS	-	-	0.00%

Figure 6: EPA's Alternate Renewable Energy Benchmark Approach, State-by-State Technical Potentials, 2012 Net Generation, and Development Rate, Wind Only.

The result of the EPA's flawed approach to setting benchmarks in the alternate renewable energy approach is that EPA would default to the IPM predictions for all states with technical potentials greater 1,000,000 GWh as well as many other states. However, the EPA has provided no demonstration of IPM's accuracy and reliability for predicting both the economic and technological feasibility of expanding renewable energy generation on a state-by-state basis. Furthermore, IPM was developed to evaluate the impact of regulations on the electric utility sector, not to establish enforceable limitations. The following is EPA's stated purpose of IPM:

> "EPA uses the Integrated Planning Model (IPM) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Consulting, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), hydrogen chloride (HCl), and mercury (Hg) from the electric power sector." EPA IPM Website: http://www.epa.gov/airmarkets/progsregs/epa-ipm/.

The EPA's use of IPM to evaluate the economic impacts of the rule does not equate to using the model to establish enforceable limits. However, using IPM to make projections of the level of renewable energy assumed to be economic for a state and then incorporating those projections directly into the state goal calculations does constitute using IPM to set enforceable limitations on the states. The states are unable to evaluate the validity of IPM's assumptions and predictions unless EPA makes all data inputs, calculations, assumptions, and all other factors used in the IPM model transparent and accessible to the states. The EPA should not use a "black box" modeling program to establish regulatory emission standards, particularly when, as here, that was not the original purpose for which IPM was developed and the EPA has provided no assurance that all factors relevant for establishing enforceable requirements on either the states or the electric utility sector are being evaluated and weighted appropriately by IPM.

4. There are numerous environmental, transmission, and practical factors that must be considered in the development of renewable energy resources, such as siting issues, transmission infrastructure, and federal law compliance issues such as Endangered Species Act and Migratory Birds Treaty Act. The EPA has not considered any of these factors in either the proposed approach for Block 3 or in the alternate approach to setting renewable energy targets.

The EPA's arbitrary assumption that Texas can more than double the state's renewable energy generation fails to consider a multitude of local, state, and federal factors. Examples of these factors include: geographic siting issues such as land use restrictions; transmission infrastructure requirements and restrictions; and local, state, and federal laws. While not subject to TCEQ permitting requirements, construction of new wind capacity is not exempt from environmental and other legal considerations. The federal Endangered Species Act and the Migratory Bird Treaty Act are just two examples of legal factors that can impact a wind generation facility's viability. Local legal issues can also be a factor, such as common law nuisance claims. The EPA's proposed approach does not consider any of these factors because the EPA arbitrarily, and incorrectly, applied Kansas' RPS to the entire South Central Region. Neither did the EPA consider these factors in the alternate renewable energy approach. As discussed in TCEQ Comment G.2 (page 32), the NREL report did not consider any of these factors. The EPA's flawed approach of setting the benchmark based on states with technical potentials exponentially lower than Texas' technical potential did not take such factors into consideration and, while IPM is essentially a "black box" model, the TCEQ does not see any means for IPM to take these factors into consideration either.

5. The EPA should abandon its attempt to incorporate renewable energy generation in its BSER determination for the proposed rule. Renewable energy should be allowed as an option for a state's compliance but not a component of the EPA's BSER determination.

As TCEQ Comments F.1 and F.2 (pages 25 and 27) illustrate, the EPA's attempts to set renewable energy targets for states are severely flawed and result in inequitable treatment of states, rewarding some states for lessor efforts and penalizing other states, such as Texas, for being leaders in renewable energy. Additionally, as discussed in TCEQ Comment I.3 (page 42), the EPA does not have the legal authority to consider renewable energy in its BSER determination. For these reasons, the EPA should abandon its attempt to incorporate renewable energy into the BSER determination for the proposed rule. Renewable energy should be allowed as an option for a state's compliance but not a component of the EPA's BSER determination.

6. The EPA's approach to account for nuclear capacity at risk of retirement is arbitrary and flawed. The EPA identifies Texas as having 290 MW of nuclear capacity at risk of retirement; however, the smallest nuclear power plant unit in Texas is approximately 1200 MW. The EPA should have considered the actual sizes of the nuclear units in the states before arbitrarily applying the 5.8% to the states' nuclear power plant fleets.

The EPA's arbitrary assumption of 5.8% of each state's nuclear fleet being at risk of retirement is flawed and not supported by a rational basis. This is particularly true when the EPA's assumed capacity at risk of retirement in Texas of 290 MW does not equate to a complete unit. The smallest nuclear power plant unit in Texas is approximately 1,200 MW. In fact, in reviewing the National Electric Energy Data System (NEEDS) data on nuclear units, the TCEQ has not found a single state with a nuclear unit small enough to correspond to the capacity which the EPA says is at risk of retirement for that state. The EPA's arbitrary application of the 5.8% without consideration of other factors has resulted in a nonsensical adjustment to the state goal. Further, the EPA's adjustment has an adverse consequence for states that actually have nuclear units at risk of retirement because EPA's approach assumes that only 5.8% of their fleet is at risk when in reality a higher percentage may actually be at risk of retirement.

G. Block 4 – Demand Side Energy Efficiency

1. The EPA has incorrectly calculated the assumed benefits of future energy efficiency improvements in Block 4 because the EPA applies the energy savings to the entire electrical generation in 2012 without accounting for the fact that some of the future generation would be from new units, which would not be subject to the rule, i.e., some of the energy savings in the future will be outside of the affected EGU fleet. Energy efficiency programs should be allowed as an option for a state's compliance but not a component of the EPA's BSER determination.

The EPA's calculation in Block 4 is fundamentally flawed in that the EPA assumes that all electricity MWh savings from energy efficiency measures can be "directed" to the fossil fuel-fired EGU fleet subject to the §111(d) rule, which does not reflect reality. Even at the base level, the calculation is incorrect because EPA based the calculation on total 2012 net sales of electricity, yet the EPA excluded some 2012 generation, i.e., existing hydroelectric power and most nuclear power. Furthermore, the EPA compounds this error by assuming that in the future, the MWh savings from energy efficiency measures can be solely attributable to the fossil fuel-fired fleet. As the EPA acknowledges in the Resource Adequacy and Reliability Analysis Technical Support Document, significant retirements are anticipated from the rule. New units to replace retirements will be built in the future as well in order to meet future demand. These new EGUs will be outside of the fleet of units subject to the state goal requirements; however, these new units are still providing power to the electrical grid as a whole and any energy savings from future energy efficiency savings would also affect the generation of the new units as well. Even further complicating this issue is the fact that some of MWh savings from energy efficiency measures would be attributable to future renewable energy generation that EPA assumes in Block 3. By applying all the energy efficiency savings to only the affected fleet of EGUs, the EPA's calculation biases the state goal low because all MWh energy savings are included in the denominator but only CO_2 emissions from the affected EGU fleet on included in the numerator. Furthermore, if states are required to make adjustments to account for only the energy efficiency attributable to affected units in estimating benefits for energy efficiency for showing compliance with the state goals when the EPA did not account for this issue in setting the state goals, this discrepancy between state goal calculation and compliance demonstration would further bias the rule against states. For this reason and the other reasons discussed in the TCEQ's comments, the EPA should abandon its attempt to incorporate energy efficiency measures in the state goal calculation. Energy efficiency measures should be allowed as an option for state plans but should not be included in the EPA's BSER determination.

2. The EPA cannot restrict the energy efficiency measures that a state might use to comply with their state goal to less than what EPA assumed in establishing the state goals using Block 4.

The EPA is taking comment on limiting the energy efficiency programs that could be included in the state plan (State Plan Considerations Technical Support Document, page 50). However, EPA did not consider any restrictions on energy efficiency programs when evaluating measures in Block 4. The EPA's Block 4 assumptions would be invalid unless EPA can show that their assumed energy efficiency growth corresponds to the programs that are allowed to be used by the states in the final rule. Furthermore, states' ability to comply with the state goals would be adversely impacted by the EPA restricting measures that can be included in the state plan when no such restriction was assumed by the EPA in establishing the state goals. While the TCEQ recommends the EPA not include energy efficiency assumptions in the state goal calculation, if the rule is finalized with Building Block 4 then the states' ability to use energy efficiency programs as compliance strategy under the §111(d) rule must be on the same basis as the EPA assumed in setting the state goals.

H. State Plan Issues

1. Some of the requirements in the proposed rule for state plans are more stringent than the requirements for a SIP for the NAAQS and are unnecessarily burdensome. The proposed rule creates an excessive burden on state agencies and affected entities by imposing excessive reporting requirements and creating needless bureaucracy.

Many of the state plan requirements proposed or being considered by EPA are unnecessarily burdensome on the states and in some cases go beyond SIP requirements for the NAAQS. The EPA is attempting to micromanage the development and implementation of state plans for the proposed rule. The intent of the SIP and state plan provisions under FCAA §110 and §111 is to allow states the latitude to implement programs in the most efficient means possible. However, as discussed in TCEQ Comments H.2 through H.9 (pages 33 – 37), the EPA is attempting to control almost every aspect of the state plan process. Some components of the proposed state plan requirements even exceed the EPA's legal authority under FCAA §111. The EPA's role in the state plan process is oversight and approval, not implementation. While federal enforceability of the state plan is a component of the process, the EPA's enforcement role is secondary to the states' role under FCAA §111(d). The EPA should not be involved in the direct implementation and enforcement of the state plans except if a federal plan is necessary or the state fails to enforce a component of an approved state plan.

2. The EPA is attempting to usurp state authority over renewable energy, energy efficiency, and similar programs through the extension provision in proposed 40 Code of Federal Regulations (CFR) §60.5760(a)(3). The EPA does not have the legal authority under FCAA §111(d) to make any demands regarding a state's current programs that are not already federally enforceable. Furthermore, the constitutions of Texas and most other states prohibit a state agency from making a federally enforceable commitment binding the state legislature from changing state law. The commitment requirement in proposed §60.5760(a)(3) makes it impossible for a state to qualify for an extension if the state has renewable energy standards, energy efficiency standards, or any other measure in state law that might somehow limit or avoid CO_2 emissions from EGUs. Proposed §60.5760(a)(3) should be removed from the rule.

In §60.5760(a)(3), the EPA is proposing that in exchange for an extension, the state must commit to not remove any existing CO_2 measures. Furthermore, the state must make the commitment in a way that allows the EPA to still enforce the measure even if the state fails to submit a final plan or EPA does not approve the final plan. Unless a state program, such as renewable energy standard, is already federally enforceable under a state plan or a SIP, the EPA does not have the authority to make any demands of the states regarding such a program. The EPA is attempting to force states to surrender that authority through §60.5760(a)(3). For the EPA to threaten to withhold an extension unless the state surrenders authority of these programs to the EPA is blatant extortion of the states.

Furthermore, no state agency can make such a federally enforceable commitment for measures in state law. The rule, as proposed, applies to the administrator of the air quality program in a state. State agencies cannot bind their legislative process in the manner EPA is requiring. The TCEQ is no more capable of making such a commitment than the EPA can commit that a provision of the FCAA will not change. Even a state legislature may not be able to restrict a future legislature from changing state law. The provision in §60.5760(a)(3) makes it impossible for a state to qualify for an extension. This provision is illegal and unnecessary and should be removed from the rule.

3. The EPA has no need or legal basis for requiring states to submit proposed rules and legislation as a condition for the EPA to grant an extension to submit a state plan. Such a requirement is unreasonable and places state agencies in the untenable position of being forced to propose rules based on draft legislation. The TCEQ cannot propose a rule that the agency does not have legal authority to propose.

The EPA is taking comment on whether states should be required to submit proposed rules and legislation to EPA as part of initial plan (79 FR 34916). Specifically, EPA states that "it may be reasonable to require that a state must document that it has at least proposed any necessary regulations and introduced any necessary legislation within the first thirteen months to qualify for additional time to submit a complete plan." Not only is such a requirement unreasonable and unnecessary micromanagement of the states, the EPA would be placing the states in the untenable position of attempting to propose rules based on draft legislation. The EPA's assumption that a state agency could propose a rule to implement legislation based solely on the introduced legislation is flawed. A state agency would not have the legal authority to propose a rule to implement legislation necessary for the state plan until that legislation has been passed and signed into law. The state's legal authority notwithstanding, to propose a rule prior to finalization of the law would likely force a state agency to re-propose the rule if the legislation changed from the introduced version of the bill, which happens frequently in the legislative process. Furthermore, legislation is beyond the control of the administrator of the state air program, to whom the proposed rule applies. As an agency of the executive branch of state government, the TCEQ is prohibited from lobbying the legislature.

4. The EPA does not have the legal authority under FCAA §111(d) to require the states to create and maintain public databases to make records submitted by affected entities available to the public and EPA. Furthermore, EPA has not accounted for the costs of creating and maintaining such a database in the RIA of the proposed §111(d) rule.

The EPA is proposing that the periodic reports from affected entities must be submitted annually, electronically, and "disclosed on a state database accessible to the public and EPA." (79 FR 34910) The EPA does not have the legal authority to mandate what media a state uses to make records available to the public. Additionally, the TCEQ does not currently have a publically accessible database for posting such records. The EPA's analysis in Section 3.11 of the RIA regarding the Monitoring, Reporting, and Recordkeeping Costs, does not provide any cost estimates for the states to create and maintain such databases. The costs for modifying an existing public database or creating a new database system would be substantial. As such, the EPA's impact analysis with regard to the burden to state agencies is not valid. Furthermore, the

EPA's analysis for the Unfunded Mandates Reform Act is also invalid because the EPA has not factored in the costs for the public databases when determining whether the proposed rule would result in expenditures of $100 million or more for state, local, and tribal governments.

5. The EPA's proposed requirement for Evaluation, Measurement, and Verification (EM&V) plans for state plans that use energy efficiency measures for compliance with a rate-based approach is more stringent than EPA SIP requirements for states that want to model SIP creditable reductions from energy efficiency measures. The EPA should have developed the guidance for the EM&V plans in time for proposal so that states could comment on the specific details. As proposed, the EM&V plan is a required element of the state plan and states have the right to comment on those required elements.

The EPA has proposed that an EM&V plan is required to be submitted with the state plan if the state wants to take direct credit for energy efficiency measures for compliance with the state goal in a rate-based approach. An EM&V plan is not required if a state wishes to claim credit for energy efficiency measures as part of a SIP attainment demonstration. The EPA's 2004 document, Guidance on State Implementation Plan Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures, requires states to submit a plan to evaluate, monitor, and report the resulting emission effects of the energy efficiency measures but does not include prescriptive steps on the contents of that plan or how to perform that verification. Even with the less prescriptive requirements in the SIP process for claiming energy efficiency measures, states have historically been reluctant to include such measures in federal plans. The EPA's prescriptive approach with this proposed rule will only further discourage states from including energy efficiency measures in state plans.

The EPA did not include a draft of the guidance for the EM&V plans with the proposed rule. While the EPA discusses some aspects of the EM&V plans in the technical support document State Plan Considerations, the information is too general and broad for the states to assess the possible impacts and provide meaningful comment. As proposed, the EM&V plan is a required element of the state plan. States have the right to comment on all required elements of a state plan required under FCAA §111(d). Given the aggressive schedule the EPA is proposing, the EPA should have released the guidance with the proposed rule. In addition to states not having adequate opportunity to comment on the guidance, the TCEQ is concerned that the EM&V plan guidance will not be available until late in the process. The EPA has historically finalized guidance so late in the process as to either result in a needless waste of state resources or the inability to incorporate the guidance due to internal timeline constraints. If EPA does not finalize guidance by time the state plan is proposed, it may be impossible for the state to adjust their state plan to meet EPA's requirements for EM&V plans.

6. The EPA does not have the legal authority to mandate to the state who may perform EM&V activities or what qualifications such evaluators may be required to have. Attempting to set such requirements may have unintended consequences and may preclude some state agencies from performing EM&V activities.

The EPA is taking comment on specifying who can perform EM&V activities and if EPA should specify qualifications for such evaluators (State Plan Considerations Technical Support Document, page 56). The EPA likens this approach to professional certification requirements in the accounting and engineering field. As an initial matter, the TCEQ does not believe that the EPA has the legal authority under FCAA §111(d) to create an entirely new regulatory certification process for the evaluation of energy efficiency programs. Furthermore, individuals potentially impacted by such a requirement would not have any adequate opportunity to comment on such requirements because EPA has not actually proposed any rule requirements to establish a certification process or define what qualifications would be necessary to allow an individual to perform the EM&V activities. The EPA also speculated that criteria for eligible evaluators might include a demonstration of independence from those implementing or administering the energy efficiency programs and measures. Such a requirement could actually preclude state agencies from conducting EM&V activities in some states. Some of Texas' energy efficiency goals set by the legislature apply to state agencies and state universities. Depending on how the EPA defines "implementing or administering" an energy efficiency programs and measures, a state may have difficulty identifying qualified evaluators that are independent. The states may be required to contract with third parties to perform the EM&V activities, which would result in fiscal implications for the states that the EPA does not appear to have considered in the RIA of the proposed rule.

7. The EPA's discussion in the proposal preamble regarding modification of an approved state plan and anti-backsliding is unclear but appears to be more stringent than FCAA §110(l) regarding SIP revisions.

The EPA states under Section VII.A.6 of the preamble (79 FR 34917), regarding modification of approved state plans, that "the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan." The EPA goes on to state that the state must "demonstrate that the revised set of enforceable measures in the modified plan will result in the emission performance at affected EGUs that is equivalent or better than the level of the emission performance required by the original state plan." The EPA's anti-backsliding discussion appears to go beyond just ensuring that the revised state plan still demonstrates compliance with the state goals, the actual enforceable component of this proposed rule that the states are required to meet. Further, the EPA's position on anti-backsliding for the purposes of FCAA §111(d) appears to be more stringent than FCAA §110(l) regarding SIP revisions. While §110(l) is not directly applicable to §111(d), §110(l) only states that the Administrator shall not approve a revision to a SIP if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress or any other applicable requirement of the FCAA. Any anti-backsliding requirement regarding the proposed rule under §111(d) should be based solely on whether the revised plan will interfere with meeting the state goals.

8. The EPA has no need or legal basis for requiring that affected entities must submit reports to the EPA as well as the states.

The EPA is taking comment on whether reports must be submitted to the EPA as well as states (79 FR34910). Such a requirement is unnecessary and would create wasteful reporting. The EPA would have access to the reports from the state as well as the affected entities themselves. The states' recordkeeping and reporting requirements included in the state plans will be federally enforceable once the plans are approved by the EPA. Further, the TCEQ questions whether the EPA regional offices are prepared to receive, log, and retain the hundreds of reports that would be submitted. Unless the EPA can provided a reasoned justification for why such duplicative reporting is necessary and what EPA intends to do with the reports, the EPA should not adopt such a requirement in the rule.

9. The EPA's proposed reporting deadline of July 1 for the states to submit annual reports for the prior calendar year is not realistic. States will need significantly more time if the state plan includes energy efficiency and renewable energy measures or a cap and trade program. At a minimum, states should have at least a full year to submit reports from the prior calendar year. States participating in a multi-state plan may require even more time. Given the 10-year averaging time for the interim goal, requiring annual reporting from the states during the interim period is an unnecessary burden on the states. The frequency of the state reporting should be reduced during the interim period.

The July 1 deadline in proposed 40 CFR §60.5815(a) for states to submit annual reports to the EPA is not realistic. The EPA has not considered all the components that might be need to be included in the report that are dependent of the approach a state might choose and what measures are included in the state plan. The energy efficiency verification process of energy efficiency measures from the prior year could take 8 – 10 months. Furthermore, if a cap and trade program is used, July 1 does not provide sufficient time for the state to review companies' annual reports and process trades in order to assess the emission performance level as EPA requires in the annual reports. States should have, at a minimum, a full year to submit annual reports, i.e., December 31 of the following year. A multi-state plan would be even more complicated and may require additional time to allow for coordinating activities between multiple states. Additionally, requiring annual reports starting in 2021 places an unnecessary burden on states. As discussed in other TCEQ comments on this propose rule, the TCEQ recommends removing the interim goals from the rule. However, if the EPA retains the interim goals, the EPA should reduce the frequency of the state reporting requirements during the interim period. Given the 10-year averaging time for showing compliance with the interim goals, the annual reporting requirement during the interim period places an unnecessary burden on the states. The states have the responsibility of ensuring compliance with state goals, not the EPA.

10. The proposed rule allows EPA twelve months to review and act on the state plans, which is almost as much time as states would be given to develop the plans. If the EPA considers itself to need additional time for the review of state plans, the EPA has no justification for holding states to an unreasonable schedule to submit state plans.

Given the immense complexity of issues and cross-agency state authority needed to implement the rule as proposed, the 13 months that EPA proposes to allow states to submit a state plan is grossly inadequate. Furthermore, as discussed in TCEQ Comment H.2 (page 33), the EPA is attempting to force states to make concessions and surrender state authority to the EPA in exchange for the EPA granting an extension, making it impossible for some states to qualify for extensions. Yet, the EPA proposes to give itself twelve months to review and either approve or disapprove a state plan, a default extension from the standard four months allowed under 40 CFR §60.27 and almost as much time as the states are given to develop and submit state plans. The vast majority of work involved in the FCAA §111(d) process falls to the states. If the EPA considers itself to need additional time to perform its smaller role in the process, then the EPA should acknowledge the burden it is imposing on the states and revise the schedule for state plans submittal. As discussed in TCEQ Comment A.9 (page 11), states should have until at least 2020 to submit state plans. Additionally, the EPA routinely fails to meet its regulatory deadlines for acting on state submittals.

10. While the TCEQ supports including provisions in the rule allowing states additional time to correct deficiencies in the state plan, the process should be clearly spelled out in the rule and include definitive deadlines for both the EPA and the states. The EPA should include a provision in the rule specifying that state plans are considered approved by default if the EPA fails to act within the required timeline.

The TCEQ agrees with the EPA's proposal to allow states time to correct deficiencies in state plans. Such a provision would be consistent with the SIP development process and is particularly important given the aggressive schedule that the EPA is proposing. However, in the interest of providing clarity for the states and all interested parties, such a provision should include definitive deadlines as well as consequences for both the EPA and states. As the EPA has pointed out, there are consequences to a state failing to submit plan by the required deadline, i.e., the EPA may issue a federal plan. Similarly, the EPA should face consequences for not acting by its required deadline. The rule should be revised to specify that a state plan is approved by default should the EPA fail to either act on the state plan submittal or notify the state of a deficiency in the state plan. Rather than excuse itself from its regulatory obligations, the EPA should hold itself to the same standard it imposes on states.

12. The EPA should allow but not require electronic submittal of state plans.

The EPA is taking comment on whether it should allow or require states to submit state plans electronically (79 FR 34917). While allowing electronic submittal of state plans may provide some advantages, states should be allowed to decide the most appropriate media to make submittals based on the circumstances. The EPA should not consider such a requirement until an electronic submittal system is fully established and vetted by the states.

13. The EPA needs to clarify the review and approval process for multistate plans, in particular if the multistate plan crosses EPA regional authorities.

While the EPA has made clear that states may enter into multistate agreements for showing compliance with the state goals and submit multistate plans, the EPA has not explained how multistate plans will be reviewed and approved by the EPA. As the proposed rule does not appear to restrict which states may participate in a multistate plan, in particular, the TCEQ requests clarification regarding how the EPA intends to handle approval of multistate plans that cross EPA regional authorities. For example, the EPA needs to clarify whether approval from all applicable EPA regional offices will be necessary or if EPA headquarters approval will be needed in such situations. States need to understand how this will work before deciding whether or not to pursue a multistate plan.

14. The EPA offers its recently released Avoided Emissions and Generation Tool (AVERT) as a possible tool for states to use in states' planning efforts; however, AVERT has limited usefulness for the purposes of developing state plans because the EPA does not recommend using the tool to forecast more than five years. Additionally, the EPA did not follow a quality assurance and quality control plan in the development of AVERT and the TCEQ has found errors and questionable results using AVERT.

The EPA cites AVERT as a possible tool to help states plan for compliance with this rule in estimating benefits from energy efficiency and renewable energy (State Plan Considerations Technical Support Document, page 28).The EPA's instructions on AVERT state that the tool should not be used to forecast more than five years from the base year data. States are required to develop and submit state plans in 2017 that project out to 2030. EPA staff have indicated that the use of AVERT would be limited to reporting purposes after programs were put into place. However, using one methodology to project future benefit of programs for state plan development purposes and another methodology to report the benefits for compliance purposes after the fact would have unacceptable risks and uncertainties unless the two methodologies were validated to produce comparable results. The EPA should make these risks clear to potential users of AVERT for the purposes of the proposed FCAA §111(d) rule. Furthermore, the TCEQ has identified errors in the AVERT tool and notified EPA staff of these errors. Additionally, the TCEQ has observed that AVERT produces unusual results, such as actual increases in emissions in some counties as a result of energy efficiency and renewable energy measures. According to the TCEQ's discussions with EPA staff, the EPA did not follow a quality assurance and quality control plan in the development of AVERT. As such, the TCEQ considers the results generated by AVERT to be questionable and the TCEQ does not intend to rely on AVERT for any purpose until the program has undergone a more thorough quality review by the EPA.

15. Proposed 40 CFR §60.5725 should be revised to specifically allow states the option to not submit a state plan. Unlike prior FCAA §111(d) rulemakings, the EPA has not proposed a federal plan with the proposed Carbon Pollution Emission Guidelines for Existing Power Plants.

Proposed 40 CFR §60.5725 requires a state to either submit a state plan or submit a negative declaration and makes no allowance for a state to choose not to submit a state plan. However, states have elected to not submit state plans in the past for prior FCAA §111(d) regulatory actions. If a state chooses to not submit a state plan under this proposed rule, the state might be considered in violation of §60.5725. This provision is in direct opposition to the choice given states by Congress under §111(d) to not submit state plans. The EPA should revise §60.5725 to reflect Congress' intent and the actual practice of how the EPA has implemented §111(d) in the past.

In prior FCAA §111(d) rulemakings, the EPA has included a model rule to serve as the federal plan should a state not submit a state plan. With the current proposal, not only has the EPA not provided a draft of the federal plan that would take the place of a state plan, the EPA has refused to answer questions regarding what a federal plan would entail. In order to make an informed decision on whether to submit a state plan, the states must have a clear understanding of what a federal plan for this §111(d) rule would require. The EPA has not provided a rational justification for not including a draft federal plan with the proposed rule. The EPA should withdraw the proposed rule until they have established a draft federal plan and are able to explain the basis for their authority to implement that federal plan if necessary.

I. Legal

1. The EPA's authority to regulate EGUs under FCAA §111(d) is without legal basis because those sources are already subject to regulation under FCAA §112.

The EPA's proposal to regulate sources under FCAA §111 is without merit or legal basis, because the EGUs subject to the proposal are already regulated under FCAA §112. Section 111(d) prohibits EPA from establishing standards of performance "for any existing source for any air pollutant…emitted from a source category which is regulated under [§112]." The plain meaning of this provision is unambiguous and excludes from §111(d) any existing sources that are subject to regulation under §112. The EPA first attempts to claim that the language of §111(d) is ambiguous because it does not speak directly to the pollutant emitted from sources at issue in this proposed rulemaking, i.e., CO_2 from fossil-fuel fired EGUs. However, the term "air pollutant" is not ambiguous, given the context of §111(d).

The EPA's basis relies upon two competing amendments to §111 adopted as part of the 1990 amendments to the FCAA. The EPA's analysis fails to consider its responsibility to give full meaning to both of the conflicting amendments. Instead, the EPA "picks the winner" without giving any consideration to the conflicting amendment, and without resolving inconsistencies with legal authority regarding which amendment should take precedence if EPA determines that only one may control. These two provisions, one prohibiting the EPA from regulating any emission from a source regulated under §112 and the other prohibiting the EPA from regulating any pollutant regulated under §112, are in fact complimentary. They exhibit Congress' intent that §111(d) rarely be used. Additionally, the EPA itself has already adopted an interpretation regarding the two conflicting amendments in its final rule to remove coal and oil-fired EGUs from the §112(c) list (70 FR 15994, March 29, 2005.) The EPA's legal memorandum does not address the change in its view from this previous interpretation; nor does it address why the Senate Amendment, which because it was labeled as a "conforming amendment" itself, illustrates the Senate's intent that it does not provide substantive changes to the law. Furthermore, the Supreme Court has confirmed that sources subject to §112 cannot be regulated under §111(d). In *AEP v. Connecticut* (131 S.Ct. 2527, 2537, n7 (2011)), the Court stated: "There is an exception: EPA may not employ [§111(d)] if existing stationary sources of the pollutant in question are regulated under [a NAAQS], or the hazardous air pollutants' program, [§112]."

Congress intended §111(d) to apply to a limited number of pollutants. The EPA's Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Generating Units, acknowledges the limited use of §111(d).

> "Over the last forty years, under FCAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., phosphate fertilizer plants (fluorides) [in 1977], sulfuric acid plants (acid mist) [also in 1977], primary aluminum plants (fluorides) [in 1980], Kraft pulp plants (total reduced sulfur) [in 1979], and municipal solid waste landfills (landfill gases) [in 1996]." Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, pages 9-10.

This abbreviated history - consisting of EPA guidelines recommending technology-based limits for a few specific emission points within narrow industry categories that significantly emit an otherwise unregulated pollutant by only one or two industries - is consistent with EPA's long-expressed understanding of the limited role that §111(d) is to play in FCAA regulation. In the overall FCAA architecture, the ubiquitous pollutants emitted by "numerous or diverse mobile or stationary sources" are to be regulated as "criteria pollutants" through development of NAAQS under §108 and §109, the designation of nonattainment areas under §107, and the SIP process generally described in §110 (as elaborated in other parts of Title I of the Act). Congress directed the control of hazardous air pollutants (HAPs) by their listing and subsequent regulation under §112, which—as it existed from 1970 to 1990—required EPA to adopt standards for new and existing sources of each listed pollutant, "at a level which in [the Administrator's] judgment provides an ample margin of safety to protect public health … ."

Congress codified in §111 the technology-forcing elements of the Act, i.e., the provisions that require control for control's sake, as opposed to controls to meet a desired environmental endpoint. Here, Congress required the EPA to list a source category if "it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Once listed, EPA must adopt "standards of performance" for newly constructed or modified sources within that category that "reflect the degree of emission limitation achievable through the application of the best system of emission reduction [(BSER)] which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."

It is one thing to prescribe national standards of performance for sources that have not yet been built and so whose construction can accommodate the constraints imposed by the NSPS. It is quite another to impose uniform technology-forcing measures on existing sources. For existing sources, §111(d) requires EPA to establish a SIP-like process for setting standards of performance for existing sources in the categories regulated by NSPS, under which states would submit source-specific plans that varied from EPA guidelines as dictated by "other factors." As the EPA recognized from its beginning, this statutory architecture left for §111(d) a very limited role: technology-forcing of controls on existing sources.

2. The EPA's authority to regulate under FCAA §111(d) is inherently limited by the requirement that the EPA must have already regulated new sources under §111(b). Given the legal uncertainties with the EPA's proposed rule under §111(b), the EPA should withdraw the proposed rule for §111(d) until the §111(b) rule is finalized and legally resolved.

The EPA's authority to regulate under FCAA §111(d) is inherently limited by the requirement that the EPA already have regulated new sources under §111(b). While the EPA has currently proposed to regulate new sources under §111(b), there is no final regulation, and significant legal concerns have been raised regarding whether that proposed rule, if finalized, will withstand judicial review. Without an effective, legal, final §111(b) rule regulating carbon pollution from new sources, the EPA lacks authority to finalize this proposed rule. The EPA claims in the proposal that it can rely on its §111(b) proposal for modified or reconstructed sources to suffice to give it authority to regulate existing sources under §111(d), but, as discussed in TCEQ Comment I.10 (page 49), this is simply not true.

3. The EPA does not have the authority to regulate 'outside the fence' through FCAA §111(d). The EPA has interpreted BSER too broadly. Section 111 applies to sources within a discrete identified source category. The EPA may not create different standards for these sources based on their location, i.e., the EPA cannot set different state goals for the same types of sources. The EPA's proposed rule to establish CO_2 emission guidelines for existing EGUs attempts to regulate the entire energy sector under §111(d).

Section 111 defines a standard of performance as "standards for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction [or BSER] which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." BSER is a source-based standard and is limited to systems of emission reduction that can be implemented on-site by the affected facility. Thus, a standard of performance under FCAA §111(d) must be based on a set of emission controls that can be implemented at the source that is subject to regulation. (See e.g. *Portland Cement Association v. Ruckelshaus*, 486 F2d 375 (D.C. Cir. 1973).) BSER cannot be read as broadly as the EPA proposes for existing sources. FCAA §111(d) directs the EPA to prescribe regulations to "establish standards of performance for any existing source of any air pollutant…" The EPA is not setting standards of performance for existing sources when it looks outside the fence line of the EGUs to establish 'building blocks' based on renewable energy and energy efficiency programs and uses them to establish a state goal or standard. A standard of performance that requires emission reductions from other sources and even other source categories is fundamentally inconsistent with the plain language of the FCAA. Historically, the EPA has limited BSER to technology-based emission controls that could be installed and implemented at the facilities subject to regulation. EPA offers no reasonable explanation for abandoning that approach in this rulemaking.

Prior to this proposed rulemaking, the TCEQ and PUCT warned EPA that it did not have broad discretion under the FCAA in setting the standards in response to EPA questions for States on §111(d) plan requirements. (TCEQ Attachment 2, Comments on CO_2 Emissions for EGUs, Section 111(d) of the Clean Air Act, Letter from Richard A. Hyde, P.E., Executive Director TCEQ, and Brian H. Lloyd, Executive Director, PUCT to Gina McCarthy, EPA Administrator, January 14, 2014). The TCEQ and PUCT also warned the EPA that the flexibility given to states in developing plans to meet the standards of performance should not, and legally cannot, be used in setting BSER. As we stated then: "[Section] 111(d) limits EPA to establishing, 'standards of performance for any existing source for any pollutant…if such existing source were a new source…' Establishment of the performance standard must be based upon BSER on a source specific basis. A 'system' standard may face additional practical and legal challenges; however, a 'system' approach should be allowed as a part of any state's plan on how it will apply the standard of performance to any particular source under the plan."

The EPA is considering coal and gas-fired EGUs collectively in setting the state goals under §111(d). In the proposed NSPS (79 FR 1430) under §111(b), the EPA established that coal and NGCC units are fundamentally different and cannot be combined for purposes of establishing a standard of performance. Having done so, the EPA cannot take an inconsistent position by combining them in setting a standard under a 'system' approach for existing sources. Further, ceasing operation of coal-fired units cannot be a 'system of emission reduction' for coal-fired EGUs. Requiring a 70% dispatch rate under Block 2 for all NGCC facilities will have the EPA's desired effect of shutting down coal-fired units. It is not economical to operate a coal-fired EGU at partial capacity and this would force shut-down of these units. The EPA acknowledges this fact in the proposal, estimating that 46 – 49 GW of coal-fired EGUs will retire by 2020 as a result of the rule under a state-by-state approach. However, the EPA has not shown how forcibly shutting down a source appropriately considers the 'remaining useful lives' of these sources, as §111(d)(1) allows.

By effectively regulating one source category out of existence through re-dispatch, increasing renewable energy production and demand side energy efficiency improvements, the EPA exceeds its delegated authority by making energy policy rather than environmental policy. The state goals established in this §111(d) proposed rule recognizes the diverse nature of the energy production and use section of the economy in attempting to look beyond the fence-line for reductions in CO_2. However, beyond the identified source categories of fossil fuel-fired EGUs, the EPA has no jurisdiction over the other identified programs. These are generally exclusively under state control through state utility regulators.

The proposed rule is arbitrary, capricious and unlawful because it will require states to regulate additional sources, including commercial buildings and residences, for mandatory reductions in order to achieve the emission reductions identified in Building Blocks 2, 3, and 4. The EPA unlawfully directs the states to impose standards of performance on affected entities that are not fossil fuel-fired EGUs. In proposed new 40 CFR §60.5820 (79 FR 34956), the EPA proposes to define "affected entities" broadly to include affected EGUs "...or another entity with obligations under this subpart for the purpose of meeting the emission performance goal requirements in these emission guidelines." Specifically, the EPA directs the states to identify "the state emission performance level for affected entities that will be achieved through implementation of the plan" and to demonstrate "that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to any affected entity." As a practical matter, by incorporating these blocks into the BSER analysis, the EPA has proposed state emission reduction targets that cannot be achieved by imposing emission reduction requirements on fossil fuel-fired EGUs alone. This is not flexibility, but instead the EPA imposing on the states performance requirements that are outside the EPA's authority to do.

The EPA's entire approach to identifying BSER based upon individual states is arbitrary. The EPA's proposed rule is more akin to 50 different state plans than the establishment of national standards for existing units within source categories regulated under §111(b). The EPA does not have the authority under §111(d) to establish a different standard of performance on a state-by-state basis. The §111(d) statutory directive applies to 'existing sources'. State plans must establish a standard of performance, based on BSER, "for any existing source." The FCAA definition of "existing source" is any stationary source other than a new source." The term "stationary source" is also clearly defined in statute as "any building, structure, facility, or installation which emits or may emit any air pollutant..."

Section 111(b)(2) gives EPA the authority to distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing standards; however, the authority to distinguish among states for the purpose of establishing standards was clearly not granted to EPA for new sources, and that authority was also not granted to EPA for existing sources. In fact, the limitation on EPA to establish standards of performance for existing sources are linked to limitations used to establish performance standards for new sources. Specifically, §111(d) limits the Administrator to... "establishing standards of performance for any existing source for any air pollutant "...to which a standard of performance under this section would apply if such existing source were a new source..."

The EPA has ignored the clear source-specific intent of this section and proposes state-specific goals instead, based on what the EPA proposes as achievable by application of BSER to the energy generation mix of that state. Texas's goal of 791 lbs CO_2/MWh is not based on what existing fossil fuel-fired EGUs can achieve, but rather a complicated EPA assumption of the state's future energy generation capabilities and energy efficiency efforts. The EPA has failed to assert clear statutory authority to establish state by state standards of performance under §111. There is no ambiguity in the statute that would defer to the EPA the authority to make such a strained interpretation of the FCAA.

This attempt by EPA to expand its reach into areas of the economy reserved to the states through a convoluted and never before used formula to establish BSER, is likely to fail to pass muster in the courts. As the United States Supreme Court recently said: "We are not willing to stand on the dock and wave goodbye as EPA embarks on this multiyear voyage of discovery." (*Utility Air Regulatory Group v. EPA*, 134 S.Ct. 2427 (2014), p. 23.)

4. EPA must make a separate endangerment finding under FCAA §111 based on emissions from the source category and cannot rely on the FCAA §202 finding to regulate under §111.

For the same reasons stated in TCEQ's May 8, 2014 comments on the CO_2 NSPS for EGUs, the EPA must conduct a proper endangerment finding for CO_2 emissions from fossil fuel-fired EGUs prior to proposing an §111(d) rule for this pollutant. The EPA cannot rely on the 2009 Endangerment Finding because it was made under §202 of the FCAA, not §111; and the §202 finding was for emissions of a group of six well-mixed GHGs emitted from mobile sources. Before the EPA proposes any standard of performance under §111(b) or (d), an independent endangerment finding must be made for each source category and for each pollutant it seeks to regulate.

In both §111(b) and §111(d) proposals, the EPA assumes that because an existing source category is already listed and because sources in that category emitted a particular pollutant, that source category must cause or contribute "significantly to air pollution which may reasonably be anticipated to endanger public health and welfare" for a different pollutant. The purpose of identifying source categories is to establish appropriate standards of performance on a pollutant-specific basis for those source categories. A standard of performance is defined as "…a standard for *emissions of air pollutants* (emphasis added) which reflects the degree of emission limitation achievable through…" Because the EPA has proposed the standard on a pollutant-specific basis, the determination of the endangerment consideration must also be on a pollutant-specific basis.

Further, GHGs are newly regulated pollutants under the FCAA, have never been evaluated for impacts on a source category by source category basis, and are wholly different from criteria pollutants generally regulated from stationary sources. These pollutants react differently in the atmosphere than any other type of pollutant and thus do not endanger public health or the environment in the same immediate or localized fashion. Therefore, a new and distinct endangerment finding should be conducted. For this same reason, EPA should not rely on the 2009 Endangerment Finding it made for emissions of six GHGs from mobile sources as a 'rational basis' for a finding of endangerment caused by emissions of only CO_2 from a specific category of stationary sources. Section 111 imposes a heightened standard requiring a source category's emission of a pollutant "… contribute[s] *significantly* to air pollution which may reasonably be anticipated to endanger public health and welfare." (42 U.S.C. § 7411(b)(1)(A) italics added) No other endangerment requirement under the FCAA requires such a finding of *significant* contribution. The EPA simply proposes in this rulemaking for existing sources that

CO_2 emissions from fossil fuel-fired EGUs cause or contribute significantly to GHG air pollution, because CO_2 emissions from existing EGUs account for almost one third of all United States emissions of GHGs, and EGUs are the single largest stationary source category of CO_2 emissions. This assertion is not a substitute for a properly conducted endangerment finding. The TCEQ is not aware of any endangerment determination made by the EPA, in this proposal or elsewhere, directly considering the effects of CO_2 emitted from new or existing fossil fuel fired EGUs on global climate change and how this specific impact is "reasonably anticipated" to endanger public health and welfare. Nor has EPA made a proper finding that United States emissions of CO_2 specifically from fossil fuel-fired EGUs are significant contributors to climate change.

As in the NSPS proposal, EPA's 'rational basis' argument for regulating CO_2 from existing fossil-fueled EGUs is flawed. The EPA does not concede that §111 requires an endangerment finding to justify regulating GHG from fossil-fired EGUs, but instead claims EPA is only required to "have a rational basis for promulgating standards for GHG emissions from electric generating plants..." The EPA concludes, "...that even if section 111 requires an endangerment finding, the rational basis described in today's action would qualify as an endangerment finding as well." The EPA's play on words, substituting "rational basis" for "reasonably anticipated" is not founded in statute. An agency provides no rational basis for regulation absent a showing that its proposed rules will have a meaningful effect on the dangers it is trying to mitigate. Here, as well as in the proposed NSPS, the EPA concedes that its rulemaking will have no effect on CO_2 concentrations in the atmosphere. Even if CO_2 emissions from EGUs is a substantial fraction of overall United States GHG emissions, the global concentration of GHG in the atmosphere are well-mixed and relatively uniform in dispersion, thus the effect of GHG emissions on the climate cannot be traced back to specific geographic emission points. The EPA provides no compelling evidence to show that the United States' contribution of EGU CO_2 emissions to global concentrations of GHG or temperature change. The EPA provides neither a proper endangerment finding nor a statutorily derived rational basis for regulating one GHG, i.e., CO_2 from EGUs.

5. The EPA's alternate argument that reduction of generation itself can represent BSER is flawed, conclusory, and contrary to FCAA §111. Reduction of generation, or reduction in the production of any product, is not BSER. The precedent of the EPA's proposed interpretation of BSER would give EPA almost unlimited authority to control which types of production may be used in the country.

The EPA attempts to backstop its lack of legal authority for Blocks 2 – 4 by presenting an alternate legal argument based on the principle that reduction in generation at the affected EGUs is itself BSER. However, the EPA's argument is fundamentally flawed. Section 111(a)(1) defines a standard of performance as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction..." Reduction in generation is not the application of any system; it is an effect resulting from other activities. The EPA cites examples such as the FCAA Acid Rain Program, the NO_X SIP Call rule, and CAIR as justification, rationalizing that reduction in generation is one of the compliance options available to and used by EGUs to comply with these requirements. While the TCEQ agrees that reduction in generation may be an option for companies to comply with mass-based regulatory requirements such as those cited by the EPA, there is a fundamental difference between a reduction in generation being an option for compliance with a regulatory requirement and being the sole basis for the regulatory requirement. The standards under the regulatory requirements which the EPA cites as examples were developed based on application of adequately demonstrated pollution control technology. As such, the examples the EPA provides are irrelevant and do not establish the precedent the EPA claims.

Finally, the EPA's proposed interpretation would give the agency effectively unlimited authority to decide which types of generation, or production process of any product, will be allowed within the United States. The EPA is attempting to argue that it has the authority to set BSER to force companies to reduce operations or cease business operations all together based solely on the EPA decision that the product that company produces can be produced using a different technology that the EPA finds to be acceptable. Not only is this interpretation a gross overreach of authority, it is also clearly contrary to §111. Section 111(b)(5) states that "nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance." Blocks 2 and 3 in particular specifically meet the FCAA definition of "technological system of continuous emission reduction", i.e., a technological process for production or operation by any source which is inherently low-polluting or nonpolluting. While the EPA may attempt to argue that this provision would only apply to new source performance standards, it would be irrational of the EPA to assume that Congress' intent was the EPA should establish more stringent emission standards on existing sources than it has determined to be feasible for new sources. Yet, this is exactly what the EPA has proposed with this rule under §111(d) and its prior proposal for new sources under §111(b). The state goals for Texas and many other states, are more stringent than the EPA's proposed standards of 1,100 lb/MWh for new coal-fired EGUs and 1,000 lb/MWh for new large NGCC units. Furthermore, there are no existing fossil fuel-fired EGUs that can meet the 791 lb/MWh final standard that the EPA has proposed for Texas, thereby forcing the state to rely on renewable energy generation facilities. The EPA may attempt to argue that they are not requiring any source to install any particular technology because the proposed rule only establishes emission guidelines for the states. Yet, given the lack of alternatives for the states to comply with their state goals without requiring reduction in generation at some sources and expansion of renewable energy, the effect is still the same. The EPA is requiring the installation of particular technological systems of continuous emission reduction, using the states as the intermediary.

6. The EPA's argument that affected EGUs may themselves implement the measures included in Blocks 2 – 4 is flawed. Utility companies do not have unfettered ability to operate their units at any capacity they choose. Blocks 3 and 4 are based predominately on state mandated programs such as state RPS and energy efficiency programs and the EPA has not evaluated the feasibility of utility companies to implement these programs outside of state legal mandates.

The EPA attempts to argue that the affected sources, i.e., utility companies, can implement Blocks 2 – 4 themselves. The EPA states that "... under our proposed approach, affected sources may themselves implement the measures included in building blocks 2, 3, and 4, so that those measures are within their control..." (79 FR 34889). This is a faulty and unsupported assumption. Operation of the utility grid and the activities and obligations of utility providers that support it are not as simplistic as the EPA appears to envision. A utility company whose fleet of affected EGUs is entirely comprised of NGCC units cannot simply decide to re-dispatch their units at a 70% capacity. Even in deregulated market-based systems such as ERCOT, the operation of individual units and companies is still subject to the overall operational needs and constraints of the electrical grid. Facilities may be ordered to either increase or decrease generation by the regional authority to ensure the integrity of the electrical grid. Furthermore, there are aspects of Blocks 2 – 4 that are clearly outside the authority of the affected sources. Utility companies with fossil fuel-fired EGUs do not necessarily have authority over the transmission system. The electrical transmission system may be operated and controlled by an entirely separate entity. For that matter, an entity which has no affected sources is not only beyond the control of the affected utility companies, but is also completely beyond the EPA's legal authority. With regard to Blocks 3 and 4, the EPA based its assumptions using predominantly state-mandated RPS and energy efficiency programs to derive the goals. The EPA has not provided any analysis of the feasibility of expanding renewable energy and energy efficiency programs outside of the state mandates that were the basis for the programs the EPA used in its original analysis. Additionally, some of these programs received state and even federal funding. The economic feasibility of energy efficiency measures funded solely by the utility companies cannot be assumed equivalent when the programs that EPA based their analysis on were at least partially government-funded.

7. The EPA's attempt to expand its definition of BSER and thereby its authority are contrary to a recent United States Supreme Court decision. The EPA cannot apply a standard of performance under §111(d) that it does not have the authority to enforce itself.

The EPA's expansion of BSER to the electric grid is unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization. The Supreme Court most recently spoke to this situation in *Utility Air Regulatory Group v. EPA (cited above).*

> "When an agency claims to discover in a long-extant statute an unheralded power to regulate "a significant portion of the American economy," we typically greet its announcement with a measure of skepticism. We expect Congress to speak clearly if it wishes to assign an agency decision of vast "economic and political significance."

The EPA's clear and documented history of applying BSER to the source of emissions dates back to the early 1970s, yet the EPA appears to have discovered forty years after the Clean Air Act was enacted by Congress that the word "system" in the term BSER applies beyond the source.

The Supreme Court also expressed concerns (in *Utility Air Regulatory Group v. EPA*) about the possibility of citizen suits arising from the non-enforceability of that the Tailoring rule decision.

> "The Solicitor General does not, and cannot, defend the Tailoring rule as an exercise of EPA's enforcement discretion. The Tailoring rule is not just an announcement of EPA's refusal to enforce the statutory permitting requirements; it purports to alter those requirements and to establish with the force of law that otherwise prohibited conduct will not violate the Act. This alteration of the statutory requirements was crucial to EPA's "tailoring" efforts. Without it, small entities with the potential to emit greenhouse gases in amounts exceeding the statutory thresholds would have remained subject to citizen suits…"

The TCEQ has similar concerns about EPA's proposed standards of performance for existing sources under §111(d). The EPA does not have authority to enforce or compel demand side efficiency improvements, renewable energy electric generating production, or re-dispatch of

NGCC in lieu of electrical generation by coal-fired EGUs under the FCAA or Texas law. The EPA has no practical enforceable mechanism to enforce these components of BSER proposed in the rule, if it were to issue a federal plan for Texas, which would open the door for citizen suits against EPA on these components of the proposed BSER. The EPA should not propose rules that are not enforceable.

The EPA cannot take control of a state's electric grid in the name of BSER seizing upon the word "system" to justify an expansion of regulatory authority that did not come from Congress, which has already spoken to issues regarding regulation of interstate transmission and whole electric sales by granting that power to the Federal Energy Regulatory Commission (FERC) under the Federal Power Act, which reserved authority over intrastate transmission and wholesale electric sales to the states. The FCAA does not give the EPA the authority to set energy policy or regulate the nation's electrical power generation system through BSER. State jurisdiction over retail power markets was recently upheld by the United States Court of Appeals for the District of Columbia Circuit in *Electric Power Supply Association v. Federal Energy Regulatory Commission*, holding that FERC Order 745 violates states' jurisdiction over retail power markets. Because EPA's Block 2, 3, and 4 were based on assumed (and ultimately will require) action by the states in these areas, they violate states' jurisdiction over retail power markets and therefore, cannot be used by the EPA to set the state goals proposed with this rule.

<u>Further, the EPA has not provided a reasoned basis for its authority under the FCAA to require states to regulate any matters subject to Building Blocks 2, 3 or 4, and cannot "bootstrap" authority by setting BSER utilizing emission reductions attributable to measures under Blocks 2, 3 or 4 that are subject to state authority unrelated to the FCAA; and requiring that states include these measures in state plans required to be submitted under FCAA, §111. The EPA has cited no basis for an interpretation that allows it to enforce anything in state plans that it does not have authority to require independently under the FCAA.</u>

8. The EPA should also take into consideration the recent United States Court of Appeals for the District of Columbia Circuit decision regarding FERC authority.

The United States Court of Appeals for the District of Columbia Circuit recently unanimously upheld FERC Order 1000, which updated and enhanced requirements for utilities to participate in regional transmission planning in addition to cost allocation reforms and other matters, which could have implications for the achievability of Blocks 2, 3 and 4 as well as costs for states with utilities subject to FERC jurisdiction. *South Carolina Public Service Authority v. F.E.R.C.*, Cause No. 12-1232, decided August 15, 2014 (D.C. Ct. App. 2014). It is unclear whether EPA assessed the impacts of FERC Order 1000 and other FERC orders in its evaluation of building blocks 2, 3 and 4, particularly with respect to cost impacts to utilities and consumers. Additionally, since FERC jurisdiction is limited in Texas, not all Texas utilities are subject to FERC Order 1000, which should be considered by EPA in evaluating the potential emission reductions attributable to building Blocks 2, 3, and 4.

9. The EPA has not provided a rational basis for its legal authority to approve multistate plans under FCAA §111(d) given the requirement for Congressional approval of interstate compacts under FCAA §102(c).

While FCAA §102 allows for interstate compacts, §102(c) states that: "No such agreement or compact shall be binding or obligatory upon any state a party thereto unless and until it has been approved by Congress." The EPA asserts that its approval of all state plans will result in federal enforceability of those state plans. Furthermore, as the proposed rule specifies in 40 CFR §60.5785, once the EPA has approved a state plan then that plan can only be revised with approval by the EPA. Once a multistate plan is federally enforceable by the EPA, states that are parties to that multistate plan cannot revise or withdraw from that multistate agreement without approval from the EPA. An EPA-approved multistate plan would be binding on all the states participating in that multistate plan. The EPA has not provided any rational basis for how the multistate plans contemplated under the proposed rule are not subject to the Congressional approval requirements of FCAA §102(c) or for the EPA's legal authority to approve a multistate plan in lieu of Congressional approval.

10. The EPA's assertion that the modified or reconstructed source rule (79 FR 34960) proposed concurrently with the proposed carbon pollution emission guidelines for existing EGUs provides the prerequisite for §111(d) is contrary to the plain language of the statute and is logically flawed.

EPA puts forth a one-line conclusory statement in the EPA's Legal Memorandum (Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, page 13) that "either of those section 111(b) rulemakings will provide the requisite predicate for this [§111(d)] rulemaking." The EPA asserts that a modified or reconstructed source is a "new source" and satisfies the requirements of §111(d) that say, "The Administrator shall…establish[es] standards of performance for any source for any air pollutant … but to which a standard of performance under this section would apply if such a source were a <u>new</u> source…." The plain language of the statute specifically requires that a standard for *new sources* (emphasis added) would need to apply first, not a standard for modified or reconstructed sources.

11. There is no legal basis for requiring existing sources subject to FCAA §111(d) to remain "subject to" state plans under §111(d) after modification or reconstruction, resulting in dual applicability for such sources under §111(b) and §111(d). Dual applicability under both §111(b) and §111(d) is contrary to the FCAA and prior EPA §111(d) rules.

The EPA provides no legal basis for requiring existing sources subject to §111(d) to continue to be regulated under state plans under §111(d), post modification or reconstruction, in addition to being subject to requirements under §111(b). In the proposal preamble (79 FR 34963), the EPA states that its reasons for this requirement were outlined in the "Legal Memorandum" supporting document filed in Docket ID: EPA-HQ-OAR-2013-0602. However, that legal memorandum does not provide any discussion regarding EPA's authority to apply both §111(d) and §111(b) requirements to existing sources. There is no rational basis to require that sources be subject to both §111(d) and §111(b) requirements; and EPA has not addressed how this concept will be implemented, particularly given the disparity in standards proposed by EPA under both §111(b) and §111(d) for states.

Additionally, the EPA's proposal does not explain what is meant by the phrase "subject to a state plan under §111(d)," and the draft rule language in the technical support documents do not provide clarity on this issue or the dual applicability of §111(b) and §111(d). The EPA provides no discussion regarding how an affected EGU could meet two different standards, the basis for the requirement to do so, or any analysis to support why such a requirement would be necessary or beneficial. The proposed rule preamble does not provide information regarding how this concept integrates with current regulatory text in 40 CFR §60.14 and §60.15 specifying that modified and reconstructed facilities become "affected facilities" if certain criteria are met. Under the EPA's proposed §111(d) rule, in proposed 40 CFR §60.5795, sources are subject to the state plan requirements of §111(d) if they commenced construction on or before January 8, 2014. All modifications and reconstructions that occur after January 8, 2014 would then be occurring at units that were applicable to §111(d).

The EPA is essentially proposing a "once in always in" rationale for units subject to §111(d), which is contrary to the statute and to past §111(d) actions taken by EPA. Ironically, the EPA says in its proposal, "It should be noted at the outset that the EPA determined that reconstructions are a type of construction, and therefore subject to CAA Section 111(b), as part of the 1975 framework regulations, and the EPA is not re-opening that determination" (79 FR 34981). Yet, the EPA has taken the contradictory position that sources that are modified or reconstructed remain regulated under §111(d). The notion that a unit is always subject to the §111(d) plan and not the standard under §111(b) is a significant flaw in logic in the proposed modification and reconstruction rule and in the §111(d) rule. If Congress intended modified sources to remain under §111(d), then there would have been no need to define "modification" in §111(a) and set standards for modified sources in §111(b), since modified sources are just existing sources that have undergone a physical change. The EPA's departure from applying BSER to the emission source in formulating state goals under §111(d), results in significantly different performance standards for modified or reconstructed sources compared to state goals, along with the impossibility of demonstrating compliance with those goals in state plans. The EPA would not be able to assume existing turbines to be re-dispatched up to 70 percent under Block 2 for the purposes of setting state goals under the proposed §111(d) rule if these units ceased to be subject to §111(d) upon reconstruction or modification. Similarly, all existing coal-fired EGUs could potentially be considered modified, depending upon the physical changes each unit implements to achieve Block 1 six percent heat rate improvement, thereby removing them from regulation under state plans formulated under §111(d). The fact that the EPA has proposed a schema for existing sources under this proposed §111(d) rule that is dependent on a "captive" source population is not a rational basis for deviating from the plan language of the FCAA and established precedent regarding modification or reconstruction of sources subject to a §111(d) state plan. Since the EPA has provided no rational basis to support this position, the EPA should withdraw its proposal regarding dual applicability under §111 and modify proposed §60.5795 to exclude modified or reconstructed sources consistent with prior §111(d) rules.

Technical Comments on the Regulatory Impact Analysis for the U.S. Environmental Protection Agency's Proposed Carbon Pollution Emissions Guidelines for Existing Power Plants

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November 10, 2014

Prepared on behalf of Texas Commission on Environmental Quality

In June 2014, the U.S. Environmental Protection Agency (EPA) released its Proposed Carbon Pollution Emissions Guidelines for Existing Power Plants, also called the "Clean Power Plan" (called the "CPP" hereafter).[2] Accompanying this proposed rule is a Regulatory Impact Analysis (referred to as the "RIA" hereafter)[3] that is required under Executive Orders 12866 and 13563 for all major rulemakings of Executive Branch agencies. The RIA contains estimates of the benefits and costs of the regulation, their implications for net societal benefits, as well as information on other aspects of regulatory impact.

My comments focus on technical issues with the RIA's benefits calculations, and its net benefits calculations. I conclude that when technical flaws are corrected, the net benefits of this rule far less than reported in the RIA.

The first section below provides a short synopsis of the benefits and net benefits reported in the RIA, and summarizes findings of my review of the RIA. Section II provides detailed explanation of the findings related to climate benefits and net benefits. Section III provides details supporting the findings about co-benefits estimates. Appendix A documents the derivation of the present value of costs from RIA technical support documents. Appendix B and C provide more detailed results on temporal distribution of costs, benefits, and net benefits under a range of different SCC values and SCC modeling scenarios.

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[1] The author wishes to thank Dr. Sugandha Tuladhar, Mr. Scott Bloomberg, and Ms. Julia Greenberger for their contributions in completing the analyses presented in these comments. The author is responsible for the final report and any errors or omissions it might contain. Opinions expressed herein do not necessarily represent the views of NERA Economic Consulting, its clients, or any other NERA consultants.

[2] 79 *Fed. Reg*. 34830, June 18, 2014.

[3] EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*. EPA-542/R-14-002, June 2014.

I. Overview of the RIA and Summary of Key Points in My Comments

There are two primary types of benefits calculated in this RIA:

1. Estimates of benefits from CO_2 reductions based on a "social cost of carbon" (SCC) value. The SCC is a present value of damages estimated over a 300-year period into the future from an incremental ton of CO_2 emissions in a given year. The SCC values include far more than health impacts, but the actual set of impacts it includes is not defined, and the portion of the SCC due to individual types of impact known to be included is not possible to determine. This "generic" dollar-per-ton ($/ton) damage estimate is multiplied against the RIA's estimate of the CPP's reductions in CO_2 tons emitted to produce the RIA's climate-related benefits estimates.

2. Estimates of health benefits from reductions in ambient $PM_{2.5}$ and ozone that may result coincidentally from the CO_2 reduction measures. These health benefits are not *climate*-related health impacts, and are thus called "co-benefits." For these co-benefits, EPA uses a short-cut approach that also relies on estimates of $/ton damages, with a different $/ton value for each type of $PM_{2.5}$ and ozone precursor emission. The RIA multiplies each of those co-benefit $/ton estimates against the tons of each respective criteria pollutant precursor emission that the RIA estimates will be coincidentally reduced when the electricity system complies with the CPP's limits on CO_2.[4]

The RIA subtracts its estimates of the annualized costs of the rule for each of three years during the rule's implementation phase (2020, 2025, and 2030) from its estimates of the climate benefits plus the co-benefits from emissions reductions in those respective years to estimate net benefits. The RIA reports that net benefits will be large and positive. For example, Tables ES-8 through ES-10 indicate that net benefits of the proposed "Option 1" (using a 3% discount rate for climate and co-benefits) will be between $27 billion and $50 billion in 2020, and increase to $48 billion to $84 billion by 2030.[5] My comments will demonstrate that these statements about the annual benefits of this greenhouse gas regulation are technically flawed, highly misleading, and far more uncertain than the RIA suggests.

[4] The precursor emissions included in the co-benefits calculations are: SO_2, NO_x, and directly-emitted $PM_{2.5}$ (individually) as precursors to ambient $PM_{2.5}$; and NO_x (again) as a precursor to ambient ozone.

[5] RIA, pp. ES-21 to ES-23.

As the remaining sections of my comments will explain in greater detail, I conclude the following about the benefits and net benefits of the CPP:

- The RIA's net benefits make an incorrect comparison of a *present value* of climate benefits to *annualized* cost estimates. <u>When corrected, EPA's estimates of the costs of the CPP are found to vastly exceed its estimates of the climate benefits in the years 2020, 2025 and 2030.</u> For example, using EPA's own costs and climate benefits calculations (for 3% discount rates), I find that:
    - Benefits estimated to occur *in* 2020 will be less than \$0.1 billion globally, compared to U.S. CPP compliance spending during 2020 of \$21 billion.
    - Estimated benefits *in* 2030 will be in the range of \$1.0 to 1.4 billion globally, while U.S. compliance spending in that year is projected to be \$11 billion.
- A technically correct net benefits calculation would not consider costs and benefits for individual years but would compare the present value of costs to the present value of benefits. This is particularly important to do correctly when the costs and benefits occur over vastly different time frames, which I show to be the case for the CPP.
    - On a present value basis (using 3% discount rates), the RIA's cost analysis indicates that the U.S. will have spent approximately \$182 billion to comply with the CPP through 2030, yet the present value of climate benefits that will have accumulated by that time (globally) are estimated to be only \$3.5 to 4.6 billion.
    - Even by 2050, the estimated global benefits from the spending through 2030 are projected to be less than \$36 billion, at a point when all \$182 billion of spending has been completed.
- Because there are such small climate benefits until long after the spending is sunk, the present value of net benefits (again using 3% discount rates) falls to a nadir of about \$180 billion by 2030, and does not become positive until sometime between 2131 and 2155.
    - This implies a payback period of 100 to 125 years on a societal investment of several hundred billions of dollars. Thus the return on the CPP investment is still negative more than a century after its complete phase in.

- The present value of global benefits for all CO_2 tons reduced through 2030 eventually accumulates to \$214 billion, which is only \$32 billion higher than the present value of costs (\$182 billion). This is a rate of return on the cost of the CPP of 0.06% per year even 250 years after the \$182 billion has been invested.

The statements above use the set of 3% discount rate SCC \$/ton estimates that the RIA uses[6] and the same compliance cost estimates that the RIA uses.[7] They differ from the RIA only because I have corrected the mismatch of units (present value benefits *vs.* annualized costs) used in the RIA, and I have assigned the stream of costs and climate benefits to the years in which they are projected to actually accrue to society.

Any RIA that involves large up-front spending with delayed benefits should report the temporal patterns in the estimated benefits and costs. Figure 1 presents that temporal pattern showing the timing of the spending and the timing of the benefits (both discounted to 2014). Figure 2 combines these into cumulative net benefits over time; as visible in the figure, the net benefits only become positive after 2100. Section II explains how I derived these results using an SCC model, and their robustness to alternative modeling assumptions.

The above findings demonstrate the importance of the temporal distribution of benefits and costs. Other distributional effects that the RIA does not– but should – explain are:

- <u>Domestic vs. Global Benefits</u>. The values for the SCC are for *global* benefits, even though all of the costs of the regulation will be borne domestically. Rough estimates of the climate benefits that will be gained by U.S. populations (now and in the future) are so much smaller that even the worst case set of SCC values would not result in net benefits greater that zero for the U.S., even by the year 2300.

- <u>Economic Burdens by Income Level</u>. There is also a distributional question of who pays and who gains from the regulation from an income distribution perspective. Typically policies that affect energy prices such as the CPP are found to disproportionately impact lower income groups. The RIA is silent on this matter, but a good RIA would also address this issue.

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[6] These are listed in RIA Table 4-2 (RIA, p. 4-12). I refer to them as a "set of values" because the value varies with the year of each avoided ton of CO_2 emission.

[7] The above cost estimates are derived from the same IPM output files that produce the annualized cost estimates for Option 1 "state compliance" in RIA Table ES-4 (RIA, p. ES-8), and which EPA has made available in the Greenhouse Gas Abatement Measures Technical Support Document (TSD). See Appendix A for more details.

Figure 1. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

(For Option 1 "state compliance," using costs from IPM runs used in RIA and for climate benefits based on the 3% SCC values in Table 4-2 of the RIA. Benefits' timing is based on DICE using the MERGE-Optimistic Scenario (the scenario with the shortest projected payback period), and climate sensitivity = 3.)

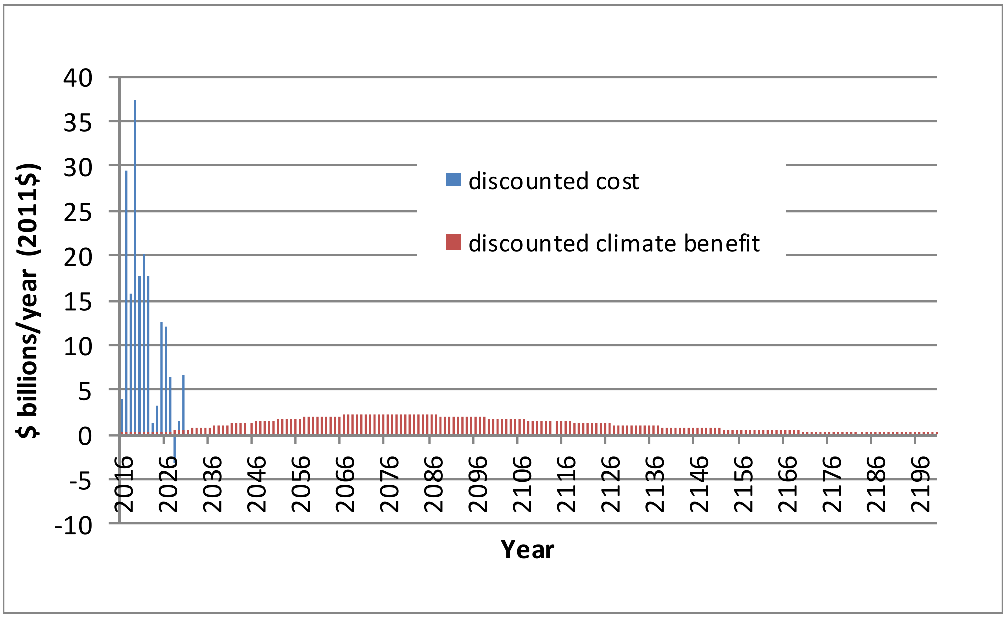
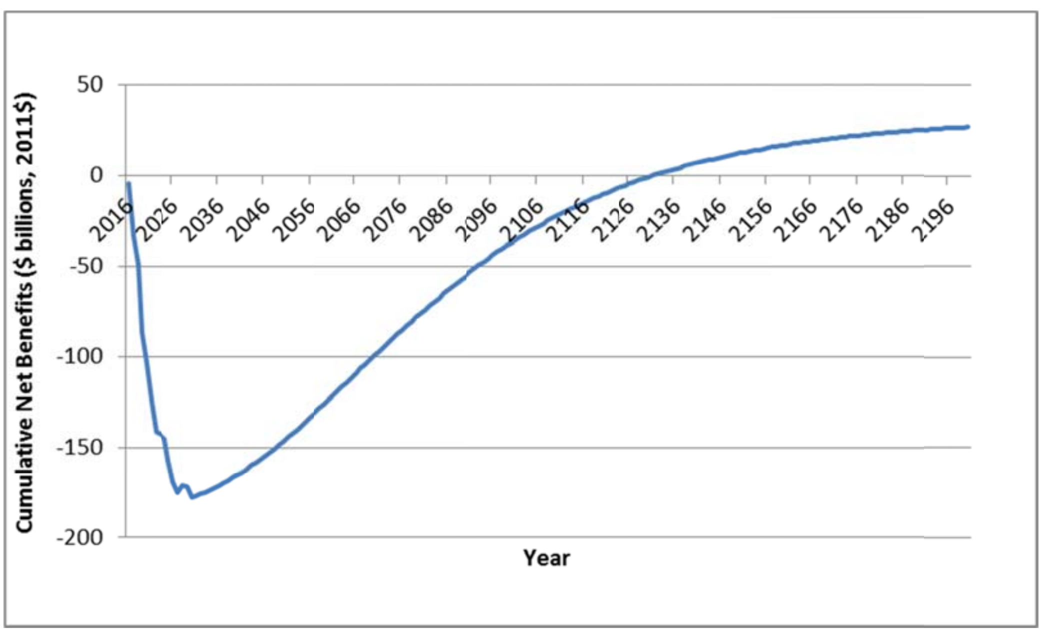


Figure 2. Cumulative Net Benefits over Time (billions of 2011$)

(For Option 1 "state compliance," using costs from IPM runs used in RIA and for climate benefits based on the 3% SCC values in Table 4-2 of the RIA. Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, the scenario with the shortest projected payback period, and climate sensitivity =3.)



Estimated Global Temperature Impacts. Much has been written about the uncertainties and unknowns in estimates of SCC values. These are valid concerns, as the range of uncertainty is much wider than implied by the already wide range of SCC values that the RIA uses. One interesting indicator of the degree of tenuousness of the climate benefits estimates for the CPP is found in the estimated temperature changes that drive its benefits estimates. The RIA is silent on the amount by which global temperature increases would be avoided by the CPP. However, analyses NERA performed in the course of preparing these comments indicate that the maximum temperature increase avoided by the CPP is about 0.003^{o}C, which occurs several decades after the CPP's emission reductions. This is about a 0.2% change in the baseline temperature increase projected by that time; it falls to less than 0.05% of the projected baseline temperature increase in later years, when much of the climate benefit is still accumulating.

This sort of very small deviation from baseline temperature change must be viewed as a very tenuous basis for any projected amount of global damage – and yet that is the nature of the computation that the integrated assessment models are using to produce the SCC values that are being used in RIAs such as this one. In light of these results, one should view the cumulative net benefits calculations above with much circumspection. The risks of no climate benefits from the CPP policy itself should be considered as likely as the possibility that they will be positive.

Co-Benefits Not Related to Climate Change or Greenhouse Gases. The RIA also presents a case that the rule will have near-term benefits exceeding its costs due to estimated benefits that have nothing to do with climate change. These are the "co-benefits" estimated to be derived from coincidental reductions in criteria pollutants. According to the RIA estimates, co-benefits from Option 1 will range from \$16 billion to \$40 billion in 2020 and rise to the range of \$25 billion to \$62 billion by 2030.[8] Taken at face value, these co-benefits alone exceed the estimated cost of the rule; one might attempt to make a case that the regulation has positive net benefits even if it would create no climate benefits at all.

These co-benefits estimates are overstated. As Section III explains in more detail:

- All of these estimated health benefits are associated with minor reductions in ambient concentrations of criteria pollutants ($PM_{2.5}$ and ozone) that are already at levels below their Federal health standards (the "NAAQS"), which are set at a level that protects the public health with an adequate margin of safety. The majority of the co-benefits estimates are due to changes in areas already below

[8] RIA, pp. ES-21 to ES-23.

their health-based NAAQS limits – locations where the EPA Administrator has concluded she has no confidence that the health-relationships continue to exist. The RIA is only able to generate these large co-benefits estimates by assuming that EPA does have full confidence in the existence of the health-effects associations all the way to zero ambient concentrations, inconsistent with the Administrator's stated judgment.

- 75% to 78% of the co-benefits are due to estimated co-incidental reductions of SO_2 emissions, which convert to one of the many different physical and chemical forms of $PM_{2.5}$. EPA acknowledges that there is no basis for determining which types of $PM_{2.5}$ represent the causal factor (if any) in the ambient $PM_{2.5}$ mix. Rather than quantify this uncertainty, EPA simply assumes all $PM_{2.5}$ constituents are equally potent[9] – an assumption that sensitivity analyses have shown overstates likely risks from $PM_{2.5}$ changes.

Co-benefits estimates for already-regulated pollutants such as $PM_{2.5}$ and ozone should not be included in benefits estimates for other types of pollutant regulations:

- Any of the $PM_{2.5}$ and ozone co-benefits that result from exposures to baseline pollutant levels that are not below NAAQS will be eliminated by compliance programs to ensure attainment with that NAAQS; this portion of the co-benefits (if it exists at all) should be attributed to the NAAQS rules, because they will be enforced without the CPP (even if current baseline regulations to do so are not yet promulgated).

- Even if one were to have confidence in the continued existence of such substantial health effects associations for $PM_{2.5}$, including the co-benefits of already-regulated pollutants to justify regulations that are intended to manage altogether different risks, such as climate change, promotes unnecessarily complex and inefficient environmental risk management.

In conclusion, the RIA's benefits estimates for climate benefits are presented in a misleading and technically incorrect manner. When the technical issues are corrected and the results presented in a more informative manner, it is clear that a benefit-cost case for the CPP based on its intended climate benefits is extremely tenuous. It will impose significant near-term costs, with almost no near-term benefits. The net benefits case that remains for the CPP is founded on very unreliable estimates of co-benefits from changes that have nothing to do with climate benefits, which are overstated even

[9] See footnote (c) on Tables ES-8 through ES-10 (RIA, pp. ES-21 to ES-23).

against the EPA Administrator's established judgments about those pollutant risks, and which should – at best – be assigned to future NAAQS-mandated regulations for criteria pollutants; such estimates should not be used to bolster a weak benefit-cost case for a totally unrelated regulation of greenhouse gases.

II. Detailed Assessment and Reanalysis of Climate Benefits in the RIA

This section explains the technical problems associated with the way the SCC values are being used to compare climate benefits to compliance costs in the RIA and provides details on how a more valid analysis that accounts for the timing of the costs and the benefits produces a much more uncertain sense that the climate benefits of the CPP outweigh its costs. It also explains other distributional considerations that affect the comparison of climate benefits to compliance costs.

Timing of Climate Benefits.

The SCC is an estimate of the total benefits through 2300 of a ton of avoided incremental CO_2 emissions in any given year, stated as a present value in the year of emission. For example, if the SCC is \$50/ton for 2020 emissions and 1 million tons of CO_2 emissions are avoided in 2020, the SCC implies that the present value of future climate-related benefits from that action would be \$50 million. This does *not* however, mean that in the year 2020, the world will actually experience the \$50 million estimated benefits. This present value reflects benefits that are projected to accrue over the long time span from 2020 through 2300 using "integrated assessment models" (IAMs) of climate change. Following are a few basic aspects of the IAM calculations that cause most of that present value to be associated with benefits far in the future:

- There are time lags of decades between when emissions occur and when most of the global temperature is expected to respond.

- Also, small changes in temperature that are projected to occur in the near term have relatively little projected climate effect because they occur against a baseline temperature that is not much different from today's. The baseline assumptions in the IAMs result in projections of rising temperature levels. Because the IAMs also assume that a given incremental change in temperature causes a larger percentage impact on GDP when it occurs against a higher baseline temperature, an emissions reduction in 2020 has much less benefit in years just after 2020 than much later in the analysis period.

- Finally, climate damages are tied to global GDP levels, which IAM model inputs assume to be rising year over year. A given percentage impact on GDP in 2020, and in years soon thereafter, produces much less benefit than the same percentage impact in years toward the end of the period 2020 through 2300.

Thus, before any consideration of discounting (a step essential to estimating a present value), the vast majority of the IAM-estimated benefits from a ton of incremental emissions avoided in years 2020 through 2030 occur not decades, but centuries in the future. Even after discounting is applied, one finds that the only a very small fraction of the present value of that ton (*i.e.*, of the SCC value) is projected to occur before 2050. In contrast, the compliance costs associated with tons reduced during the period 2020-2030 must, by definition, occur before or during the year of avoided emission. Thus there is a conceptual mismatch of units in any RIA that compares the present value of largely future projected climate benefits (using the RIA's SCC-based method) to costs that occur contemporaneously.

It is certainly reasonable to compare benefits and costs on a present value basis, but the economic risk of a policy with net benefits that depend on far-future benefits from large up-front spending may be large. For that reason, RIAs should provide information on the timing of their present values of costs and benefits. In the case of this RIA, there is a strong potential that readers may be misled into thinking that the climate benefits of tens of billions of dollars per year that it attributes to 2020, 2025 and 2030 are benefits that will actually be experienced in those years, or at least within the average readers' lifetimes. This is not the case.

To estimate the timing of the global climate benefits reported in the RIA, I have gone back to original IAM calculations that replicate the SCC values used in this RIA and extracted the year by year benefits that add up to those SCC values. To do this, I used the same version of DICE 2010 that was used by the Federal Interagency Working Group (IWG) to produce those SCC values.[10] First, I replicated the 2020 SCC values attributed to the DICE model in an appendix to the IWG's reports, confirming that I could replicate DICE's SCC values for every combination of the five socioeconomic scenarios and three discount rates. I did this for the median equilibrium climate sensitivity parameter (ECS) of 3, and also for the 95th percentile ECS of 7.14. Then, I used the IAM's projected undiscounted benefits in each year of the modeled time period to construct the temporal distribution of when the total benefits are projected to occur from the year of the emission through 2300. This temporal distribution differs with the socioeconomic

[10] That is, the version of DICE that produces the SCC values in IWG (2013).

scenario and with the ECS. Since the summary tables of net benefits in the RIA use the average SCC (roughly equivalent to the SCC with an ECS of 3) and the 3% discount rate, I applied the five temporal distributions from the DICE runs performed with the median ECS of 3 to the tons of avoided emissions in each year under the CPP.[11] For each year, starting in 2016 when the RIA cost analysis assumes CO_2 control measures are initiated, I accounted for the benefits ensuing over time from that year's CO_2 reductions. I then calculated the total undiscounted benefits in each individual future year through 2030 as the sum of the undiscounted benefits continuing to accrue from each of the prior years' reductions, plus the additional benefit *in* that year from that year's additional emission reductions. When these total benefits by year are discounted at 3% and summed through 2300, one obtains the full present value of benefits from the CPP that is associated with the SCC values that are used by the RIA – and one also obtains a timeline of the accrual over time of that present value. The same was done using other discount rates and for the 95th percentile ECS case (for a 3% discount rate).

A summary of the results is provided in Table 1 below for the 3% discount rate case that is the focus of the RIA net benefits comparisons. The RIA states that the climate benefits of the CPP would be $18 billion for 2020 reductions, $25 billion for 2025 reductions, and $31 billion for 2030 reductions.[12] Using my more complete analysis (which replicates the RIA's values when stated in the RIA format), I find that the present value of all the reductions under the CPP through 2030 is $214 billion, but that the benefits actually accrued through 2030 are only $3.5 billion to $4.6 billion.[13] Other temporal aspects of these benefits are shown in Table 1. It is this timeline of climate benefits that should be compared to the timeline of CPP compliance spending over the same period 2016-2030 (which, as explained in Appendix A, EPA's own CPP cost modeling results indicate have a present value of $182 billion through 2030). The climate benefits estimates in Table 1 are global benefits; the portion that the U.S. population will gain is smaller, as discussed later in these comments.

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[11] These tons are reported for 2020, 2025 and 2030 in Table ES-2 of the RIA (RIA, p. ES-7). I obtained reductions for earlier years from the IPM model output files (see Appendix A), and I interpolated the tons for individual years between the modeled years.

[12] RIA, pp. ES-21 to ES-23.

[13] My range reflects the different temporal distributions of benefits associated with each of the five IWG socioeconomic scenarios. The DICE scenarios were run using the IWG's median equilibrium climate sensitivity parameter of 3. I also ran a sensitivity test using the timing profile from the 95th percentile climate sensitivity (*i.e.*, 7.14) to see if higher climate sensitivity might alter the temporal distribution of benefits. It actually reduced near-term benefits, thus making the payback period longer than those estimated for the median ECS. The reason is that while a higher ECS generates higher present values of SCC, it also shifts the proportion of the total climate damages farther into the future.

Table 1. Estimated Global Climate Benefits of CPP Reductions through 2030
(Using 3% discount rate SCC values, and temporal patterns from DICE run with ECS=3, ranges reflecting results from all five socioeconomic projections)

Time Period	Present value in 2014 ($billions, 2011$)	Undiscounted Value in that Year ($billions, 2011$)
Benefit occurring in 2020 from reductions in 2016 - 2020	$0.06 to $0.08	$0.08 to $0.1
Benefit occurring in 2025 from reductions in 2016 -2025	$0.3 to $0.4	$0.4 to $0.5
Benefit occurring in 2030 from reductions in 2016 - 2030	$0.6 to $0.8	$1.0 to $1.4
Cumulative benefits through 2030	$3.5 to $4.6	not applicable
Cumulative benefits through 2050	$27 to $36	not applicable
Cumulative benefits through 2100	$119 to $144	not applicable
Cumulative benefits through 2300 (full period modeled to estimate $/ton SCCs used in RIA)	$215	not applicable

Table 1 shows that a large fraction of the climate benefits that the RIA attributes to the CPP occur far in the future under the 3% discount rate SCC values that are emphasized in the RIA's net benefits summaries. The RIA does note that the climate benefits are highly dependent on the choice of discount rate or if a pessimistic view ("95th percentile") is taken of the climate impact assumptions. Although the present value of climate benefits is highly dependent on these alternative (largely judgmental) discount rate and other assumptions, our analysis shows that these variations have very little impact on benefits that would be experienced before 2050. Table 2 shows the climate benefits over time associated with all four alternative sets of SCC values. These cases are all based on the socioeconomic scenario that produces the highest share of benefits in the early years (*i.e.*, the "MERGE-optimistic" projection). In all four cases, total climate benefits experienced between 2016 and 2030 (the period over which U.S. costs of $182 billion are being incurred) are less than $10 billion globally. While a larger portion of the ultimate climate benefits is accrued by 2050 under the 5% discount rate, the full present value of benefits under that assumption never exceeds the present values of the CPP costs (*i.e.*, $182 billion). Only the very pessimistic set of climate impact assumptions results in benefits that exceed costs before 2080, or 50 years after the CPP targets will have been fully implemented.

Table 2. Timing of Global Climate Benefit Accrual for Four Alternative Sets of SCC Values in RIA. ($ billions 2011$, present value in 2014)
(For CPP Option 1, "state compliance" case; timing of benefits based on DICE model using the "MERGE-Optimistic" case. For average SCC values, ECS=3 was assumed; for "95th percentile SCC values" ECS=7.14 was assumed.)

Time Period	**5% Discount Rate**	**3% Discount Rate**	**2.5% Discount Rate**	**95th %ile (3% DR)**
Cumulative benefits through 2030	$3	$5	$5	$9
Cumulative benefits through 2050	$18	$36	$43	$77
Cumulative benefits through 2080	$39	$106	$138	$268
Cumulative benefits through 2300 (the full period used to estimate SCCs used in RIA)	$52	$215	$335	$656

Net Benefits.

The above benefits reflect the total benefits from compliance with the CPP during the years 2020-2030, including benefits to populations outside of the U.S. To assess the net benefits of the rule, the present values of those benefits should be compared to the *present values* of the CPP compliance spending. The RIA has not presented the present value of costs at all. Instead, the RIA presents only estimates of annualized costs in the three years 2020, 2025 and 2030. These values, in essence, reflect that year's payoff of a societal debt incurred by compliance spending up to that year. In fact, the tons of reduction that are achieved in those years result from the full expenditure of the capital investments that enable those reductions, and that capital spending occurs entirely in the years before, not after, the emissions reductions can be achieved. Thus, while individual companies and consumers who must undertake the capital investments will be able to pay off their costs over time, via loans, actual spending – and its impact to society as a whole – are not spread over time. The present value of the *societal* cost of a policy must recognize the spending in the years in which the society actually makes those investments of capital and labor.

Fortunately, Technical Support Documents released with the RIA provide more complete details of the actual capital and operations spending that occur to comply with the CPP. These are estimated by the IPM model. Appendix A explains how I used the raw results from EPA's IPM model runs to assess the actual timing and present value of the compliance costs that are reported in annualized form in RIA Table ES-4.[14] In brief, I find that the present value of spending from 2016 through 2030 to reduce CO_2 emissions in the amounts that serve as the basis for the climate benefits estimates is $182 billion (2011$, present value in 2014). This is the present value of the Option 1 "state compliance" scenario, discounted by 3% as are the central climate benefit estimates.[15]

Combining this cost estimate with the climate benefits based on the 3% discount rate set of SCC values, the present value of net benefits of Option 1 (for "state compliance") is about $30 billion (2011$, present value in 2014), once computed through the year 2300. <u>However, it will be many years before that return on the $182 billion regulation is achieved</u>. When considering the respective timings of the estimated costs and their associated estimated climate benefits, the CPP regulation appears to provide far less net benefit than the tens of billions of dollars per year that the RIA suggests will occur for 2020, 2025 and 2030. For example:

- Benefits estimated to occur *in* 2020 are less than $0.1 billion globally, compared to U.S. CPP compliance spending <u>during</u> 2020 of $21 billion.

- Estimated benefits in 2030 will be in the range of $1.0 to 1.4 billion globally, while U.S. compliance spending in that year is projected to be $11 billion.

Because there are such small climate benefits until long after the spending is sunk, the present value of net benefits (again using the 3% discount rate SCC values) falls to a nadir of about $180 billion by 2030 (2011$, present value in 2014), and does not become positive until sometime between 2131 and 2155.

- This implies a payback period of 100 to 125 years on a societal investment of several hundreds of billions of dollars when using the discount rate of 3%. Thus

[14] RIA, p. ES-8.

[15] Total spending before discounting is $225 billion through 2030.

the return on the CPP investment is still negative well over a century after its complete phase-in.

- The present value of global benefits for all CO_2 tons reduced through 2030 eventually accumulates to $214 billion, which is only $32 billion higher than the present value of costs ($182 billion). This is a rate of return on the cost of the CPP of 0.06% per year even 250 years after the $182 billion has been invested.

The statements above use the same set of 3% discount rate SCC $/ton values that the RIA uses and the same compliance cost estimates that the RIA uses.[16] In other words, these statements are based on EPA's own set of cost and benefit estimates. I have not attempted to present any alternative SCC estimates, nor to present alternative cost estimates. I have only corrected the mismatch of units (present value *vs*. annualized) used in the RIA and assigned the costs and benefits to the years in which they will actually accrue to society.

Any RIA that involves large up-front spending with delayed benefits should report the temporal patterns in the estimated benefits and costs in this manner. Figure 1 (in Section I above) presented that temporal pattern showing the timing of the spending and the timing of the benefits (both discounted to 2014). Figure 2 (also in Section I) combined them into cumulative net benefits over time, which showed that the net benefits only become positive after 2100. Those two figures were based on the timing pattern of benefits associated with the socioeconomic scenario used by the IWG that produces the shortest payback period of all five of those scenarios. The results vary only slightly for the other four socioeconomic scenarios, which Appendix B provides for completeness. As Table 2 showed, the ultimate net present value by 2300 does vary for different sets of SCC values, but the timing of those benefits remains predominantly in the far future too. Appendix C provides the same summary figures as Figures 1 and 2, but for the remaining three of the four different sets of SCC values used in the RIA.

Other Distributional Impacts.

After correcting the mismatch of units being compared, and taking into account the very different temporal distribution of costs and climate benefits, the net benefit case for the CPP appears much weaker than the RIA summary would suggest. There are additional types of distributional impacts that the RIA does not explain but should:

[16] The absolute SCC values from each DICE run vary around, but are not exactly equal to the Federal SCC values, which are averages over many IAM runs, however, DICE's SCC estimates were not used for this analysis. Rather, the DICE model was used only to develop the temporal distribution of the benefits, which was then applied to the RIA's own SCC $/ton values.

- Another important distributional impact that RIAs should report is the relationship between who bears the regulation's costs and who receives the benefit. This has special relevance when the central benefits calculations are based on the social cost of carbon. The values for the SCC used in the RIA are based on estimates of global benefits. Although those values have not been formally disaggregated to parts of the globe, even the working group that produced those estimates noted that the portion of the benefits that would accrue to U.S. residents could be between 7% and 23%.[17] Even using the worst case (95th percentile) SCC present value through 2300 of $656 billion (see Table 2), if domestic damages are 23% of those estimated global damages, the net benefits of the CPP will be negative even through 2300. The RIA should present these facts to its readers as well.[18]

- There is also a distributional question of who pays and who gains from the regulation from an income distribution perspective on which the RIA is silent. It is, however, common knowledge that regulations that affect the delivered prices of electricity and natural gas, as the CPP will do, impose a disproportionate burden on lower income than on average and higher income families. Since the domestic climate benefits will be smaller than domestic policy spending, as noted above, almost all U.S. residents currently alive will experience net welfare losses, regardless of income level. However, lower income families will probably feel the unrequited costs more heavily than others.

Temperature Changes underlying These Climate Benefit Estimates.

It is also a relevant point that the very small climate benefits that accrue in the first decades of the policy are highly dubious because they are based on miniscule changes in projected global temperatures. The RIA is silent on the amount by which global temperature increases would be decreased. Relying on the same version of the DICE model that was used in developing the SCC values (and using the median equilibrium climate sensitivity), the temperature increase avoided per 1 billion metric ton (1 gigaton, 1 Gt) of avoided carbon emissions in 2020 or 2030 is 0.0019^{o}C. The cumulative tons removed by 2030 under the CPP are about 6 Gt CO_2, which is 1.64 Gt carbon. This suggests the temperature increase avoided by the CPP will be about 0.003^{o}C.[19] This

[17] See IWG (2010), p. 11.

[18] Also, the developers of the SCC estimates should do more to identify the likely geographical disaggregation of those estimates to enable RIAs to do this.

[19] I confirmed this by running DICE to directly calculation temperature changes from the actual tons reduced under the CPP, which produced a maximum temperature change of 0.0032^{o}C.

avoided increase in temperature peaks about 35 years after the year of an avoided emission, when projected global temperature increase would otherwise be between 1.8^{o}C and 2.3 ^{o}C, or about a 0.2% change in projected temperature change at most. In later years, when the projected temperatures are much higher (they rise in some of the ECS=3 cases to as high as 4^{o}C by 2100 and 7^{o}C by 2200), the temperature differences due to the CPP reductions have declined, and they at that time represent less than 0.05% of the overall temperature change.

This sort of very small deviation from baseline temperature change must be viewed as a very tenuous basis for any projected amount of global damage – and yet that is the nature of the computation that the integrated assessment models are using to produce the SCC values that are being used in RIAs such as this one. In light of these results, one should view the cumulative net benefits calculations above with much circumspection. The risks of no climate benefits from the CPP should be considered as likely as the possibility that they will be positive.

Remaining Issues with Climate Benefits Estimates.

As noted, the above weakening of the seemingly large estimates of net climate benefits from the CPP that the RIA provides is based entirely on the assumptions, data, and models that EPA has adopted. There are many other criticisms that can be leveled at the SCC $/ton estimates themselves, and at whether it is appropriate to use such incremental benefits estimates in the case of emissions that represent a global environmental risk.

In particular, the damage functions that are embedded in the IAM models that have been used to generate the SCC $/ton estimates are at best speculative. They are founded on minimal and highly inconsistent empirical evidence of climate damages associated with very small global average temperature changes (*i.e.*, less than 3^{o}C), combined with assumed functional forms that fit the empirical data very poorly and are complete extrapolations for the higher temperature changes that represent the more pronounced risks from unchecked greenhouse gas emissions. Pindyck (2014) first articulated this concern, while NERA (2014) provides a thorough review of the weakness of the empirical and theoretical basis for the IAM damage functions. Further, Smith (2014a) provides a comprehensive assessment of the many additional sources of uncertainty that are not completely represented in the SCC estimates on which the RIA relies.

The evidence presented above regarding the miniscule nature of the temperature changes that generate the hundreds of billions of dollars of present value benefits estimates that the RIA attributes to the CPP's emissions reductions further highlights the questionable reliability of these abstract and speculative IAM damage functions.

III. Technical Issues with Estimates of Co-Benefits and with Their Use in a Climate-Related RIA

The RIA also presents a case that the rule will have near-term benefits exceeding its costs due to estimated benefits that have nothing to do with climate change. These are the "co-benefits" estimated to be derived from coincidental reductions in criteria pollutants. According to the RIA estimates, co-benefits from Option 1 will range from \$16 billion to \$40 billion in 2020 and rise to the range of \$25 billion to \$62 billion by 2030.[20] Taken at face value, these co-benefits exceed the estimated cost of the rule but there are many reasons why these estimates should be viewed as overstated. There are also reasons why co-benefits should not be included in an RIA when they are derived from already-regulated pollutants, as is the case in this RIA. Some of the key reasons are discussed in this section, and a more thorough treatment of this issue is found in Smith (2011 and 2014b).

Sources of Overstatement in Co-Benefits Estimates.

Projected co-incidental reductions in ambient ozone and $PM_{2.5}$ account for all of the co-benefits estimates, but all of these estimated health benefits are associated with minor reductions in ambient concentrations of the criteria pollutants $PM_{2.5}$ and ozone that are already at levels below the Federal health standards for those pollutants (*i.e*., the national ambient air quality standards, or "NAAQS") – standards that are set at a level that protects the public health with an adequate margin of safety.

Although a health-based NAAQS is not considered to be free of any remaining health risk, it *is* considered to be stringent enough that risk estimates associated with further reductions are based on statistical associations that EPA lacks confidence continue to exist at lower levels. The EPA Administrator's articulation of this lack of confidence can be found in the preambles for the current $PM_{2.5}$ and ozone NAAQS.[21] The majority of

[20] Tables ES-8 to ES-10 in RIA, pp. ES-21 to ES-23.

[21] See 78 Fed. Reg. 3086, January 15, 2013 for PM2.5 NAAQS rationale, and 76 Fed. Reg. 16436, March 27, 2008 for ozone NAAQS rationale. For example, in 78 *Fed. Reg*. 3086 at 3139: "In reaching decisions on alternative standard levels to propose, the Administrator judged that it was most appropriate to examine where the evidence of associations observed in the epidemiological studies was strongest and, conversely, where she had appreciably less confidence in the associations observed in the epidemiological studies;" and at 3161: "The Administrator views this information as helpful in guiding her determination as to where her confidence in the magnitude and significance of the associations is reduced to such a degree that a standard set at a lower level would not be warranted to provide requisite protection that is neither more nor less than needed to provide an adequate margin of safety." Similarly, for

the co-benefits estimates that are due to changes in $PM_{2.5}$ and ozone in areas already attaining their health-based NAAQS are calculated using the very same health risk relationships the existence of which the Administrator has said he/she has no confidence. In essence, this implies the expected value of those co-benefits is *de minimis*. The RIA is only able to generate large co-benefits estimates by assuming that EPA does have full confidence in the existence of the health-effects associations all the way to zero ambient concentrations.

As discussed below, any of the $PM_{2.5}$ and ozone co-benefits that might result from exposures to baseline levels that exceed the NAAQS will be eliminated by compliance programs to ensure attainment with that NAAQS; this portion of the co-benefits (if any exist at all) should be attributed to the NAAQS rules, because they will be enforced without the CPP (even if current baseline regulations may not yet address them).

An additional reason to view the co-benefits estimates as overstated is because 75% to 78% of the co-benefits are due to estimated co-incidental reductions of SO_2 emissions, which convert to the sulfate form of $PM_{2.5}$. EPA acknowledges that there is no basis for determining which $PM_{2.5}$ constituents represent the causal factor (if any) in the ambient $PM_{2.5}$ mix.[22] Rather than quantify this uncertainty, EPA simply assumes all $PM_{2.5}$ constituents are equally potent[23] – an assumption that has the sole virtue of being certain to be incorrect. As shown in quantitative studies,[24] the equal potency assumption overstates likely risks from $PM_{2.5}$ changes. The probability that the overstatement is very large (even 100%) rises when the risk estimate is based on changes in just one of the many possible $PM_{2.5}$ culprits. That is much the situation here, where such a very large portion of the co-benefits are derived from a single $PM_{2.5}$ constituent, sulfate.

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the current ozone NAAQS, the District Court for District of Columbia accepted EPA's rationale for the current ozone NAAQS in 76 *Fed. Reg*. 16436 that an ozone NAAQS did not need to be lower than 0.075 ppm despite clinical evidence of some health responses at lower concentrations "because it 'would only result in significant further public health protection if, in fact, there is a continuum of health risks in areas with 8-hour average O3 concentrations that are well below the concentrations observed in the key controlled human exposure studies and if the reported associations observed in epidemiological studies are, in fact, causally related to O3 at those lower levels.' *Id* [at 16,483]. Based on the uncertainties EPA had identified 'in interpreting the evidence from available controlled human exposure and epidemiological studies at very low levels,' EPA was 'not prepared to make these assumptions.' *Id*." (U.S. Court of Appeals for the District of Columbia Circuit, State of Mississippi v. Environmental Protection Agency, No. 08-1200, decided July 23, 2103.)

[22] RIA, p. 4-41.

[23] See footnote (c) on Tables ES-8 through ES-10 (RIA, pp. ES-21 to ES-23).

[24] Smith and Gans (2014); Fraas and Lutter (2013).

The above problems are not possible to completely demonstrate for this RIA because EPA has relied on very simplistic $/ton estimates for the criteria pollutant precursor emissions. These $/ton estimates are unable to account for the level of criteria pollutant in the areas where the tons are reduced.[25] Indeed, EPA does not even develop a baseline projection of the $PM_{2.5}$ and ozone levels against which the CPP-related precursor emissions would occur. These create large uncertainties in an already dubious and uncertain risk analysis process.[26]

In fact, it is highly likely that each of the precursor emissions will increase in some locations, while decreasing in others. This is the standard result of a policy like the CPP that allows the electricity generation system (which is a network of many individually-located electricity generating units) to find the least-cost compliance strategy with flexibility in where the compliance actions will occur. That is, as some generating units are shut down to meet the CPP, others that do not shut down may increase their generation to make up for the lost load. This pattern of geographically differential impacts to emissions is a primary concern expressed by advocates for environmental justice.

This geographical distribution of emissions changes could also greatly alter the RIA's total co-benefits estimates – they could potentially be much smaller if the increases in emissions occur in more populated areas than where the decreases occur. However, the RIA does not explore this possibility. Instead, the RIA states that it has no ability to determine where the air quality changes will occur,[27] which is a substantial overstatement of the problem. The estimates of precursor tons reduced that are the basis for the co-benefits estimates come from IPM model outputs. The IPM model has unit-specific detail, which means that locational information on the emissions reductions also could be obtained from its outputs.[28] At a minimum, the RIA should provide maps showing the location of increases and decreases of emissions from existing generating units, even though EPA's short cut of using $/ton benefits values

[25] RIA, pp. 4-23 to 4-24.

[26] See Smith and Gans (2014) for a detailed exploration of the uncertainties in the $PM_{2.5}$ risk analyses that are used to generate the $/ton estimates used to generate the benefits estimates in this RIA, as well as in EPA's other, more sophisticated criteria pollutant benefits analyses.

[27] RIA, p. 4-40.

[28] The main complication for estimating the location of emissions increases would apply only to NO_x, which is the only precursor emission that would come from future new generating capacity. The IPM model does not identify the precise location of new capacity, but only where it would be within one of 64 electricity market regions of the U.S. However, because all of the SO_2 emissions changes under the CPP will be from currently existing coal-fired power plants, the precise location of the SO_2 changes can easily be identified from IPM model results, including where the increases occur and where the decreases occur.

does not allow the benefits calculation to be more refined. Environmental justice advocates would be particularly interested in this aspect of the co-benefits, as they might reveal inequities that can be traced to locations of disadvantaged populations. However, EPA only reports the net CO_2, NO_x, and directly emitted $PM_{2.5}$ reductions in three large regions of the country ("East", West", and California),[29] and does not note that these net reductions are made up of emissions increases in some locations and decreases in others.

Although it would be possible for EPA to map the locations of the emissions changes for its specific implementation assumptions, there are many additional uncertainties with those estimates due to uncertainty on how compliance with the CPP might be achieved. EPA's analysis considers only two alternative implementation strategies even though the array of compliance options is vast and highly uncertain. Small differences in issues such as whether end-use energy efficiency programs will be a major element of compliance activities or whether greater changes in the generation mix will be required can vastly change the number of tons of SO_2 that may be reduced under the CPP. It can also change the location of where reductions will occur. These have not been considered in the RIA, although they are eminently amenable to analytical evaluation through additional IPM runs. If explored, it is likely that the range of uncertainty on the co-benefits estimates would be much greater.

Reasons Co-Benefits of Already-Regulated Pollutants Should Not Justify Regulations of Other Types of Pollutants.

As noted above, most of the co-benefits in the RIA would be attributed to changes in the criteria pollutants in areas already in compliance with the health-based NAAQS. Those co-benefits must be viewed as overstated and potentially non-existent. That leaves the question of what should be done with co-benefits in areas that the baseline regulatory scenario does not find to be attaining the NAAQS. First, although the RIA does not provide the requisite data, this must be an exceedingly small portion of the co-benefits, if any, because the baseline for the CPP contains all existing regulations. Since the annual $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$ is already promulgated, its compliance should be mostly assured already.[30] Second, although the ozone NAAQS is currently under review and may be set more stringently by the time that the CPP is being implemented, only a tiny fraction of the co-benefits are due to ozone rather than $PM_{2.5}$. Nevertheless,

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[29] RIA, Tables 4-10 to 4-12, pp. 4-28 to 4-30.

[30] Further, the RIA for that NAAQS (EPA, 2012) indicated that only a few areas in California would not attain that NAAQS by 2020. Additional analyses by Smith (2014b) show that only a very small geographic portion of those areas would actually be above the NAAQS level.

whatever small quantity of the co-benefits that the RIA attributes to the CPP are associated with changes in areas not already attaining each NAAQS, those reductions are going to occur even if the CPP were not to be implemented. State implementation plans (SIPs) will be required and enforced in those areas during the same time period, whether or not the CPP exists. Thus, that fraction of those so-called co-benefits should not be attributed to the CPP – they will occur as direct benefits of NAAQS, both present and future. The CPP should not take credit for those estimated eventual NAAQS-related health benefits merely because the RIA for the CPP precedes some of the eventual NAAQS-mandated controls on criteria pollutant precursor emissions.

Finally, even if individuals other than the EPA Administrator were to have confidence in the continued existence of such substantial health effects associations for $PM_{2.5}$ and ozone, to let a climate-related regulation take credit for those reductions is a recipe for unnecessary regulations that result in economically inefficient management of the public health. For this reason, the co-benefits of already-regulated pollutants such as the criteria pollutants should not be included as benefits in regulations that are intended to manage altogether different risks, such as climate change.

IV. Conclusion

In conclusion, the RIA's benefits estimates for climate benefits are presented in a misleading and technically incorrect manner. When the technical issues are corrected and the results presented in a more informative manner, it is clear that a benefit-cost case for the CPP based on its intended climate benefits is extremely tenuous, and will impose significant near-term costs, with almost no near-term benefits. The net benefits case that remains is founded on very unreliable estimates of co-benefits from changes in pollution that have nothing to do with climate benefits. Further, they are overstated even against the EPA Administrator's established judgments about those pollutant risks, and should – at best – be assigned to future NAAQS-mandated regulations for criteria pollutants; such co-benefits estimates should not be used to bolster a weak benefit-cost case for a totally unrelated regulation of greenhouse gases.

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Appendix A

Deriving the Present Value of Total Compliance Costs that Summarized in the RIA Only As Annualized Values for the Years 2020, 2025, and 2030

The EPA's annual compliance costs presented in this report are derived from EPA's IPM Model outputs,[31] along with input assumptions from EPA's *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*,[32] selected Technical Support Documents, and other assumptions as described below.

The starting point for the annual incremental costs associated with the CPP are the EPA's "SSR" output files, which include a range of results for each model year (2016, 2018, 2020, 2025, 2030, 2040, and 2050). These outputs include "Total Annual Production Costs," with the costs broken down between Variable O&M, Fixed O&M, Fuel, Capital, Pollutant Transport & Storage, and Total.[33] EPA outputs for the Base Case and Option 1 – State have been reproduced in Table A1 and Table A2.

Table A1: Base Case Annual Production Costs from EPA Output File

Base Case – April 2014 Draft							
	2016	2018	2020	2025	2030	2040	2050
15. Total Annual Production Cost [MMUS$](*)							
Variable O&M	13870	14334	14668	15427	15960	18059	20485
Fixed O&M	50617	52448	53261	56723	59347	54116	45188
Fuel	90035	95899	100214	115005	126656	164619	239103
Capital	4919	8228	9660	15772	22733	32504	48501
Pollutant Transport & Storage	0	0	-27	-27	-27	-27	-27
Total	159441	170908	177777	202901	224670	269270	353250
Sales Revenue	0	0	0	0	0	0	0
(*) Costs include only those items that are important for determining incremental cost of pollution control							

[31] IPM Model Outputs ("SSR" files) are available at: http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html. These costs are from the EPA Base Case for the proposed Clean Power Plan and Option 1- State.

[32] IPM model documentation is available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

[33] These data are included in Table 15 on the Table 1-16_US worksheet for the SSR file for both the Base Case and Option 1- State.

Table A2: Option 1 – State Annual Production Costs from EPA Output File

Option 1 State – April 2014 Draft							
	2016	**2018**	**2020**	**2025**	**2030**	**2040**	**2050**
15. Total Annual Production Cost [Million US2011$](*)							
Variable O&M	13747	13621	13330	13057	13001	14839	17072
Fixed O&M	48706	50302	50156	52687	54667	49193	40151
Fuel	90093	90213	94883	94873	101247	126195	188355
Capital	4696	10884	16694	18929	21807	23291	36471
Pollutant Transport & Storage	0	0	-27	-27	-27	-27	-27
Total	157242	165019	175036	179519	190695	213492	282023
Sales Revenue	0	0	0	0	0	0	0
(*) Costs include only those items that are important for determining incremental cost of pollution control							

It is important to note that Total Annual Production Costs do not include any costs associated with Energy Efficiency. Energy efficiency costs are from a *Technical Support Document for GHG Abatement Measures*.[34] The relevant energy efficiency costs are the Annual first-year costs (including both the program and participant costs of the energy efficiency). These costs are available for each year beginning in 2017 (not just years modeled in IPM), and are reproduced in Table A3. I note that in EPA's Regulatory Impact Analysis, they have used annualized energy efficiency costs as part of their summary of compliance costs (Table ES-4), which has the impact of pushing costs out into the future (undiscounted first-year costs in Table 3 for 2017 through 2030 are $513 billion, while undiscounted annualized energy efficiency costs are $320 billion, or nearly $200 billion lower) and making the compliance spending in 2020, 2025, and 2030 appear lower than they would actually be (even while still using only EPA's cost assumptions).

Table A3: Annual First-Year Energy Efficiency Costs

Table 4A. National level information on costs (2017 - 2050)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual first-year costs (2011 $ M)														
Annual total cost of EE	$14,728	$20,475	$26,054	$30,778	$34,706	$39,118	$41,990	$43,604	$43,750	$43,663	$43,615	$43,605	$43,634	$43,699
Annual program cost of EE	$7,364	$10,238	$13,027	$15,389	$17,353	$19,559	$20,995	$21,802	$21,875	$21,832	$21,807	$21,803	$21,817	$21,850
Annual participant cost of EE	$7,364	$10,238	$13,027	$15,389	$17,353	$19,559	$20,995	$21,802	$21,875	$21,832	$21,807	$21,803	$21,817	$21,850

To translate costs for different model years to each individual year it is necessary to know how EPA maps non-modeled years to model years. This information is included in EPA 5-13_Base_Case DAT Replacement File.xlsx, in the RunUniverse worksheet. Table A4 contains the mapping of non-modeled years to modeled years from this file. Thus, when determining costs for non-modeled years I looked at the Year Map column (*e.g.*, to get the costs for 2017, a non-modeled year, I used the costs for 2016). This methodology was used for the following cost categories: Variable O&M, Fixed O&M, Fuel, and Pollutant Transport & Storage. This approach is not appropriate for capital

[34] Available at: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-ghg-abatement-measures-appendix5-4.xlsx. The relevant numbers are in the Opt 1 Costs @ 3% or Opt 1 Costs @ 7% worksheet.

costs because they are one-time charges. This approach is also not used, nor is it relevant for energy efficiency costs, because these costs are available in each year, not just modeled years.

Table A4: EPA IPM Year Mapping

Universe Year	RUN(Y/N)	Year Map
2016	YES	2016
2017	NO	2016
2018	YES	2018
2019	NO	2020
2020	YES	2020
2021	NO	2020
2022	NO	2020
2023	NO	2025
2024	NO	2025
2025	YES	2025
2026	NO	2025
2027	NO	2025
2028	NO	2030
2029	NO	2030
2030	YES	2030

The final step in converting EPA's cost outputs into those used in this report was to convert from the reported annualized capital costs to estimated overnight capital spending. Annualized capital costs are representative of the payments on capital made by the borrowing companies over time, and do not reflect that the capital will actually be spent entirely in the few years prior to the start of the emissions reductions that will ensue due to that spending. For example, if one were to build a new 500 MW natural gas combined cycle unit that begins commercial operation in 2020, it would cost about $500 million, with these costs incurred in 2017, 2018, and 2019, rather than a series of payments of $50 million per year for 20 years starting in 2020. Similar to its treatment of energy efficiency costs, EPA also included annualized capital costs as part of its summary of compliance costs (Table ES-4 in the RIA).

Performing these calculations required identifying the different capital investments between the Base Case and Option 1 – State. These investments include differences in new capacity builds and retrofits of energy efficiency on existing capacity. The capacity builds and retrofits for each case are included in the same "SSR" file that includes the Total Annual Production Costs, except that they appear on the Summary worksheet. First, I calculated the differences in new capacity builds and retrofits by type (*e.g.*, natural gas combined cycle, wind, heat rate improvement). Sometimes the difference was positive (more builds in the Option 1 – State case than in the Base Case) and sometimes the opposite was true. The differences (in GWs) were then multiplied by the overnight capital costs for each type of technology. These overnight capital costs are included in Chapter 4 of the IPM model documentation (for new capacity builds) and in Chapter 5 for the retrofits.

Finally, I spread out the overnight capital spending into the years leading up to the online year using a construction cost profile from the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook (AEO)*. The information from the AEO specifies, by technology type, how spending is shared in the years prior to new capacity coming online. For example, AEO specifies that for a new combined cycle generator, 25% of the costs would be spent three years before commercial operation, 50% would be spent two years before, and the remaining 25% would be spent in the last year before commercial operation. Thus, if there were incremental capital costs of $4 billion associated with new combined cycle builds coming online in 2020, this would be reflected in the annual costs as $1 billion in 2017, $2 billion in 2018, and $1 billion in 2019. Table A5 includes the spending schedules from AEO for the five technologies with differences in builds.[35]

Table A5: AEO Construction Cost Profile

Technology	t - 4	t - 3	t - 2	t - 1
Biomass	15%	30%	40%	15%
Other[36]	0%	0%	10%	90%
Wind	0%	5%	10%	85%
Combined Cycle	0%	25%	50%	25%
Combustion Turbine	0%	0%	35%	65%

The resulting net estimated overnight capital spending, including both increases and decreases in capital spending between the Base Case and Option 1- State, were then placed into the appropriate years for purposes of the cost analysis prepared in these comments.

Combining the Variable O&M, Fixed O&M, Fuel, and Pollutant Transport & Storage costs with the Energy Efficiency costs (adjusted to be first-year costs) and the Capital costs (adjusted to be overnight costs) produced the total expenditures by year of actual spending that are used in these comments to estimate the timing and present value of CPP compliance costs for 2016-2030. The resulting values are shown in Table A6. All of

[35] Note that AEO did not provide similar information for retrofits. I have assumed that 100% of the capital spending occurs in the year prior to the retrofit becoming operational.

[36] EPA denotes some new capacity bujlds as "Other." I have assumed that these are solar PV capacity, since these are expected to be fairly common builds going forward, and EPA does not separately list these types of new capacity builds.

these estimates are derived from EPA's own modeling and output files. The total spending through 2030 is $224 billion, which has a present value in 2014 of $182 billion (still stated in 2011$, as are the benefits estimates in the RIA). It is the present values of spending ("discounted costs") that are graphed in Figure 1 of the comments and in the odd-numbered figures in Appendix B and C.

Table A6: Total Real and Discounted Compliance Spending by Year Relative to Baseline Costs (billions of 2011$; 3% discount rate used for row 2)

	Total (2016-2030)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Spending during each year (billions of 2011$)	**224**	4	32	18	43	21	25	22	2	4	17	17	9	(5)	2	11
Present value in 2014 (billions of 2011$)	**182**	4	29	16	37	18	20	18	1	3	12	12	6	(3)	2	7

Appendix B
Five Alternative Temporal Profiles for Climate Benefits and Net Benefits of CPP

Figure B1. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

For Option 1 "state compliance," using costs from IPM runs used in RIA and for climate benefits based on the 3% SCC values in Table 4-2 of the RIA. Benefits' timing is based on DICE with MERGE-Optimistic case.

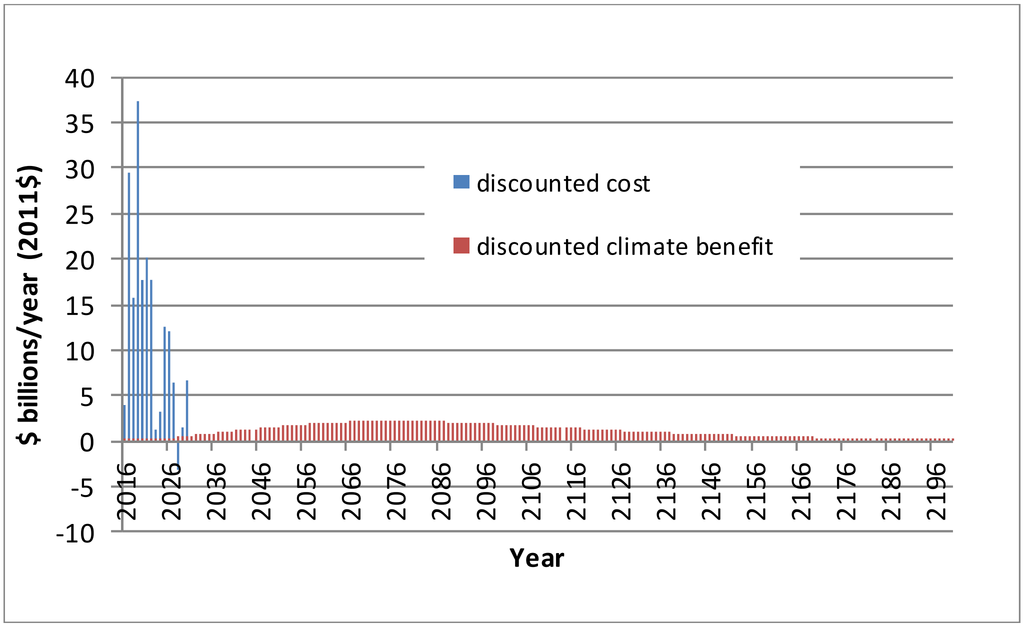


Figure B2. Cumulative Net Benefits over Time (billions of 2011$)

For Option 1 "state compliance," using costs from IPM runs used in RIA and for climate benefits based on the 3% SCC values in Table 4-2 of the RIA. Benefits' timing is based on DICE with MERGE-Optimistic case.

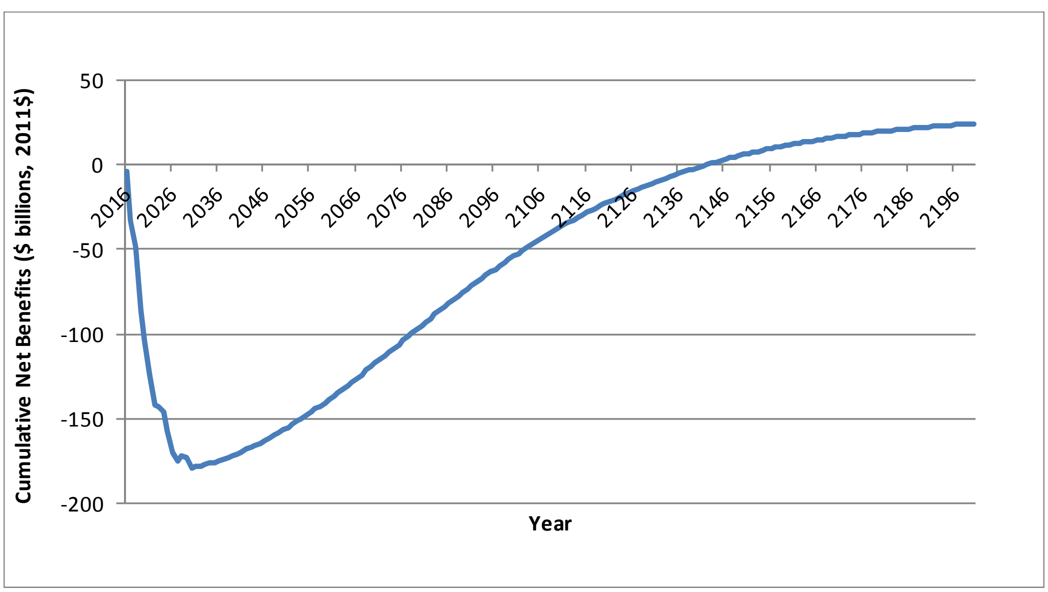


Figure B3. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

Benefits' timing is based on DICE using the IMAGE Scenario, climate sensitivity = 3, and discount rate =3%.

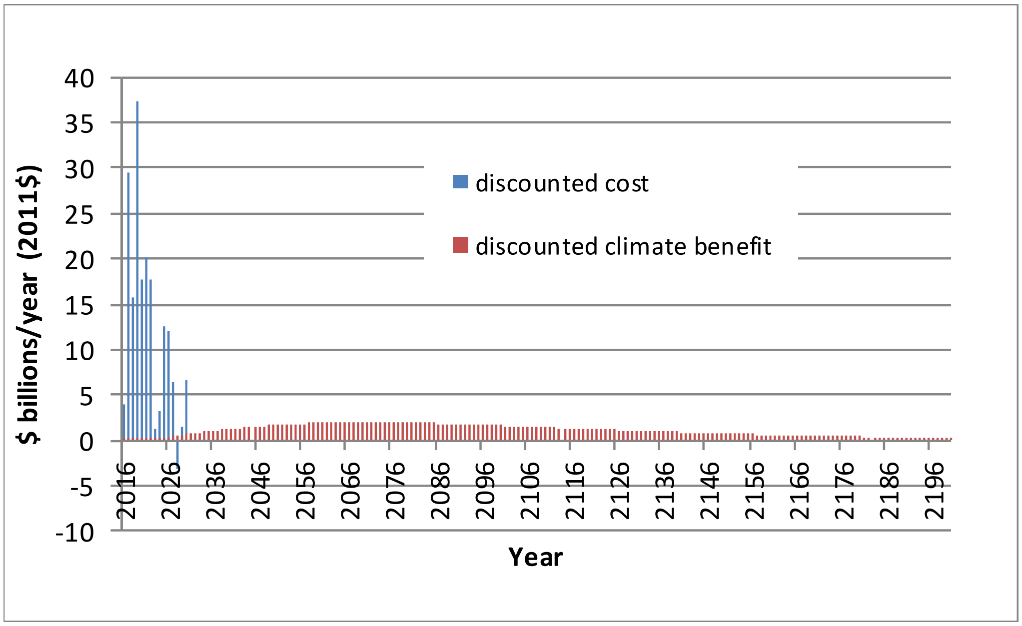


Figure B4. Cumulative Net Benefits over Time (billions of 2011$)

Benefits' timing is based on DICE using the IMAGE Scenario, climate sensitivity = 3, and discount rate =3%.

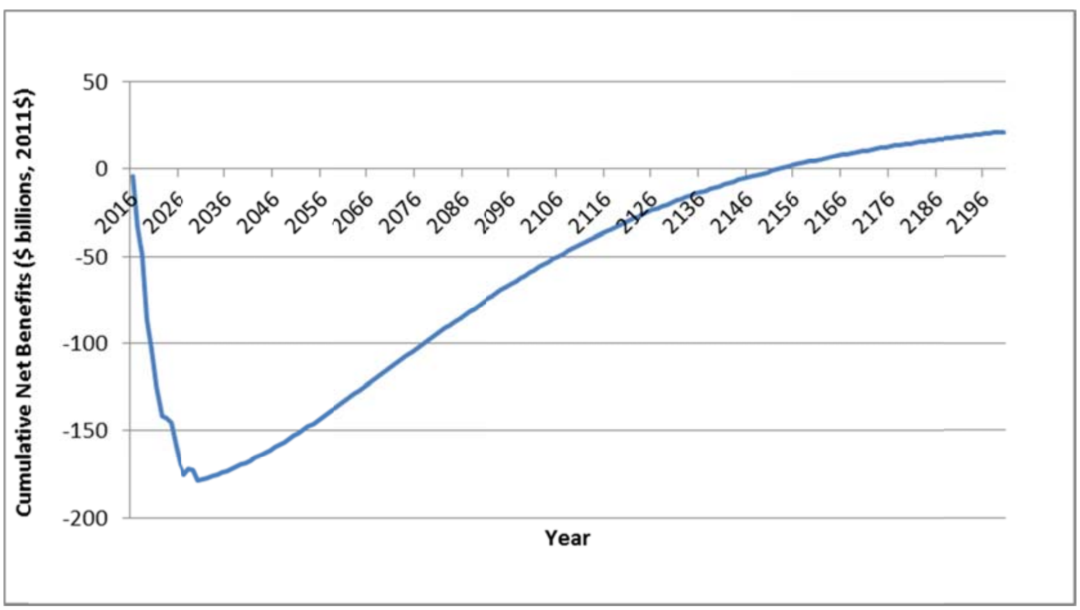


Figure B5. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

Benefits' timing is based on DICE using the Message Scenario, climate sensitivity = 3, discount rate =3%.

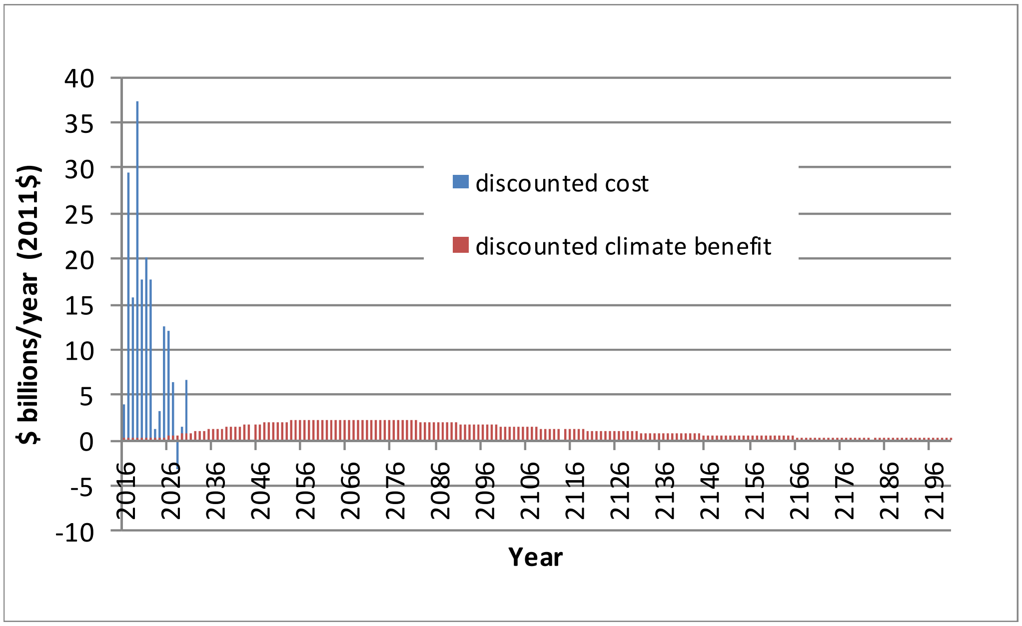


Figure B6. Cumulative Net Benefits over Time (billions of 2011$)

Benefits' timing is based on DICE using the Message Scenario, climate sensitivity = 3, discount rate =3%.

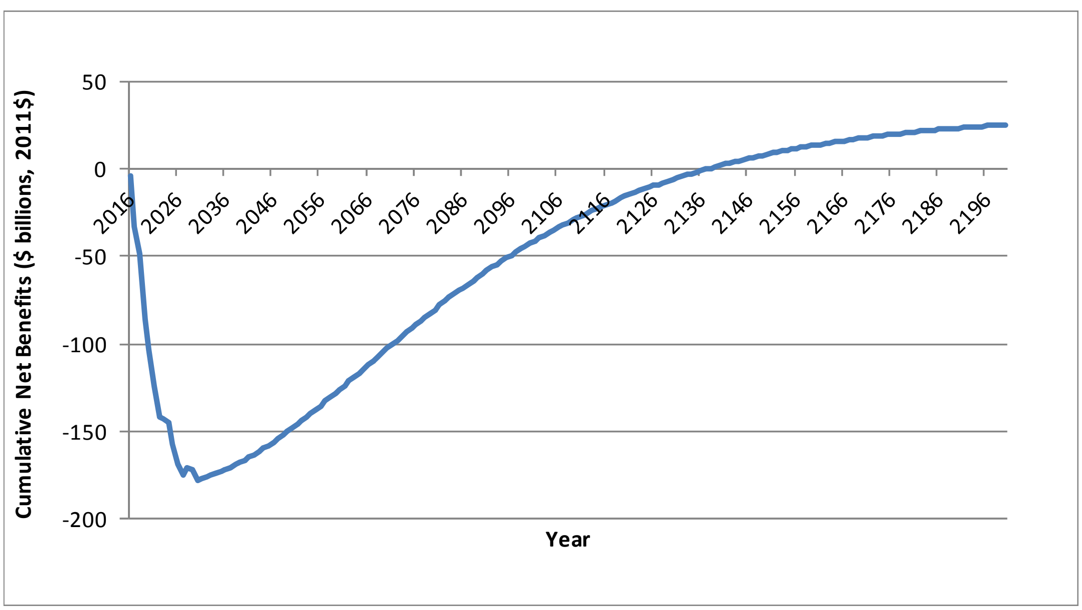


Figure B7. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

Benefits' timing based on DICE using MiniCAM base Scenario, climate sensitivity = 3, discount rate =3%.

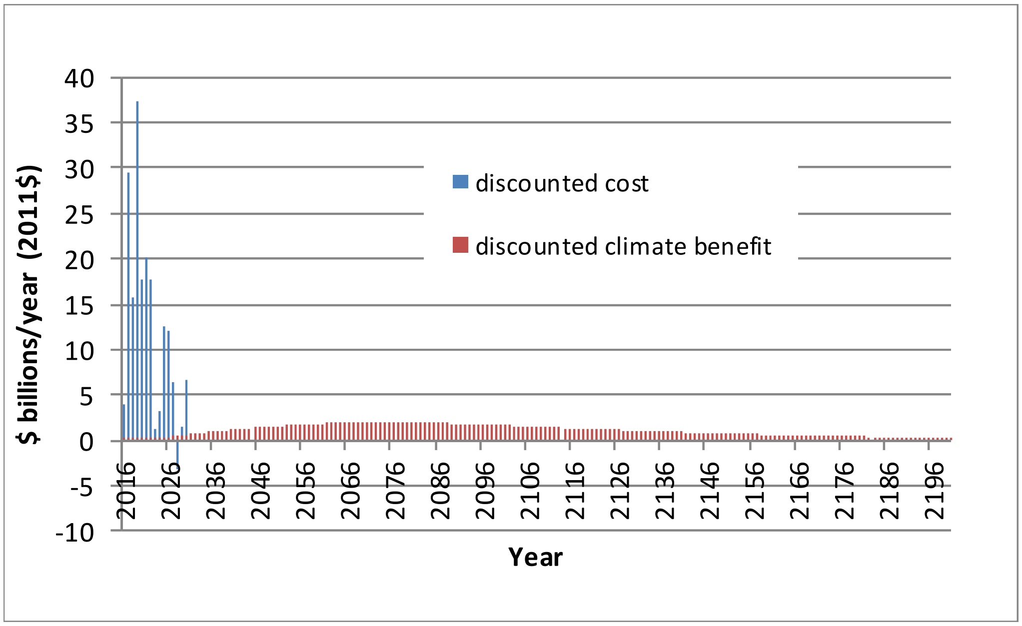


Figure B8. Cumulative Net Benefits over Time (billions of 2011$)

Benefits' timing is based on DICE using MiniCAM base Scenario, climate sensitivity = 3, discount rate =3%.

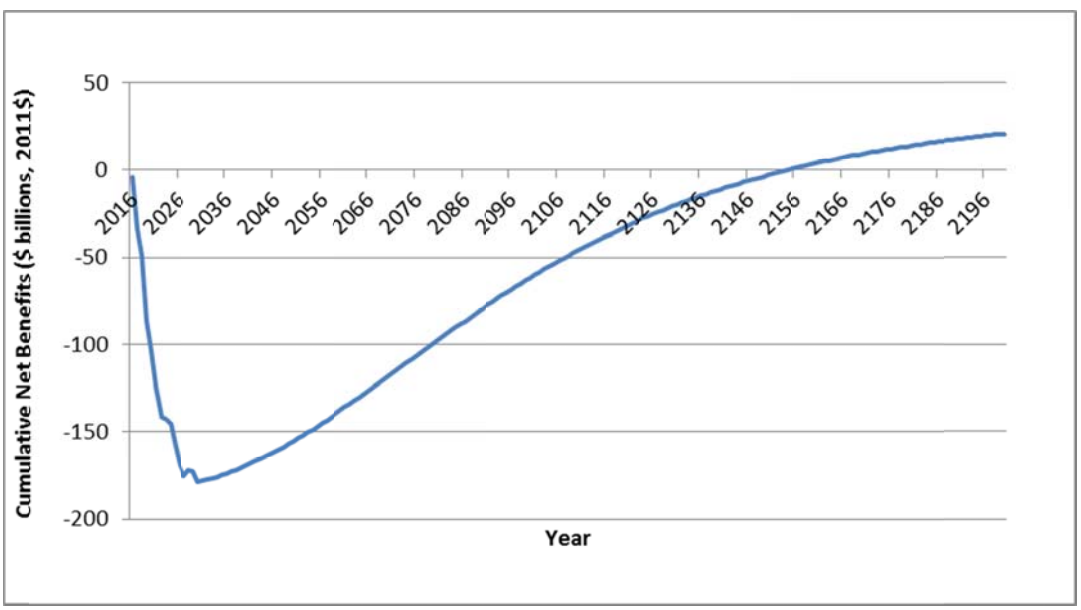


Figure B9. Present Value of Spending (blue) and Climate Benefits (red) by Year ($ billions per year, 2011$)

Benefits' timing is based on DICE using the 5th Scenario, climate sensitivity = 3, and discount rate =3%.

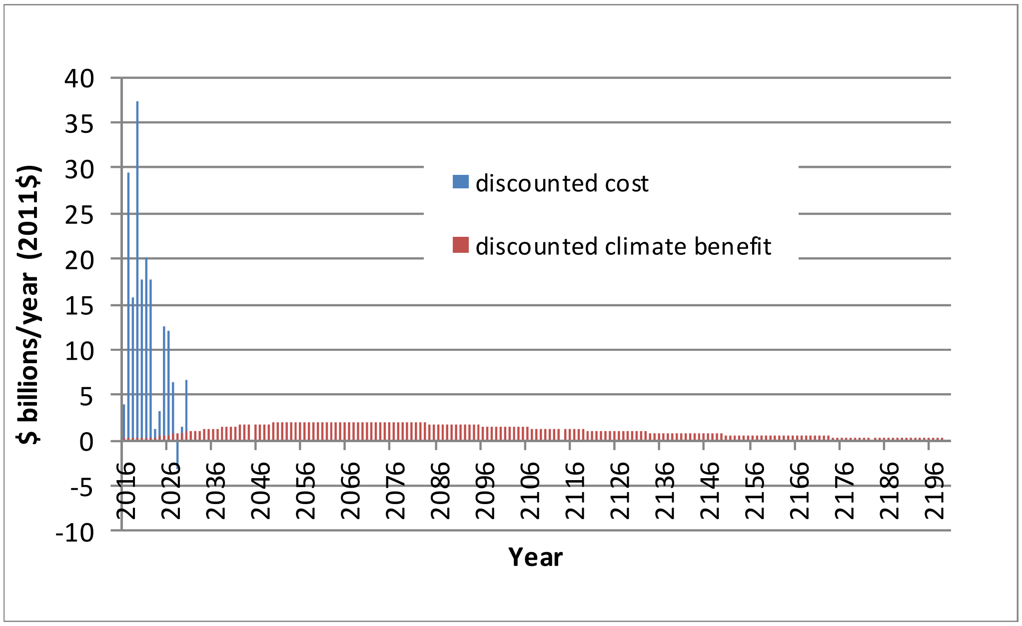
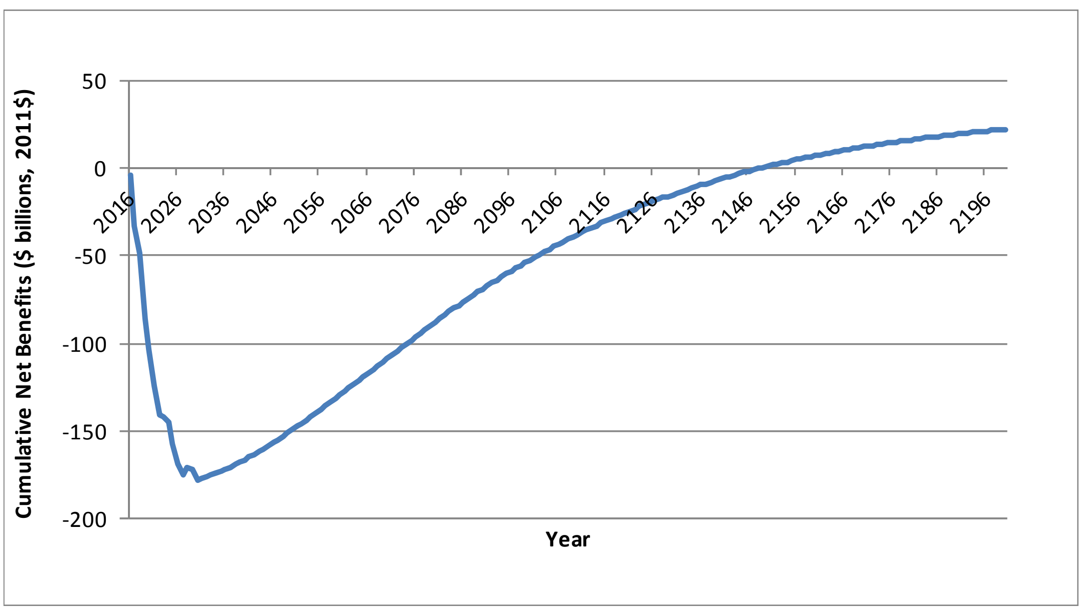


Figure B10. Cumulative Net Benefits over Time (billions of 2011$)

Benefits' timing is based on DICE using the 5th Scenario, climate sensitivity = 3, and discount rate =3%.



Appendix C

Timing of Net Benefits for the Remaining Three Sets of Federal SCC Values

Note: Results for the 3% discount rate SCC values are Figures B1 and B2 of Appendix B.

Figure C1. Present Value of Spending (blue) and Climate Benefits (red) by Year for 5% SCC Values ($ billions per year, 2011$)

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, climate sensitivity = 3, and discount rate = 5%.

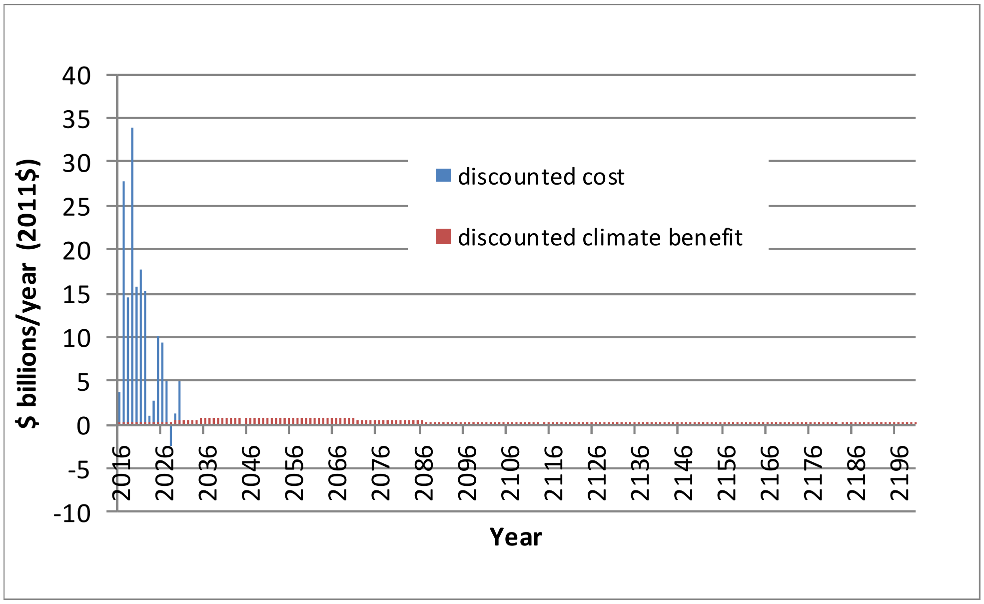


Figure C2. Cumulative Net Benefits over Time (billions of 2011$) for 5% SCC Values

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, climate sensitivity =3, and discount rate = 5%.

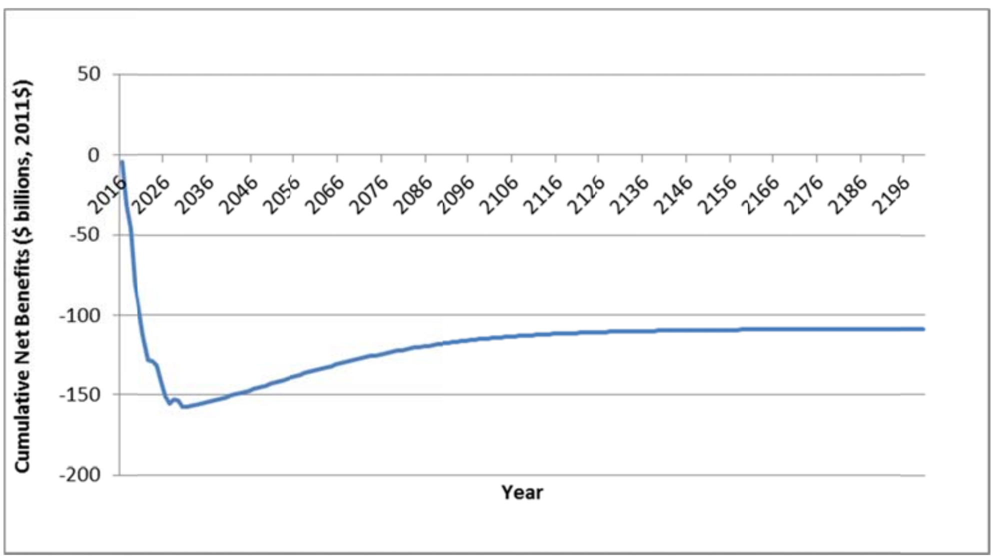


Figure C3. Present Value of Spending (blue) and Climate Benefits (red) by Year for 2.5% SCC Values ($ billions per year, 2011$)

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario (the scenario with the shortest projected payback period), climate sensitivity = 3, and discount rate =2.5%.

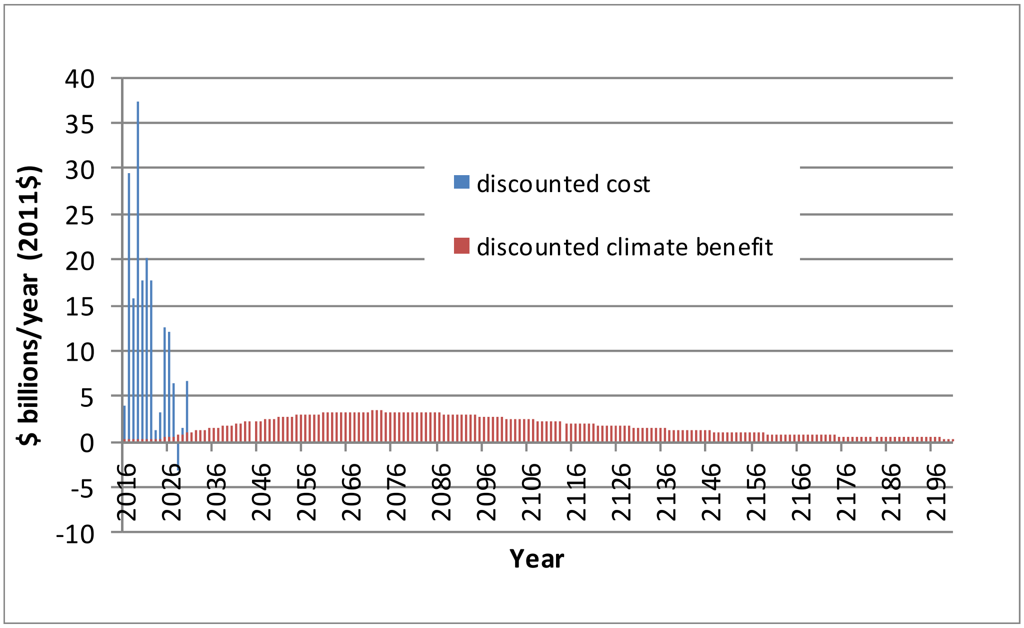


Figure C4. Cumulative Net Benefits over Time (billions of 2011$) for 2.5% SCC Values

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, the scenario with the shortest projected payback period, climate sensitivity =3, and discount rate = 2.5%.

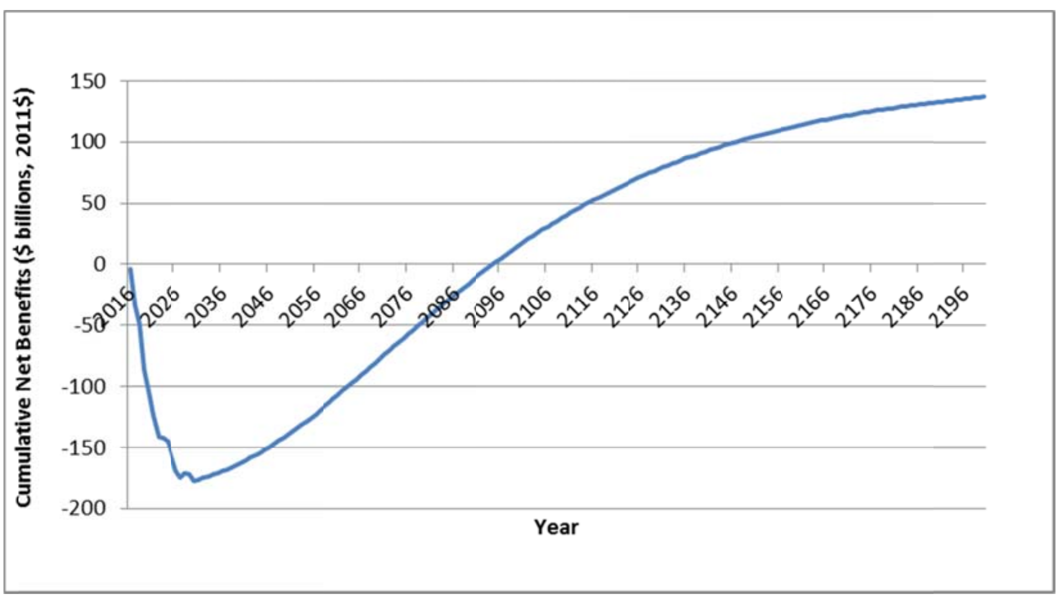


Figure C5. Present Value of Spending (blue) and Climate Benefits (red) by Year for 95th Percentile SCC Values ($ billions per year, 2011$)

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, climate sensitivity = 7.14, and discount rate = 3%, *i.e.*, the 95th percentile pessimistic SCC value

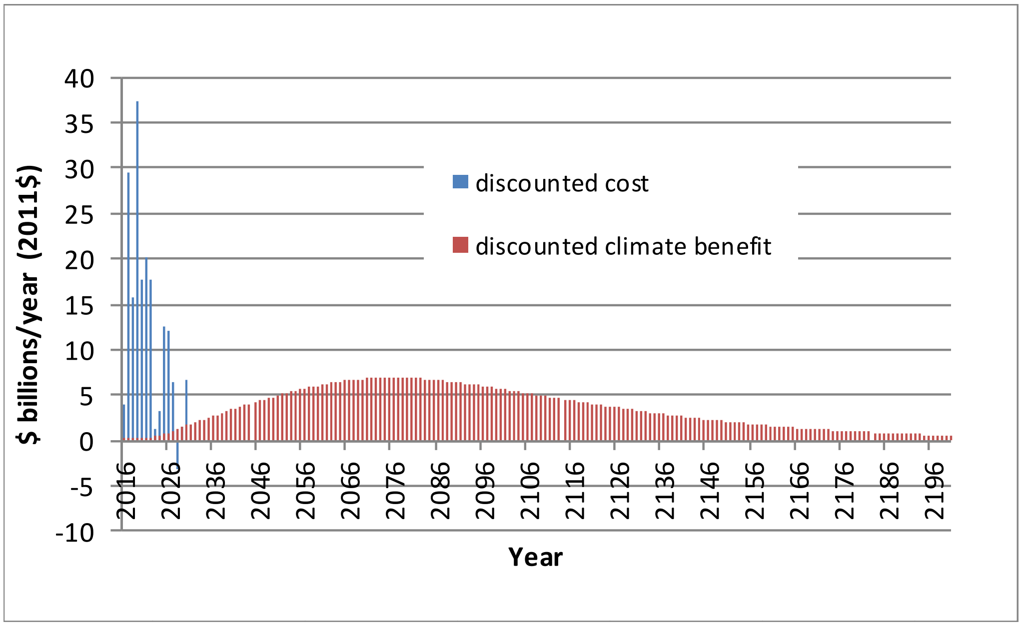
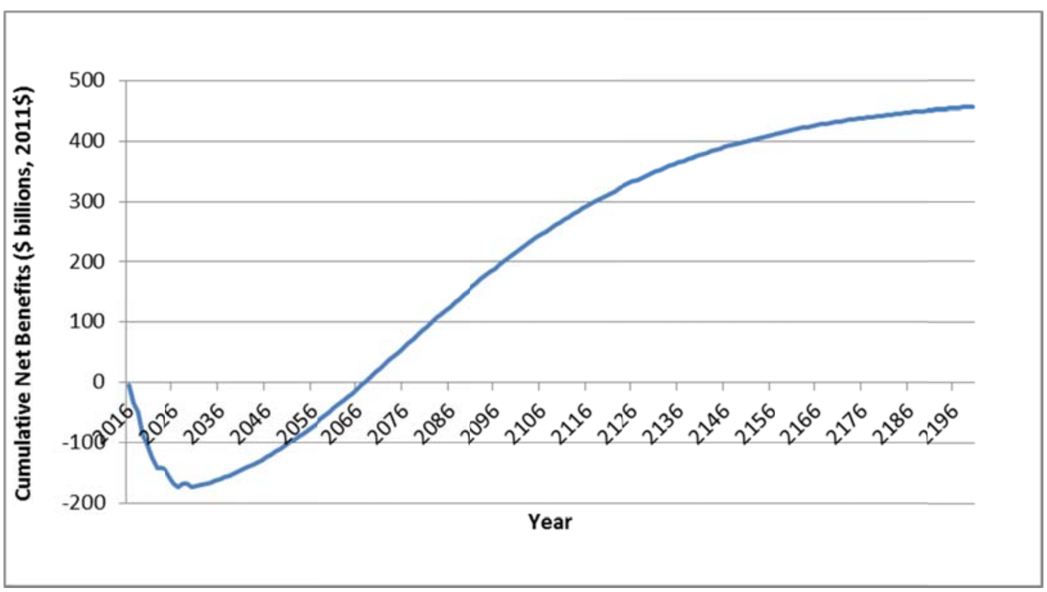


Figure C6. Cumulative Net Benefits over Time (billions of 2011$) for 95th Percentile SCC Values.

Benefits' timing is based on DICE using the MERGE-Optimistic Scenario, climate sensitivity =7.14, and discount rate = 3%, *i.e.*, the 95th percentile pessimistic SCC value.



Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Interim Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

January 14, 2014

Ms. Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Comments on CO_2 emissions for EGUs, Section 111(d) of the Clean Air Act

Dear Administrator McCarthy:

The Texas Commission on Environmental Quality (TCEQ) and the Public Utility Commission of Texas (PUCT) appreciate the opportunity to provide input to the Environmental Protection Agency (EPA) regarding its plans to develop regulations to address carbon dioxide (CO_2) emissions from existing electric generating units (EGUs) under Section 111(d) of the Clean Air Act (CAA).

We have enclosed our initial responses to the list of questions EPA developed to solicit input from states and other stakeholders on the design of the 111(d) proposal. In addition, we also want to emphasize four specific overriding concerns and issues that require specific consideration by EPA.

First, the State of Texas believes that climate change policy should be at the direction of Congress and not through EPA regulatory efforts under sections of the CAA that were not specifically developed to address the complex nature of greenhouse gases. However, we understand that, under the President's direction, EPA is moving forward in development of regulations under CAA 111(d). In that light, the comments provided herein should not be interpreted as TCEQ's or PUCT's endorsement of EPA's regulatory initiative. In addition, our comments are necessarily initial impressions at this time and not final opinions, and we reserve the ability to alter our opinions based on the EPA's continued development of its regulatory program.

Second, we are also concerned that CAA 111(d) is not the appropriate vehicle for regulating CO_2 emissions from existing EGUs. Under Section 111(d)(1), EPA does not have the authority to prescribe regulation under Section 111(d) for an air pollutant if the source category is already regulated under Section 112 of the Clean Air Act. Existing EGUs are now a regulated source category under Section 112 of the CAA through the EPA's Mercury and Air Toxics Standards and as such, are precluded from regulation under 111(d).

Additionally, section 111(d) of the CAA is not a technology-forcing standard. Under 111(d), the Best System of Emission Reductions (BSER) must be adequately demonstrated and take into account cost and energy requirements. We note that you have publicly stated that carbon capture and storage (CCS) will not be considered as a requirement as EPA moves forward in its development of 111(d) rules. TCEQ and PUCT support this position and do not consider CCS to be "commercially available" as defined in the CAA for either new or existing EGUs. CCS is not in full-scale operation at any plant in the United States, and current CCS projects have only been possible through significant incentives, government subsidies, and proximity to enhanced oil recovery reserves.

Third, due to the specifics of federal and state electricity regulation, each state has a unique set of circumstances relevant to the provision of electricity in their state which creates unique complications for standard-setting under 111(d). Regulated vs. deregulated electricity market designs as well as the existence or lack of multistate independent service operators/regional transmission organizations within a state may affect how different states are able to address reliability and cost issues within their states. EPA must provide maximum flexibility to states to craft state plans to meet a performance standard to account for the diverse nature of each state's power generation mix and market structures.

In the Electric Reliability Council of Texas (ERCOT) region, which manages the electric grid for over 85% of Texas's electricity load and 23 million customers, economic dispatch is already resulting in lower GHG emissions. The fall in natural gas prices has led to seasonal mothballing of coal units and overall lower output from coal units in the ERCOT fleet, which, of course results in lower GHG emissions. Low natural gas prices have also led to the development of more natural gas plants, which have lower emissions than coal plants.

However, generation resource retirements can affect the reliability of the grid by reducing system-wide reserve margins and by creating areas of the grid (load pockets) in which local generation and import capacity provided by existing transmission infrastructure are insufficient to serve expected peak customer demand. In ERCOT, competition in the current energy-only market design has led to system-wide reserve margins that are at or near the current target reserve margin of 13.75% (established based on a risk tolerance of one outage event due to insufficient system-wide resources every 10 years). If a change in regulations resulted in the retirement of a significant amount of generation capacity, the ERCOT system would likely be left without sufficient reserves to minimize the risk of rotating outages during peak load conditions until changed market conditions led to new investment in generation resources. Given the current timeframe to permit and build new base-load natural gas-fired generation (approximately four years), an implementation period for new greenhouse gas regulations would have to be at least five years (from announcement of unit retirements) in order for the ERCOT market to compensate for any significant unit retirements. An additional year would be necessary for resource owners to complete economic assessments of their generation assets and to determine which units should be retired. One year for retirement analysis and five years for generation development results in the need for at least a six year implementation period from publication of final requirements to rule implementation. Please note that this six year horizon is based on the assumption that the new regulations would not create new barriers to the development of new economically competitive dispatchable generation resources.

ERCOT has a well-developed interconnection wide transmission planning process that assesses system needs for the following six years and establishes any necessary projects to maintain system reliability. This six year planning process has been established because it typically takes up to six years for major transmission projects to be planned, routed and constructed. Based on this experience, any significant unit retirements resulting from new regulations would have to allow a six year window of implementation to allow for assessment, planning and implementation of any transmission projects needed to address local load-serving needs.

In the event that a proposed unit retirement is expected to result in a local transmission reliability issue, ERCOT has the authority to negotiate Reliability-Must-Run (RMR) contracts with the resource owner. However, the resource owner is not required to enter into an RMR contract. Also, there is no precedent in ERCOT for trying to establish an RMR contract to maintain the operation of a resource that is being retired due to not being in compliance with environmental regulations. So, this alternative may not be sufficient to eliminate the risk of new regulations affecting local transmission reliability.

ERCOT is a summer peaking region with the greatest demands typically taking place during August and early September. EPA should allow states the flexibility to operate their electric grids without penalty in ways that will maintain system reliability. For example, to maintain reliability, ERCOT may require that all available units to operate during peak summer hours. Generators should not be penalized for operating units needed to maintain system reliability, especially during peak periods.

Texas's renewable energy story is well known. Texas is by far the single largest wind energy producing state in the nation. Texas's wind capacity is more than twice the amount of the second closest state (Iowa). Through calendar year 2012, Texas has added 12,776 MW of installed wind capacity. Because wind generation is an intermittent resource, it is necessary to have other generation available to serve load in the event expected wind generation is unavailable. Cycling of fossil fuel units in response to the variable output of wind generation can lead to greater GHG emissions by these plants. Again, generators should not be penalized for increased GHG emissions that may result from operating their plants as needed to maintain system reliability.

The PUCT and TCEQ urge EPA to consider all aspects of grid reliability in developing any GHG rule for existing sources. Maintaining electric reliability and minimizing consumer costs as a result of the rulemaking is a necessity. EPA must be clear and transparent about data and assumptions they make regarding effects on reliability and costs to consumers. In addition, there should not be tradeoffs between EPA's desire to reduce CO^2 emissions and the progress that states have made in reductions of other air pollutants.

Fourth, it is also very important that EPA not penalize states for demographic and geographic factors that complicate the supply of, and demand for, electricity within and between states. Texas's population is growing faster than any other state. Texas is also the nation's leading producer of oil and gas, refined products, and chemicals. These industries are energy dependent, and Texas should not be penalized for the energy used by these industries that provide products to the rest of the nation and the world. According to the U.S. Energy Information Administration (EIA), Texas is also the largest lignite producer and the fifth largest coal producer in the nation.

Texas produces more electricity than any other state, generating almost twice as much as the next largest generating state. Texas is also the largest electricity consuming state. Unlike other regions where large net interstate electricity deliveries are available, the Texas power grid is largely isolated from the interconnected power systems serving the eastern and western United States. The largest portion of the retail electricity sales in Texas is to the residential sector. One-half of the households in the state use electricity as their primary heating fuel. The residential use of electricity is higher in Texas than in other states, in part because of population size, but also because of high demand for air conditioning during the hot summer months and the widespread use of electricity as the primary energy source for home heating during the generally mild winter months.[1] Any program developed by EPA under 111(d) that does not take factors such as these into account could result in unequal negative impacts on Texas economy relative to other states.

EPA should recognize the difficulty stakeholders have in providing meaningful comment without knowing what direction EPA intends to take. As EPA starts to develop its proposal, it is of the utmost importance that EPA continues to be open regarding its intentions and be inclusive in the process. Not knowing what EPA intends to propose until the rule is actually proposed will not allow adequate time for states to be able to provide meaningful input into the process and prepare for the task of developing state plans.

Thank you for the opportunity to provide comments on this important matter. If you have any questions, please contact Mr. Steve Hagle, Deputy Director of the TCEQ Office of Air at (512)239-2104 (Steve.Hagle@tceq.texas.gov) and/or Mr. Tom Hunter, Agency Counsel of the PUCT at (512)936-7280 (Tom.Hunter@puc.texas.gov).

Sincerely,

Richard A. Hyde

Richard A. Hyde, P.E., Interim Executive Director
Texas Commission on Environmental Quality

Brian H. Lloyd

Brian H. Lloyd, Executive Director
Public Utility Commission of Texas

Enclosure

[1] http://www.eia.gov/state/analysis.cfm?sid=TX

Texas Commission on Environmental Quality and Public Utility Commission of Texas

Response to EPA Questions for States on Federal Clean Air Act (FCAA) §111(d) Plan Requirements for Regulating Carbon Dioxide (CO_2) from Existing Power Plants

1. What is state and stakeholder experience with programs that reduce CO_2 emissions in the electric power sector?

- What actions are states, utilities, and power plants taking today that reduce CO_2 emissions from the electric power system? How might these be relevant under section 111(d)?

While Texas does not implement programs specifically to target CO2 emission reduction at this time, Texas has consistently implemented programs designed to both reduce energy demand and to encourage renewable energy resources. States should be allowed to take credit for programs such as renewable energy development, energy efficiency, and demand response for purposes of compliance with a 111(d) performance standard. Texas has more installed wind energy than any other state in the U.S. and has significantly expanded transmission capability in the state to integrate wind-generated electricity into the state's power supply. Texas has over 12,000 MW of wind capacity, more than twice the amount of any other state and more than all but five countries worldwide. In addition, Texas has a number of energy efficiency programs that result in energy savings. Demand response activities have resulted in an impact of greater than 900 MW in 2012. Efforts by states to address both energy demand and renewable energy development could be relevant in EPA's consideration of how a state demonstrates compliance with any standard.

- What systems do states and power plants have in place to measure and verify CO_2 emissions and reductions?

Texas at this time does not have specific regulatory requirements for the reporting of CO2 emissions or reductions in CO2 emissions, but rather relies on the EPA greenhouse gas reporting requirements.

Texas can provide information on its renewable energy portfolio and energy efficiency savings. Specifically, the Energy Systems Laboratory of Texas A&M University develops annual reports of energy savings due to energy efficiency measures in collaboration with the Public Utility Commission of Texas (PUCT), Texas Commission on Environmental Quality (TCEQ), and USEPA's Office of Atmospheric Programs. The energy savings submitted in the reports are based on projects implemented and achieved through the PUC energy efficiency program adopted under state legislation in 1999, 2001, 2007, and 2011.

- How do state programs and measures affect electricity generation and emissions at a regional level? How are interstate effects accounted for when measuring the progress of a state program? For example, are the multi-state effects of state renewable portfolio standards, end use energy efficiency resource standards, emissions performance standards, and emissions budget trading programs currently accounted for by the state, and if so, how?

The TCEQ and PUCT acknowledge that regional issues can result due to the overlapping nature of the electrical grid in most states. Accounting for renewable energy programs and energy efficiency measures may necessitate coordination with other states for areas that have regional independent service operators (ISOs) or RTOs for electric markets that cross multiple state boundaries. However, ERCOT, which manages the flow of electricity to 85% of Texas, only operates within Texas. As such, while the areas of Texas outside of ERCOT are comprised of several other ISOs that encompass more than one state, Texas' renewable energy and energy efficiency programs in the ERCOT region will not have significant interstate linkages. The EPA needs to consider such unique circumstances when deciding what requirements may be needed for states that wish to include energy efficiency and renewable energy measures in their state plans.

2. How should EPA set the performance standard for state plans?

- Which approaches to reducing CO_2 emissions from power plants should be included in the evaluation of the "best system of emission reduction" that is used to determine the performance level(s) that state plans must achieve? Should the reduction requirement be source- or system-based?

A single approach is not appropriate given the diverse nature of the states' generation mix and utility market structures. A source-based approach may be appropriate for some states while a system-based approach is more appropriate in other states. A system approach would likely provide the most flexibility for Texas given our diversified generation mix.

111(d) limits EPA to establishing, "... standards of performance for any <u>existing source</u> for any pollutant...if such existing <u>source</u> were a new <u>source</u>,..." Establishment of the performance standard must be based upon BSER on a source specific basis. A "system" standard may face additional practical and legal challenges; however, a "system" approach should be allowed as a part of any state's plan on how it will apply the standard of performance to any particular source under the plan.

- How does the amount of flexibility that states are given to include different types of programs in their state plans relate to the "best system of emissions reduction" that is used to set the performance bar for state plans? For example, if state standards to improve end-use energy efficiency were included in state plans, should EPA consider potential improvements in end-use energy efficiency in setting the performance target for states?

The states should have the flexibility to consider and account for current and possible future energy efficiency and renewable energy measures in developing state plans. However, the EPA *<u>should not</u>* attempt to incorporate assumptions regarding energy efficiency or renewable energy generation when setting the performance target under FCAA §111(d). A state's ability to improve energy efficiency measures or expand renewable energy generation is dependent on a

multitude of technical, geographic, and legal factors. If the EPA attempts to set a more stringent performance target for states that account for energy efficiency or renewable energy in their state plans, this will only serve as a disincentive for states to include energy efficiency and renewable energy. Additionally, the EPA may inadvertently penalize states that have been proactive in implementing energy efficiency and renewable energy measures.

111(d) does not convey flexibility to EPA in how they are to establish standards of performance, simply because states are given implementation flexibility in preparing plans that describe how standards of performance will be applied to existing sources. EPA's flexibility exists in its approval of each unique state plan.

- What should be the form and specificity of the performance level(s) in EPA guidelines? (Rate-based or mass-based? Separate levels for each subcategory of sources, or one level for the covered sources in the state? A uniform national level, or different levels by state/region based on an established evaluation process?)

As with the question of source-based vs. system-based, a single approach may not be appropriate for all states. A rate-based approach may be more appropriate in some states whereas a mass-based approach could be more appropriate in others. Rate-based standards of performance may appear to be the most defensible form of a potential standard because they could account for BSER on a source specific basis. However, whatever form of the standard the EPA ultimately decides on, states should have the latitude to translate the standards from one basis to another for purposes of developing the state plans, e.g., converting rate-based standards to a mass-based strategy for compliance, or source-based standards to system-wide approach. The EPA should provide guidance on various mechanisms in which a state can convert the standards to difference compliance approaches for the §111(d) plans.

Regardless of the different possible forms or specificity of the standards of performance, EPA must recognize the difference in source categories [e.g., coal-fired utility boilers (sub-critical, supercritical, and ultra-supercritical), gas-fired boilers, liquid-fired boilers, simple-cycle combustion turbines, combined-cycle units] in developing the standards of performance that reflect BSER. Because of the unique design characteristics of plants that burn different types of coal, performance standards should be based on a further subcategorization of coal plants.

Regional differences in electric markets create additional complexity in the setting of a standard under 111(d). While 111(d) doesn't appear to give EPA authority to establish different standards of performance based upon geographical considerations, the TCEQ supports considerations of regional issues in the standard setting process based on the unique nature of the regulated pollutant and the multiple overriding statutory and regulatory constraints for electric generation.

- When can emission reductions from existing power plants be achieved, considering different reduction strategies?

The amount of time necessary to achieve the emission reduction is dependent on how much reduction will be required to comply with the FCAA §111(d) requirements and the form of the standard. Without knowing the degree of reduction required and what options are available, states cannot estimate the amount of time necessary. We note that 111(d) has no specific compliance timeframes unlike other statutory air programs such as Section 112. We believe that under Section 111(d), that states have the authority to determine compliance timelines through their state plans. This is absolutely necessary given the differences in state energy mixes and the need to ensure that electric reliability is maintained. States need the flexibility to establish compliance deadlines based on a number of factors including the economic and energy needs of the state, the remaining useful life of affected EGUs, grid reliability, and unit-specific factors.

- How should a state, in applying a standard of performance to any particular source, consider a facility's "remaining useful life" and other factors?

The consideration of "remaining useful life" is one that is left to states under 111(d). States should be able to consider the relative age of different portions of its fleet, the present and future investment in pollution controls made at individual plants, and the amount of stranded investment if plants were to be prematurely required to shut down.

3. What requirements should state plans meet, and what flexibility should be provided to states in developing their plans?

- What level of flexibility should be provided to states in meeting the required level of performance for affected EGUs contained in the emission guidelines?

Given the diversity among the states' utility market structures and generation mixes, the EPA should give the maximum flexibility allowed by the FCAA.

- Can a state plan include requirements that apply to entities other than the affected EGUs? For example, must states place all of the responsibility to meet the emission performance requirements on the owners or operators of affected EGUs, or do states have flexibility to take on some (or all) of the responsibility to achieve the required level of emissions performance themselves or assign it to others (e.g., to require an increase in the use of renewable energy or require end-use energy efficiency improvements, which will result in emissions reductions from affected EGUs)?

Energy efficiency and renewable energy measures from sources other than affected EGUs should be tools that states can use in developing state plans. Energy efficiency and renewable energy ultimately affect the energy produced by affected EGUs. However, while we encourage EPA to provide maximum flexibility to states in developing state plans, including other sources that do not have this direct linkage back to the affected EGUs may be problematic. For example, if a state wishes to include non-EGU combustion sources in its state plan, will the state or the EPA decide the appropriate level of performance for these non-EGU sources?

- What components should a state plan have, and what should be the criteria for approvability?

Since EPA has already promulgated general requirements that all state plans must meet in 40 CFR Part 60, Subpart B, the TCEQ and PUCT are unclear as to the intent of EPA's question. If the EPA's question is whether the components in 40 CFR Part 60, Subpart B, are necessary for state plans for control of CO_2 emissions from existing EGUs, then the TCEQ supports reviewing these general requirements to determine whether they are necessary or appropriate in this case. If EPA's question is whether there should be requirements in addition to those in 40 CFR Part 60, Subpart B, it is difficult to answer that question without specific details of the form of the standard and what options will be available for development of the state plans. In general, the TCEQ and PUCT reemphasize the previous comment that maximum flexibility needs to be provided to states in order for states to address their unique situations. Similarly, with regard to approvability, criteria for approval of state plans should be broad in order to better fit the flexibility of the standard currently under consideration.

- Can a state plan include programs that rely on a different mix of emission reduction methods than assumed in EPA's analysis of the "best system of emission reduction" that is used to set the performance standard for state plans?

Yes. EPA should not attempt to limit the methods states might use in their state plans. A performance-based approach encourages innovative solutions.

- What should be the process for demonstrating that a state plan will achieve a level of emissions performance comparable to the level of performance in the EPA emission guidelines?

The information necessary to demonstrate a state plan will achieve emissions performance comparable to that established by the EPA's emission guidelines will be dependent on the form of the standards in the emission guidelines and the approach that a state chooses to follow in their state plan. The TCEQ and PUCT encourage the EPA to be flexible in this process to allow for the wide range of approaches that states are likely to implement in the state plans.

- What enforceability, measurement, and verification issues might arise, depending on the types of state measures and programs that states include in their plans? For example, what issues are raised by actions that have indirect effects on EGU emissions, such as end-use energy efficiency resource standards, renewable portfolio standards, financial assistance programs to encourage end-use energy efficiency, building energy codes, etc.?

With regard to energy efficiency and renewable energy measures, does the EPA intend to hold states to the same requirements as in EPA's guidance for claiming credit for such measures in the state implementation plan (SIP) process? If so, this may be a strong disincentive for states to rely upon energy efficiency and renewable energy in state plans for FCAA §111(d), as has been the case with the SIP process.

- Do different CO_2 reduction methods under different state plan approaches necessitate different timelines for the achievement of emission reductions?

Yes. If a standard is set that will require changes to a state's generation mix, it will take substantial time to avoid adverse consequences for electric reliability. Demand side changes, such enhancing energy efficiency programs, can also require substantial time for the cumulative benefits to be realized. Additionally, factors such as the utility regulatory and market structure, the diversity of the generation fleet, and the amount of reserve resources available in a particular region can also affect the amount of time needed for a particular strategy, i.e., a particular strategy may require more time in one region than may be necessary in another.

- What issues arise from the fact that operation and planning of the electricity system is often regional, but FCAA section 111(d) calls for state plans? How should interstate issues be addressed, where actions in one state may affect EGU emissions in another state? For example, where actions have interstate impacts, which state would receive credit for the emission reductions in its state plan? Could EPA provide for coordinated submittal of state plans that demonstrate performance on a regional basis?

Due to the specifics of federal and state electricity regulation, each state has a unique set of circumstances relevant to the provision of electricity in their state which creates unique complications for standard-setting under 111(d). Given the fact that many ISOs cross state boundaries makes development of individual state plans even more complicated. States should have the flexibility and necessary time to coordinate with other states and ISOs so that individual plans are complementary.

4. What can EPA do to facilitate state plan development and implementation?

- What types and amount of guidance and implementation support should be provided to states?

Given the EPA's aggressive schedule on the FCAA §111(d) rulemaking and for states to develop state plans, states need detailed information early in the process. EPA should not wait until the rule is proposed to give specifics to the states. A 30 or 60-day comment period will not be sufficient for state environmental and utility agencies to assess the potential impacts of the performance level proposed by EPA. EPA needs to continue to be transparent and communicative with states while they develop the 111(d) guidance.

Given the extreme complexity of state energy programs, market structures, ISOs that may cross state lines, etc., Texas is very concerned that the regulatory timelines that EPA is working under may not be adequate for states to develop their plans. At a minimum, guidance regarding EPA's expectations dealing with multijurisdictional issues will be critical and should be available no later than the effective date of the standard.

- Are there benefits for coordination among neighboring states in the development and submittal of state plans? Should EPA facilitate the coordination of multi-state plan submittals?

It is difficult to answer this question without knowing the final nature of the performance standard. In any case, EPA facilitation of multi-state planning process should only occur if requested by the states involved.

- Would certain types of measures that might be included in state plans increase the need for coordination among states?

- Are there model rules that EPA could develop that would assist states, and what would those rules cover?

<u>Other Questions and Issues</u>

States may need to include an emergency provision or a "safety valve" in their state plans for energy emergencies.

COMMENTS BY THE PUBLIC UTILITY COMMISSION OF TEXAS REGARDING THE CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: EMISSIONS FROM EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS; PROPOSED RULE; EPA DOCKET ID NO. EPA-HQ-OAR-2013-0602

I. EXECUTIVE SUMMARY

The Public Utility Commission of Texas (PUCT) provides these comments on the Environmental Protection Agency's (EPA) proposed rule on *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Rule 111(d)).[1] The PUCT's primary concerns with Proposed Rule 111(d) are:

- Rule 111(d) will create significant electric reliability problems in Texas.
- Rule 111(d) unfairly penalizes Texas for its success in the early adoption of renewable energy and energy efficiency programs, its diverse fuel mix, and its highly successful and competitive electricity market (ERCOT).
- EPA's attempt to control the nation's electricity markets through the adoption of Rule 111(d) is an unlawful intrusion into areas it has neither the authority nor the expertise to regulate.
- The carbon emission limits for Texas:
  - are arbitrary and unreasonable;
  - result from numerous flawed assumptions about the operation of electricity markets;
  - fail to recognize the substantial CO_2 reductions already achieved as a result of Texas's significant investment in natural gas and renewable capacity;
  - will have virtually no impact on worldwide CO_2 emissions;
  - will result in significantly increased costs for Texas electricity customers. Some estimates of these increased costs include:

[1] 79 Fed. Reg. 34,830 (June 18, 2014).

- $10-$15 billion total annual compliance costs by 2030;[2]
- total electricity-related costs in Texas alone could be in excess of $10 billion;[3]
- increased energy costs for consumers in ERCOT of up to 20% in 2020, which does not include additional costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT.[4]
- $3 billion per year to comply with the energy efficiency mandate alone.[5]

- The compliance timeline for the proposed rule, particularly for the interim goal, is unworkable and unattainable.
- Unlike any other state, Texas has four separate electricity markets. As such, compliance with Rule 111(d) would be especially and uniquely difficult for Texas.

Given the problems outlined above, the PUCT strongly urges EPA to withdraw Rule 111(d) in favor of a more reasonable and workable rule on CO_2 emission reductions.

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[2] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*--Presentation of Charles S. Griffey at slide 12 (Aug. 15, 2014). All documents filed in PUCT Project No. 42636 that are cited in these comments are available on the PUCT's website at: http://interchange.puc.texas.gov/WebApp/Interchange/application/dbapps/filings/pgSearch.asp

[3] Prepared Testimony of Luminant CEO Mac McFarland before Texas House Committee on Environmental Regulation at 7 (Sept. 29, 2014).

[4] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 1 (Nov. 17, 2014) (attached as Appendix A to these comments).

[5] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of the Joint Utilities at 2 (Sept. 5, 2014).

Glossary

BSER	Best System of Emission Reduction
CAA	Clean Air Act
CSAPR	Cross-State Air Pollution Rule
Coop	Member-owned electric cooperative
EGU	Electric Generating Unit
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ETI	Entergy Texas, Inc.
FERC	Federal Energy Regulatory Commission
FP	Federal Plan
FPA	Federal Power Act
PUCT	Public Utility Commission of Texas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MOU	Municipally-owned electric utility
NERC	North American Electric Reliability Corporation
NODA	Notice of Data Availability
IRP	Integrated Resource Planning
ISO	Independent System Operator
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
RRC	Railroad Commission of Texas
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SP	State Plan
SPP	Southwest Power Pool

- SPS Southwestern Public Service Company
- SWEPCO Southwestern Electric Power Company
- TCEQ Texas Commission on Environmental Quality
- TDU Transmission and Distribution Utility (ERCOT only)
- WECC Western Electricity Coordinating Council

II. INTRODUCTION

On June 18, 2014, EPA published proposed Rule 111(d) for comment. The PUCT hereby submits these comments on Rule 111(d). EPA's Rule 111(d) suffers from numerous legal flaws, incomplete and incorrect assumptions and analysis, and should be withdrawn.

The legal infirmities alone dictate withdrawal of this rule in favor of a legally supportable approach to reducing CO_2 emissions. Simply put, Rule 111(d) effectively seeks to unlawfully seize jurisdiction over fundamental wholesale and retail electric utility policy from states and the FERC. This rule goes far beyond EPA's authority to regulate Electric Generating Units (EGUs) under the Clean Air Act (CAA). Furthermore, Rule 111(d) contemplates regulation of significant "outside the fence" activities that, if adopted, would require fundamental and significant changes to Texas's extremely successful competitive electricity market that serves the vast majority of Texas,[6] and would cause equally significant economic disruption and risks to reliability in the markets overseen by the Federal Energy Regulatory Commission (FERC) in which other Texas utilities operate.

EPA's attempt to usurp the authority of the Texas Legislature and the PUCT in areas of electric power market design, renewable energy mandates and energy efficiency programs is an impermissible federal intrusion into areas it has neither the authority nor the expertise to regulate. Through Rule 111(d), EPA is attempting to assert authority and control over the entire electricity market of the United States.

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[6] The Electric Reliability Council of Texas (ERCOT) serves 24 million Texas customers and approximately 90 percent of the state's electric load.

EPA vastly underestimates both the cost of the proposed rule as well as the potential threats to system reliability. ERCOT has performed an analysis of the impacts of Rule 111(d) on grid reliability and electricity costs in the ERCOT region. The results of ERCOT's analysis are discussed throughout these comments and ERCOT's report is attached hereto as Appendix A. ERCOT is currently working on a more complete analysis of the impacts on ERCOT of Rule 111(d) and other environmental rules including MATS, CSAPR, the Regional Haze program, the 316(b) Cooling Water Intake Structures rule, and the coal ash rules which will be released in mid-December 2014. Unfortunately, due to time and resource constraints, ERCOT was unable to complete this analysis before the December 1 comment deadline. The PUCT will file ERCOT's final analysis with EPA as soon as it is complete and urges EPA to consider this report as it finalizes Rule 111(d).

The proposed rule also suffers from numerous flawed assumptions about the operation of electricity markets. Rule 111(d) illustrates how little EPA understands about the complex operations of these markets and the continual balance that states and the FERC must achieve with respect to ensuring that the reliability of power grids that is critical to the operation of the modern American economy is preserved. EPA fails to understand that Texas's robust competitive markets already create incentives for existing power plants to operate efficiently, making further heat rate improvements very difficult to achieve. Additionally, EPA does not recognize the time necessary to add substantial new electric transmission facilities, difficulties in ensuring that there are adequate natural gas pipelines to provide reliable natural gas to new power plants, and the importance of certain large generating plants to local grid reliability. EPA also fails to appreciate the limits of the ERCOT power grid in continuing to integrate the substantial large amount of renewable energy that EPA seeks to mandate by Rule 111(d). While EPA has made much of the supposed flexibility its "building blocks" approach would provide, it in fact provides no flexibility for Texas as each of these blocks is likely unachievable, particularly in the timeframes required in the proposed rule.

Proposed Rule 111(d) is unworkable. The rule establishes completely unachievable timelines for this fundamental remaking of the power industry, creating great threats to the ability of Texas to manage and operate our electricity system. The policies that Rule 111(d) seeks to force upon Texas would require substantial changes to Texas state law, PUC regulation, and protocols of the ERCOT, MISO, and Southwest Power Pool (SPP). The rule would also require intense coordination with other states connected to these power grids. It is unreasonable to require states to accomplish these tasks by the proposed deadline for submitting State Plans (SPs) in June of 2016. This is particularly acute for states like Texas with Legislatures that only meet every other year, and will not be able to even consider the necessary changes arising from a final rule until 2017.

Finally, Rule 111(d) also has an unreasonable and disproportionate effect on Texas. Texas produces 11% of the electricity in the United States, but its proportion of total carbon dioxide reduction required by Rule 111(d) by 2030 is 17.87%.[7] Texas is by far the country's leading producer of renewable energy capacity, but is required to increase its renewable energy output by 150%. EPA has based Texas's renewable energy requirement on the renewable energy portfolio standard of Kansas, a state whose electricity production is one-tenth that of Texas. In these and other ways discussed herein, Rule 111(d) arbitrarily penalizes Texas.

The PUCT's comments are focused on the state goals in the proposed rule. While the PUCT does not specifically address the alternate goals proposed by EPA, the following comments are equally applicable to the alternate goals. In short, the alternate goals are no more reasonable or workable than the state goals.

On October 30, 2014, EPA issued a Notice of Data Availability (NODA). In the NODA, EPA sought comments on several topics raised by stakeholders. The three main topics addressed in the NODA were emission reduction interim goals for 2020 to 2029, certain aspects of the building block methodology and the way state-specific goals are calculated. For reasons discussed herein, the NODA does not change the PUCT's ultimate conclusion that Rule 111(d) is unworkable and should be withdrawn.

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[7] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*—Partnership for a Better Energy Future at slide 15 (Aug. 15, 2014).

For the reasons outlined herein, the PUCT respectfully requests EPA to withdraw proposed Rule 111(d). In the alternative, the PUCT urges EPA to revise the proposed rule to address the concerns raised herein. Chief among the PUCT's concerns is Texas's interim emissions rate requirement of 853 lbs. CO_2/MWh. The interim mandate would be phased in over a ten year period between 2020 and 2029. However, in order for Texas to meet its interim mandate, approximately 77% of its CO_2 reductions must be accomplished by 2020, as the interim mandate is averaged over the 10-year period from 2020 to 2029.[8] If Texas is too far above the interim mandate in the early years, it will not successfully meet EPA's interim goal without extremely over-controlling its carbon dioxide emissions in the latter part of the decade. For the numerous reasons enumerated below, this is a completely unrealistic and unattainable goal for Texas. The PUCT therefore requests that, at a minimum, EPA eliminate the interim goal from the rule.

On August 15, 2014, the PUCT, together with the TCEQ and the Railroad Commission of Texas (RRC)[9], held a joint public workshop in which numerous industry stakeholders provided comments on Rule 111(d). At the workshop and in post-workshop comments stakeholders provided useful information on the effects that Rule 111(d) would have on Texas. The PUCT will cite and discuss some of these stakeholder presentations and comments in its comments below.

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[8] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of TCEQ at 16 (Dec. 1, 2014) (the comments of TCEQ and the PUCT were filed at EPA on December 1, 2014 under a joint cover letter from TCEQ, PUCT and the Railroad Commission of Texas).

[9]The RRC is a Texas state agency that serves as the primary regulator of the oil and gas industry in Texas. The RRC: 1) oversees all aspects of oil and natural gas production, including permitting, monitoring, and inspecting oil and natural gas operations; 2) permits, monitors, and inspects surface coal and uranium exploration, mining, and reclamation; 3) inspects intrastate pipelines to ensure the safety of the public and the environment; 4) oversees gas utility rates and ensures compliance with rates and tax regulations; and 5) promotes the use of propane and licenses all propane distributors. *Texas Sunset Advisory Commission: Final Report With Legislative Action related to the Railroad Commission of Texas* at 7 (July 2013)
(Available at:
https://www.sunset.texas.gov/public/uploads/files/reports/Railroad%20Commission%20Staff%20Report%202013%2083rd%20Leg_0.pdf).

III. RULE 111(D) IS LEGALLY UNSUPPORTABLE AND ILLEGALLY SEEKS TO IMPOSE EPA JURISDICTION OVER MATTERS THAT ARE IN THE PURVIEW OF STATES.

A. The PUCT Agrees With The Comments Of TCEQ

The numerous legal and practical problems with Rule 111(d) are thoroughly outlined in the comments of the TCEQ.[10] For example, TCEQ has correctly concluded that EPA lacks the legal authority to regulate "outside the fence" activities included in Blocks 2-4. TECQ also rightly argues that EPA cannot regulate power plant emissions under CAA §111(d) because these plants are already subject to regulation under the Mercury and Air Toxics Standards (MATS) rule adopted under CAA §112. TCEQ also discusses the numerous other legal problems with the proposed rule. The PUCT supports and agrees with the arguments raised by TCEQ in its Rule 111(d) comments.

B. Rule 111(d) Would Illegally Usurp Texas's Regulatory Authority Over Its Electricity Industry

In addition to the comments of TCEQ, the PUCT objects to the attempt by EPA through Rule 111(d) to seize jurisdiction from state public utility commissions regarding the planning, operation, and resource decisions made in electricity markets. It has long been the law of the land that authority over retail electricity markets nationwide and wholesale markets in ERCOT are the sole province of state public utility commission, except where the Federal Power Act (FPA)[11] authorizes FERC regulation.[12] Environmental regulation has been limited to specific

[10] *See* Docket ID No. EPA-HQ-OAR-2013-0602--Comments of TCEQ (Dec. 1, 2014).

[11] 16 U.S. Code § 824 *et.seq*.

[12] As discussed in more detail below, ERCOT is the only Independent System Operator (ISO) in the country that is wholly contained within one state and is not synchronously interconnected to the remainder of the United States. ERCOT is unique among the nation's ISOs in that it is subject to very limited and specific jurisdiction by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA). The transmission of electric energy occurring wholly within ERCOT is not subject to FERC's rate setting authority under FPA sections 205 or 206 nor is it subject to FERC's sale, transfer and merger authority under section 203 of the FPA. (See: http://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp). Pursuant to FPA section 215, FERC does have jurisdiction to establish and enforce reliability standards for users of the bulk power system within ERCOT. Finally, under FPA sections 210, 211 and 212, FERC has limited jurisdiction to order certain entities within ERCOT to interconnect and provide transmission service. Historically, FERC orders issued under FPA section 212 that are applicable to entities in ERCOT have expressly stated that the utilities in ERCOT that are not currently public utilities under the FPA will not become public utilities and therefore subject to FERC jurisdiction for any purpose

requirements on specific power plants, and has never been interpreted to grant EPA broad authority to dictate the operation of the entire electricity system. The manner in which power markets are dispatched, how much and how renewable energy should be integrated, and how end-use customers should use electricity has never been under the purview of EPA. Rather these decisions are left best to states and the FERC, as experts in these areas. The policies that EPA seeks to force through Rule 111(d); namely renewable energy portfolio standards, energy efficiency standards, and cap-and-trade carbon emissions systems have ***always and only*** been implemented by deliberation in state legislatures or public utility commissions. The failed American Clean Energy and Security Act of 2009[13] was an attempt by the U.S. Congress to authorize and impose these policies on the nation as a whole. EPA cannot now do what the elected representatives of the American people declined to authorize simply by reinterpreting long-extant statutes to suddenly provide such authorization.

With Rule 111(d), EPA would force Texas and other states to cede complete authority over their electricity markets as a prerequisite for obtaining approval of a SP under Rule 111(d). In order for a SP to be approved by EPA, a state must agree that the various elements of the plan, including the measures required under Blocks 1-4, are enforceable by EPA. In addition, EPA's enforcement of these measures is not discussed or even touched upon in this proposed rule. Should a state choose not to file a SP, it risks the same result (loss of authority over its electricity market) when EPA imposes a Federal Plan (FP) to implement the rule. EPA cannot and should not mandate that states adopt measures to address CO_2 emissions that EPA itself has no authority to impose.

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other than carrying out the provisions of FPA sections 210, 211 and 212. *See e.g., Kiowa Power Partners*, LLC, 99 FERC ¶ 61,251 (May 31, 2002).

[13] H.R. 2454 of the 111th U.S. Congress. This legislation, also known as the Waxman-Markey Bill, was passed by the U.S. House, but failed in the Senate.

C. EPA Is, At Most, Authorized To Implement A Reasonable Form Of Block 1 As The Policies In Blocks 2-4 Are Purely State Or FERC Matters

While Block 1 of Rule 111(d), though flawed as will be explained below, may arguably be within the scope of EPA's authority under the CAA,[14] Blocks 2-4 clearly go well beyond EPA's authority under the CAA. EPA could certainly permit states to consider tools consistent with Blocks 2-4 in lieu of the "inside the fence" requirements in Block 1, but it cannot compel them to do so as it seeks to do under Rule 111(d). Blocks 2-4 (dispatch of natural gas plants, renewable energy portfolio standards and energy efficiency programs) are clearly areas over which states and their state utility commissions, not EPA, have jurisdiction. EPA has provided no convincing legal authority for mandating the sweeping changes to electricity markets made in the proposed rule.

Block 2 seeks to fundamentally upend markets that operate through centrally dispatched grid operators/regional transmission organizations. It seeks to impose EPA's judgment on how power plants should be dispatched in lieu of the economic dispatch market systems approved by the FERC and PUCT. EPA possesses no independent authority to order such a change. Rather, the changes that would be necessary to implement such a draconian re-dispatch through an explicit environmental dispatch regime – a prohibition on output from power plants where economics support their operation (and in fact market rules often require production due to market power concerns), or imposition of cap and trade systems integrated with the power markets--would all require changes in state and federal law, market protocols, FERC tariffs, public utility commission regulations, market monitoring regimes, and the like. Simply put, EPA cannot impose requirements on states and power markets that it has no authority to independently implement.

Blocks 3 and 4 are also clearly outside of any legal authority given to EPA to mandate or assume in developing state emission standards. Renewable energy and energy efficiency

[14] While EPA believes it has authority to promulgate this rule pursuant to CAA Section 111(d), the PUCT believes the stronger argument is that EPA lacks authority to adopt Rule 111(d) under this provision because EPA is restricted from regulating any pollutant emitted by a source category that is regulated under CAA Section 112. Because Hazardous Air Pollutants from EGUs are currently regulated under CAA Section 112, EPA is legally prohibited from regulating CO_2 from EGUs under CAA Section 111(d).

standards are, by definition, resources that do not emit any emissions, including greenhouse gases. EPA therefore has no regulatory authority to regulate the use of these sources.[15]

Use of renewable energy, energy efficiency, and decisions on the types of power plants that should be built to meet retail customer demand have never been within the domain of EPA's authority. Rather, states have always used a suite of tools from integrated resource planning, renewable portfolio standards, market forces, and other legislative or regulatory tools to make these decisions. While EPA has authority to dictate the types of emissions controls that certain types of power plants must have, it does not have the authority to order them not to be used. The claim of authority that EPA now asserts to do so is breathtaking in its scope, not only as it relates to electricity markets, but also implies that EPA could do so for ***any*** business whose production process include regulated emissions.

IV. BACKGROUND ON TEXAS'S UNIQUE AND COMPLEX ELECTRICITY MARKET

Even assuming that EPA had requisite legal authority to adopt Rule 111(d) as proposed, EPA has failed to account for the unique factors of the Texas electricity sector that make the compliance deadlines in the rule wholly unworkable.

Texas is unique among all states in the fact that a large portion of the state operates in a vibrant and extremely successful competitive wholesale and retail electric market (ERCOT), while other portions of the state operate within 3 distinct competitive wholesale markets that are overseen by the Federal Energy Regulatory Commission (FERC) and traditional cost-of-service regulated retail markets, that are subject to the PUCT's jurisdiction (SPP, MISO, and WECC). Because of this unique circumstance, compliance with Rule 111(d) would be especially difficult for Texas in the timeframe contemplated by the rule.

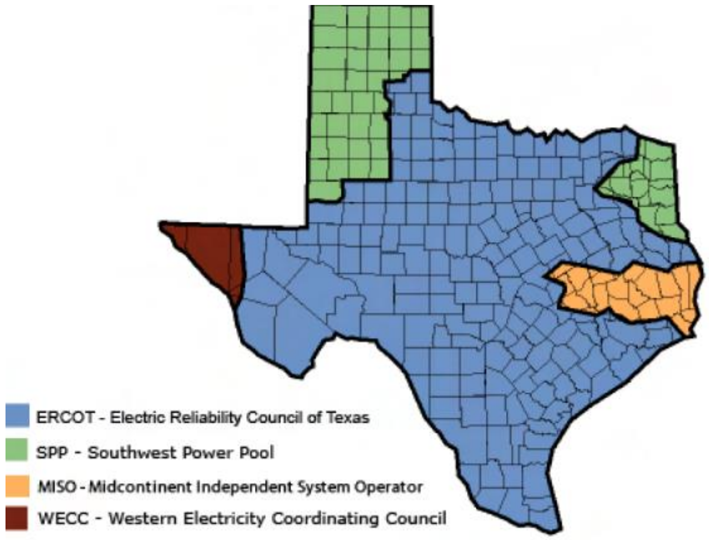
[15] While EPA does have authority to set certain standards for appliances and other equipment, it has no authority to compel the usage by consumers of specific devices as it seeks to do through Rule 111(d).

ERCOT, which was founded in 1970, is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature**.** ERCOT is a non-FERC jurisdictional restructured, competitive, energy-only wholesale and largely competition retail market responsible for overseeing the reliable operation of the electric grid for the ERCOT region of Texas. All of Texas's largest metropolitan areas, including Dallas/Fort Worth, Houston, San Antonio and Austin are located in ERCOT. ERCOT is the only independent system operator (ISO) in the U.S. that is located entirely within one state. As the ISO for the region, ERCOT schedules and dispatches power on a grid that connects approximately 43,000 miles of transmission lines and 550 generating units. ERCOT also handles the financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.7 million premises in competitive choice areas.[16] A map of ERCOT's footprint is provided below in Figure 1.

Figure 1: Map of ERCOT Footprint

[16] *See* ERCOT website at: http://www.ercot.com/about .

Figure 2: Map of RTO Interconnections in Texas



As shown in Figure 2 above, the remaining 10% of electric consumption takes place in areas outside of ERCOT served by cooperatives and vertically integrated, investor-owned utilities whose retail rates and terms of retail service are regulated by the PUCT. The IOUs operating in Texas are each part of multi-state utility systems. The non-ERCOT areas of Texas are located in far West Texas, North Texas, and far East Texas. All of the electricity markets in the non-ERCOT areas of Texas operate in multi-state competitive wholesale electricity markets that are overseen by FERC. Investor-owned El Paso Electric Company (EPE) serves far west Texas, including the City of El Paso, and operates within the Western Electricity Coordinating Council (WECC). While it is not a FERC-approved RTO, WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC also assists its members in the development of reliability standards and the coordination of the operating and planning activities of its members. WECC is geographically the largest and most diverse of the eight Regional Entities with delegated authority from the North American Electric

Reliability Corporation (NERC) and FERC. WECC's service territory extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico,[17] and all or portions of 14 Western states.

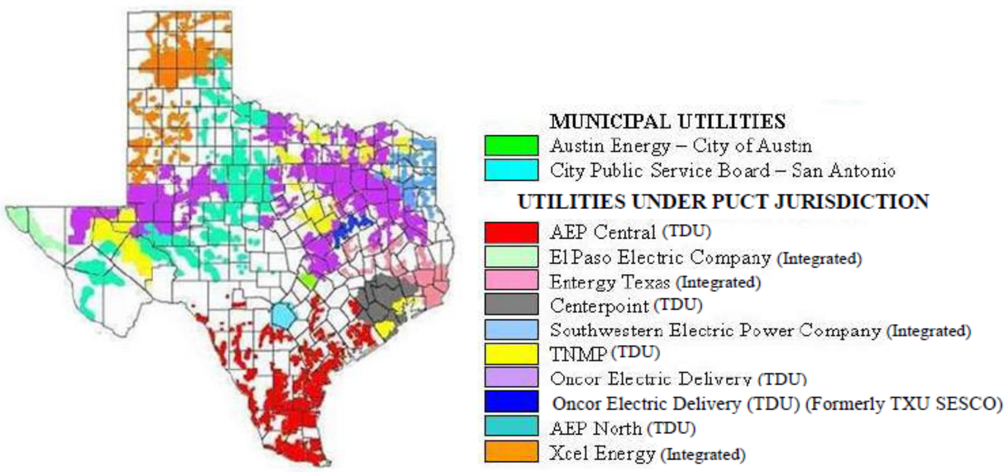
North Texas, including the cities of Amarillo and Lubbock, is served primarily by Southwestern Public Service Company (SPS), an investor-owned utility which operates within the Southwest Power Pool (SPP). The SPP is an RTO charged with ensuring reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. SPP currently operates in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Far northeast Texas is served by Southwestern Electric Power Company (SWEPCO), which also operates within SPP.

Finally in far East Texas, Entergy Texas, Inc. (ETI), an investor-owned utility, operates in the Midcontinent Independent Transmission System Operator (MISO). MISO is an independent, not-for-profit RTO responsible for maintaining reliable transmission of power in 15 states in the mid-continental U.S. and the Canadian province of Manitoba. All of the Texas utilities (public or private) located in the eastern interconnection are members of SPP or MISO.

The Texas service territories of the electric IOUs, TDUs and two largest municipally-owned utilities are shown below in Figure 3.

[17] Given that portions of WECC extend to Canada and Mexico, Rule 111(d) may affect power markets in these countries. It is unclear whether EPA has considered the possible international law implications of Rule 111(d).

Figure 3: Municipal, Investor Owned, & TDUs in Texas[18]



Rule 111(d) does not take into account the broad scope of electric service offered in Texas, and the nearly insurmountable obstacles it would pose for Texas to implement the rule as proposed.

V. RELIABILITY IMPACTS OF RULE 111(d)

ERCOT's primary concern with the Rule 111(d) is that, given the ERCOT region's market design and existing transmission infrastructure, the timing and scale of the expected changes needed to reach the CO_2 emission goals could have a harmful impact on reliability. Specifically, implementation of the Rule 111(d) in the ERCOT region, particularly to meet the rule's interim goal, is likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges. There is a natural pace of change in grid resources due to advancing cost effective technologies and changing market conditions. This pace can be accelerated, but there is a limit to how fast this change can occur within acceptable reliability constraints. It is unknown, based on the information currently available, whether compliance with the proposed

[18] Source: http://www.myutilitychoice.com/custom/index.cfm?id=152686.

rule can be achieved within applicable reliability criteria and with the current market design. Nevertheless, there are certain grid reliability and management challenges that ERCOT will face as a result of the resource mix changes that the proposed rule will induce:

- The anticipated retirement of up to half of the existing coal capacity in the ERCOT region will pose challenges to reliable operation of the grid due to the reduction in dispatchable generation capacity and loss of reliability services provided by these resources.

- Integrating new wind and solar resources will increase the challenges of reliably operating all resources, and pose costs to procure additional regulating services, improve forecast accuracy, and address system inertia issues.

- Accelerated resource mix changes will require major improvements to ERCOT's transmission system, posing significant costs not considered in EPA's Regulatory Impact Analysis.

- Rule 111(d) could require substantial changes to ERCOT's energy market design with accompanying implementation costs.

These issues highlight the need for the final rule to include a process to effectively manage electric system reliability issues that may arise due to implementation of Rule 111(d), as well as include more implementation timeline flexibility to address each state's or region's unique market characteristics.

A. Rule 111(d) Contains No "Reliability Safety Valve" To Protect The Electric Grid Against The Harm the Rule Will Inflict

EPA does not address how or even whether the proposed emissions standards could or should be relaxed or temporarily waived in the event of electric grid emergencies, including natural disasters, terrorist attacks, and forced outages. There is nothing in the proposed rule that allows a state to suspend the requirements of a state plan in an energy emergency. While the state could exercise enforcement discretion in such situations, utilities would still be potentially vulnerable to private citizen lawsuits for non-compliance with a CAA requirement. If Rule

111(d) is adopted, it must include some sort of reliability safety valve (RSV) that would allow states to suspend the operation of the rule in energy emergencies.

The ISO/RTO Council (IRC)[19] has outlined the parameters of a possible reliability safety valve (RSV) that could be incorporated into Rule 111(d).[20] The PUCT understands that the IRC provided its RSV proposal to EPA staff before proposed Rule 111(d) was drafted. The IRC's proposal seeks to ensure that any federal CO_2 rule or related State Implementation Plan (SP) "includes a process to assess, and, as relevant, to mitigate, electric system reliability impacts resulting from related environmental compliance actions."[21] If EPA adopts Rule 111(d), the PUCT strongly urges EPA to consider inclusion of some form of RSV in its adopted Rule 111(d). In its Rule 111(d) comments to EPA, the SPP has also recommended that a reliability safety valve be incorporated into the rule.[22] In addition, NERC supports a reliability backstop as well as other measures to maintain reliability. [23]

B. Impact Of Unit Retirements[24]

ERCOT's modeling results raise two reliability concerns associated with implementation of Rule 111(d) in ERCOT. These concerns are associated with the impacts of unit retirements and increased levels of renewable generation on the ERCOT grid. The model retired between 3,300 and 5,700 MW of coal-fired capacity in the carbon scenarios, relative to the baseline.

[19] The IRC is composed of the nine Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), including ERCOT, that serve more than two thirds of electricity customers in the U.S and more than half of the electric customers in Canada. IRC member responsibilities include "integrating a diverse mix of power resources onto the electric grid reliably, orchestrating the generation and transmission of electricity [for a large portion of North America], [and matching] power generation instantaneously with demand to keep the lights on." *See* http://www.isorto.org/about/Role

[20] IRC-- *EPA CO2 RULE – ISO/RTO COUNCIL RELIABILITY SAFETY VALVE AND REGIONAL COMPLIANCE MEASUREMENT AND PROPOSALS*, (Jan. 28, 2014) (available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf).

[21] *Id*. at 1.

[22] Docket ID No. EPA-HQ-OAR-2013-0602—SPP Comments at 8 (Oct. 9, 2014).

[23] Docket ID No. EPA-HQ-OAR-2013-0602—*Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 22. North American Electric Reliability Corporation (Nov. 2014).

[24] Excerpt from *ERCOT Analysis of the Impacts of the Clean Power Plan* at 9-11.

However, these results represent a lower bound on the number of potential coal unit retirements due to the logic used to retire units in the model, generic unit cost information, and the impacts of other factors not considered by the model. ERCOT directed the model to retire capacity at the point when generic operating and fixed costs exceed revenues. However, in the modeling results for the carbon scenarios, there are several units operating at low revenues and/or low capacity factors that would likely be retired, especially when other non-modeled factors are taken into account. One important factor not considered in the modeling is the capital and operating cost impacts of other pending environmental regulations including the Mercury and Air Toxics Standard, the Regional Haze program, the 316(b) Cooling Water Intake Structures Rule, and the coal ash rules.

Based on a review of capacity factors and operating revenues for the remaining coal units ERCOT anticipates the retirement of an additional 2,000 MW of coal capacity and the seasonal mothball of 1,000 MW of coal capacity beyond what is specified in the model output, compared to the $25/ton CO_2 modeled scenario. These results indicate the overall impact to the current coal fleet will be the retirement or seasonal mothballing of between 3,300 MW and 8,700 MW.

The accelerated retirement or suspended operations of coal resources would pose challenges to maintaining the reliability of the ERCOT grid. Coal resources provide essential reliability services, including reactive power and voltage support, inertial support, frequency response, and ramping capability. The retirement of coal resources will require reliability studies to determine if there are any voltage/reactive power control issues that can only be mitigated by those resources; how to replace frequency response, inertial support, and ramping capability provided by retiring units, and the necessity of potential transmission upgrades.

The model also predicted the retirement of 1,300 to 1,600 MW of natural gas steam capacity in the carbon scenarios, which is less than the 2,000 MW retired in the baseline scenario. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, which improves the economics of natural gas steam units during this period. However, as with coal resources, there are a number of factors that may result in additional natural gas steam unit retirements compared to those found by the model. ERCOT estimates that an additional 1,500 to 4,500 MW of natural gas steam capacity may be at risk of retirement based on low net revenues in the model results combined with the need to comply with the 316(b) rule, CSAPR, and other environmental regulations.

The modeling results indicate that generation from retiring coal capacity will in large part be replaced by increased production from existing natural gas capacity. Though ERCOT is not currently affected by natural gas supply issues, the increased use of natural gas nationally could lead to increased market dislocations, such as seen in the winter of 2013-2014. Depending on the magnitude of these issues, there could be implications for maintaining reliable natural gas supply in ERCOT for electric generation in the future.

It should also be noted that prospective compliance with Rule 111(d) in 2020 will impact the decisions generation resources make now about investments to comply with other pending environmental regulations. With the implementation of Rule 111(d) to consider, owners of generation resources in Texas may choose to retire units early rather than install control technology retrofits for compliance with the Mercury and Air Toxics Standard (MATS), the Regional Haze Program, or the 316(b) Cooling Water Intake Structures rule. For example, the compliance date for the MATS rule is April 2015, but several coal-fired units in Texas have received a one-year compliance extension from the TCEQ. The pending market impacts due to the proposed rule could result in resource owners deciding to retire these units rather than invest in the retrofit technology required to achieve compliance with MATS. Similarly, it is anticipated that EPA will issue a Federal Implementation Plan (FIP) for Texas for the Regional Haze program in the coming weeks. Depending on the FIP requirements, generators may need to make similar decisions about whether to make significant investments in control technology retrofits or instead retire their units, in light of eventual compliance with Rule 111(d). With earlier retirements of fossil fuel-fired capacity, ERCOT could experience the aforementioned grid reliability challenges well before the rule’s first compliance date in 2020.

C. Impact On Transmission Infrastructure In ERCOT[25]

As previously noted, ERCOT's analysis indicates that imposition of the constraints proposed by Rule 111(d) will result in retirement of legacy base-load generation and development of new renewable generation resources. These changes to the ERCOT generation mix will likely require significant upgrades to the transmission infrastructure of the ERCOT system.

The retirement of a large amount of coal-fired and/or gas steam resource capacity in the ERCOT region would have a significant impact on the reliability of the transmission system. The transmission system is currently designed to reliably deliver power from existing generating resources to customer loads, with the existing legacy resources that are located near major load centers serving to relieve constraints and maintain grid reliability. Retirement of these resources would result in a loss of real and reactive power, potentially exceeding thermal transmission limitations and the ability to maintain stable transmission voltages while reliably moving power from distant resources to major load centers. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of coal-fired and gas steam resources were to be displaced. If new natural gas combined cycle resources were to locate at or near retiring coal-fired and gas steam resources, the impact would be lessened.

In the ERCOT region, it takes at least five years for a new major transmission project to be planned, routed, approved, and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be seen at least five years in advance. Given the competitiveness of the current ERCOT market, unit retirement decisions will likely be made with only the minimum required notification (currently 90 days). Reliability-must-run contracts may provide an avenue to maintain generation resources necessary to support grid reliability, but these make-whole contracts could incur significant market uplift costs,

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[25] Excerpt from *ERCOT Analysis of the Impacts of the Clean Power Plan* at 14-15.

especially if they are needed for several years or if the contracted units require capital investments in order to maintain compliance with other environmental regulations.

The growing loads in the ERCOT urban centers are causing continued growth in customer demand and a resulting need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. A new 345-kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston region, at an estimated cost of more than $590 million. Long-term studies indicate a potential need for further upgrades in the mid-2020s.[26] The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed project. Retirement of generation after 2018 would accelerate the need for additional transmission from the long-term horizon (6-15 years) into the near-term horizon (1-6 years).

Similarly, in the San Antonio and the Dallas-Fort Worth regions, there are multiple new transmission projects that are being planned to serve existing load growth. At costs of hundreds of millions of dollars, the need for these and similar projects would be accelerated by retirement of legacy units in these regions.

Growth in renewable generation would also likely have a significant impact on transmission requirements. Although ERCOT did not estimate the costs of these transmission infrastructure improvements in this study, recent projects can be illustrative of the potential costs. In early 2014, the transmission upgrades needed to integrate CREZ were completed: more than 3,600 miles of new transmission lines constructed at a cost of $6.9 billion dollars. The project took nearly a decade to complete. The CREZ project has contributed to Texas's status as the largest wind power producer in the U.S.

[26] *See* ERCOT's 2013 *Report on Existing and Potential Electrical System Constraints and Needs*. (Available at: http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf).
Nineteen LMPs for the CO_2 limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

While the CREZ transmission upgrades provide transmission capacity beyond current generation development, these new circuits will not provide sufficient capacity to reliably integrate the amount of renewables necessary to achieve the requirements of the proposed rule. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, further significant transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve the proposed compliance requirements in the Clean Power Plan, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

D. The Block 1 Mandated Coal Plant Retirements Will Also Significantly Impact Cost and Reliability In The Non-ERCOT Areas Of Texas

Implementing Rule 111(d) in the non-ERCOT areas of Texas would be no less daunting than implementing it in ERCOT. In traditionally regulated electric utility markets, retail rates are established based on the cost of utility plant (including generation costs) that is used and useful in providing electric service to retail customers. IOUs in non-competitive areas of the country (including portions of Texas) are regulated by state utility commissions which establish a utility's rates after reviewing the utility's cost of serving its customers in a retail electric rate case. As such, in the non-ERCOT markets of Texas, there is at least a regulatory mechanism in place in which the substantially increased costs of electricity that will result from Rule 111(d) could be passed on to retail ratepayers. However, there are also significant problems in implementing Rule 111(d) as proposed in regulated electricity markets.

As discussed elsewhere in these comments, the non-ERCOT regions of Texas (and the rest of the U.S.) are subject to the jurisdiction of FERC. Among other things, FERC also regulates the reliability of the bulk electric power system in North America through the North American Electric Reliability Corporation (NERC). NERC is the electric reliability organization for North America and is subject to oversight by FERC and governmental authorities in Canada. Pursuant to federal law, NERC has adopted and enforces reliability standards for the bulk power system. The RTOs must maintain reliability in accordance with their FERC approved tariffs.

Companies that fail to maintain reliability in accordance with their FERC tariffs and NERC reliability standards are subject to significant penalties levied by FERC. In the same way that Rule 111(d) would require significant changes in Texas law to implement in ERCOT, Rule 111(d) will almost certainly require significant changes to existing federal law to implement throughout the rest of the country. Any rules, behavior, pricing, and revenue distribution that need to be changed as a result of Rule 111(d) must be filed with and approved by FERC. Rule 111(d) will have a significant impact on FERC-regulated entities, including electric utilities operating in Texas. The reliability impacts of Rule 111(d) should be as daunting for FERC as they are for the PUCT. However, as explained below, EPA has had little meaningful input from FERC on the reliability impacts of Rule 111(d).

E. EPA's Cursory Coordination With FERC Regarding Rule 111(d) Has Failed To Adequately Address Reliability Concerns Raised By The Proposed Rule

On September 15, 2014, the U.S. Government Accounting Office (GAO) released a report entitled *EPA REGULATIONS AND ELECTRICITY: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements.* As explained by GAO, the purpose of the report was as follows:

> [t]he Department of Energy (DOE), the Environmental Protection Agency (EPA), and the Federal Energy Regulatory Commission (FERC) have taken initial steps to implement a recommendation GAO made in 2012 that these agencies develop and document a joint process to monitor industry's progress in responding to four proposed or finalized EPA regulations affecting coal-fueled generating units. GAO concluded that such a process was needed until at least 2017 to monitor the complexity of implementation and extent of potential effects on price and reliability. Since that time, DOE, EPA, and FERC have taken initial steps to monitor industry progress responding to EPA regulations including jointly conducting regular meetings with key industry stakeholders. Currently, these monitoring efforts are primarily focused on industry's implementation of one of four EPA regulations—the Mercury and Air Toxics Standards—and the regions with a large amount of capacity that must comply with that regulation. Agency officials told GAO that in light of EPA's recent and pending actions on

> regulations including those to reduce carbon dioxide emissions from existing generating units, these coordination efforts may need to be revisited.[27]

While the GAO Report notes that EPA has had some consultations with FERC and the Department of Energy on other EPA rules including CSAPR, MATS, the Cooling Water Intake Structures rule, and the Disposal of Coal Combustion Residuals rule, the exact nature and extent of those consultations remains unclear. It is even less clear exactly what consultations EPA has had with FERC and DOE on Rule 111(d) since this issue was not the primary focus of the GAO Report.[28]

However, a hearing held by the House Energy and Power Subcommittee of the House Energy and Commerce Committee in July 2014 does shed some light on the nature of the limited interaction between EPA and FERC on Rule 111(d). At this hearing, all five FERC commissioners were present and answered questions on the proposed rule, including questions on the nature of FERC's input on Rule 111(d). In his opening statement at this hearing, Commissioner Moeller noted the importance of understanding the reliability impacts of the proposed rule:

> Essentially, what I have been calling for is a more formal role for our commission as we deal with EPA on these issues, kind of an open and transparent role, so that basically we can get the engineers together to discuss the challenges involved because it really comes down to a very granular level with reliability. The laws of physics will trump regulations. There are always unintended consequences when

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[27] *EPA REGULATIONS AND ELECTRICITY: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements (GAO Report)* (U.S. Government Accounting Office (GAO)) at 1 (Sept. 15, 2014).

[28] In its report, GAO noted that "[t]he meetings EPA holds have included a separate monthly conference call with the three agencies and each of the four RTOs [PJM, MISO, SPP and ERCOT] that have a large amount of generating capacity in their regions that must comply with the MATS regulation. According to one EPA official, the memorandum was intended to be an evolving document that the agencies would revisit as appropriate, for example, as additional EPA regulations are finalized. The meetings [between EPA, FERC and DOE staff] include discussion of the region's capacity and resource adequacy concerns, announced and potential retirements, air pollution control equipment in use and retrofit plans, and other information such as reliability assessments under way in the region." GAO Report at 9-10. However, in an article discussing the GAO report, the author observed: "But whether these meetings were token consultations or substantive discussions remains unclear. EPA declined to go into detail about the discussions taken place at the meetings." *GAO: Agencies met regularly to discuss reliability impacts of proposed EPA rules, SNL*, September 15, 2014.
(Available at: http://www.snl.com/InteractiveX/article.aspx?ID=29224688). The PUCT cannot speak for EPA's meetings with any of the other RTOs, but PUCT is unaware of any meaningful, detailed input on the impacts of Rule 111(d) requested by EPA from ERCOT or provided by ERCOT to EPA.

> we shut down power plants because, although they may not produce a lot of power, they may be producing other products, ancillary services that maintain reliability in the grid. And the location of those plants is key, and sometimes you can't replicate a plant in that location.[29]

In response to a question from Congressman Whitfield on whether EPA requested (or FERC provided) written comments on the reliability impacts of Rule 111(d), FERC Chairman LaFleur stated:

> [n]o, they did not request written comments. My understanding, this is the first time I have been through the interagency review, but there were a number of staff meetings and then a, kind of a formal debrief where we made our comments over at the OMB [Office of Management and Budget] with a number of EPA people there. And we kept a memo, but we did not turn them in in writing because that has not been the practice.[30]

Based on Chairman LaFleur's response, it is clear that EPA did not seek a thorough reliability analysis of Rule 111(d) from FERC, but instead sought FERC's informal input as part of a standard interagency review process. This perfunctory exercise was clearly insufficient to provide EPA with a thorough and unbiased analysis of the reliability impacts of Rule 111(d), nor was an issue as crucial as the effect of EPA's proposed rule on the reliability of the nation's electric system even memorialized so that it could be made public for affected stakeholders to scrutinize. Affected stakeholders can have no confidence in the apparently informal and limited discussions between EPA and FERC which seems to have produced no written analysis for the public to analyze. EPA has not performed a sufficient analysis of the reliability impacts of Rule 111(d), and must do so prior to issuing any final rule.

RTOs, including ERCOT, have not had sufficient time to perform a thorough reliability analysis of Rule 111(d). While ERCOT has provided its initial analysis of Rule 111(d), its complete analysis will not be completed until mid-December 2014. The PUCT will provide ERCOT's complete analysis to EPA as soon as it is available. Other RTOs, including SPP, have

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[29] Hearing of House Energy & Power Subcommittee of the Energy & Commerce Committee, FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and Other Grid Reliability Challenges, Tr. at 26 (July 29, 2014) (available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Preliminary-Transcript-EP-FERC-Clean-Power-Grid-Challenges-2014-7-29.pdf).

[30] *Id* at 41.

provided EPA their initial reliability analyses of Rule 111(d). However, additional analysis on the overall reliability impacts of Rule 111(d) still need to be performed. This is yet another reason that EPA should withdraw the proposed rule. At a minimum, implementation of Rule 111(d) should be delayed to allow the appropriate entities, including FERC, NERC and RTOs, to provide meaningful input and analysis on the reliability impacts of the proposed rule or any subsequent rule before it is adopted.

F. Resource Adequacy Impacts Of Rule 111(d) In SPP

As explained by SPP in a recent presentation on the impacts of Rule 111(d), SPP operates regional security-constrained, economically dispatched markets. This model considers both reliability and economics. Reliability actions and generation dispatch provide regional solutions to needs over a multi-state area. These solutions are not limited to state boundaries. SPP performs regional transmission planning and directs transmission construction for its member companies. All generator interconnection requests and transmission service requests are directed to and processed by SPP. Transmission planning is a significant function of SPP and the other RTOs. Transmission planning, design, permitting and construction is very time-intensive. In SPP, planning, designing and construction of transmission lines can take up to eight and a half years.[31]

SPP has performed a reserve margin assessment as if Rule 111(d) were implemented as proposed. SPP's study was completed on October 8, 2014 and has been provided to EPA. SPP's study results indicate that Rule 111(d) will have a significant reliability impact on the SPP. SPP's minimum current reserve margin requirement is 13.6% and according to its study, SPP estimates that under Rule 111(d), its reserve margin would plummet to 4.7% by 2020—8.9% below its minimum reserve margin requirement.[32] This represents a capacity margin deficiency of approximately 4,500 MW. By 2024, SPP expects that its reserve margin would further drop

[31] Docket ID No. EPA-HQ-OAR-2013-0602—SPP comments at 8.
[32] *Id.* at 7.

to -4.0%, which represents a capacity margin deficiency of approximately 10,000 MW. Stated differently, SPP forecasts that of its 14 load serving members, 9 would be deficient by 2020 and 10 members would be deficient by 2024. SPP's anticipated generation capacity deficiencies resulting from the proposed rule would be 4.6 GW in 2020 and 10.1 GW in 2024.[33]

SPP's analysis paints a grim picture of the electric grid if Rule 111(d) is adopted as proposed. As explained in SPP's Reliability Analysis of Rule 111(d), SPP developed power grid models to ascertain the effects of Rule 111(d) on reliability in the SPP region. SPP's modelling reflected the plant retirements included in EPA's Integrated Planning Models (IPMs). Part 1 of SPP's modelling assumed the plants retired in SPP would be replaced by existing unused capacity within SPP and surrounding areas. Part 2 of SPP's analysis assumed retired plants would be replaced by a combination of existing capacity and new gas fired units and wind generation.[34] Other assumptions, explained by SPP, were also part of its analysis. SPP's analysis revealed significant impacts on reliability. SPP found that the assumed plant retirements in SPP would result in significant reactive power deficiencies, the most notable of which were in the Texas Panhandle region.[35] The results of Part 2 of SPP's analysis were even more troubling as SPP noted that: "[p]ortions of the system in the Texas panhandle, western Kansas, and northern Arkansas were so severely overloaded that **cascading outages and voltage collapse** would occur."[36] The reliability impacts of Rule 111(d) might be at least partially offset by the construction of transmission line upgrades. However, planning and construction of new 345 kV transmission lines can typically take up to 8.5 years. As such, any needed transmission upgrades would almost certainly not be in place by 2020, when SPP's reserve margin is expected to drop to 4.7%.[37]

SPP's overall conclusion is that proper implementation of Rule 111(d) would require more comprehensive planning with stakeholders using new tools and metrics as well as "broader

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[33] *Id.* at 5-6.
[34] *Id.* at 2.
[35] *Id.* at 4.
[36] Docket ID No. EPA-HQ-OAR-2013-0602—SPP Reliability Impact Assessment of the EPA's Clean Power Plan at 5 (Oct. 9, 2014) (emphasis added).
[37] *Id.* at 5-6.

system assessments of the bulk power system and natural gas pipeline and storage systems based on environmental constraints…..”[38] SPP noted that it was only able to perform a preliminary reliability analysis of Rule 111(d). SPP explained that additional studies, including how the projected EGU retirements would affect reliability under potential critical scenarios such as drought and polar vortex conditions, the evaluation of the technical feasibility of implementing each of the four building blocks, and the compliance timeline under by Rule 111(d), would be needed to assess the full impact of Rule 111(d).[39] The PUCT shares SPP's concerns, particularly given the significant adverse impacts Rule 111(d) would have on the Texas panhandle region as noted in SPP's study. SPP's study is further evidence of the need for EPA to withdraw Rule 111(d) and replace it with a more reasonable and achievable proposal for reducing carbon emissions.

G. Specific Impacts Of Rule 111(d) On Texas Utilities

At the joint PUCT/TCEQ/RRC workshop on August 15, 2014, a number of industry stakeholders provided comments on Rule 111(d)'s impacts on Texas. SWEPCO president Venita-McCellon Allen outlined various reliability concerns for SWEPCO's approximately 600,000 retail Texas customers. SWEPCO is a non-ERCOT IOU operating in far Northeast Texas, which is located in the SPP RTO. Under EPA's IPM, EPA projects that SWEPCO must retire its Welsh Units 1 and 3 and its Pirkey Plant by 2020.[40] This represents almost 1,700 MW or 30% of SWEPCO's total installed capacity.[41] As explained by Ms. McCellon-Allen, this projected retirement will present major reliability impacts for SWEPCO's customers. SWEPCO would not have sufficient capacity in Texas to make up for the forced retirement of these coal units. SWEPCO would instead be forced to purchase capacity (assuming such capacity were even available) from outside Texas to serve its customers. Because SWEPCO is located on the

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[38] *Id.* at 6.
[39] Docket ID No. EPA-HQ-OAR-2013-0602-- SPP Comments at 8 (Oct. 9, 2014).
[40] *See* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Venita McCellon-Allen at 8 (Aug. 15, 2014).
[41] *Id*.

western seam between SPP and ERCOT, there is currently insufficient transmission from which to import the capacity that would be needed to replace its retired coal units.[42] EPA fails to recognize the significant investment in new capacity and new transmission that SWEPCO would be required to make if Rule 111(d) were adopted as proposed. This problem would be exacerbated in the winter months when natural gas curtailment issues due to weather are most likely to arise. EPA's Rule 111(d) implementation timeline provides "no recognition to the planning, approval, permitting and siting time needed to approve and install new generation and transmission."[43] Ms. McCellon-Allen further explained that the Rule 111(d) timeline fails to recognize that the East HVDC tie between ERCOT and SPP currently relies on var support from the Welsh units (slated to be retired under EPA's IPM). SWEPCO rightly noted that the final Rule 111(d) must address these unique reliability and operational concerns.

At the August 15 joint workshop, SWEPCO also outlined the conflict between Rule 111(d) and other EPA regulations. SWEPCO is currently investing approximately $750 million in its coal plants to comply with MATS. SWEPCO explained that it has already spent approximately $120 million installing emission controls on its Welsh Units 1 and 3 to comply with MATS. SWEPCO noted that this retrofit is the most economic decision for its customers, is the only solution available to allow it to meet its MATS April 2016 compliance deadline, and helps to preserve reliability of SWEPCO's system. However, in Rule 111(d), EPA has assumed that both of these units will be shut down by 2020.[44] SWEPCO further explained that if the Welsh Units are not available to serve SWEPCO's 600,000 Texas customers, reliability will be at risk. SWEPCO noted that the Welsh units should not be retired unless and until: 1) SPP has an opportunity to study the impact of these retirements on reliability; 2) SWEPCO's regulators, including the PUCT, have time to review available alternatives and issue required approvals for new transmission and generation and 3) SWEPCO has sufficient time to complete the

[42] *Id.* at 9-11. *See also* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 9 (Sept. 5, 2014).
[43] *See* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Venita McCellon-Allen, at 10 (Aug. 15, 2014).
[44] *Id.* at 11-12.

engineering, design and installation of the chosen alternatives.[45] Finally, SWEPCO explained that there is no realistic way for all of these steps to be completed before the projected 2020 retirement date of the Welsh units.[46] The PUCT is confident many other generators in Texas and throughout the nation face a similar quandary. This clearly demonstrates EPA's lack of analysis on the real effects that Rule 111(d) will have on grid reliability.

A significant flaw in EPA's analysis may explain why EPA is not as concerned about the reliability impacts of Rule 111(d) as it should be. EPA uses its IPM to project likely future electricity market conditions. EPA explains that:

> Since the model must maintain adequate reserves in each region, a portion of the reduced operational capacity in the policy case is taken from reserves that currently exceed the target reserve margin and will not be needed in the future. In order to maintain resource adequacy in each region where existing resources retire, the model relies on this excess reserve reduction, additions of new capacity, and reduced total resource requirements from increases in energy efficiency.[47]

In short, EPA has concluded that Rule 111(d) will not affect resource adequacy because the IPM model ***does not let it*** affect resource adequacy. This assumption is not supportable and does not reflect how electricity markets actually operate. Operators like SWEPCO, who actually understand and operate the units slated for retirement under the rule, know better. Rule 111(d) will have a very real and significant effect on reliability.

Another utility that will be adversely affected by Rule 111(d) is the East Texas Electric Cooperative (ETEC). ETEC also participated in the PUCT/TCEQ/RRC joint workshop on August 15, 2014. ETEC is a generation and transmission electric cooperative whose members include four generation and transmission cooperatives—Northeast Texas Electric Cooperative, Sam Rayburn G&T, Tex-La Electric Cooperative, and East Texas Electric Cooperative. These four G&T cooperatives provide wholesale electric service to their member distribution

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[45] *Id.* at 12.
[46] *Id*.
[47] EPA Docket ID No.--EPA-HQ-OAR-2013-0602, *Technical Support Document: Resource Adequacy and Reliability Analysis* at 3 (emphasis added) (available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf).

cooperatives. ETEC's ten electric distribution cooperatives provide retail electric service to approximately 330,000 retail customers in east Texas and Louisiana.[48]

There are significant concerns about the effect of Rule 111(d) on Texas's cooperatives like ETEC. Under Rule 111(d), four of the coal units used to serve ETEC's customers will be retired. ETEC estimates the total cost impact to its members of Rule 111(d) to be $2.9 billion. This figure includes $365 million in stranded costs and $585 million in replacement power costs.[49] In addition, EPA fails to address many other issues, including how Rule 111(d) would work for companies, like ETEC, with power plants located in three states and operating in three different RTOs and how Rule 111(d) will apply to entities like ETEC, not currently regulated by state public utility commissions.[50] Electric cooperatives (coops) and municipally-owned electric utilities (MOUs), many of which own and operate coal plants in Texas, are subject to only limited oversight by the PUCT. This oversight does not include regulation of the generation assets of these entities.[51] However, these entities are clearly intended to be subject to and are affected by Rule 111(d). Without the requisite state law authority to regulate these entities, it is unclear how coops and MOUs can be included as part of either a state or federal plan to implement Rule 111(d).

EPA has failed to address how generators will acquire and pay for replacement capacity for units forced to retire under the rule, how generators will be compensated for stranded costs associated with retired units and whether there will be sufficient natural gas and associated infrastructure available to replace lost coal plant capacity. Again, these are the real world impacts of Rule 111(d) that must be answered before the adoption of Rule 111(d).

The ERCOT grid has limited interconnections to the rest of country and therefore has limited ability to import power from other RTOs. There are also transmission line limitations into the non-ERCOT Texas utilities that operate in multi-state RTOs. Planning, designing,

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[48] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Edd Hargett, at slides 3-4 (Aug. 15, 2014).
[49] *Id.* at slides 2-3.
[50] *Id.* at slide 10.
[51] *See* TEX. UTIL. CODE ANN. §40.004 (jurisdiction of the PUCT over MOUs) & §41.004 (jurisdiction of the PUCT over electric cooperatives) (West 2007 & Supp. 2014).

permitting and constructing additional electric transmission lines for electric utilities operating in interstate markets is a slow and time-consuming endeavor. As noted previously, SPP's typical transmission line planning and construction timeline is typically 8.5 years.[52] Similar planning and timing issues exist in planning and building additional natural gas pipelines which would undoubtedly be required if Rule 111(d) were implemented.

In a case similar to the proposed Rule 111(d), SPS applied with the PUCT to recover costs related to EPA's Cross-State Air Pollution Rules (CSAPR). SPS was under a short time frame, (as Texas would be in order to comply with the interim goals under Rule 111(d)) and there were not a sufficient number of allowances available for SPS to purchase. To comply with CSAPR in the short term, SPS proposed "reduc[ing] the output from its coal-fired facilities and [increasing] the output from gas-fired facilities."[53] An SPS witness testified in 2011 that the effect of CSAPR on SPS's production cost would be approximately $206 million.[54] To maintain system reliability under rules that attempt to minimize the use of coal-fired plants is a difficult and expensive prospect.

H. Resource Adequacy Impacts Of Rule 111(d) In MISO

MISO, which operates in portions of East Texas, performed a study in the fall of 2014 on the impacts of Rule 111(d). This study is not exhaustive but is an initial review of the impacts of the rule that is intended to assist MISO stakeholders as they prepare comments on Rule 111(d). The study does not recommend any particular outcome or solution to the concerns raised. The MISO study did not consider the reliability impacts of Rule 111(d).[55]

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[52] *See supra* at page 27.
[53] PUCT Docket No. 39925, *Application of Southwestern Public Service Company for Authority to Revise its Fuel Factor Formulas; Change its Fuel Factors; and For Related Relief*, Direct Testimony of Dean R. Metcalf at 11 (available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39925_2_711724.PDF)
[54] *Id*. at Direct Testimony of David G. Horneck at 14. (available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39925_4_711721.PDF).
[55] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Letter of Todd P. Hillman, Vice President, MISO South Region, at 1-3 (Oct. 13, 2014).

MISO's general conclusions are that the compliance timeline would present significant problems with resource adequacy. MISO estimates compliance costs would be $55-90 billion on a net present value basis. MISO further concludes that many of the most economical solutions to implementing Rule 111(d) would result in an additional 14 GW of coal retirements in MISO. MISO also notes that regional compliance and carbon reduction measures beyond EPA's four building blocks provide the most economic options for meeting Rule 111(d) CO_2 reduction targets.[56]

The PUCT assumes MISO's transmission line planning-energization timeline is similar to ERCOT's, which is anywhere from 5-6 years. The remaining RTOs in the U.S. presumably have similar timelines for constructing transmission lines. Transmission planning and construction would be a critical component implementing Rule 111(d) in MISO and throughout the country. Because of the magnitude of coal plant retirements expected under the rule, utilities and generators will be required to quickly find other sources of generation to serve their customers. Obtaining the additional capacity is only part of the problem. Generators and utilities must also find a way to deliver this capacity to their customers. Existing transmission constraints (like those faced by SWEPCO discussed above) will prevent generation from being able to serve where it is needed most, at least for the foreseeable future. Because of its location at the southern end of MISO, Entergy Texas also faces transmission constraints similar to SWEPCO's. Rule 111(d) provides no solution for the transmission issues that Texas and other states will face in order to implement the rule. Even if Texas were able to file a state plan by 2016 (which for reasons discussed above, it cannot), there is not enough time between 2016 and 2020 to plan for and replace the lost coal plant capacity as well as resolve existing transmission constraints that may prevent this replacement generation from being fully utilized.

On November 25, 2014, MISO filed comments on Rule 111(d) which recommended that EPA eliminate the interim emission performance period and levels from the rule. MISO also recommended that the final rule provide "structured flexibility to support a variety of compliance

[56] *Id.* at 2.

strategies to preserve reliability of the electric system."[57] MISO echoes many of the same reliability concerns raised by NERC, SPP, PUCT and many others. EPA must consider the serious reliability impacts of the proposed rule raised by the entities charged with maintaining the reliability and integrity of the electric grid.

VI. COST IMPACTS OF RULE 111(d)

EPA has vastly underestimated the costs of Rule 111(d). EPA concludes that the costs to implement the proposed rule are approximately $7-9 billion nationwide.[58] ERCOT stakeholders have provided estimates of the cost of complying with Rule 111(d). For example, Texas Industrial Energy Consumers has estimated that the statewide total annual costs of complying with Rule 111(d) will be from $12-$15 billion by 2030.[59] A recent Energy Ventures Analysis[60] study on the impacts of Rule 111(d) together with other environmental regulations that were in effect in August 2013, estimated that the cumulative impacts on Texas of these environmental regulations would be as follows:

- Total annual cost of power and gas would increase to more than $80 billion in 2020--
    - this would represent a $42 billion annual cost increase for electricity and gas in Texas;
    - annual power costs in Texas would increase by almost $30 billion and annual gas costs would increase by $13 billion.

[57] Docket ID No. EPA-HQ-OAR-2013-0602—MISO Comments at 5 (Nov. 25, 2014).
[58] Docket ID No. EPA-HQ-OAR-2013-0602—EPA Regulatory Impact Analysis at ES-8, incremental cost vs. base case (2030, Option 1).
[59] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Charles Griffey at slide 12 (Aug. 15, 2014).
[60] Energy Ventures Analysis, *Energy Market Impacts of Recent Federal Regulations On The Electric Power Sector* at 27 and 38 (Nov. 2014).

Luminant, the largest generator in ERCOT, has estimated that total electricity-related costs for Rule 111(d) in Texas alone could be in excess of $10 billion.[61]

Based on its analysis, ERCOT has concluded that Rule 111(d) would result in increased energy costs for consumers of up to 20% in 2020, without accounting for the associated costs of transmission upgrades, natural gas supply infrastructure upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. Consideration of these additional factors would result in even higher energy costs for consumers.[62]

Despite the staggering costs of implementing Rule 111(d), the rule would do little to reduce worldwide CO_2 emissions. EPA has also failed to provide a single quantifiable climate benefit for implementing this rule. In its comments, TCEQ discusses both of these issues in some detail.[63] Finally, others have noted that EPA has vastly overstated the health benefits of Rule 111(d).[64]

ERCOT's model output included detailed cost information that can be used to characterize the impact of Rule 111(d) on energy prices in ERCOT. The study included cost impacts for the baseline, $20/ton CO_2, and $25/ton CO_2 scenarios. ERCOT is still working on completing the results of the cost analysis for the CO_2 limit scenario; these results will be available in the full report which is expected to be completed in mid-December 2014. All cost figures are reported in nominal dollars, except capital costs, which are in real 2015 dollars. It is important to understand that the cost estimates provided in ERCOT's report do not include the associated costs of building or upgrading transmission infrastructure, natural gas infrastructure upgrades, ancillary services procurement, energy efficiency investments, Reliability Must-Run (RMR) contracts, renegotiation or termination of coal supply contracts, accelerated

[61] Docket ID No. EPA-HQ-OAR-2013-0602—Luminant Comments, NERA Economic Consulting Analysis of the Clean Power Plan at 20 (Dec. 1, 2014).
[62] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 16.
[63] Docket ID No. EPA-HQ-OAR-2013-0602--TCEQ Comments at 2-8.
[64] *See, e.g.* PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*—Partnership for a Better Energy Future at slide 34 (Aug. 15, 2014).

decommissioning of retiring units, or increased maintenance associated with more frequent cycling of coal-fired units.[65]

ERCOT's study concluded that the inclusion of carbon prices resulted in higher average locational marginal prices (LMPs) compared to the baseline scenario. In the $20/ton carbon price scenario, the average LMP in ERCOT was $66.17 in 2020 and $81.13 in 2029 – 34% and 13% above the baseline scenario LMPs for those years, respectively. In the $25/ton carbon price scenario, the average LMP was $73.58 in 2020 and $84.28 in 2030 – 49% and 17% above the baseline scenario estimates.[66] As a general estimate, if wholesale power is 40% of the consumer bill, these increases in average LMPs would result in a retail energy price increase of 14 to 20% in 2020, and 5 to 7% in 2029. The increase in wholesale and consumer energy costs compared to the baseline decreases by 2029 due to the addition of new solar capacity, which has virtually no variable costs, and the accrual of energy efficiency savings. The costs of investments in energy efficiency are not estimated in ERCOT's analysis.[67]

The LMP reflects the variable cost associated with the generation resource on the margin. Though this measure provides an estimate of wholesale energy prices for consumers, the increase in production costs for generators would differ. The model results indicate that generators' variable costs by 2029 will increase by 15 to 18% in the $20/ton CO_2 and $25/ton CO_2 scenarios, respectively, compared to the baseline. This increase is due in large part to the CO_2 emissions price, which in 2029 posed a cost of $3.8 billion in the $20/ton CO_2 scenario and $4.4 billion in the $25/ton CO_2 scenario, comprising 19% and 21% of total variable costs for the two respective scenarios.[68]

Additionally, ERCOT noted that there will be capital costs associated with the new capacity built in both the baseline and carbon scenario cases. The capital costs in the carbon scenarios are $7 to $11 billion higher in the carbon scenarios compared to the baseline, or an

[65] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 15-16.
[66] *Id.* at 17, Table 8.
[67] *Id.* at 15-16.
[68] *Id.* at 16.

increase of 52 to 77%.[69] Though not reflected in LMPs, these costs will also ultimately be reflected in consumers' energy bills. ERCOT's modeling results showed a decrease in the ERCOT reserve margin in the early years of the Rule 111(d) compliance timeframe. In a recently completed report prepared for the PUCT, the Brattle Group quantified the cost to consumers associated with periods of reduced reserve margins.[70] These costs include the assumed capital costs of new generation, which increase at higher reserve margins, and a range of production costs, including the cost of emergency generation, the cost of utilizing interruptible customers, the costs of utilizing all of the available ancillary services, and the impact to consumers from firm load shedding, all of which increase at lower reserve margins. Based on this report, the retirement of 6,000 MW of generation capacity would be expected to reduce the system reserve margin by about 8%. If this change occurred when the system reserve margin was approximately 14%, the increased annual production costs at the resulting 6% reserve margin would be approximately $800 million higher than would be expected prior to the regulatory impact.[71]

Finally, it should be noted that ERCOT used the same natural gas price assumptions in all four scenarios. However, with the increased usage of natural gas anticipated not only in ERCOT but nationally, natural gas prices could increase beyond the levels anticipated in this modeling analysis. This could pose additional costs to consumers, which are not captured in this study.

A. Stranded Costs Implications Of Block 1

Block 1 would also result in significant stranded costs for coal plant owners in both the ERCOT and non-ERCOT regions of Texas. In both the ERCOT and non-ERCOT areas in Texas, Rule 111(d) mandates the move from least-cost generation dispatch to carbon dioxide-based dispatch, drastically diminishing the value of many coal plants and rendering many of

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[69] *Id.* at 17.

[70] *Estimating the Economically Optimal Reserve Margin in ERCOT*, The Brattle Group (Jan. 2014) (available at: http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf).

[71] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 17.

them uneconomic to run during all but the peak summer months. Because coal plant owners built their plants under one regulatory construct, only to have those plants rendered uneconomic by the federal imposition of a different construct (command and control resulting from Rule 111(d)), they may credibly argue for compensation for the value of their lost investment or stranded cost. It is therefore possible that both state and federal takings laws may be implicated by Rule 111(d). EPA has failed to address this potential cost of implementing Rule 111(d).

As part of the legislation creating the competitive retail electric market in ERCOT, the Texas Legislature allowed investor-owned electric utilities (IOUs) to recover "all of [their] net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service."[72] Stranded cost claims from coal plant owners resulting from Rule 111(d) are costs that are not addressed in the proposed rule. If Rule 111(d) is adopted as proposed, the Texas Legislature would need to determine whether to change Texas law to allow recovery of stranded costs resulting from the rule. If recovery of such costs were allowed by the Texas Legislature, these costs would ultimately be borne by all Texas electricity customers.

B. EPA Has Likely Underestimated The Compliance Costs Of The Rule

EPA's Regulatory Impact Analysis indicates that two full-time staff per state will be needed to oversee implementation, assess progress, develop annual reports, and perform other necessary functions.[73] States are required to track their progress in complying with the rule and must begin submitting annual reports to EPA on July 1, 2021.

EPA has failed to take into account the interagency cooperation necessary to implement Rule 111(d) and has also failed to account for the increased costs this will place on states. TCEQ advises the PUCT that Rule 111(d) will require creating an entirely new program within TCEQ to track industry compliance with Rule 111(d) alone. TCEQ believes that it will require two to

[72] TEX. UTIL. CODE ANN. §39.252(a) (West 2007 & Supp. 2014).
[73] Docket ID No. EPA-HQ-OAR-2013-0602--*Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, at page 3-47.

three full-time staff to fulfill its responsibilities under Rule 111(d).[74] While TCEQ would be responsible under Rule 111(d) for developing and submitting any State Plan to EPA, it will need assistance from the PUCT and possibly other Texas state agencies, since Blocks 2-4 involve "outside the fence" activities that are typically overseen by state public utility commissions and/or the FERC, not by EPA or state environmental agencies. For example, the PUCT has considerable experience in overseeing electric utility energy efficiency programs and would presumably need to provide assistance to TCEQ in monitoring compliance with this portion of Rule 111(d).[75] The PUCT's best estimate at this time is that assisting TCEQ in monitoring compliance with energy efficiency programs would likely require one to two additional staff members. Providing a meaningful estimate of the cost of compliance on the energy efficiency portion of the rule is difficult, however, because EPA has yet to provide guidance on the evaluation, measurement & verification (EM&V) standards for renewable energy or demand side energy efficiency programs that states must use.[76]

VII. EACH OF THE OF EPA'S FOUR BUILDING BLOCKS USED IN PROPOSED RULE 111(D) TO DEVELOP TEXAS'S EMISSIONS LIMITS IS BASED ON FLAWED ASSUMPTIONS ABOUT THE OPERATION OF ELECTRICITY MARKETS

A. EPA's Proposed Building Blocks

Rule 111(d) includes state-specific, adjusted output-weighted average CO_2 emission rates (quantity of CO_2 per MWh of electricity generated) that affected fossil-fuel fired Electric Generating Units (EGUs) could achieve, on average, through application of Best System of Emission Reduction (BSER), as determined by EPA. The BSER approach used by EPA is based on reductions from the four categories explained below. Each of these four building blocks is used in determining each state's emission rate goals.

[74] Docket ID No. EPA-HQ-OAR-2013-0602--TCEQ Comments at 11.

[75] The PUCT will address energy efficiency in more detail later in these comments.

[76] "[T]he EPA *intends to develop guidance* for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans." (emphasis added). 79 Fed. Reg. 34,913 (June 18, 2014).

- Building Block 1: Heat Rate Improvement on coal fired units. EPA proposes a 6% heat rate improvement in Texas's existing coal generating plants. EPA has proposed an alternative 4% heat rate improvement for coal units, which must be achieved by 2025 EPA's proposed heat rate improvement goal would result in a Texas reduction of approximately 54 lbs. CO_2/MWh.

- Building Block 2: Redispatch to Existing Natural Gas Combined Cycle Plants (NGCC). EPA proposes that existing NGCCs operate at a 70% capacity factor (CF) or, in the alternative, a 65% CF that must be met sooner than the proposed 70% CF goal. EPA's proposed redispatch goal results in a Texas reduction of approximately 283 lbs. CO_2/MWh.

- Building Block 3: Renewable and Nuclear Energy. EPA proposes a national renewable energy goal of 13% of 2012 total generation by the beginning of 2030. However, the state-specific renewable goal for Texas EPA used in setting Texas's final emissions goal is 20% of generation by 2030, or approximately 86 million megawatt-hours (MWh). EPA proposes an alternate Texas goal of 15% of generation by 2025 or approximately 65 million MWh. Both EPA's proposed and alternate state goals include nuclear capacity under construction (5.5 GW) and at-risk nuclear capacity (~5.8% of nuclear capacity). EPA's estimated at-risk nuclear capacity for Texas is 290 MW. The smallest nuclear unit in Texas is approximately 1,200 MW. EPA's proposed renewable energy goal would result in a Texas reduction of approximately 222 lbs. CO_2/MWh.

- Building Block 4: End-use Energy Efficiency: EPA proposes a 10.7% national cumulative savings by the beginning of 2030. The specific cumulative energy efficiency savings assumed for setting Texas's final goal is 9.91% of 2012 retail sales. EPA proposes an alternate goal of 5.2% national cumulative savings by the start of 2025 and thereafter. The specific cumulative energy efficiency savings assumed for setting Texas's final goal under the alternative proposal is 4.4% of retail sales. EPA's proposed energy efficiency goal results in a Texas reduction of approximately 70 lbs. CO_2/MWh.

B. Rule 111(d) Does Not Provide Flexibility for Texas

EPA claims that the rule would allow states flexibility to determine what measures to implement in order to meet EPA's emission limits for each state. However, for Texas at least, this flexibility is a mirage. Because EPA has used each of the four building blocks in an extremely aggressive manner in establishing Texas's performance mandates, Texas must implement each of these goals in order to have any hope of attaining either its interim requirement of 853 lbs. CO_2/MWh or the final requirement of 791 lbs. CO_2/MWh. There are simply no other options to achieve this level of GHG reductions in the electricity sector in Texas. Moreover, EPA has indicated that even if a state can demonstrate that a particular building block is not feasible, EPA will not adjust a state's emissions goal unless the state can demonstrate that additional controls on the other building blocks are not feasible.[77] As TCEQ explains in its comments, this is a flawed interpretation of CAA § 111(d) regarding what constitutes BSER and should be rejected.[78] Additionally, as will be explained below, there are likely no excess reductions available under any of the building blocks that can meaningfully mitigate the draconian requirements of another block.

In the NODA, EPA notes that stakeholders have expressed concern that the interim goals do not provide flexibility for some states. EPA then seeks comment on two alternative proposals: 1) allowing states to take credit for early CO_2 emission reductions that could be used to defer additional reductions to later in the 2020-2029 period and 2) phasing in Block 2 over time. EPA did not provide any additional data to support either of these alternatives. Moreover, because EPA did not change the December 1 comment deadline, stakeholders will have a little over a month to comment on the NODA. This is insufficient time for the PUCT to fully analyze these proposals.

However, based on its limited review, the PUCT does not believe either of the alternate glide path proposals provides reasonable alternatives to Rule 111(d) as proposed. First, Block 2 is an "outside the fence" activity over which EPA has no authority. EPA is neither authorized nor qualified to dictate to states how their natural gas units should be operated or dispatched. Second, Rule 111(d) does not provide flexibility for Texas, but instead would require Texas to implement approximately 77% of its emission reductions by 2020, which is both unreasonable and unachievable. The alternate glide path proposals in the NODA do not appear to provide any meaningful flexibility for Texas to meet EPA's interim emissions goals. In short, the NODA does not alter the PUCT's ultimate recommendation for EPA to withdraw the proposed rule or, in the alternative, eliminate the interim goals altogether in the final rule.

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[77] 79 Fed. Reg. 34,893 (June 18, 2014).
[78] Docket ID No. EPA-HQ-OAR-2013-0602—TCEQ Comments at 19.

VIII. BLOCK 1: INCREASED EFFICIENCY OF COAL PLANTS

A. Texas Coal Plants Have Limited Additional Efficiency Gains Available

EPA's proposed rule arbitrarily[79] assumes that substantial thermal efficiencies can still be obtained from coal plants in Texas. However, within the ERCOT interconnection that comprises most of Texas, there is little room for improvement in Block 1's heat rate improvement goal. Block 1 assumes that there *are* additional efficiencies available; however, the ERCOT market has forced coal-fired generators to adopt state of the art technologies available to improve thermal efficiencies in order to compete effectively, and there are few additional gains available.

Competitive wholesale electricity markets generally operate using security constrained economic dispatch (SCED).[80] That is, every electricity generator will bid into the market, and

[79] A recently released report by Energy Ventures Analysis (EVA) takes issue with each of the assumptions underlying EPA's 6% heat rate improvement requirement for Block 1. First, EPA assumes that a 4% improvement can be achieved by using best practices. This figure was derived from a regression analysis using capacity factor and ambient temperature. EVA notes that EPA has provided insufficient data to support its regression analysis and that EPA's analysis very likely failed to account for various factors affecting heat rate. Second, EVA notes that EPA assumed that 2% of the heat rate improvement could come from an average capital upgrade investment of $100/kW, which was derived from a 2009 Sargent and Lundy study. EVA concludes that EPA has misinterpreted the Sargent and Lundy study, stating, "[n]owhere in the report did Sargent and Lundy conclude that average plant efficiencies for all coal-fired plants could be improved from 2008 levels (let alone current levels) by 2% for $100/kW. The study 'cautions that the costs provided. . . are not indicative of those that may be expected for a specific facility. . . The costs should not be used as a basis for project budgeting or financing purposes.' Yet this is precisely what the EPA has done." *Energy Market Impacts of Recent Federal Regulations On The Electric Power Sector*, Energy Ventures Analysis, at 12 (Nov. 2014).

[80] In the Energy Policy Act of 2005, Congress defined SCED as the "operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." Energy Policy Act of 2005, § 1234 (b), Public Law 109-58, 109th Congress, (Aug. 5, 2005). Both SPP and MISO operate using SCED. Under Texas law, the PUCT has been given broad authority to establish and oversee the competitive market in ERCOT. In PURA §39.001(a) the Texas Legislature stated, "that the production and sale of electricity is not a monopoly, warranting regulation of rates, operations and services and that the public interest in competitive electric markets requires that… electric services and their prices should be determined by customer choices and the normal forces of competition." TEX. UTIL. CODE ANN. § 39.001(a) (West 2007 and Supp. 2014). In PURA 39.001(d) the PUCT is required to "authorize or order competitive rather than regulatory methods to achieve the goals of this chapter to the greatest extent feasible and shall adopt rules and issue orders that are both practical and limited so as to impose the least impact on competition." TEX. UTIL. CODE ANN. §39.001(d) (West 2007 and Supp. 2014). In its wholesale market design rule for ERCOT, the PUCT directed that ERCOT's rules and protocols for operating the wholesale market, " shall be developed with consideration of microeconomic principles and shall promote economic efficiency in the production and consumption of electricity; support wholesale and retail competition" 16 Tex. Admin. Code § 25.501(a). Finally, the PUCT has directed that ERCOT wholesale market prices be established using SCED. 16 Tex. Admin. Code § 25.501(f).

the grid operator will select the lowest set of the bids that meets demand. In well-functioning markets, generators are motivated to bid at or near their marginal cost of operation. Therefore, these markets provide strong incentives for every generator to maximize their efficiency through measures to reduce their heat rates and fuel consumption. Failure to do so will cause power plants to be dispatched less frequently, ultimately leaving them undispatched for a large portion of the year, or forced from the market entirely. In fact, since 2002, over 13,000 MW of old thermal generation plants have been retired in ERCOT. By using 2012 as the base year, EPA gives no credit to Texas for having already achieved a significant amount of EPA's Block 1 goals.

NERC, with its extensive expertise in electricity markets that EPA does not possess, shares these concerns. In its November 2014 reliability assessment of Rule 111(d), NERC stated:

> NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice.[81]

In addition, the Electric Power Research Institute (EPRI) also commented:

> [Heat rate improvements] may also 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.[82]

Based on the testimony at the August 15 joint PUCT/TCEQ/RRC workshop, generation owners confirmed that they have already made many if not all of the cost-effective

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[81] *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 2. North American Electric Reliability Corporation (Nov. 2014) (available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf).

[82] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of the Electric Power Research Institute at 9 (Oct. 20, 2014).

improvements that can be made on their coal units.[83] Further mandates like those required in the proposed rule will likely require substantial investments to further improve heat rates, an effort that is already complicated by the implementation of onerous and expensive requirements from other EPA rules, including MATS. It is unclear why coal plant owners would continue to invest money to make these improvements given the mandates of Rule 111(d) that will make it extremely difficult to operate these units at a profit. Indeed, as will be discussed further, the mandates of Blocks 2 and 3, will result in a much lower level of dispatch of coal plants, destroying any heat rate efficiency improvement accomplished through the Block 1 mandate as explained below.

B. Growth Of Renewable Energy Has Already Impacted Heat Rates Of Texas Power Plants

EPA also fails to recognize that the growth of renewable energy generation in Texas has also impacted the heat rate of power plants in Texas, and will increasingly make it difficult to maintain even the current heat rates. Figure 4 shows the ERCOT generation fleet stack for a week in April 2014.

[83] *See, e.g.,* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Presentation of Luminant at 12 (Aug. 15, 2014).

Figure 4: ERCOT Generation By Fuel, April 11-17, 2014

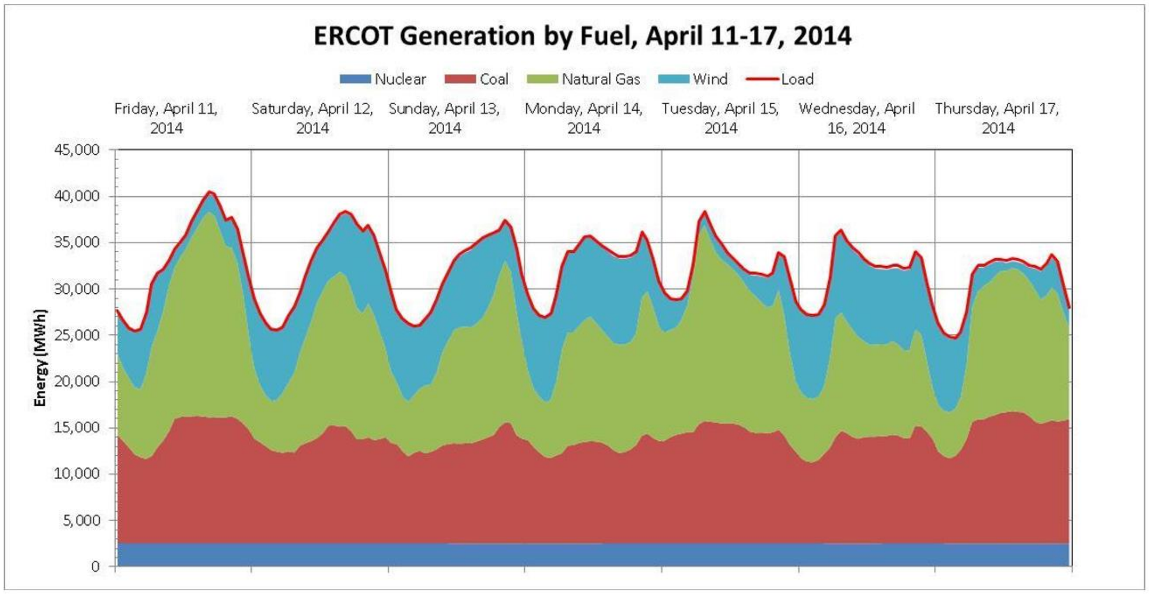

Figure 4 illustrates that Texas's 11,000 MW of wind power has substantial impacts on the operations of coal plants, particularly in the spring. This result occurs during days with relatively low load, gas-fired generation is often curtailed as much as can feasibly be done (while still ensuring adequate ancillary services and reserves on the grid), necessitating ramping of the coal fleet in order to maintain system reliability. This ramping naturally results in coal plants running in a less than optimally efficient manner, and consequently a higher heat rate. EPA's method of calculating state emissions rates does not take into account this unavoidable consequence of the introduction of large amounts of renewable energy into power systems, and further illustrates the flaws in Rule 111(d).

While not motivated by the same competitive pressures that exist in ERCOT, electric utilities in the non-ERCOT regions of Texas have also likely made most or many of the heat rate efficiency improvements that can reasonably be made without triggering the new source review

(NSR) provisions of the CAA.[84] In comments provided at the August 15 joint PUCT/TCEQ/RRC workshop, SWEPCO[85] explained:

> [M]ost of the heat rate improvement opportunities identified by EPA have already been implemented at SWEPCO's Texas units. SWEPCO plans to retire one unit at the Welsh Power Plant in 2016, and has emission control projects underway at the other two Welsh units in order to comply with the [MATS] Rule. The existing unit at Pirkey will also be equipped with activated carbon injection systems for MATS compliance. By the time the projects are completed, all of SWEPCO's Texas units will have sophisticated emission control systems that will allow them to operate for many more years and provide the fuel diversity and flexibility to respond to changing market conditions and provide a hedge against price volatility in the natural gas markets.[86]

In this same filing, SWEPCO detailed numerous flaws in EPA's analysis that "lead to a gross over-estimation of the potential heat rate improvements that could be reasonably and cost-effectively achieved by the fleet of coal-fired power plants that will be impacted by [Rule 111(d)]."[87] The PUCT concurs with these assessments, namely that EPA:

> (1) ignored certain of the caveats and conclusions included in the engineering reports, and the impact on heat rate of the emission control projects currently under construction to comply with other rules; (2) inappropriately assumed that heat rate variability that is not associated with unit load or ambient temperatures can be controlled through operational practices or capital improvements; (3) conducted a statistical analysis that (a) includes a number of units that will be retired prior to the initial interim compliance date, (b) uses gross heat rate data

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[84] In lawsuits filed by citizen groups, plaintiffs have argued that by improving efficiency, generators will be able to operate their plants for a greater number of hours throughout the year, which will increase emissions above the thresholds that require an NSR permit. As noted by SWEPCO in comments before the PUCT, "EPA offers no relief from NSR enforcement for operators who seek to comply with [Rule 111(d)] by improving unit efficiency, and without such relief, many operators will be reluctant to engage in more expensive efficiency improvements like turbine replacements and other equipment upgrades that offer the most cost-effective improvements." PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 7 (Sept. 5, 2014).

[85] As explained in these comments, SWEPCO is a multi-state, investor-owned utility operating within the SPP. Its Texas service area is located in the far northeastern portion of the state.

[86] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 5 (Sept. 5, 2014). For additional explanation of SWEPCO's emission control projects on its Texas coal plants, *see* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Venita McClellon-Allen at 5-7 (Aug. 15, 2014).

[87] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 4 (Sept. 5, 2014).

> and inappropriately applies the results to a net heat rate goal, and (c) ignores additional sources of variability that are not controllable; (4) erroneously assumed that capital projects and operational practices could be universally applied to improve the efficiency of all coal-fired generating units; and (5) failed to collect any industry data on the extent to which such improvements have already been implemented and therefore are reflected in current plant efficiency values.[88]

In sum, the use of an arbitrary average 6% heat rate improvement factor in setting Texas's emissions rate is flawed because it fails to reflect that most generators in Texas have already made many of the improvements cited as rationale for that standard and fails to credit Texas for the improvement already made through use of the 2012 base year.[89] EPA must remedy this flaw through one of two options. First, rather than use an arbitrary 6% heat rate improvement requirement on all units, EPA should have instead performed an analysis as to which plants have not already implemented the improvements identified in the technical support documents and only required those power plants to implement those cost-effective and technically feasible practices. Alternatively, EPA should use an earlier date of 2002 for purposes of measuring the base from which the heat rate improvement would be calculated. Finally, EPA should account for the impacts of increased renewable energy generation on power grids; namely the degradation of heat rates as coal plants are ramped up and down to accommodate the intermittency of wind and solar power.

While EPA asserts that Rule 111(d) does not explicitly mandate the heat rate improvements used in the calculations of the state goals and that states are free to overachieve in other blocks or propose other methods to reduce carbon dioxide emissions, the following analysis of Blocks 2-4 illustrates that the goals for each of these blocks are equally unachievable for Texas.

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88 *Id*.
89 Excerpt from testimony of PUCT Commissioner Kenneth W. Anderson, Jr. before U.S. House Power and Energy Subcommittee of the House Energy and Commerce Committee (Sept. 9, 2014).

IX. BLOCK 2: INCREASED USE OF NATURAL GAS CAPACITY

A. Block 2 Contemplates A Fundamental, Forced Redesign Of Electricity Markets

In calculating emissions limits for states, Rule 111(d) assumes that the current natural gas generation fleet will be dispatched a greater proportion of the time; namely at a 70% capacity factor. Coal and oil/gas steam units will consequently be operated less frequently. EPA's methodology is inherently flawed and represents an unreasonable intrusion on electricity market policy.

Both regulated and competitive electricity markets operate on a lowest cost dispatch model; that is, whether through auction bidding or variable cost analysis, power systems operate through running the lowest cost generation first, with higher and higher variable cost units then progressively operated until demand is met. Rule 111(d) instead assumes an arbitrary dispatch completely incompatible with Texas's policy goals of providing the most economically efficient dispatch of power plants. Block 2 represents an attempt by EPA to substitute its judgment for that of the competitive market on which generation plants should be utilized in ERCOT. EPA has no authority under the CAA to require this. In the non-ERCOT areas of the state, the wholesale rates of electric utilities operating in Texas are market-based, but are subject to the oversight of FERC. EPA similarly lacks authority to usurp FERC's authority over the wholesale rates of utilities operating in the non-ERCOT portions of Texas. Retail rates of non-ERCOT utilities are set by the PUCT based on traditional cost of service principles. Block 2 also conflicts with current Texas law that requires utilities to provide power to their customers at a just and reasonable rate.[90]

Additionally, Rule 111(d) penalizes Texas for the very thing the rule will purportedly achieve: the addition of modern, efficient natural gas-fired generation. ERCOT has added substantial new efficient natural gas combined cycle generating plants over the last decade.

[90] TEX. UTIL. CODE ANN. § 36.003 (West 2007 & Supp. 2014).

Since 2001, ERCOT has added 14,775 MW[91] of natural gas combined cycle generating capacity and currently has more installed natural gas capacity than any other state.

Because of the existing base of natural gas fired generation capacity, Block 2 effectively requires a 52% reduction, or a staggering 72 million megawatt hours, in Texas's utilization of coal fired electricity. This reduction is more than the total coal generation in all but six other states. As will be discussed in greater detail below, EPA's methodology inappropriately discriminates against Texas because of the existing base of natural gas fired generation capacity. In stark contrast, other states with a very high proportion of their total electricity generation provided by coal are impacted very minimally by Block 2's application, resulting in a vastly disparate impact to Texas.

EPA offers no analysis on the possible impacts of requiring increased use of natural gas generation. Existing transmission constraints may preclude some EGUs from operating their natural gas plants in accordance with the Block 2 requirements. Additionally, with the dramatic increase in natural gas use in Texas (and throughout the country) resulting from Rule 111(d), there will be a need for additional gas pipeline infrastructure.

A GAO report analyzed public records of interstate gas pipeline permitting processes (as FERC does not collect such data) and noted that, "for those projects that were approved from January 2010 to October 2012, the average time from pre-filing to certification was 558 days; the average time for those projects that began at the application phase was 225 days."[92] The GAO report did not even have data for the time frames required to obtain intrastate gas pipeline permits. Interstate permitting must comply with various federal laws, including the National Environmental Policy Act, the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act. The GAO report goes on to state: "[b]oth the interstate and intrastate

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91 *Report on the Capacity, Demand and Reserves in The ERCOT Region* (May 2014) (available at: http://www.ercot.com/content/gridinfo/resource/2014/adequacy/cdr/CapacityDemandandReserveReport-May2014.pdf).

92 United States Government Accountability Office Report to Congressional Committees. *Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Processes Include Multiple Steps, and Time Frames Vary* at 1. (Feb. 2013).

pipeline permitting processes are complex in that they can involve multiple federal, state, and local agencies, as well as public interest groups and citizens, and include multiple steps."[93]

Planning, permitting, and constructing such infrastructure takes time and is expensive. EPA does not appear to have taken this factor into account in the proposed rule, and instead implicitly assumes no lag time in its model for bringing natural gas pipelines online. Moreover, while EPA acknowledges that the increased use of natural gas mandated by Block 2 will result in the need for additional gas pipeline infrastructure and will increase natural gas prices, EPA failed to study existing natural gas transmission constraints, contractual arrangements, and other factors including unit design or age of equipment that could limit the feasibility, reliability, or sustainability of running individual units at such high capacity factors.[94] In short, to comply with Rule 111(d), and bring in the amount of natural gas required by the rule, will take much more time than is contemplated by the proposed rule. This creates particular risks to Texas because of the disproportionate impact that Block 2 has on Texas's interim emissions rate. Rule 111(d) assumes the entire re-dispatch is accomplished beginning in 2020, resulting in approximately 77% of Texas's final emissions reduction be achieved by 2020. Simply put, the time between the adoption of a final rule and the compliance deadline of 2020 is woefully insufficient to assess, plan, construct, and operate the infrastructure that such a dramatic shift in electricity production will require.

In comments filed with the PUCT on Rule 111(d), SWEPCO notes that the dispatch provisions of Block 2 of the proposed rule also violate federal law:

> Dispatch of SWEPCO's EGUs within Texas is controlled by the Southwest Power Pool (SPP), according to market-based tariffs and operating agreements that are intended to capture the benefits of security constrained market-based economic dispatch across wide regions of the United States in order to secure more cost-effective operation of these collective assets for the benefit of wholesale and retail customers. 16 U.S.C. §824a(a). The operations of SPP are based on agreements of the system owners and operators, and are subject to oversight by FERC, but even FERC has no ability to compel any particular technique of coordination.

[93] *Id.* at 12.
[94] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 7-8 (Sept. 5, 2014) (emphasis added).

> *Atlantic City Elec. Co. v. FERC,* 295 F.3d 1 (D.C. Cir. 2002). SWEPCO is aware of no provision of state or federal law that would allow EPA or the state to alter those arrangements and dictate a specific technique to achieve this arbitrary level of dispatch for a specific type of unit. The energy markets recently developed in SPP have been carefully structured to achieve the least cost dispatch operation of committed generation, and to allow operators of the individual units the flexibility to respond to dynamic and constantly changing circumstances in both the supply of and demand for electricity.[95]

SWEPCO further explains that neither EPA nor the states have the authority to regulate emissions by creating preferences for one type of generation over another.[96]

B. The Paradoxes Of Building Blocks 1 & 2[97]

As discussed above, the requirement for coal EGUs to increase their efficiency through the Block 1 component conflicts with the requirement to then reduce the dispatch of coal EGUs in Block 2. Coal units, particularly in Texas, were designed to operate in a baseload manner. Operation of these units at low capacity factors where the plants must start and stop more frequently and/or ramp up and down will significantly degrade the very heat rate improvements that Block 1 seeks to require. Rule 111(d) also fails to analyze the increased NO_X and SO_2 emissions increases that will result from operating coal plants in this manner.

C. The Paradoxes Of Building Blocks 2 and 3

Application of Block 2 essentially contemplates that coal fired power plants will operate in a ramping mode, or will be entirely shut down and unavailable during long periods during the year. This ignores the reality of the needs for changing amounts and types of electric generation during the day.

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[95] *Id.* at 7.
[96] *Id.* at 8.
[97] Excerpt from testimony of PUCT Commissioner Kenneth W. Anderson, Jr. before U.S. House Power and Energy Subcommittee of the House Energy and Commerce Committee (Sept. 9, 2014).

Figures 5 and 6 below illustrate seasonal load profiles experienced in Texas. Figure 5 is a typical August day in Texas. The ERCOT load almost doubles on a summer day, increasing from about 36,000 MW to over 68,000 MW. Simply put, during Texas' (and other states') peak demand days, all available generation must be running in a reliable fashion. That means coal plants must run consistently around the clock due to their inability to effectively ramp to meet customer demand.

Similarly, Figure 6 is a typical spring or fall day and shows how low the load in ERCOT typically can dip in the spring or fall. Texas must have a balanced, diversified generation mix in order to be able to start up generation facilities as load climbs, and then be able to ramp them down as load declines.

Figure 5: Typical Summer Load Profile

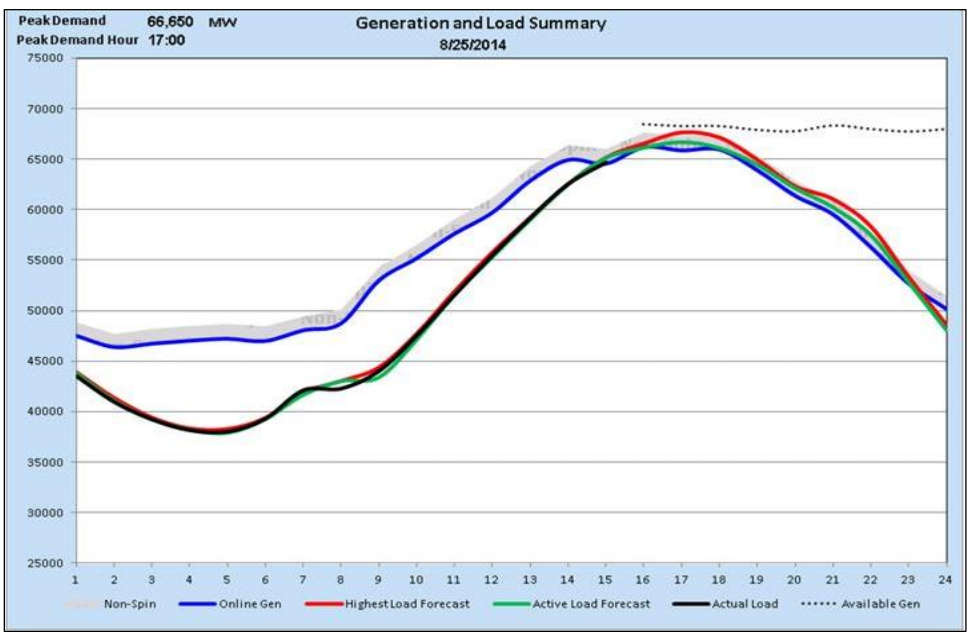


Figure 6: Spring/Fall Load Profile

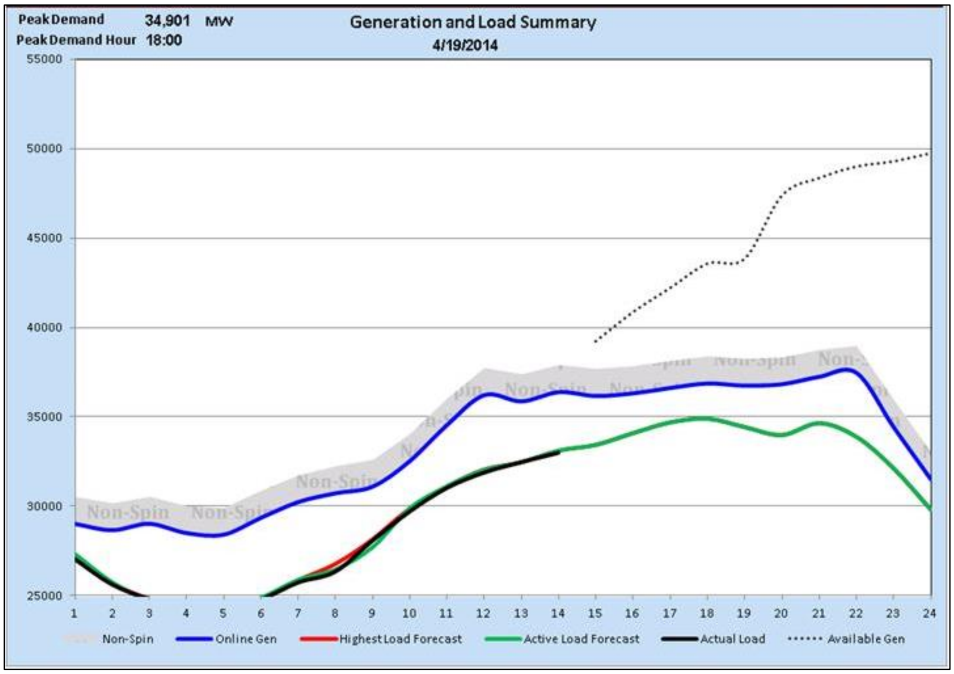


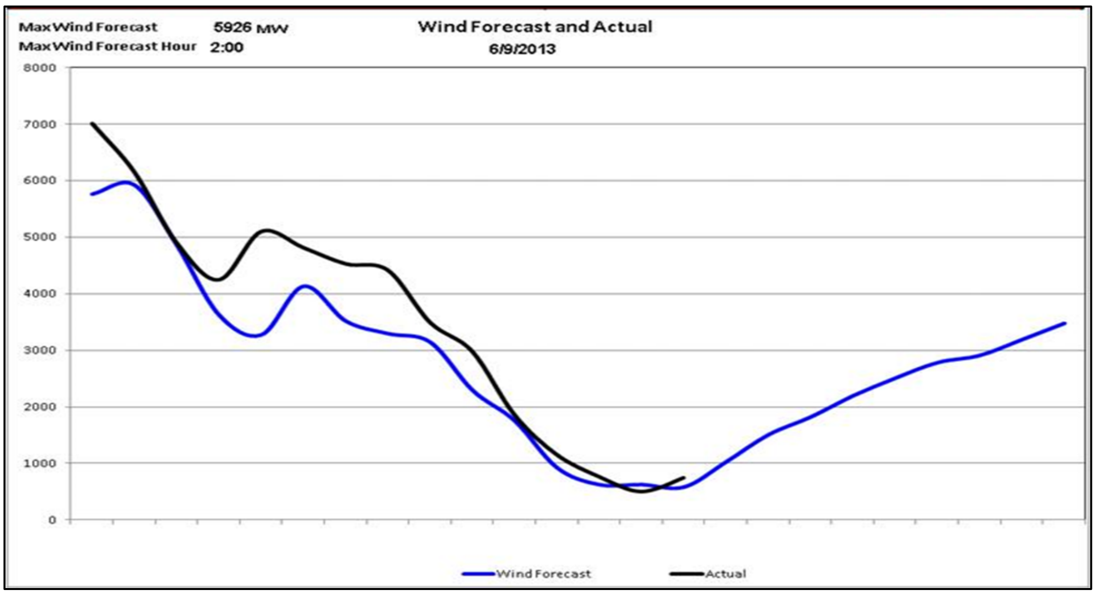
Figure 6 demonstrates a different problem that can occur with too much renewable generation as Rule 111(d) seeks to mandate through application of Block 3. Between 3:00 a.m. and 6:00 a.m. electricity consumption can drop below 25,000 MW. ERCOT previously has experienced days in which wind has provided as much as 38.4%[98] of the generation on the system. Rule 111(d) fails to acknowledge this reality through its use of Block 2's methodology, which creates both practical difficulties and perverse results. Wind turbines in Texas typically have a much higher capacity factor during spring and fall months. During the spring and fall a 20% renewable energy goal as proposed by EPA under Block 3 could put more renewable generation on the grid than there is existing load. Consequently, during the early morning hours ERCOT would have to both curtail a substantial amount of the wind and back down or even shutdown much of the nuclear fleet and all other thermal generation, which would simultaneously reduce the

[98] ERCOT News release, *Wind generation output in ERCOT tops 10,000 MW, breaks record*, reporting two records broken. On March 26, 2014 instantaneous output reached 10,296 MW at 8:48 p.m. (nearly 29% of total system load), and on March 27, 2014 at 3:19 a.m. when 9,868 MW served a record 38.43% of the 25,677 MW system-wide demand.

effectiveness of both Block 2 and Block 3. As has been previously shown, coal plants cannot effectively operate in a manner that would have them ramp up and down to meet load.

But Blocks 2 and 3 yield a paradox as well. In a diversified, efficient market (like ERCOT), Blocks 2 and 3 work at cross purposes. Figures 7 and 8 show the high variability of wind.

Figure 7: 93% Drop in Wind Production in 12 Hours



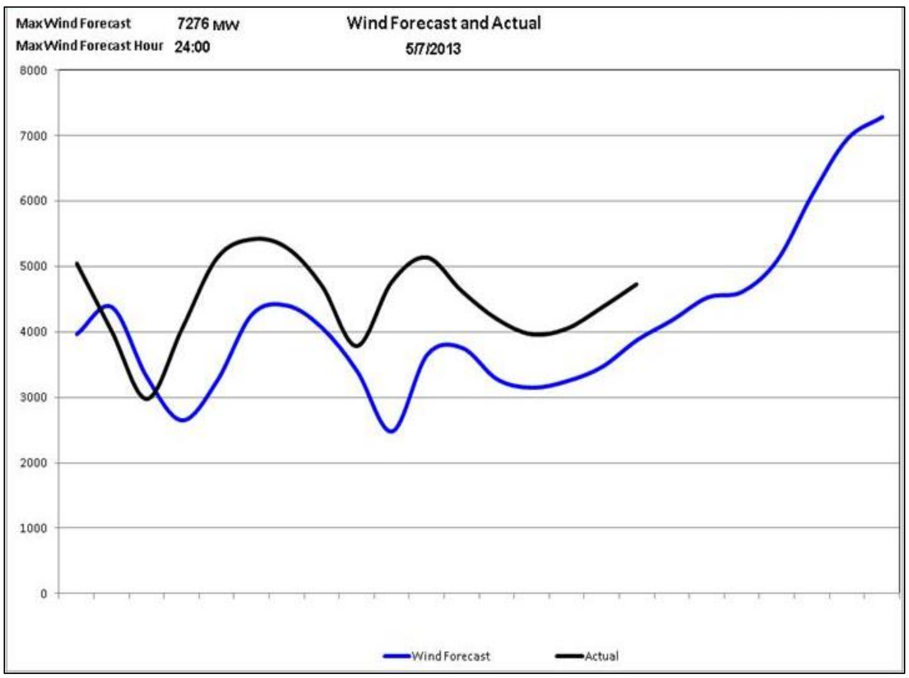
On the day referenced in Figure 7, wind generation dropped 93% (a total loss of 6,500 MW) over 13.5 hours. An over reliance on wind coupled with a possible 93% reduction of wind generation on any given day mandates an increased reliance on flexible gas generating units and less on base load units to ensure system reliability and sufficient availability of power.[99] This introduces enormous costly redundancies into ERCOT's system and likely means that nuclear generating units will be backed down when it is windy, only to be replaced with combined cycle or simple

[99] Yih-huei Wan, *Analysis of Wind Power Ramping Behavior in ERCOT*, NREL Technical Report NREL/TP-5500-49218, (March 2011). "It is clear that the variability of wind power affects the system operations." at 3. "The more installed wind power capacity will result in a higher wind power ramping-rate, and wind power can change at a very fast rate in a short-time frame." at 13. The more wind capacity there is on the system, the greater the magnitude of the ramping events will be. Figure 7 shows a magnitude of 6,500 MW (2014). The worst case in 2008 was a 3,430 MW loss of wind power in 10.8 hours. The greater the magnitude, the less Texas can rely on base load generation like nuclear generation.

cycle gas turbine units. Because significant variability of wind and other renewable generation can occur rapidly, within minutes, ERCOT's nuclear fleet cannot respond efficiently because the units are not designed for load following operations.

An example of what the ERCOT generation mix must be able to handle over very short periods of time is shown in Figure 8 below.

Figure 8: Variability of Wind Can Be Frequent and Extreme



On May 7, 2013, ERCOT experienced three cycles of fluctuations in wind generation between 2,000 and 8,000 MW over a 14 hour period. This is equivalent to having 1,500 MW of thermal generation trip off line three times in 14 hours. Flexible natural gas-fired generation is capable of matching the variability of wind and other renewable generation best due to its ramping ability; however, even gas combined cycle generation is most efficient when operated at or near 100% capacity.

Block 2 also effectively assumes that coal plants would be unavailable to operate during the winter months, when the risk of natural gas curtailments due to cold weather is highest. This scenario presents serious reliability problems in the event of a cold weather event such as the one that occurred in Texas in February 2011. Retirement of 10,000-12,000 MW of coal units by 2020 would present serious and immediate resource adequacy problems for ERCOT. The reliability implications of Rule 111(d) are discussed in more detail later in these comments.

Because of all these factors, the PUCT is concerned that Rule 111(d) may effectively force coal generation to essentially zero. Block 2 requires a 72 million MWh reduction in annual production from coal plants in calculating emissions limits. Block 3 then requires a 54 million MWh increase in renewable energy. While this increase in renewable energy would normally reduce natural gas fired electricity, such a result would cause Texas's average emissions rate to rise. Block 4 further requires a 38 million MWh reduction in total energy use through the energy efficiency calculation. Similarly, most efficiency programs reduce marginal energy consumption/generation which would be natural gas-fired units in normally functioning competitive markets; however, this outcome would also cause Texas's emission rate to rise necessitating further coal generation decreases. Simply put, the sum of the implied CO_2 emission reductions in Blocks 2 – 4 exceeds the total 2012 coal generation with which EPA begins its emissions limits calculation.

D. 2012 Baseline Year Not Representative Of Natural Gas Prices

Rule 111(d) fails to recognize that choosing emissions reductions based on a 2012 baseline year results in many faulty assumptions, including the price of natural gas. An article in the electric industry journal *Fortnightly* stated,

> [o]ut of all the years one could choose, 2012 is probably the least representative of likely future conditions in terms of commodity price relationships [….] the spread between coal and gas prices was less than $0.40/MMBtu during the year. […] Virtually all industry forecast expect gas prices to rise faster than coal prices

relative to 2012. This fact is important because it makes the cost of generating from gas plants even more expensive than coal plants.[100]

EPA apparently fails to understand what the true impact of implementing Block 2 would be by relying on a baseline year of unusually low natural gas prices. The Electric Power Research Institute noted in its report on Rule 111(d),

> [h]istory 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."[101]

In the NODA, issued just over a month from the December 1 comment deadline, EPA seeks comment on using data from 2010 or 2011 in lieu of the 2012 data year used in the proposed rule. The PUCT would need more time to thoroughly analyze all of the effects of this proposal. Use of an alternate data year might decrease Texas's renewable energy requirement, but only slightly. However, at this time, the PUCT does not believe use of an alternative data year would change the PUCT's ultimate conclusions regarding Rule 111(d).

X. BLOCK 3: NUCLEAR AND RENEWABLE ENERGY

A. Block 3 Includes Flawed Assumptions On Nuclear Energy And Arbitrarily and Unrealistically Assumes a Vast Expansion of Renewable Energy in Texas

1. Flawed Assumptions Regarding Nuclear Energy

EPA's assumption that 5.8% of each state's nuclear fleet is "at risk" for retirement is flawed. For Texas, EPA assumed that 290 MW of nuclear capacity is "at risk" for retirement even though this does not equate to a full nuclear unit. EPA should have considered the actual size of nuclear units that were actually at risk for retirement rather than applying an arbitrary percentage to all states. EPA does not specify any type of monitoring or verification for at risk

[100] David Bellman, "EPA's Clean Power Plan: An Unequal Burden", *Fortnightly Magazine* (Oct. 2014).
[101] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of the Electric Power Research Institute at 4 (Oct. 20, 2014).

nuclear generation. Nor is it clear how or whether actual net nuclear generation would be taken into account for complying with Rule 111(d).[102] While this assumption does not appear to have a meaningful impact on Texas's emissions rate, it further illustrates the arbitrary and unreasonable manner that EPA has used in promulgating Rule 111(d).

In addition, as EPRI notes, 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."[103] As with other components of the proposed building blocks, Rule 111(d) gives no consideration to the regulatory burden that is placed on the states for their nuclear fleets. EPA must consider the difficulties states face in renewing nuclear licenses.

2. Flawed Assumptions Underlie EPA's Renewable Energy Target for Texas

Rule 111(d) establishes a drastic renewable energy goal for Texas: 20 percent of capacity. EPA makes several critical mistakes in its assumption for setting Texas's renewable energy goal. First, EPA derived this capricious and unrealistic goal by arbitrarily lumping Texas with five other states, of which only Kansas has a planned RPS. EPA states that this methodology represents "a level of renewable resource development for individual states – with recognition of regional differences – that we view as reasonable and consistent with policies that a majority of states have already adopted based on their own policy objectives and assessments of feasibility and cost."[104] On the contrary, this methodology ignores all differences between states. In this calculation, EPA ignores Texas's own statutorily mandated RPS standard of 5,880 MW of renewables capacity.[105] Instead, the proposed rule averages all existing RPS targets in a

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[102] *See* PUCT Project No. 42636--C*ommission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 9-10 (Sept. 5, 2014).
[103] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of the Electric Power Research Institute at 5 (Oct. 20, 2014).
[104] 79 Fed. Reg. 34,866 (June 18, 2014).
[105] TEX. UTIL. CODE ANN. § 39.904(a) (West 2007 & Supp. 2014).

"region" and assigns the "average" to each state. There is no basis to use Kansas's RPS as the basis for a 20% energy RPS for Texas. Kansas's RPS is tailored to Kansas – a capacity-based RPS which includes biofuels and hydropower – and is inappropriate for the intermittent zero carbon dioxide emitting renewable resources of Texas. Conversion of Kansas' 20% capacity RPS to a 20% energy RPS for all states in EPA's South Central grouping is the very definition of arbitrary. The Kansas Corporation Commission recognized this in its own comments to EPA:

> EPA states that it uses only energy-based RPS standards in assigning targets. Because Kansas has a capacity-based RPS, Kansas was assigned the South Central Region's average target of 20% of generation as a default. Besides Kansas, Texas has the only other RPS target in the South Central Region. Like Kansas, Texas's RPS target is capacity-based. Because no other states in the region have RPS standards, EPA had no energy-based RPS targets in the region that could establish an energy-based target for the region. Thus, EPA used an arbitrary energy-based RPS target of 20% for Kansas and the rest of the South Central Region.[106]

Additionally, Kansas's RPS has numerous safety valves should retail rates rise above 1%. EPA failed to analyze the likelihood that these cost containment provisions effectively bind the Kansas RPS (or its application in other states) to a lower standard.

Moreover, application of one state's renewable standard to other states is arbitrary because it does not account for the relative size of the states. Kansas's electricity sector is 1/10th the size of Texas's electricity market, accounting for only 6 percent of the South Central state region's retail power sales, and has the third-best wind resources in the country.[107] A 20% renewable standard for Kansas implies approximately 2,800 MW of wind generation capacity (at a 35% annual capacity factor). The same standard for Texas implies over 25,000 megawatts of wind generation capacity. Such results clearly demonstrate that the Block 3 component of the emissions calculation is both disparate and arbitrary. EPRI also notes in its report: "This

[106] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of Kansas Corporation Commission at 15 (Oct. 29, 2014).
[107] Docket ID No. EPA-HQ-OAR-2013-0602--*Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 12. North American Electric Reliability Corporation (Nov. 2014).

[regional] assumption is problematic when regions are large and encompass states with appreciably different renewable energy resources."[108]

In its October 30 NODA, EPA also seeks comment on certain aspects of its building block methodology. For Block 3, EPA notes that some stakeholders "have suggested that state targets could be developed by defining regional RE targets, then assigning shares of those regional targets to individual states within the region." The PUCT has not had sufficient time to analyze fully this proposal. Because EPA has not provided additional data or information, the PUCT does not know what the effect of this proposal might be and therefore cannot provide any meaningful comments on this part of the NODA at this time. However, based on its limited review of the NODA, the PUCT does not believe it resolves the many fundamental problems with Block 3 outlined in these comments.

In the October 30 NODA, EPA also seeks comment on ways to change the state goal calculation to make the adjustments for Blocks 3 and 4 similar to Block 2.[109] For reasons discussed in the comments of TCEQ,[110] the PUCT opposes this adjustment. The prioritized adjustment would have the effect of zeroing out all coal-fired as well as oil and natural gas steam generation for state goal calculation purposes. TCEQ estimates this adjustment would drastically alter Texas's final goal to approximately 540-550 lbs/MWh.[111] This outcome would have an even more detrimental effect on reliability than the 791 lbs/MWh emissions goal proposed in the original rule. For this and the other reasons outlined by TCEQ, the PUCT strongly urges EPA to reject this modification to the state goal calculation.

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[108] Docket ID No. EPA-HQ-OAR-2013-0602—Comments of the Electric Power Research Institute at 5 (Oct. 20, 2014).
[109] 79 Fed. Reg. 64,552 (Oct. 30, 2014).
[110] Docket ID No. EPA-HQ-OAR-2013-0602—Comments of TCEQ at 20-21 (Dec. 1, 2014).
[111] *Id*. at 20.

B. EPA Overestimates The Generating Capacity Of Texas Wind From A Reliability Standpoint[112]

In determining the BSER for Block 3, EPA uses a capacity factor for Texas wind of between 39% and 41%.[113] For reliability purposes, ERCOT previously assigned wind an 8.7% wind capacity factor which was the estimated availability of wind during summer peak. ERCOT recently approved a new methodology for calculating wind capacity factor. Under its new methodology, ERCOT will use historical performance of wind generation facilities in different parts of the state to predict the percentage of installed capacity ERCOT can expect during summer and winter peak conditions. The installed capacity factors for non-coastal wind generation facilities (which constitute the majority of installed wind capacity in Texas) resulting from this new methodology are expected to be substantially below the capacity factor EPA assigns to Texas wind energy.

C. Texas Receives No Credit For Previous Renewable Investments Made

Rule 111(d) as proposed also ignores the significant renewable energy development that has occurred in Texas during the preceding decade. Even with the extreme variations in wind generation that can occur over the course of the year, in 2013 Texas wind generation produced 35.917 million MWh (16.24% of the nation's non-hydro renewable generation). However, the 2012 base year selected by EPA for the proposed Rule 111(d) does not give Texas credit for the societal and financial commitments to facilitate renewable energy. Instead Rule 111(d) punishes early movers like Texas by setting tremendous and unrealistic renewable goals. Furthermore, the early movement of renewable investment in Texas has resulted in greater knowledge and improved technology – from which other states, with reduced renewable goals, will now be able

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[112] Excerpt from testimony of PUCT Commissioner Kenneth W. Anderson, Jr. before U.S. House Power and Energy Subcommittee of the House Energy and Commerce Committee (Sept. 9, 2014).

[113] United States Environmental Protection Agency, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*, Table 4-21, at 4-46, referencing The United States Department of Energy's National Renewable Energy Laboratory (NREL) capacity factors for different wind classes. For wind class in Texas, refer to NREL's United States Wind Resource Map (50m), http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf (May 6, 2009). From the map, wind power class in Texas, is shown as either wind power class 3 or 4.

to benefit. Texas has taken on the risk of exploring renewable technology, yet will receive none of the benefit, and in fact will be penalized for having moved so early into renewables by Rule 111(d)'s aggressive goal. This penalty occurs because EPA has applied its annual growth factor of renewable energy to the base that existed in 2012. Thus states like Texas that have already expanded cost effective renewable energy are expected to add substantially more than states – even in the same regional grouping – that have little or no renewable energy today.

From 2005 through 2011 Texas added over 8,500 MW of wind capacity, 8,300 MW of which were built within ERCOT. Table 1 shows the $6.9 billion investment Texas has made in approximately 3,600 miles of new competitive renewable energy zone (CREZ) transmission lines.

Table 1: CREZ Transmission Line Investment in Texas[114]

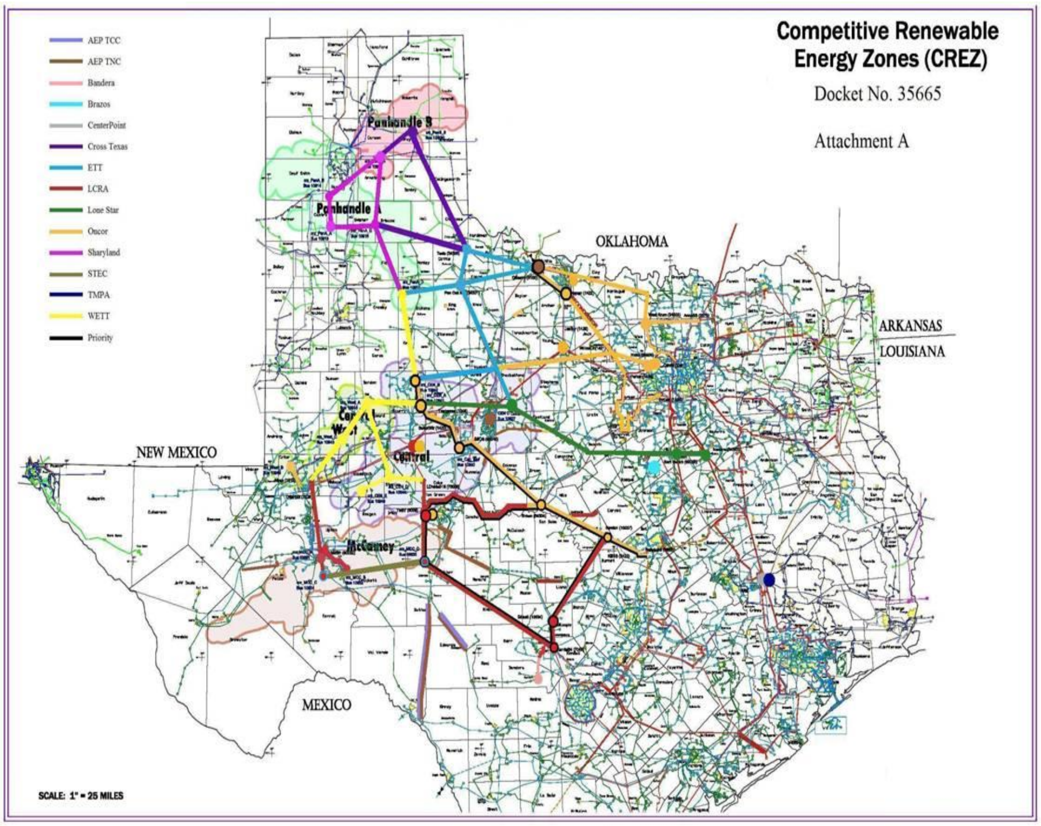
TSP	CTO Estimate	Current Estimate	Spent to Date	CTO Miles	Current Miles
Bandera	$20,000,000.00	$5,859,301.09	$5,859,301.09	16	15
Brazos	$5,000,000.00	$16,548,929.00	$16,548,929.00	0	0
Cross Texas	$402,570,000.00	$424,417,000.00	$411,045,961.55	222	237
ETT	$936,610,000.00	$1,492,399,978.00	$1,477,451,596.00	498	636
LCRA TSC	$607,500,000.00	$600,508,945.35	$599,928,792.56	445	428
Lone Star	$588,740,000.00	$746,200,000.00	$727,828,813.00	243	329
Oncor	$1,346,160,000.00	$2,023,311,682.90	$1,981,929,867.00	863	1084
Sharyland	$393,560,000.00	$620,047,000.00	$604,119,560.00	253	299
STEC	$191,800,000.00	$238,174,500.00	$207,010,388.00	137	188
TMPA and Center Point	$2,000,000.00	$0.00	$0.00	0	0
WETT	$482,380,000.00	$749,724,000.00	$846,361,866.00	286	374
Totals	**$4,976,320,000.00**	**$6,917,191,336.34**	**$6,878,085,074.20**	**2963**	**3589**

The investment in CREZ infrastructure has contributed to a more than threefold increased contribution from wind generation to total ERCOT generation from 2007 to 2013 from 3% to 9.9%,[115] yet, as noted previously, Texas receives no credit for the growth between 2005 and

[114] *Competitive Renewable Energy Zone Program Oversight—Progress Report No. 16* at 9 (July 2014) (available at: http://www.texascrezprojects.com/page2960323.aspx).
[115] Potomac Economics, LTD., *2013 State of the Market Report for the ERCOT Wholesale Electricity Markets,* at 63 (September 2014). Potomac Economics LTD. is the independent market monitor for the ERCOT market.

2012 because of the 2012 base year used by EPA. Figure 9 illustrates the significance of the CREZ project in relation to ERCOT's overall transmission system.

Figure 9: The ERCOT Transmission System[116]



D. The Texas CREZ Experience

As EPA well knows, Texas is by far the country's leading producer of renewable capacity. As of May 2014, ERCOT had 11,182 MW of installed wind and solar capacity.[117] An additional 4,700 MW of renewable generation (central station wind and solar) is currently under

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[116] PUCT Docket No. 35665—*Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy From Competitive Renewable Energy Zones, Order on Rehearing* at Attachment A (May 15, 2009).

[117] *Report on the Capacity, Demand and Reserves in The ERCOT Region* (May 2014). (Available at: http://www.ercot.com/content/gridinfo/resource/2014/adequacy/cdr/CapacityDemandandReserveReport-May2014.pdf).

construction. The PUCT and ERCOT therefore have more experience in planning for and integrating renewable energy onto the grid than any other state in the country and most countries in the world. The PUCT and ERCOT have learned from extensive engagement that integrating large amounts of renewable energy into ERCOT introduces a number of unique and challenging technical and operational issues. Some of these technical challenges have only recently surfaced, years after the construction and energizing of renewable energy generation and the associated electric transmission lines. As further explained below, ERCOT expects to encounter additional technical and operational issues as the amount of renewable energy built in Texas increases. Finally, Rule 111(d) does not adequately address other issues associated with integrating large amounts of renewable capacity, including the impact on market prices, the need for additional ancillary services, and how any renewable energy credit program might work.

1. Integrating Renewable Resources is a Slow, Costly Process

Rule 111(d) does not take into consideration the length of time and cost involved in adding substantial new transmission in order to integrate large amounts of intermittent renewable energy. Renewable resources are generally (but not always) located in areas that are more remote from customer demand which requires the addition of electric transmission lines to move renewable energy to more populated areas of the state. Texas's CREZ experience is a prime example of the level of transmission investment necessary to move renewable energy from the where it is produced to where it will actually be used. Table 2 below is a comparison of key statistics at the beginning of the CREZ program in 2008 and the actual status of the CREZ program as of June 15, 2014. This table illustrates the difficulty of accurately estimating the costs of a project of the size and scope of Texas's CREZ build out. What is clear is that projects of this size will, due to a variety of factors, almost always cost more than the initial estimates.

Table 2: CREZ Key Statistics[118]

Program Start (2008)	Today
System Planning Studies (CTO, Reactive Power), Preliminary Routing and CCN Preparation	Environmental / CNN process Complete, now in Final Design and Construction
Estimated cost $4.97 Billion	Estimated Cost $6.92 Billion
2963 Projected Miles	3588 Projected Miles
109 Estimated Projects	186 Total Projects - 17 Projects Canceled/Inactive - 1 Total Active Project - 168 Completed to date

In 2005, the Texas Legislature directed the PUCT to designate areas of the state as CREZs with the enactment of SB 20; nine years would pass until the completion of the final CREZ transmission lines in 2014. From May 2005 to December 2013, the PUCT designated CREZ zones, selected transmission providers to build the transmission, and decided 37 contested transmission CCN applications which authorized the construction of approximately 3,600 miles of transmission lines. Some areas of West Texas have not reached their full CREZ capacity build-out. Other areas, such as the Panhandle, will require a significant amount of new transmission in order to accommodate more renewable resources. As evidenced from Texas's own experience, integrating renewable resources successfully requires a significant investment of time and money.

EPA has also failed to account for other restrictions that could delay construction of renewable capacity and the transmission infrastructure necessary to support this capacity, including the Endangered Species Act.

2. Technical/Operational Lessons Learned From Texas's CREZ Experience

ERCOT studies have indicated several technical challenges with integrating a large amount of renewable resources in West Texas. These challenges are primarily due to two

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118 *Competitive Renewable Energy Zone Program Oversight—Progress Report No. 16* at 6 (July 2014) (available at: http://www.texascrezprojects.com/page2960323.aspx).

factors: 1) renewable resources in West Texas are located far from load centers requiring their power be transmitted over long distances; and 2) most renewable resources use power electronic based devices and not synchronous machines. Together, these factors induce power system challenges not previously observed on a large scale.

As an example, in the Texas Panhandle, the combination of long transmission lines and a lack of synchronous generation machines have led to a weak system which can be defined as low short circuit ratio. The challenges associated with a weak system include potential oscillatory responses caused by wind turbines which can lead to high/low voltage collapse, and system instability. The solutions to these challenges include the installation of synchronous generation, synchronous condensers and new transmission lines.

Another challenge of transferring power over long distances is handling the reactive losses in long transmission lines. Often these reactive losses become more limiting than the inherent thermal capability of a transmission conductor for long transmission lines. The solutions to this challenge include installing dynamic reactive compensation devices, building transmission lines at higher voltages (i.e. 500 kV or 765 kV), constructing more transmission lines, or installing series compensation on transmission lines. Each of these solutions has drawbacks. Dynamic reactive devices are expensive and provide only limited benefit for long transmission lines. Construction of higher voltage transmission lines is often opposed by the public because of right-of-way issues and the aesthetic impact of these lines.

ERCOT chose to handle this challenge primarily by installing series compensation devices. However, these devices can cause sub-synchronous oscillations with existing generation plants. Sub-synchronous oscillations can cause mechanical damage to a generator, and mitigation measures must be put in place to prevent this from happening. Prior to 2009 it was generally assumed that sub-synchronous oscillations were not a problem for power electronic-based devices, such as renewable resources. However, in 2009 a wind generation resource in Texas experienced sub-synchronous oscillations of its control system with a series compensation device. This event caused significant damage to both the wind generation resource and series compensation device.

E. Integration Impacts of Increased Renewable Energy Generation Required By Rule 111(d)[119]

ERCOT expects that integrating new wind and solar resources will increase the challenges of reliably operating the ERCOT grid. In 2013, almost 10% of the ERCOT region's annual generation came from wind resources. In order to accommodate this level of intermittent generation, ERCOT has needed to evaluate impacts on operational reliability and improve wind output forecasting capabilities. The increased penetration of intermittent renewable generation, as projected by ERCOT's modeling results, will increase the challenges of reliably operating all generation resources. If there is not sufficient ramping capability and operational reserves during periods of high renewable penetration, the need to maintain operational reliability could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed rule deadlines.

ERCOT modeled four distinct scenarios over the timeframe 2015-2029 to evaluate the implications of Rule 111(d) on reliability in the region:

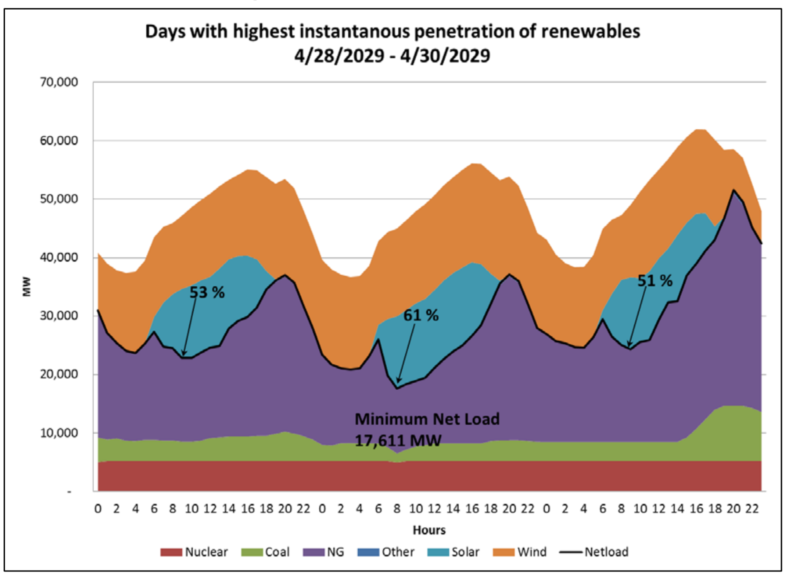
> **Baseline** – This scenario estimates a baseline of the ERCOT system under current market trends against which anticipated Clean Power Plan changes will be compared.
>
> **CO_2 Limit** – This scenario applied the limits in the Clean Power Plan to the ERCOT system to determine the most cost-effective way to comply with the limits. This scenario did not place a price on CO_2 emissions.
>
> **\$20/ton CO_2** – This scenario applied a \$20/ton price on carbon dioxide emissions to the ERCOT system. With a \$20/ton CO_2 price, the ERCOT system attains an emission intensity of 904 lb CO_2/MWh in 2020 and 877 lb CO_2/MWh in 2029 – above both the interim and final goals.
>
> **\$25/ton CO_2** – This scenario applied a \$25/ton price on carbon dioxide emissions to the ERCOT system. With a \$25/ton CO_2 price, the ERCOT system attains an emission

[119] Excerpt from *ERCOT Analysis of the Impacts of the Clean Power Plan* at 11-14.

intensity of 840 lb CO_2/MWh in 2020 and 792 lb CO_2/MWh in 2029 – below the interim goal and approximately meeting the final goal.[120]

Based on the \$25/ton CO_2 scenario, intermittent renewable generation sources will contribute 22% of energy on an annual basis in 2029. However, during 628 hours of the year intermittent generation will serve more than 40%[15] of system load. During 128 hours instantaneous renewable penetration will be higher than 50%, and the peak instantaneous renewable penetration from the model results is 61%. The significant change from present experience is that the highest renewable penetration hours will be driven by maximum solar production during relatively high wind periods. These periods occur during the day (8 a.m. to 5 p.m.), as opposed to early morning hours (usually 2 a.m. to 4 a.m.), as currently experienced in ERCOT. The high instantaneous renewable penetration hours in 2029 occur year round except for the July-September period. Figure 10 shows generation output by fuel type for the days with the highest instantaneous penetration of renewables in 2029 in the \$25/ton CO_2 scenario.

Figure 10: Days with the Highest Instantaneous Penetration of Renewables[121]



[120] *Id*. at 3. ERCOT did not attempt to calculate a carbon price to precisely meet the emissions limits. Instead, ERCOT found a carbon price range within which the system is anticipated to achieve the Rule 111(d) emissions standards.

[121] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 12. (Nov. 17, 2014).

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Due to load growth, the lowest net load (defined as total load minus generation from intermittent energy resources) in 2029 is higher than current record (14,809 MW in 2014 and 17,611 MW in 2029). Therefore, during low net load hours there will be no significant change compared to current operating conditions in terms of MW of thermal generation online, inertial response and frequency response available during generation trip events.

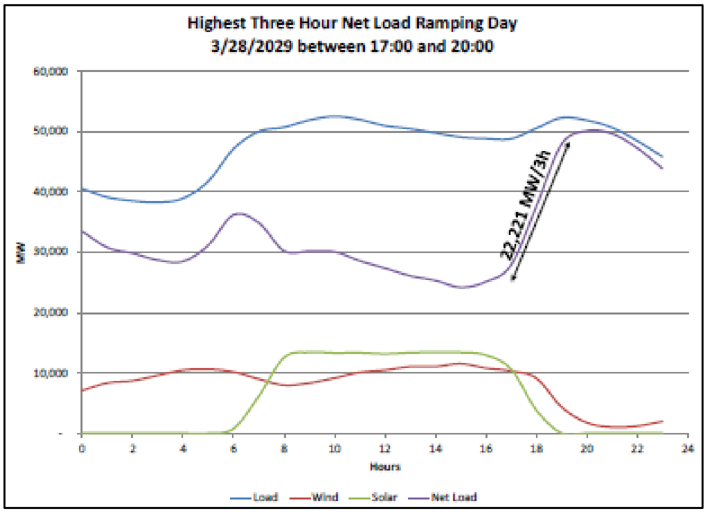
Significant increase can be seen in net load ramps compared to current experience. While the net load down ramps in 2029 are still largely defined by decreases in load at night, as is the case currently, the highest net load up ramps are defined by rapid solar production decline at sunset and simultaneous decline in wind production during evening load pick-up. Table 3 displays the maximum ramp-up and ramp-down in 2029 in the \$25/ton CO_2 scenario. Figure 11 shows wind and solar generation output and customer demand (load) on the day with the highest three hour net load ramp in 2029 from the \$25/ton CO_2 scenario.

Table 3: Maximum Ramp-up and Ramp-Down[122]

Net Load	Maximum 60-min Ramp-up (MW/60Mins)	Maximum 60-min Ramp-down (MW/60Mins)	Maximum 180-min Ramp-up (MW/180Mins)	Maximum 180-min Ramp-down (MW/180Mins)
2011 Net Load (actual)	6,267	-6,124	16,058	-18,985
2012 Net Load (actual)	6,563	-7,019	14,997	-15,977
2013 Net Load (Jan-May) (actual)	6,247	-5,446	12,200	-14,373
2029 Net Load (modeled \$25/ton CO_2 scenario)	11,074	-11,938	22,221	-22,560

[122] *Id*.

Figure 11: Highest Three Hour Net Load Ramping Day[123]



The simulation model assumes perfect foresight and ensures that there is sufficient amount of thermal generation with sufficient ramping capability committed to follow such rapid net load ramps. In real time operation, however, accommodating the maximum ramps resulting from simultaneous solar and wind generation decline would be more challenging. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. It is important that market mechanisms are adopted so that the need for flexible generation (with short start-up times and high ramping capability) is reflected in real-time energy prices. Market mechanisms to include dispatchable load resources could also help to address flexibility needs. Enhancing wind and solar forecasting systems to provide more accurate wind and solar generation projections will become increasingly important. Regulation and non-spinning reserves will need to be increased to address increased intra-hour variability and uncertainty of power production from wind and solar. Tools available to system operators must be enhanced to include short-term (10-min, 30-min, 60-min, 180-min) net-load ramp forecasts and simultaneous assessment of real-time ramping capability of the committed thermal generation to assist operators in maintaining grid reliability.[124]

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[123] *Id*. at 13.

[124] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating*

Though all solar capacity additions predicted by the model were utility-scale, it is likely that a significant portion of future solar generation capacity will be embedded in the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels). ERCOT does not currently have visibility of these resources. To produce accurate solar production forecasts, ERCOT would need to have information regarding the size and location of distributed solar installations. Additionally, to ensure grid reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems.[125]

Based on ERCOT's modeling, the majority of new renewable generation resource additions are anticipated to be solar. However, if ERCOT instead sees a large amount of wind resource capacity additions, then the reliability impacts may be more severe. Wind production in West Texas results in high renewable penetration during early morning hours, when load is lowest. An expansion in wind production, rather than solar, may result in lower net loads and significant reliability issues. If ERCOT cannot reliably operate the grid with these high renewable penetration levels, then production from these resources will be curtailed to maintain operational reliability. Should this occur, it would reduce production from renewable resources, leading to possible non-compliance with the proposed rule deadlines.

F. Market Price Issues

Wind and solar generators tend to bid into the market at a price of zero or even negative, which reflects the value of federal production tax credits. This has a tendency to lower market prices for all generators. The bidding behavior of renewable generators also tends to reduce the run time of other generators, primarily natural gas generation, but it also tends to replace coal plants in off-peak hours. Adding the level of renewable energy required by Rule 111(d) will

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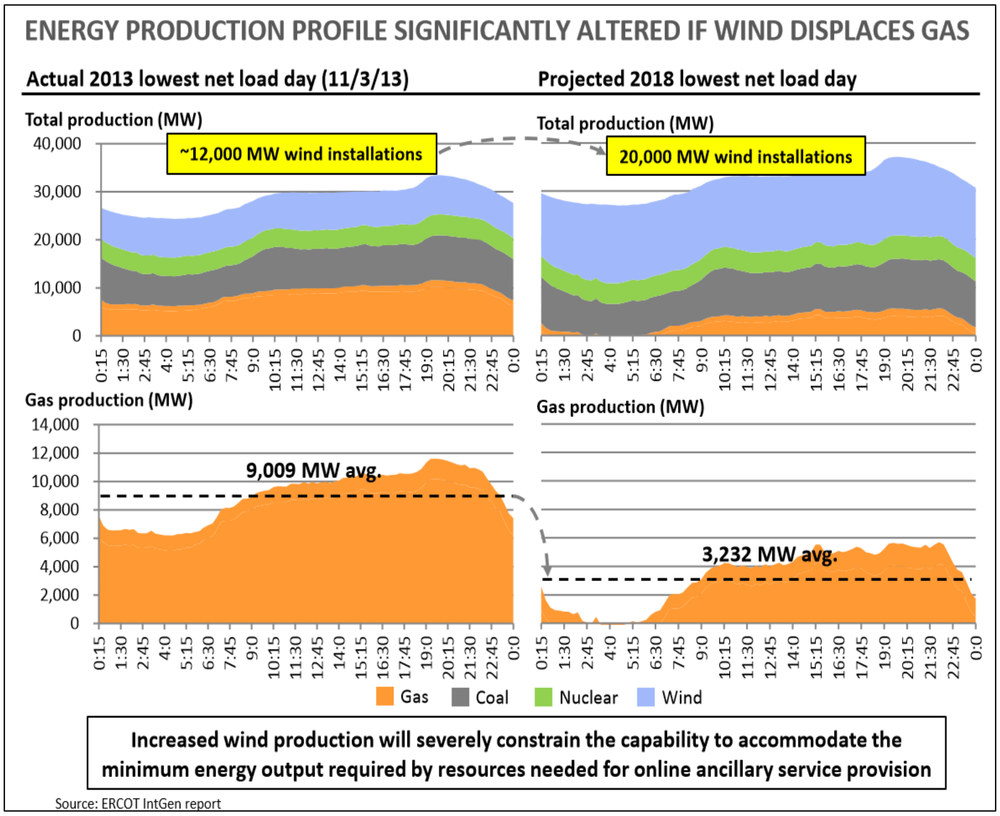
Variable Energy Resources, November 2013 (available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf).

[125] *Id.*

further distort ERCOT's energy market prices. Figure 12 below illustrates how the energy production profile is altered when wind generation displaces natural gas production.

Figure 12: Energy Production Profile if Wind Displaces Natural Gas[126]



G. Rule 111(d) Would Introduce A Level Of Renewables Into The System That Could Jeopardize The Security Of Ancillary Services

The need for ancillary services will increase with the introduction of additional renewables on the grid. In its *Summer 2014 Energy Market and Reliability Assessment*, FERC stated, "[r]apid changes in wind and solar generation, particularly in the morning and evening,

[126] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Presentation of APEX CAES at slide 6 (Aug. 20, 2014).

are expected to increase the need for flexible capacity for balancing and regulation."[127] Generally, ancillary services are supplemental services to the ERCOT energy market that are needed to maintain system reliability. Because the five-minute dispatch in ERCOT does not insure that appropriate resources are available to balance system generation and system load, ERCOT procures ancillary services to ensure that sufficient resources with necessary characteristics are available to balance any additional variability and to maintain system frequency through a variety of potential conditions, including unit trips, large up or down ramps, and ensuring enough capacity is available. With Texas's swath of renewables introducing variability into the grid, ancillary services are crucial to maintaining grid reliability. Rule 111(d) would introduce a level of renewables into the system that could jeopardize the security of ancillary services. NERC recognized this in its reliability assessment report on Rule 111(d):

> [t]he anticipated changes in the resources mix and new dispatching protocols will require comprehensive reliability assessment to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.[128]

H. Renewable Energy Credits

Under current Texas law, renewable generators are issued a "renewable energy credit" (REC) for each MWh of energy produced. Retail electric providers (the entities who contract to buy and sell power for end users in ERCOT) must purchase RECs and turn them in to comply

[127] FERC *Summer 2014 Energy Market and Reliability Assessment* (May 15, 2014) (available at: http://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2014/05-15-14.pdf).
[128] Docket ID No. EPA-HQ-OAR-2013-0602--*Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 2. North American Electric Reliability Corporation (Nov. 2014).

with their share of the renewable energy mandate. RECs are an additional subsidy to renewable generators. However, current REC prices in ERCOT are very low (less than $1 per REC/MWh) and therefore provide insignificant subsidies at this point.

Under Rule 111(d), it unclear exactly how REC trading would work between states. If, for example, Texas opts for a regional approach to comply with Rule 111(d), the regional plan would include REC trading credits. If a wind generator in Texas has contracted to sell RECs out of state, which state would get the credit for the renewable generation, Texas or the purchasing state? The PUCT is also concerned that Rule 111(d) would subject retail electric providers in ERCOT (who under current Texas law bear the burden of Texas's current RPS and who presumably would bear a similar responsibility under the proposed rule) to enforcement by EPA and to citizen lawsuits under the CAA. The PUCT believes this is neither appropriate nor legal under the CAA. These are examples of unanswered questions raised by Rule 111(d). Without more detail on precisely how REC trading might work, it is difficult for the PUCT to provide any meaningful comments on this aspect of the rule.

XI. BLOCK 4: DEMAND SIDE ENERGY EFFICIENCY

A. Block 4 Imposes A Burdensome, Expensive, And Unachievable Goal For Texas

Under existing Texas law, EPA's proposed incremental and cumulative savings targets for energy efficiency are not achievable.[129] Extensive amendments to both the statute and the PUCT's rule would be required to revise the electric utilities' energy efficiency savings goal, allow direct marketing by the utilities, and either require adoption of the EM&V framework yet to be established by EPA or revisions to the EM&V framework enacted by the Texas Legislature in 2011. Additional amendments to the PUCT's rule would be required to adjust the cost caps for residential and commercial customers, as well as to adjust the administrative cost cap to promote increased outreach and marketing by the utilities.

[129] TEX. UTIL. CODE. ANN. §39.905 (West 2007 & Supp. 2014) and 16 Tex. Admin. Code §25.181.

Due to the time required for the Texas Legislature to pass legislation to amend current statute and for the PUCT to adopt conforming rules and approve programs, as well as the extraordinarily high cost required to implement this block, which would undoubtedly result in significant rate shock to electric consumers, the demands of Rule 111(d)'s Block 4 are simply not realistic.

B. Block 4 Would Require New and Aggressive Goals

Block 4 accelerates the state's energy efficiency improvements from 2017, based on a state's 2012 performance, incrementally up to a maximum rate of 1.5% of retail sales (Option 1) per year by 2029 or alternatively, a demand-side energy efficiency requirement that uses 1.0% savings target scenario (Option 2). The incremental energy efficiency savings as a percentage of retail sales in 2012 in Texas was 0.19% and cumulative savings as a percentage of retail sales was 1.54%. Under option 1, with a start year of 2017, Rule 111(d) requires an increase in incremental savings of 0.2% per year, with Texas reaching cumulative energy efficiency savings as a percentage of retail sales of 1.78% by 2020 and 9.91% by 2029. However, in order for these energy efficiency measures to count toward a state's goal, Rule 111(d) also requires enforceable EM&V, although the specifics of that requirement, to date, have not been finalized.[130]

To reach the cumulative energy efficiency savings proposed in Option 1, the Joint Utilities[131] predict they will have to ramp up energy savings to approximately 6,700,000 MWh per year. Energy efficiency savings would most likely not be able to significantly ramp up until 2020. This could create a situation where the annual savings rate would have to increase at a far more aggressive rate than the already aggressive annual rate included in the proposed rule.

[130] Docket ID No. EPA-HQ-OAR-2013-0602-- *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*, Chapter 5: Demand Side Energy Efficiency, 5-1 to 5-77.

[131] The "Joint Utilities" are utilities subject to the provisions of TEX. UTIL. CODE. ANN. §39.905 and 16 Tex. Admin. Code §25.181.

The scope of the utilities' energy efficiency goals will likely need to change as well. Texas's statute provides for an energy efficiency goal based on demand savings.[132] In order to decrease CO_2 emissions by increasing energy savings at the rate suggested in Rule 111(d), both the statute and the rule may need to be amended to include demand savings outside of summer or winter peak demand.[133] Furthermore, if the purpose of the utilities' energy efficiency programs is changed to include reduction in power plant emissions, consideration also needs to be given to how the addition of a specific kWh goal would contribute to meeting savings at the rate required by Rule 111(d). The utilities' current energy savings goal that requires utilities to meet an energy goal calculated from its demand savings goal using a 20% conservation load factor will not be sufficient to meet EPA's target for energy efficiency improvements. Furthermore, even if the PUCT increased the conservation load factor to 100% of the current demand savings goal, it would still not be sufficient to meet the target set by Rule 111(d).

C. The Price Tag of the Energy Efficiency Measures Required by the Proposed Rule is Astronomical

The electric utilities in Texas spent approximately $137,776,000 on energy efficiency programs statewide in 2013. Meeting EPA projected targets for energy efficiency will require a significant increase in statewide spending. While there may be attendant benefits to customers associated with this increased spending, these benefits would be outweighed by the dramatic increase in costs that customers will be required to pay as a result of Rule 111(d). In order to reach EPA's energy efficiency savings growth rate of 1.5% of sales per year and the 9.91% cumulative savings target, the Joint Utilities' initial projections suggest that spending will necessarily increase to approximately $3.0 billion per year.[134] This amounts to approximately ***22 times*** the amount spent on energy efficiency in 2013. Based on historical data, the Joint Utilities assumed a current cost of energy efficiency savings of $250/MWh, close to the estimate for

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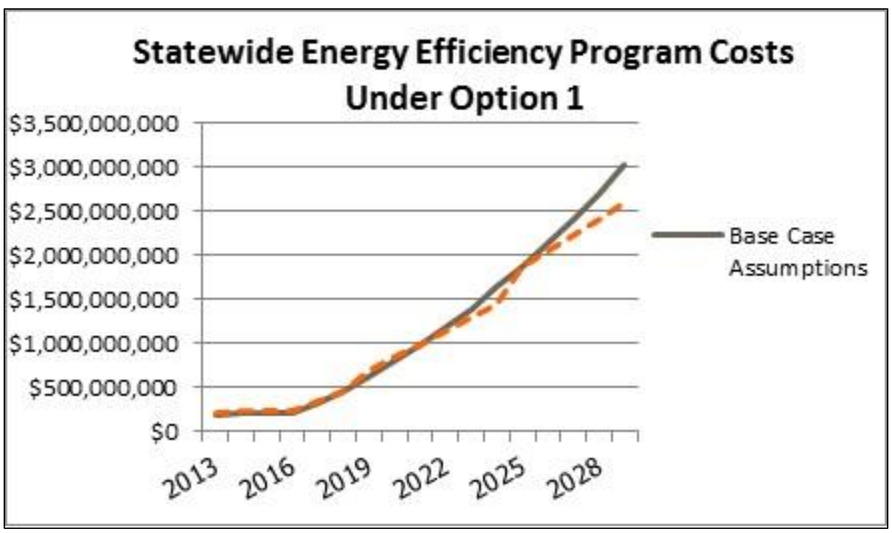
[132] TEX. UTIL. CODE. ANN. §39.905(a)(3) (West 2007 & Supp. 2014).
[133] TEX. UTIL. CODE. ANN §39.905(a)(3) and 16 Tex. Admin. Code §25.181.
[134] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of the Joint Utilities at 8 (Sept. 5, 2014).

Texas of $260/MWh provided by ACEEE.[135,136] To achieve the magnitude of energy efficiency requirements proposed by Rule 111(d), costs will have to rise as more expensive energy efficiency programs are required to meet Rule 111(d)'s goal for Texas. As shown in Figure 13 below, the Joint Utilities' base case projection assumes that program costs required to achieve higher levels of energy savings increase gradually from $250/MWh to $450/MWh in 2029 which is consistent with costs incurred in Vermont, Massachusetts, California, and Rhode Island--all states with aggressive energy efficiency efforts that had significantly higher cumulative energy savings as a percentage of retail sales in 2012 than did Texas. The utilities' alternate estimate uses EPA's assumed first year program cost of saved energy of $275/MWh and increases it to $385/MWh in 2029. The energy efficiency component is only one block of four prescribed for Texas in the proposed rule, and it alone would have a $3 billion impact to Texas's electric customers.

Figure 13: Statewide Energy Efficiency Program Costs[137]



[135] *Id*. at 2.
[136] Molina, Maggie. "*The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.*" American Council for an Energy Efficient Economy, 18-19 (March 2014).
[137] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of the Joint Utilities at 2 (Sept. 5, 2014).

Customer economic challenges present another barrier to increasing energy efficiency savings at the rate proposed by Rule 111(d). SWEPCO anticipated that utilities will need to place increased reliance on energy efficiency improvements that require customers to make significant capital investments in order to achieve incremental energy efficiency improvements going forward. SWEPCO stated that because their territory is perpetually disadvantaged, they expect continued difficulty motivating customers to pay for more expensive energy efficiency improvements such as HVAC upgrades and weatherization measures.[138]

Based on the Joint Utilities' cost estimates, a residential customer will see average charges for energy efficiency rise to nearly $9.00 per month, possibly higher for some customers, far more than the average monthly cost of approximately $0.80 seen in 2013. Several of the Texas utilities have little ability to raise energy efficiency savings by the magnitude required to reach the target proposed by EPA. Sharyland Utilities, Texas New Mexico Power, and American Electric Power Texas North provide service to rural, noncontiguous areas and sparsely populated areas of Texas. Historically, these utilities have encountered difficulty attracting energy efficiency service providers who prefer instead to work with utilities that serve contiguous, densely populated areas. These utilities face similar conditions as many of the municipally-owned utilities (MOUs) and electric cooperatives; these conditions have proved to be obstacles for these utilities in providing energy efficiency measures throughout their service territory. In addition, lack of marketing and outreach, typically performed by energy efficiency service providers, has resulted in lower customer interest in these service territories. To combat this issue, legislation in 2011 provided that, upon meeting certain demonstration requirements, an electric utility operating in an area open to competition could provide rebates or incentive funds directly to customers in rural areas to facilitate the adoption of energy efficiency measures. However, such self-delivered programs are still in their infancy and expanding the programs or initiating new programs at the rate anticipated by the EPA target is not feasible. Another utility, El Paso Electric Company, will also likely face difficulties expanding their programs at the rate necessary to achieve the EPA target. Residential customers in El Paso's territory rely very little

[138] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO (Sept. 5, 2014).

on refrigerated air conditioning and consume far less energy than the state average, which has contributed to low participation in that sector. For these reasons, much of the burden of achieving the EPA's target cumulative savings may fall to the larger utilities serving densely populated areas that have more potential for growth in their energy efficiency portfolios. Residential customers in these areas may be faced with a monthly bill that is higher even than the average monthly bill estimated by the Joint Utilities. In order to implement Rule 111(d), not only will the Texas Legislature need to increase the utilities' energy efficiency savings goal, but PUCT will need to amend its rule to increase the cost caps for residential (set at $.0012/kWh in 2013) and commercial customers, beyond the CPI adjustment already allowed in the rule.

In addition, should the burden of reaching the savings requirement fall more to the utilities with densely populated, contiguous service areas that have more ability to expand their energy efficiency portfolios, legislation will be required that will set differing goals for the utilities. Unlike current Texas law which treats utilities consistently regarding program requirements, Rule 111(d) would introduce an important fairness issue that customers in more densely populated areas should have to pay more for energy efficiency programs than customers living outside of these areas, all because of the aggressive requirements of Block 4.

D. Rule 111(d)'s Timing Makes Interim Goal Compliance For Block 4 Impossible

The timing mandated by Rule 111(d) is simply incompatible with Texas's legislative schedule. Like the other blocks, implementing Block 4 would require statutory changes. Even at an aggressive pace, the PUCT could likely not adopt a rule until early 2018. This would mean that any programs tailored to meet Rule 111(d)'s energy efficiency goals would not become effective until the 2019 energy efficiency program year, as the PUCT attempts to avoid adopting rule amendments mid-program year to avert complications in cost-recovery and program planning. However, it is more likely that the rule will not be adopted in time for the utilities to make the necessary program changes until the 2020 program year, the time at which Rule 111(d) contemplates Texas meeting its interim goal.

In order to meet the Block 4 target, the utilities will have to offer new programs and redesign and expand existing programs. Time is required to ramp up new programs and make program redesigns. In addition, prior to offering and making the investment necessary to launch a new program, utilities typically run a pilot program to gauge customer interest, market penetration rate, and the ability to make the program cost-effective long-term. Pilot programs, which typically run for more than one year, are not required to pass the cost-effectiveness test their first year of implementation in order to recognize program start-up costs, but are expected to pass in subsequent years. Pilot programs serve an important function in the utilities' energy efficiency portfolios by exploring the feasibility of programs designed to increase market penetration of new technologies, reach underserved customer segments, and/or explore new distribution channels. Given all of these factors, it is simply infeasible to conduct traditional deployment of the energy efficiency programs that would be required by the proposed rule under the extremely short timeline required by Rule 111(d).

E. Errors In Block 4 Goal Calculation

EPA inaccurately calculates the transmission and distribution line loss by dividing the total supply of electricity less direct use energy by retail sales using information from the EIA's United States Electricity Profile 2010. This results in EPA's proposed line loss of 7.51%. Calculating line loss by dividing estimated losses by total supply of electricity using information from the EIA's United States Electricity Profile 2012 table on the supply and disposition of electricity, provides a more accurate and timely reflection of the line loss. This calculation results in a United States line loss of 4.955%.

Additionally, EPA has failed to adjust total retail sales to remove zero CO_2-emitting generation. Zero CO_2-emitting generation would presumably grow annually as each state approaches the renewable energy percentage deemed achievable by EPA. Adjusting for the growth in zero CO_2-emitting generation results in the Block 4 goal determination being different in each year, as the number being added to the denominator of EPA's equation would decrease each year to account for the corresponding increase in renewable energy being developed in accordance with Block 3.

XII. THE RULE PROVIDES AN UNWORKABLE COMPLIANCE TIMELINE

A. Rule 111(d) Would Require Implementing Extensive Coordination Among Multiple Texas State Agencies and FERC

Rule 111(d) as proposed clearly intermingles matters within the jurisdiction and expertise of the TCEQ, PUCT and the RRC. While TCEQ, as the Administrator of Texas's air quality program under the CAA, would be responsible for submitting any State Plan and monitor compliance with same, it would clearly need the assistance of the PUCT and possibly the RRC.[139] EPA has failed to address the extensive level of coordination among state agencies that would be necessary to implement this rule. For example, TCEQ would need assistance from the PUCT in implementing the energy efficiency requirements of the rule and with measurement and verification of the energy efficiency requirements. The coordination among Texas state agencies that will be required by Rule 111(d) would also require changes to Texas law. Setting aside the fact that EPA has no authority to require changes to Texas law, such laws could not be amended until 2017 at the earliest. The additional state laws required to implement Rule 111(d) in Texas would in turn almost certainly require the adoption of new or amended rules by each affected state agency, including TCEQ, PUCT, and possibly the RRC and would almost certainly require interagency contracts or agreements between these agencies. EPA's compliance deadlines, particularly its interim compliance deadlines, do not account for the time needed for state agency coordination (and the associated costs) required by Rule 111(d).

[139] For example, as the regulator of intrastate natural gas pipelines in Texas, the RRC would be responsible for permitting additional natural gas pipelines that may be necessary to comply with the increased use in natural gas in Texas and throughout the nation that is contemplated in Rule 111(d).

Rule 111(d) will also require extensive coordination with FERC to ensure that all entities (both inside and outside of ERCOT) comply with existing FERC reliability standards.[140] This is a potentially significant aspect of compliance that EPA has not addressed in the proposed rule. Because Rule 111(d) will almost certainly impact grid reliability in Texas and throughout the nation, the compliance obligations of Rule 111(d) may conflict with the compliance obligations of entities subject to FERC reliability standards. EPA has also failed to address the cost and time implications for states and utilities in coordinating with FERC to implement Rule 111(d). In short, EPA cannot maintain its cavalier attitude to the realities of this infrastructure challenge without grave threats to the reliability of Texas's multiple power grids.

B. Rule 111(d) Provides Insufficient Time For Coordination With Partners In Multi-State Power Grids

Texas's singularly unique composition of fully-competitive service territories, with wholesale and retail markets within ERCOT that are overseen by the PUCT, and the non-ERCOT traditional integrated utilities subject to the traditional retail cost of service ratemaking jurisdiction of the PUCT, adds an additional layer of complexity and difficulty for Texas in determining how to comply with the already dizzyingly complex Rule 111(d). Particularly with respect to Texas utilities not in ERCOT, consideration of a compliance plan will necessarily involve the PUCT consulting with all states in the MISO, SPP, and WECC, along with the respective grid operators. It is important to note that this consultation will need to occur even if Texas ultimately decides to file a Texas-only SP. That is because Texas, as well as all of the other states in the power grids, along with FERC and NERC, will need to understand every other state's plan in order to properly assess the reliability impacts. This process will likely need to be iterative, and the projected one year between the final promulgation of Rule 111(d) and the current June 2016 SP deadline is wholly inadequate for this purpose. Rule 111(d) also provides no clarity as to the permissions given the RTOs, especially with respect to renewable energy

[140] FERC regulates the interstate transmission and movement of electricity, natural gas, and oil. NERC regulates the reliability of the bulk power system in North America and assesses seasonal and long-term reliability of the U.S. power system.

credit trading, evincing the lack of forethought contemplated in Rule 111(d). Finally, the proposed rule does not recognize the complex level of interaction required between the PUCT and TCEQ, as well as possibly other state agencies, that would be required – not only among four distinct RTOs, but also all the states within the footprints of those RTOs, which would result in Texas having to coordinate with almost half of the states in the country.

This also illustrates a fatal flaw in the interim goals required by Rule 111(d). States in regional power grids will not even know the final composition of all the state plans by 2020, when compliance with the interim goals begins. Again, because Texas's interim goal is not substantially different from its final goal, there will simply not be enough time under the current timeline for the planning and construction of new power plants, transmission, and gas pipelines necessitated by the rule. EPA vastly underestimates the complexity of the power system planning process and the time it takes for new infrastructure development. By point of reference, Texas's CREZ process took nearly 9 years from concept to completion – and Texas was in complete control of the execution of this process. Transmission and natural gas pipeline planning, which can require approvals from multiple states and federal agencies, will take even longer.

C. Rule 111(d) Provides Inadequate Time For Texas To Develop A State Plan

Texas's Public Utility Regulatory Act (PURA) §39.001(a) provides as follows:

> The legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, *electric services and their prices should be determined by customer choices and the normal forces of competition.*[141]

If Rule 111(d) were adopted, market prices in ERCOT would no longer be established by "customer choices and the normal forces of competition," but would instead be driven by the

[141] TEX. UTIL. CODE ANN. §39.001(a) (West 2007 & Supp. 2014).

relative CO_2 emissions of power plants operating in ERCOT. Setting aside the issue of EPA's authority to require such a far-reaching change to Texas's electric markets, this system would require a comprehensive, time-consuming, and expensive overhaul of the ERCOT market.

In ERCOT today, only TDUs remain subject to traditional cost-of-service rate regulation by the PUCT. All ERCOT market participants, including the generators (known in ERCOT as power generation companies or PGCs) that would be subject to Rule 111(d), are required to "observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT."[142] However, nothing in PURA, the PUCT's rules, or ERCOT's protocols allows either the PUCT or ERCOT to require PGCs to implement the heat rate improvements for coal-fired units under Block 1 or the re-dispatch of existing natural gas combined cycle plants under Block 2 as is contemplated under proposed Rule 111(d).[143]

Rule 111(d), with its mandates on how coal and natural gas plants must be operated is essentially a federally-imposed integrated resource planning (IRP). In traditional cost-of-service regulated electric markets that practice IRP, utilities must obtain approval from state regulators to plan for and construct the lowest-cost generating plants that are necessary to serve their customers. However, as at least one commenter has noted, Rule 111(d) functionally imposes an IRP process without the "normal constraints of cost, reliability, and resource adequacy."[144] The Texas Legislature has not delegated to the PUCT, or any other state agency, the authority to implement and enforce the CO_2-based IRP requirements that Rule 111(d) would impose on Texas. Adoption of Rule 111(d) as proposed would require the Texas Legislature to enact legislation authorizing some agency or agencies, to implement, oversee and enforce the restructuring of the ERCOT market. Such legislation would necessarily require more regulation of PGCs than exists today in the ERCOT market. Adoption of Rule 111(d) would require Texas

[142] *Id*. at §39.151(j) (West 2007 & Supp. 2014).
[143] As discussed in these comments, the assertion by EPA that states have "flexibility" in determining which of the four Blocks (or other measures designed to accomplish the same result) they use to achieve EPA's emission reduction limits, is a mirage, at least for Texas. In order to meet either EPA's interim or final emissions goals, Texas must implement all four Blocks.
[144] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*--Presentation of Charles S. Griffey at slide 5 (Aug. 15, 2014).

law to be changed to authorize the PUCT and ERCOT to implement all "policies, rules, guidelines and procedures" necessary to impose Rule 111(d) on these entities. There is simply not enough time for Texas to complete all of these steps under the compliance timeline proposed in Rule 111(d).

D. Rule 111(d) Provides Impossible Compliance Deadlines For Texas Because Of Texas's Legislative Schedule

Under EPA's current adoption and implementation deadlines for Rule 111(d), Texas will not be able to make the numerous statutory changes necessary to submit a SP by June 2017. Some state legislatures, including Texas, do not meet every year. The Texas Legislature meets only in odd-numbered years beginning the second Tuesday of January and ending 140 days later.[145] Given the time table for Rule 111(d) adoption (June 2015) and the extremely aggressive time tables in the rule (i.e., SPs due June 2016), Texas will not be able to submit a SP until at least 2017.[146]

EPA has put Texas (and all other states) in a no-win, Catch-22 situation. Texas must either submit a SP, and thereby cede its authority over the regulation of electricity markets, or risk imposition of a FP by EPA, which would also very likely result in Texas losing its authority over its electricity markets—both untenable outcomes for Texans. If Texas chooses to submit a SP, it must do so by June 2016 under the schedule proposed by EPA. Texas cannot submit a SP unless and until numerous state laws are amended by the Texas Legislature by 2017 at the earliest. Therefore, Texas will be unable to submit a SP by June 2016. In order to file for a one-year extension for filing a SP, a state must submit an initial plan by June 2016 that includes

[145] "The Legislature shall meet every two years at such time as may be provided by law and at other times when convened by the Governor." Tex. Const. art. III, § 5. The regular sessions of the Texas Legislature convene at noon on the second Tuesday in January of odd-numbered years. TEX. GOV'T CODE ANN. §301.001 (West 2013). The maximum duration of a regular session is 140 days. Tex. Const. art. III, § 24.

[146] *See* Gifford, Raymond, Sopkin, Gregory, Larson, Matthew, *State Implementation of CO_2 Rules—Institutional and Practical Issues with State and Multi-State Implementation and Enforcement* at 8-9 (Release 1.0—July 2014). (Available at: http://www.wbklaw.com/uploads/file/Articles-%20News/White%20Paper%20-%20State%20Implementation%20of%20CO2%20Rules.pdf).

"commitments to concrete steps that will ensure that the state will submit a complete plan by June 2017..."[147] Moreover, the state's initial plan must also:

> include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO_2 emissions, an explanation of the path to completion, and a summary of the state's response to any significant public comment on the approvability of the initial plan.[148]

Texas will also be unable to do this because a state agency (presumably TCEQ and possibly PUCT) could not agree (as part of the SP extension process) to bind a future Texas Legislature to pass the laws necessary for Texas to implement Rule 111(d). While states can also request a two-year extension from compliance with Rule 111(d) if they are part of a regional plan, this option presents the same problem for Texas as the one-year extension request. Texas will not be in a position in 2016 to make commitments about whether Texas law will be changed in 2017 to permit Texas to implement a regional plan to comply with Rule 111(d). Moreover, since development of a multi-state regional plan would be even more complex and time-consuming than developing a state-only plan, it is unrealistic to expect states to develop a regional plan by 2018. Under EPA's current timeline for implementation of Rule 111(d) therefore, Texas would be precluded from timely filing a SP or from seeking a one year extension for filing a SP. This in turn, could result in the imposition of a FP for Texas by EPA, under which Texas would also presumably lose jurisdiction over its electricity markets. Section 111 of the CAA does not allow EPA to impose a standard that states must meet through a state plan if EPA does not have the authority to implement the standard through a federal plan.[149]

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[147] 79 Fed. Reg. 34,838 (June 18, 2014).
[148] *Id.*
[149] *See* Docket ID No. EPA-HQ-OAR-2013-0602--Comments of TCEQ (Dec. 1, 2014); s*ee also* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Luminant Energy Company, LLC and Luminant Generation Company, LLC (Luminant) at 7 (Sept. 5, 2014).

E. PUCT Rule Changes Required to Implement Rule 111(d)

Even beyond the difficulties in developing a SP in the timelines contemplated by Rule 111(d), EPA has also failed to understand the time it will take for state utility commissions and grid operators to implement a plan after EPA approval. The PUCT reviewed which PUCT regulations are potentially impacted by Rule 111(d). Some of the rule changes would also require changes in Texas law before they could be adopted by the PUCT. Possible PUCT rule changes resulting from Rule 111(d) include:

--16 Texas Admin. Code §25.51 (Power Quality)
--16 Texas Admin. Code §25.53 (Electric Service Emergency Operations Plans)
--16 Texas Admin. Code §25.54(Cease and Desist Orders to PGCs)
--16 Texas Admin. Code §25.93 (Wholesale Electricity Transaction Information)
--16 Texas Admin. Code §25.91 (Generating Capacity Reports)
--16 Texas Admin. Code §25.109 (Registration of Power Generation Companies and Self Generators)
--16 Texas Admin. Code §25.172 (Goal for Natural Gas)
--16 Texas Admin. Code §25.173 (Goal for Renewables
--16 Texas Admin. Code §25.174 (Competitive Renewable Energy Zones)
--16 Texas Admin. Code §25.181 (Energy Efficiency Goal)
--16 Texas Admin. Code §25.183 (Reporting and Evaluation of Energy Efficiency Programs)
--16 Texas Admin. Code §25.200 (Load shedding, Curtailments and Redispatch);
--16 Texas Admin. Code §25.211-213 (Rules related to Distributed Generation)
--16 Texas Admin. Code §25.217 (Distributed Renewable Generation)
--16 Texas Admin. Code §25.235 (Fuel Costs)
--16 Texas Admin. Code §25.236 (Recovery of Fuel Costs)
--16 Texas Admin. Code §25.237 (Fuel Factors)
--16 Texas Admin. Code §25.238 (Purchased Power Capacity Cost Recovery Factor)
--16 Texas Admin. Code §25.251 (Renewable Energy Tariff)
--16 Texas Admin. Code §25.261 (Stranded Cost Recovery of Environmental Cleanup Costs)
--16 Texas Admin. Code §25.361 (ERCOT)
--16 Texas Admin. Code §25.365 (Independent Market Monitor)
--16 Texas Admin. Code §25.421 (Transition to Competition for a Certain Area Outside the ERCOT Region)
--16 Texas Admin. Code § 25.422 (Transition to Competition for Certain Areas in the Southwest Power Pool)
--16 Texas Admin. Code §25.501-508 (ERCOT wholesale market design rules)

Even if the Texas Legislature passed laws giving the PUCT the authority to adopt and/or amend existing rules necessary to carry out the mandates of Rule 111(d), the sheer number of rule amendments presents an impossible implementation issue for the PUCT, given the aggressive compliance timelines under Rule 111(d). Amending this many rules is an undertaking similar in scope to the rules adoption required in response to the implementation of retail electric competition in ERCOT. Implementing all of the rules needed for retail competition in ERCOT took almost 3 years (1999-2002). Completion of rule amendments necessary to implement Rule 111(d) would also likely take several years, making the timelines in Rule 111(d) impossible to meet.

F. ERCOT Protocol Revision And System Change Timelines

A separate but related implementation issue would be amendments to existing ERCOT market rules[150] or adoption of new market rules to implement Rule 111(d). Similar issues are likely to occur in power markets overseen by SPP and MISO. Again, because Rule 111(d) would involve fundamental changes to the way electricity markets operate, ERCOT would need to adopt or amend numerous market rules to move from the current competitive market to the command and control market mandated under Rule 111(d). Additionally, ERCOT would very likely need to adopt significant information technology system changes if Rule 111(d) as proposed were implemented.

Development and approval of a new market rule or an amendment to an existing market rule (*e.g.*, a Nodal Protocol Revision Request ("NPRR")) typically takes 5 to 12 months on a normal timeline or 2 to 4 months on an urgent timeline. Market rule changes may require changes to ERCOT and market participant systems. Implementation of any necessary system changes resulting from a rule change typically takes an additional 9 to 18 months on a normal timeline or 8 to 12 months on an urgent timeline. However, depending on the complexity of the

[150] The market rules in ERCOT include protocols, market guides, policies, and procedures. Current market rules can be found on ERCOT's website at: http://www.ercot.com/mktrules .

change, the timelines for both rule development and system implementation can vary. The above-discussed timelines do not include market participant appeals of protocol changes to the PUCT, which is permitted under PUCT rules.[151] The appeal to the PUCT of a protocol adopted by ERCOT can take anywhere from 5 to 15 months, depending on the complexity of the protocol that is being challenged. The above-discussed timelines also do not include the appeal of a PUCT decision in court, which can take several years.

If compliance with Rule 111(d) requires substantial changes to ERCOT market rules, development and approval of the rule changes and implementation of the necessary system changes would likely take a minimum of 14 months and could take significantly longer. Two examples illustrate the process and timeline for making such changes. In September 2012, a stakeholder proposed changes to congestion revenue rights credit calculations and payments.[152] Stakeholders reviewed and discussed the proposal for five months, and the ERCOT Board of Directors ("Board") approved market rule changes in March 2013. To meet the target timeline for the most critical components, the implementation was divided into three phases. Implementation of the necessary system changes for the initial phase took 8 months. The remaining phases are targeted to begin in 2015.

In September 2013, the PUCT directed ERCOT to implement an operating reserve demand curve ("ORDC") for its real-time market.[153] Prior to directing ERCOT to implement an ORDC, the PUCT had discussed the merits of the proposal and implementation details for at least 9 months. Stakeholders reviewed and discussed the changes required to implement the PUCT's direction for two months, and the ERCOT Board approved market rule changes in November 2013. Implementing the necessary system changes then took an additional 8 months. Furthermore, additional market rule changes proposed by stakeholders to implement the ORDC were deferred from the initial changes so that the ORDC could be implemented prior to the 2014 summer peak electricity demand period. Some of those additional market rule changes have

[151] 16 Tex. Admin. Code §22.251.
[152] *See* Nodal Protocol Review Request 484, Revisions to Congestion Revenue Rights Credit Calculations and Payments, Luminant Energy Company, LLC, ERCOT (Sept. 28, 2012).
[153] Nodal Protocol Revision Request 568, Real-Time Reserve Price Added Based on Operating Reserve Demand Curve, ERCOT (Sept. 19, 2013).

been reviewed and discussed by stakeholders for 10 months, and the ERCOT Board is currently scheduled to consider them at its December 2014 meeting.[154] ERCOT has estimated that actually implementing the necessary system changes will take a further 4 to 7 months after the rule changes are approved by the ERCOT Board.

Again, EPA has vastly underestimated the regulatory and electricity system changes needed to comply with the mandates of Rule 111(d). These changes simply cannot be accomplished in the timelines required by the rule in a manner that will minimize costs to ratepayers and preserve the reliability of electric service in Texas. EPA should withdraw Rule 111(d) and meaningfully engage the nation's grid operators and electricity system regulators regarding these issues in advance of EPA's next attempt to implement a lawful rule.

XIII. RULE 111(D) HAS A DISPROPORTIONATE AND UNFAIR IMPACT ON TEXAS

Rule 111(d) raises substantial questions of fairness given that Texas is disproportionately affected by the rule. Certain aspects of the inequitable and disparate treatment that Texas would suffer under proposed Rule 111(d) have already been discussed. There are more. For example, evaluating EIA and U.S. Census data shows that, from 2000 to 2010, Texas, the second most populous state in the United States, has reduced its carbon dioxide emissions by 8.05%.[155] In comparison, over the same time period, California, the most populous state, has reduced its carbon dioxide emissions by only 4.36%.[156] On a per-capita basis, California reduced its carbon dioxide emissions by 15.49% over the same time period while Texas has reduced its carbon dioxide emissions by nearly 24% on a per-capita basis;[157] during this time Texas maintained grid reliability while transitioning to competitive (and very successful) wholesale and retail markets.

[154] *See* Nodal Protocol Revision Request 595, RRS Load Resource Treatment in ORDC, Tenaska Power Services Co., ERCOT (Jan. 29, 2014).
[155] U.S. Energy Information Administration, *State CO2 Emissions* (Feb. 25, 2014) (available at: http://www.eia.gov/environment/emissions/state/state_emissions.cfm).
[156] *Id*.
[157] *Intercensal Estimates of the Resident Population for the United States, 2000 – 2010,* United States Census Bureau (available at: http://www.census.gov/popest/data/intercensal/state/state2010.html).

Instead, Texas's heavy investment and remarkable transformation is penalized by a final target of 791 lbs. of CO_2/MWh, which could not even be met by a state-of-the-art combined cycle power plant with existing technology. Texas produces 11% of the electricity in the United States, but its proportion of total carbon dioxide reduction required by Rule 111(d) by 2030 is 17.87%.[158] EPA offers no reasonable explanation for the disparate, seemingly punitive, treatment of Texas under the proposed rule.

Significantly, both the interim 853 lbs. CO_2/MWh mandate and final 791 lbs. CO_2/MWh mandate applied to Texas are substantially lower than the CO_2 per MWh emission level required by EPA to be achieved by new coal or gas power plants under Section111(b) of the CAA. EPA's proposal would require Texas to account for somewhere between 18 to 25% of the country's total CO_2 reductions. It is important to note that Texas's CO_2 emissions rate in 2012 is 1,284 pounds of CO_2/MWh, a rate lower than the <u>final goal</u> set by EPA for 13 states.[159] In a fashion, EPA deems rates higher than Texas's *current* carbon dioxide emissions levels as satisfactory final goals for other states, for what appear to be entirely arbitrary reasons. EPA does not even apply a uniform *percentage* reduction of carbon dioxide emissions from each state's current level of carbon dioxide emissions. This is yet another example of how Rule 111(d) would subject Texas to unfair and disparate treatment.

A. Texas's Renewable Energy Mandate Under Rule 111(d) Far Exceeds The Requirement For Any Other State

Rule 111(d) would effectively require Texas to add 52 million MWh of renewable energy by 2030. The renewable energy mandate for Texas far exceeds the renewable energy requirement for any other state. Texas, already the nation's largest renewable energy producer,

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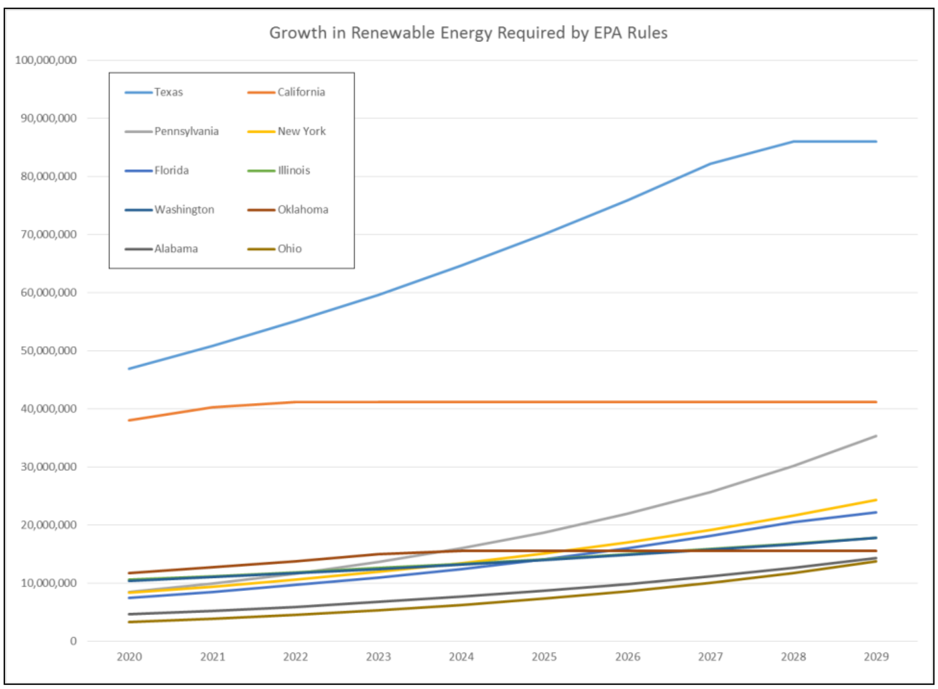
[158] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*—Partnership for a Better Energy Future at slide 15 (Aug. 15, 2014).

[159] Docket ID No. EPA-HQ-OAR-2013-0602—Table 8—<u>the following states all have **final goals higher than Texas's current levels of CO_2 emissions**:</u> Hawaii (1,306 lbs. of CO_2/MWH); Indiana (1,531 lbs. of CO_2/MWH); Iowa (1,301 lbs. of CO_2/MWH); Kansas (1,499 lbs. of CO_2/MWH); Kentucky (1,763 lbs. of CO_2/MWH); Missouri (1,544 lbs. of CO_2/MWH); Montana (1,771 lbs. of CO_2/MWH); Nebraska (1,479 lbs. of CO_2/MWH); North Dakota (1,783 lbs. of CO_2/MWH); Ohio (1,338 lbs. of CO_2/MWH); Utah (1,322 lbs. of CO_2/MWH); West Virginia (1,620 lbs. of CO_2/MWH); and Wyoming (1,714 lbs. of CO_2/MWH). *See* 79 Fed. Reg. 34,895 (June 18, 2014).

would be required to increase its renewable portfolio by 153% over the next 8-14 years, while the next largest renewable energy producer, California, would only be required to increase its renewable energy portfolio by 37%.[160] The required increase in Texas's renewable energy fleet required under the rule would be greater than the increases of 29 states combined.[161] Finally, Texas's renewable energy portfolio resulting from Rule 111(d) would be larger than the present day wind and solar fleets of every country in the world, except for the U.S.[162] The magnitude of Texas's renewable energy mandate compared to certain other states is illustrated below in Figure 14. EPA offers no credible or reasonable explanation for this disparate treatment of Texas in the proposed rule.

Figure 14: Growth in Renewable Energy Required by Rule 111(d)[163]



[160] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Partnership for a Better Energy Future, at slide 28 (Aug. 15, 2014).
[161] *Id.* at slide 29.
[162] *Id.* at slide 30.
[163] Presentation of Brian Lloyd, PUCT Executive Director, Air Pollution Control Association Conference at slide 16 (Sept. 11, 2014).

B. Rule 111(d) Disproportionally Harms Texas's Non-Profit Electric Cooperatives

Texas has a number of electric cooperatives that have been providing service since the Rural Electrification Act of 1934. These cooperatives have heavy coal-fired generation portfolios, which allow them to serve their communities at a low cost. Comments from one cooperative noted that "eliminating our coal-fired generation could increase our wholesale power costs by as much as 40 percent" with a corresponding "30 – 35 percent increase in retail electric rates."[164] This cooperative noted that coal-fired generation represented 63 percent of its fuel portfolio in 2012. Rule 111(d)'s impact on electric cooperatives would also adversely impact small businesses and rural, low-income communities that are served by these non-profit, member-owned cooperatives. Electric cooperatives in Texas serve a disproportionate number of low-income customers as well as the elderly, who are dependent on the low cost of fossil-fuel fired generation for reasonably priced electricity. Rule 111(d) would likely eliminate many coal plants owned by electric cooperatives—plants that provide jobs and economic health in Texas's rural communities. One cooperative explained that its coal-fired power plant provides good jobs to approximately 1,200 citizens and their families: "This may not sound like much in our greater metropolitan centers, but to these five northeast Texas counties, the impact on the rural economy, the local tax base, and social services would be devastating."[165]

XIV. CONCLUSION

The PUCT has outlined the numerous, significant problems, both legal and operational, with Rule 111(d). For all of the reasons discussed in these comments, the PUCT urges EPA to withdraw the proposed rule. In the alternative, the PUCT urges EPA, at a minimum, to eliminate the interim emissions goals from the final rule.

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[164] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Rusk County Electric Cooperative at 2 (Aug. 29, 2014).
[165] *Id*. at 1.

APPENDIX A

TO THE COMMENTS OF

THE PUBLIC UTILITY COMMISSION OF TEXAS

ERCOT Analysis of the Impacts of the Clean Power Plan

ERCOT Analysis of the

Impacts of the Clean Power Plan

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the Texas Interconnection, encompassing approximately 90% of electric load in Texas. ERCOT is the independent organization established by the Texas Legislature to be responsible for the reliable planning and operation of the electric grid for the ERCOT interconnection. Under the North American Electric Reliability Corporation (NERC) reliability construct, ERCOT is designated as the Reliability Coordinator, the Balancing Authority, and as a Transmission Operator for the ERCOT region. ERCOT is also registered for several other functions, including the Planning Authority function.

In June 2014, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan, which calls for reductions in the carbon intensity of the electric sector. The Clean Power Plan would set limits on the carbon dioxide (CO_2) emissions from existing fossil fuel-fired power plants, calculated as state emissions rate goals. For Texas, EPA has proposed an interim goal of 853 lb CO_2/MWh to be met on average during 2020-2029, and a final goal of 791 lb CO_2/MWh to be met from 2030 onward. EPA calculated the state-specific goals using a set of assumptions about coal plant efficiency improvements, increased production from natural gas combined cycle units, growth in renewables generation, preservation of existing nuclear generation, and growth in energy efficiency.

ERCOT has evaluated the potential implications of the proposed Clean Power Plan for grid reliability and conducted a modeling analysis of the impacts to generation resources and electricity costs in the ERCOT region. Based on this analysis, ERCOT anticipates that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. ERCOT estimates that the proposed CO_2 emissions limitations will result in the retirement of between 3,300 MW and 8,700 MW of coal generation capacity, could result in transmission reliability issues due to the loss of generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region by up to 20% in 2020, without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. This summary report describes the results of ERCOT's analyses.

1. Summary of ERCOT Concerns with the Clean Power Plan

ERCOT approaches this analysis from the perspective of an independent grid operator in a competitive market which has achieved significant success in using competition to drive efficient outcomes. Existing market policies and investments in transmission in ERCOT have incentivized market participants to maximize the efficiency of the generating fleet and develop new technologies including renewable generation. With recent investments in transmission, more than 11 GW of wind capacity have been successfully integrated into the ERCOT grid. The ERCOT region maintains a forward-looking open market and provides affordable and reliable electricity to consumers in Texas.

ERCOT's primary concern with the Clean Power Plan is that, given the ERCOT region's market design and existing transmission infrastructure, the timing and scale of the expected changes needed to reach the CO_2 emission goals could have a harmful impact on reliability. Specifically, implementation of the Clean Power Plan in the ERCOT region, particularly to meet the Plan's interim goal, is likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges. There is a natural pace of change in grid resources due to advancing cost effective technologies and changing market conditions.

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This pace can be accelerated, but there is a limit to how fast this change can occur within acceptable reliability constraints. It is unknown based on the information currently available whether compliance with the proposed rule can be achieved within applicable reliability criteria and with the current market design. Nevertheless, there are certain grid reliability and management challenges that ERCOT will face as a result of the resource mix changes that the proposed rule will induce:

- The anticipated retirement of up to half of the existing coal capacity in the ERCOT region will pose challenges to reliable operation of the grid in replacing the dispatchable generation capacity and reliability services provided by these resources.

- Integrating new wind and solar resources will increase the challenges of reliably operating all resources, and pose costs to procure additional regulating services, improve forecast accuracy, and address system inertia issues.

- Accelerated resource mix changes will require major improvements to ERCOT's transmission system, posing significant costs not considered in EPA's Regulatory Impact Analysis.

These issues highlight the need for the final rule to include a process to effectively manage electric system reliability issues that may arise due to implementation of the Clean Power Plan, as well as include more implementation timeline flexibility to address each state's or region's unique market characteristics. With respect to the need to manage reliability issues, ERCOT supports the ISO/RTO Council (IRC) proposal for the inclusion of a reliability safety valve process in the context of the CO_2 rule, as well the need for states to consult with ISOs/RTOs during the development of State Plans.

2. Results of ERCOT Modeling

This summary report draws on results from an ongoing analysis of the expected impacts of several recently finalized and proposed environmental regulations on grid reliability in the ERCOT region. The study uses stakeholder-vetted planning processes and methodologies consistent with the regional Long-Term System Assessment studies conducted by ERCOT. A full report on this environmental regulatory impact study will be released in mid-December 2014.

The sections that follow describe the modeling methodology and summarize the results from the modeling analysis. Next, the modeling results are compared to those obtained by EPA in its analysis of the Clean Power Plan. This is followed by a discussion of the impacts of these results for grid reliability and transmission infrastructure. The report concludes with a discussion of cost impacts.

2.1. Modeling Methodology

ERCOT evaluated the proposed Clean Power Plan using two methodologies. First, ERCOT considered a scenario with the Clean Power Plan limits applied as a constraint, to allow the long-term simulation model to select the most cost-effective way to achieve the proposed carbon intensity from electric generating resources. Second, a carbon emission fee was used to cause the system to achieve the proposed standard over the allotted compliance period. The benefit of the first approach is that it would be expected to minimize the overall cost to the system, and should lead to results that are comparable to the methodology utilized by the EPA in its analysis of the rule impacts. However, it may not be a change that is achievable within the current electricity market design in ERCOT. For this reason, ERCOT also modeled emissions fee scenarios. Though a carbon price is not an explicit component of EPA's proposal, it is one option that Texas could use to comply with the limits, and is included here in order to

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assess the system impacts of a potential approach to compliance. In both cases, ERCOT evaluated the limits in the Clean Power Plan by applying the proposed emissions rate limits for Texas (in lb/MWh) to the ERCOT system.

ERCOT modeled four distinct scenarios over the timeframe 2015-2029 to evaluate the implications of the Clean Power Plan on reliability in the region:

1. **Baseline** – This scenario estimates a baseline of the ERCOT system under current market trends against which anticipated Clean Power Plan changes will be compared.

2. **CO_2 Limit** – This scenario applied the limits in the Clean Power Plan to the ERCOT system to determine the most cost-effective way to comply with the limits. This scenario did not place a price on CO_2 emissions.

3. **\$20/ton CO_2** – This scenario applied a \$20/ton price on carbon dioxide emissions to the ERCOT system. With a \$20/ton CO_2 price, the ERCOT system attains an emission intensity of 904 lb CO_2/MWh in 2020 and 877 lb CO_2/MWh in 2029 – above both the interim and final goals.

4. **\$25/ton CO_2** – This scenario applied a \$25/ton price on carbon dioxide emissions to the ERCOT system. With a \$25/ton CO_2 price, the ERCOT system attains an emission intensity of 840 lb CO_2/MWh in 2020 and 792 lb CO_2/MWh in 2029 – below the interim goal and approximately meeting the final goal.[1]

It should be noted that ERCOT did not require the system to maintain a specific reserve margin in the modeled scenarios. The target reserve margin criterion in ERCOT is not binding and it is possible that market conditions will result in a lower reserve margin than the recommended level. By contrast, EPA's modeling, described later, required that ERCOT maintain a 13.75% reserve margin. This difference in assumptions results in different amounts of capacity additions, and has implications for grid reliability.

This study uses stakeholder-vetted assumptions consistent with ERCOT's Long Term System Assessment (LTSA).[2] These assumptions include the anticipated expiration of the Production Tax Credit (PTC) and phase out of the Investment Tax Credit (ITC). Natural gas price projections are based on an average of the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 forecast and the forecast from Wood Mackenzie, shown in Figure 1. The same natural gas price assumptions were applied in all scenarios.

[1] ERCOT did not attempt to calculate a carbon price to precisely meet the emissions limits. Instead, ERCOT found a carbon price range within which the system is anticipated to achieve the Clean Power Plan emissions standards.

[2] For more information, visit ERCOT's Regional Planning Group (RPG) website at http://www.ercot.com/committees/other/rpg/index.html.

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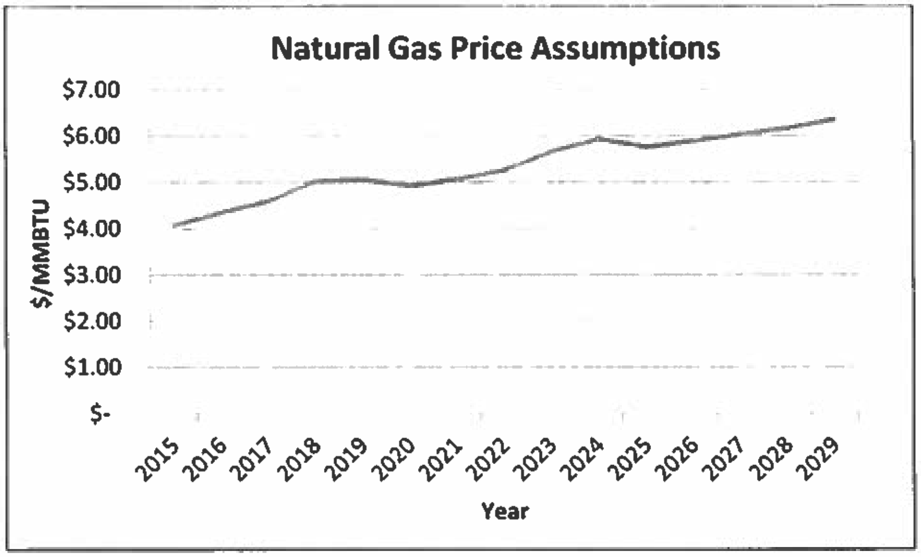

Figure 1: Natural Gas Price Assumptions

ERCOT assumed capital costs consistent with those used in the LTSA, with the exception of solar capital costs. After review of information provided by stakeholders and updated reports by the National Renewable Energy Laboratory (NREL) and Lazard, it is clear that solar capital costs continue to decline at a rapid rate. To be more in line with these lower costs, solar capital costs were lowered in the near term years of this study to reflect this latest information. ERCOT estimated solar capital costs based on a review of information provided by Lazard,[3] Solar Energy Industries Association,[4] and Citi Research.[5] Figure 2 displays the solar capital costs used by ERCOT in this analysis. Capital costs for all other generation technologies were taken from the EIA AEO 2014.

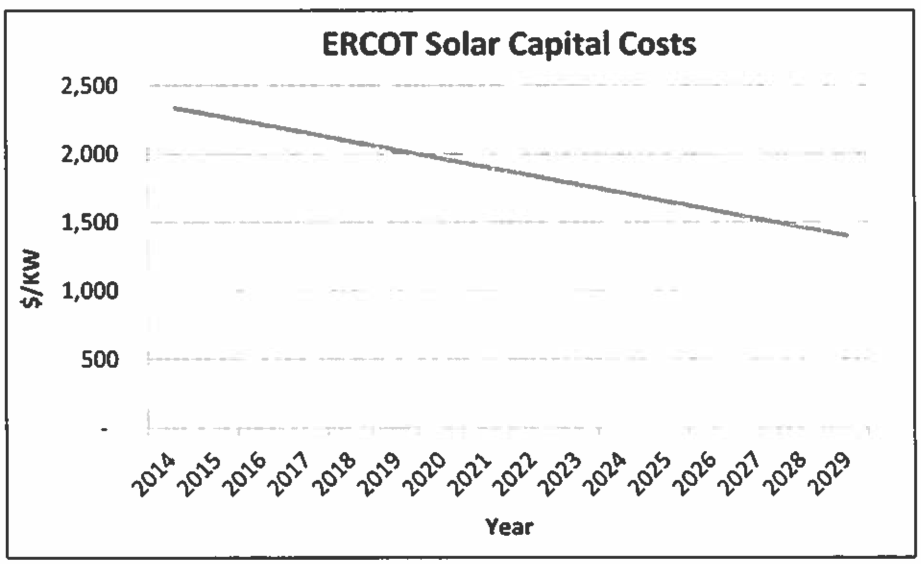

Figure 2: ERCOT Solar Capital Costs

[3] Lazard. *Lazard's Levelized Cost of Energy Analysis – Version 8.0*, September 2014. Available from http://www.lazard.com/pdf/levelized%20cost%20of%20energy%20-%20version%208.0.pdf.
[4] Greentech Media, Inc and Solar Industries Association. *U.S. Solar Market Insight Report.* Q1 2014. Confidential Report.
[5] Citi Research. *Launching on the Global Power Sector: The Sun Will Shine but Look Further Downstream.* February 6, 2013. Confidential Report.

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With regard to the generation fleet, ERCOT modeled the capacity listed in ERCOT's May 2014 Capacity, Demand, and Reserves (CDR) report,[6] with the addition of planned generation resources that had started construction by Summer 2014, as well as the full capacity of Private Use Networks (PUNs).[7] Table 1 shows the baseline capacity assumptions used in the modeling. Generation from wind and solar resources was modeled based on wind and solar production profiles that estimate the amount of wind and solar resources available for every hour of the year, based on the 2010 weather year. For wind, ERCOT used county-specific wind production profiles provided by AWS Truepower. The solar production profiles were provided by URS and are based on data from weather stations in West Texas.

Table 1: Baseline Capacity Assumptions

Fuel Type	Capacity (MW)
Nuclear	5,200
Coal	19,900
Natural Gas	58,900
Wind	16,700
Solar	250
Hydro	500
Other	1,000
Total	102,450

Within the scenarios, ERCOT varied some assumptions pertaining to implementation of the Clean Power Plan and compliance with other environmental regulations. First, scenarios 2-4 required compliance with the Cross-State Air Pollution Rule (CSAPR) limits, imposed as a limit in Scenario 2 and as an emission fee in scenarios 3 and 4.[8] Second, due to data availability limitations, ERCOT was only able to model through 2029. In scenario 2, to approximate compliance with the final goal in the Clean Power Plan, ERCOT applied the final CO_2 limit as a constraint over 2028-2029, and the interim CO_2 limit over 2020-2027. In this scenario, the ERCOT interconnection was required to meet the applicable emission rate goal in each year; the other scenarios did not include this requirement.

Finally, in the baseline scenario ERCOT assumed energy efficiency savings at 1% of load for all modeled years, consistent with current levels of energy efficiency as measured by the Electric Utility Marketing Managers of Texas (EUMMOT).[9] For scenarios 2-4, ERCOT assumed growth in energy efficiency savings to a level of 5% by 2029. EPA's building blocks assumed Texas could achieve a cumulative 9.91% savings from energy efficiency by 2029. ERCOT did not elect to use the energy efficiency savings level estimated by EPA because this level of energy efficiency is not consistent with current trends in energy efficiency in Texas.[10] ERCOT's more moderate assumption is consistent with the approach taken by the Mid-Continent Independent System Operator (MISO) in its analysis of the impacts of the Clean Power Plan.[11] MISO modeled three energy efficiency assumptions: base energy efficiency trends, EPA's Building Block 4, and 50% of EPA's Building Block 4. ERCOT's approach of using 5% is consistent with the third assumption modeled by MISO, and represents a moderate, and more realistic, energy efficiency growth assumption, between the current level of savings and EPA's goal.

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[6] ERCOT's *Report on the Capacity, Demand, and Reserves in the ERCOT Region* is available at http://www.ercot.com/gridinfo/resource/index.html.

[7] In addition to PUN capacity, ERCOT also separately modeled PUN load.

[8] ERCOT assumed an SO_2 emission price of \$800/ton, an ozone season NO_x emission price of \$1,600/ton, and an annual NO_x emission price of \$1,000/ton. ERCOT estimated these prices based on a series of model iterations as part of this study.

[9] EUMMOT's *Energy Efficiency Accomplishments Report* is available at http://www.texasefficiency.com/index.php/publications/reports.

[10] For information about energy efficiency trends in Texas, visit the EUMMOT website at http://www.texasefficiency.com/.

[11] MISO. *GHG Regulation Impact Analysis*, July 30, 2014. Available from https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140730/20140730%20PAC%20Item%2012a%20GHG%20Regulation%20Impact%20Analysis.pdf.

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2.2. Summary of Modeling Results

The modeling results for the four scenarios indicate incremental unit retirements and incremental renewable capacity additions in the CO_2 limit and carbon price scenarios compared to the baseline. In the CO_2 limit and carbon price scenarios, the model retired 2,900 MW to 5,000 MW of capacity incremental to retirements in the baseline, as shown in Table 2. Most of the incremental retirements were coal units, with between 3,300 MW and 5,700 MW of incremental coal unit retirements compared to the baseline. The amount of incremental coal retirements in the carbon scenarios is higher than the total amount of incremental retirements because of natural gas steam retirements that occur in the baseline but not in the carbon scenarios. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, improving the economics of natural gas steam units during this period. Note that in the baseline, 800 MW of coal capacity retires, corresponding to the announced retirement of CPS Energy's J. T. Deely units 1 and 2 in 2018.

Table 2: Unit Retirements by 2029

Generation Technology Type	Baseline	CO_2 Limit	CO_2 \$20/ton	CO_2 \$25/ton
Retired Gas Steam (MW)	2,000	1,600	1,600	1,300
Retired Coal (MW)	800	4,100	4,100	6,500
Total Retirements (MW)	**2,800**	**5,700**	**5,700**	**7,800**

The CO_2 limit and carbon price scenarios also resulted in between 5,500 and 7,100 MW incremental renewable capacity additions compared to the baseline, which itself saw 9,900 MW of new solar capacity.[12] As noted previously, ERCOT assumed the expiration of the PTC as per current law, which is the reason there are no wind capacity additions in the baseline scenario. All three scenarios built less natural gas-fired capacity compared to the baseline. Table 3 summarizes the capacity additions for each scenario.

Table 3: Capacity Additions by 2029

Generation Technology Type	Baseline	CO_2 Limit	CO_2 \$20/ton	CO_2 \$25/ton
Wind (MW)	0	3,400	2,800	3,500
Solar (MW)	9,900	12,500	12,600	13,500
Combined Cycle (MW)	0	0	0	1,300
Combustion Turbine (MW)	4,600	1,000	1,000	1,000
Total (MW)	**14,500**	**16,900**	**16,400**	**19,300**

As shown in Figure 3, the retiring coal and gas steam capacity would be replaced by solar, wind, and natural gas-fired capacity by 2029, taking into account the contribution of energy efficiency measures. However, within the modeled timeframe there are some years for which the ERCOT capacity reserve margin may be considerably less than historically targeted for reliability, as capacity retires before new resources come online and energy savings from energy efficiency measures begin to materialize. In the model results, these shortages occur towards the beginning of the compliance timeframe, between 2020 and 2022. During this timeframe, the modeled retirements and capacity additions result in a reserve margin 2 to 3% below the reserve margin in the baseline scenario for these years, in the CO_2 limit and \$20/ton CO_2 scenarios.[13] By 2029, the reserve margin in these scenarios is comparable to the baseline scenario. The

[12] The solar capacity additions modeled in this study are consistent with the results of ERCOT's 2013 Long-Term Transmission Analysis, which indicated that large amounts of solar would be economic in ERCOT after 2020. For more information, visit ERCOT's Long-Term Study Task Force website at http://www.ercot.com/committees/other/lts/index.html.

[13] The ERCOT reserve margin is calculated using wind capacity contribution values of 12% for non-coastal resources and 56% for coastal resources, consistent with the ERCOT Board approved methodology outlined in Nodal Protocol Revision Request (NPRR) 611. The data used to

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reserve margins are generally higher in the \$25/ton CO_2 scenario, because the increased price on CO_2 results in increased capacity additions. As previously described, ERCOT did not require the simulation model to maintain a specific reserve margin in the four scenarios.

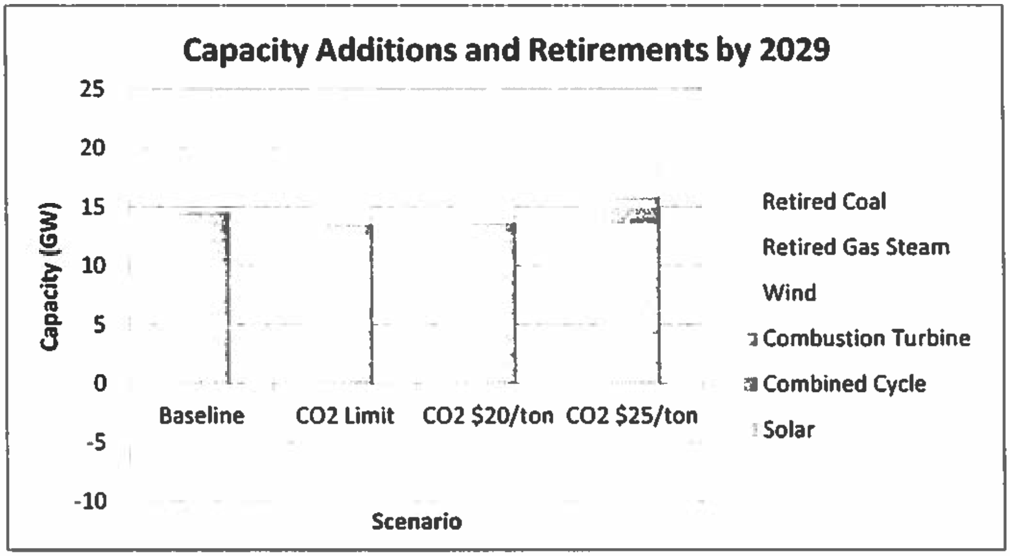

Figure 3: Capacity Additions and Retirements by 2029

With the modeled retirements and capacity additions, the generation mix in the modeling results shifts towards increased generation from natural gas and renewable generation resources, and decreased generation from coal generation resources. Table 4 and Table 5 show the generation mix in 2020 and 2029, respectively, across the four scenarios. In 2020, natural gas-fired units contribute 60% or more of total energy in the carbon scenarios, up from 44% in the baseline. Coal generation correspondingly decreases to 11 to 14%, from a baseline of 32% of total generation. By 2029, renewable generation accounts for 21 to 22% of total generation in the three CO_2 scenarios, up from 17% of total 2029 generation in the baseline scenario.

Table 4: Generation Mix in 2020 (% of MWh)

Fuel Type	Baseline	CO_2 Limit	CO_2 \$20/ton	CO_2 \$25/ton
Natural Gas (%)	44	60	60	63
Coal (%)	32	14	14	11
Wind (%)	12	15	15	16
Solar (%)	< 1	< 1	< 1	< 1
Nuclear (%)	10	10	10	10
Other (%)	1	< 1	< 1	< 1

Table 5: Generation Mix in 2029 (% of MWh)

Fuel Type	Baseline	CO_2 Limit	CO_2 \$20/ton	CO_2 \$25/ton
Natural Gas (%)	45	53	53	55
Coal (%)	29	16	16	13
Wind (%)	11	14	14	14
Solar (%)	6	7	7	8
Nuclear (%)	9	9	9	9
Other (%)	< 1	< 1	< 1	< 1

The modeling results indicate significantly higher generation from natural gas-fired resources under the Clean Power Plan. This trend is most distinct early in the

calculate the wind capacity contribution is available on the ERCOT website at http://www.ercot.com/gridinfo/resource/index.html. For solar capacity, ERCOT assumes a 70% capacity contribution based on the modeled solar output during peak hours (16:00 to 18:00) as a percentage of total installed capacity.

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compliance period, before the bulk of solar capacity additions and energy efficiency savings materialize. In 2020, natural gas consumption by the power sector is 35 to 50% higher annually in the carbon scenarios compared to the baseline, as shown in Figure 4. By 2029, natural gas consumption is 15 to 20% above the amount consumed annually in the baseline.

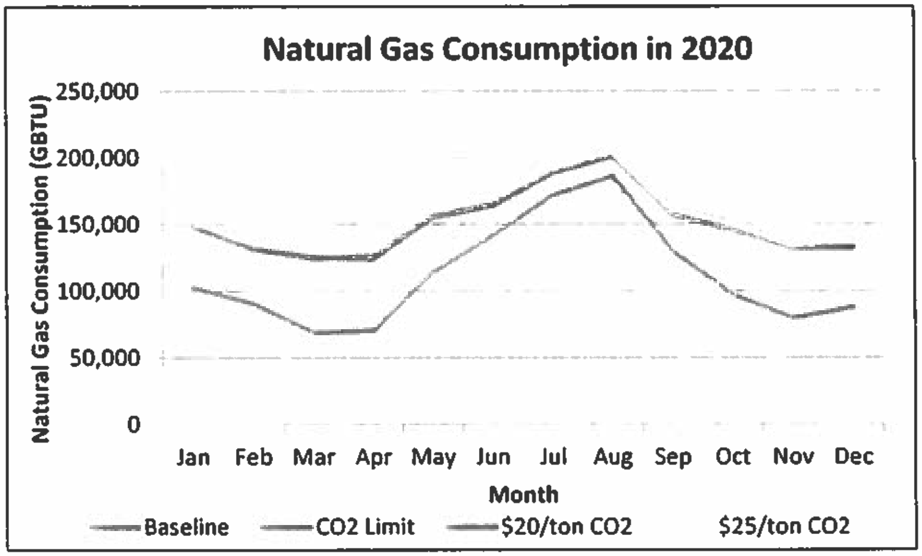

Figure 4: Natural Gas Consumption in 2020

Table 6: Carbon Dioxide Emissions Intensity

CO_2 Intensity	Baseline	CO_2 Limit	CO_2 \$20/ton	CO_2 \$25/ton
2020 CO_2 Intensity (lb/MWh)	1,175	853	905	840
2029 CO_2 Intensity (lb/MWh)	1,089	791	877	792

The four scenarios resulted in different levels of carbon intensity. As noted previously, the \$20/ton CO_2 scenario resulted in a carbon intensity above both the interim and final emissions limits in the Clean Power Plan, while the \$25/ton CO_2 scenario resulted in a carbon intensity below the interim goal and approximately meeting the final goal (see Table 6 and Figure 5). In the baseline scenario, ERCOT's carbon intensity is at 1,175 lb/MWh in 2020 and 1,089 lb/MWh in 2029. The projected emissions intensity for ERCOT in the baseline is below the Clean Power Plan emissions rate goals for 19 other states, an indication of the impact that existing market policies and investments in transmission in Texas have had on maximizing the efficiency of the generating fleet and integrating new technologies including renewable generation.

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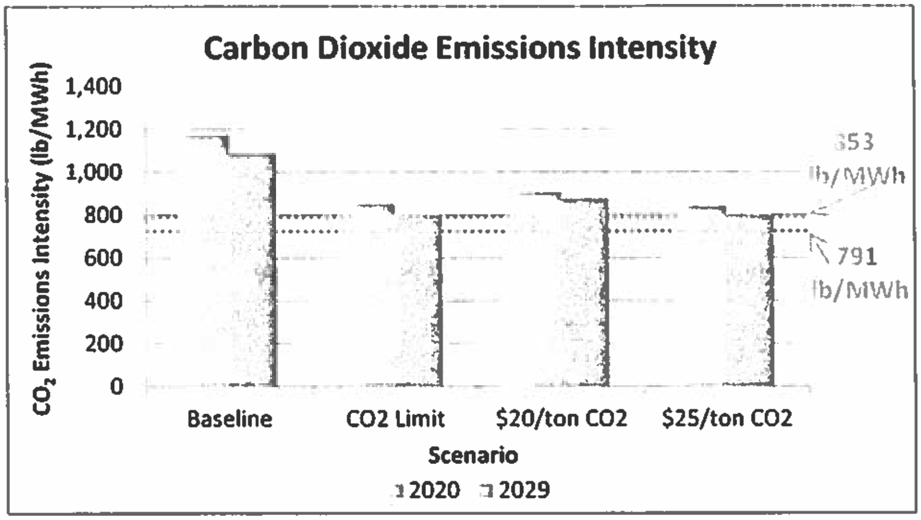

Figure 5: CO_2 Emissions Intensity

2.3. Comparison to EPA's Modeling Results

EPA conducted an analysis of the Clean Power Plan by applying the carbon limits to the U.S. electric system, and allowing their simulation model to solve for the most cost-effective solution. The results referenced here are for EPA's "Option 1 State Compliance" scenario, as compared to the base case.[14]

EPA's modeling results predict that there may be 9 GW of coal unit retirements in ERCOT due to the Clean Power Plan – most occurring before the initial 2020 compliance date. ERCOT's modeling predicted up to 6 GW of coal unit retirements, but ERCOT believes that there could be up to 9 GW of coal unit retirements resulting from the Clean Power Plan due to additional factors not considered in the model (discussed in Section 3.1). Similarly, both EPA's and ERCOT's modeling saw a major shift in the generation mix in 2020 to comply with the interim goal, with substantially increased production from natural gas generation resources and substantially decreased production from coal generation resources. However, EPA's modeling resulted in much fewer renewable capacity additions compared to ERCOT's results and significantly more new natural gas generating capacity. The lower amount of renewable capacity additions is due to EPA's use of higher capital cost assumptions for new solar capacity. The larger amount of natural gas capacity additions is due in part to EPA's modeling requirement that ERCOT maintain a 13.75% reserve margin, as discussed previously. EPA's modeling predicts more than 10 GW of new natural gas capacity by 2030 in the state compliance scenario, whereas ERCOT's carbon scenarios added 1 to 2 GW of new natural gas capacity.

3. Impact on Reliability

The modeling results raise two reliability concerns associated with implementation of the Clean Power Plan in ERCOT. These concerns are associated with the impacts of unit retirements and increased levels of renewable generation on the ERCOT grid.

3.1. Impact of Unit Retirements

As previously described, the model retired between 3,300 and 5,700 MW of coal-fired capacity in the carbon scenarios, relative to the baseline. However, these results represent a lower bound on the

[14] EPA's modeling run files are available from http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html.

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number of potential coal unit retirements due to the logic used to retire units in the model, generic unit cost information, and the impacts of other factors not considered by the model. ERCOT directed the model to retire capacity at the point when generic operating and fixed costs exceed revenues. However, in the modeling results for the carbon scenarios, there are several units operating at low revenues and/or low capacity factors that would likely be retired, especially when other non-modeled factors are taken into account. One important factor not considered in the modeling is the capital and operating cost impacts of other pending environmental regulations including the Mercury and Air Toxics Standard, the Regional Haze program, the 316(b) Cooling Water Intake Structures Rule, and the coal ash rules.

Based on a review of capacity factors and operating revenues for the remaining coal units ERCOT anticipates the retirement of an additional 2,000 MW of coal capacity and the seasonal mothball of 1,000 MW of coal capacity beyond what is specified in the model output, compared to the \$25/ton CO_2 modeled scenario. These results indicate the overall impact to the current coal fleet will be the retirement or seasonal mothballing of between 3,300 MW and 8,700 MW.

The accelerated retirement or suspended operations of coal resources would pose challenges to maintaining the reliability of the ERCOT grid. Coal resources provide essential reliability services, including reactive power and voltage support, inertial support, frequency response, and ramping capability. The retirement of coal resources will require reliability studies to determine if there are any voltage/reactive power control issues that can only be mitigated by those resources; how to replace frequency response, inertial support, and ramping capability provided by retiring units; and the necessity of potential transmission upgrades, which will be discussed later in this document.

The model also predicted the retirement of 1,300 to 1,600 MW of natural gas steam capacity in the carbon scenarios, which is less than the 2,000 MW retired in the baseline scenario. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, which improves the economics of natural gas steam units during this period. However, as with coal resources, there are a number of factors that may result in additional natural gas steam unit retirements compared to those found by the model. ERCOT estimates that an additional 1,500 to 4,500 MW of natural gas steam capacity may be at risk of retirement based on low net revenues in the model results combined with the need to comply with the 316(b) rule, CSAPR, and other environmental regulations.

The modeling results indicate that generation from retiring coal capacity will in large part be replaced by increased production from existing natural gas capacity. Though ERCOT is not currently affected by natural gas supply issues, the increased use of natural gas nationally could lead to increased market dislocations, such as seen in the winter of 2013-2014. Depending on the magnitude of these issues, there could be implications for maintaining reliable natural gas supply in ERCOT for electric generation in the future.

It should also be noted that prospective compliance with the Clean Power Plan in 2020 will impact decisions generation resources make now about investments to comply with other pending environmental regulations. With the implementation of the Clean Power Plan to consider, owners of generation resources in Texas may choose to retire units early rather than install control technology retrofits for compliance with the Mercury and Air Toxics Standard (MATS), the Regional Haze Program, or the 316(b) Cooling Water Intake Structures rule. For example, the compliance date for the MATS rule is April 2015, but several coal-fired units in Texas have received a one-year compliance extension from the Texas Commission on Environmental Quality (TCEQ). The pending market impacts due to the Clean Power Plan could result in resource owners deciding to retire these units rather than invest in the retrofit technology required to achieve compliance with MATS. Similarly, it is anticipated that EPA will

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issue a Federal Implementation Plan (FIP) for Texas for the Regional Haze program in the coming weeks. Depending on the FIP requirements, generators may need to make similar decisions about whether to make significant investments in control technology retrofits or instead retire their units, in light of eventual compliance with the Clean Power Plan. With earlier retirements of fossil fuel-fired capacity, ERCOT could experience the aforementioned grid reliability challenges well before the Clean Power Plan's first compliance date in 2020.

3.2. Impact of Renewables Integration

Integrating new wind and solar resources will increase the challenges of reliably operating the ERCOT grid. In 2013, almost 10% of the ERCOT region's annual generation came from wind resources. In order to accommodate this level of intermittent generation, ERCOT has needed to evaluate impacts on operational reliability and improve wind output forecasting capabilities. The increased penetration of intermittent renewable generation, as projected by these modeling results, will increase the challenges of reliably operating all generation resources. If there is not sufficient ramping capability and operational reserves during periods of high renewable penetration, the need to maintain operational reliability could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed rule deadlines.

Based on the \$25/ton CO_2 scenario, intermittent renewable generation sources will contribute 22% of energy on an annual basis in 2029. However, during 628 hours of the year intermittent generation will serve more than 40%[15] of system load. During 128 hours instantaneous renewable penetration will be higher than 50%, and the peak instantaneous renewable penetration from the model results is 61%. The significant change from present experience is that the highest renewable penetration hours will be driven by maximum solar production during relatively high wind periods. These periods occur during the day (8 a.m. to 5 p.m.), as opposed to early morning hours (usually 2 to 4 a.m.), as currently experienced in ERCOT. The high instantaneous renewable penetration hours in 2029 occur year round except for the July-September period. Figure 6 shows generation output by fuel type for the days with the highest instantaneous penetration of renewables in 2029 in the \$25/ton CO_2 scenario.

[15] The record in the ERCOT region for wind penetration occurred on March 31, 2014 at 2:00 a.m., when wind resources met 39.44% of load.

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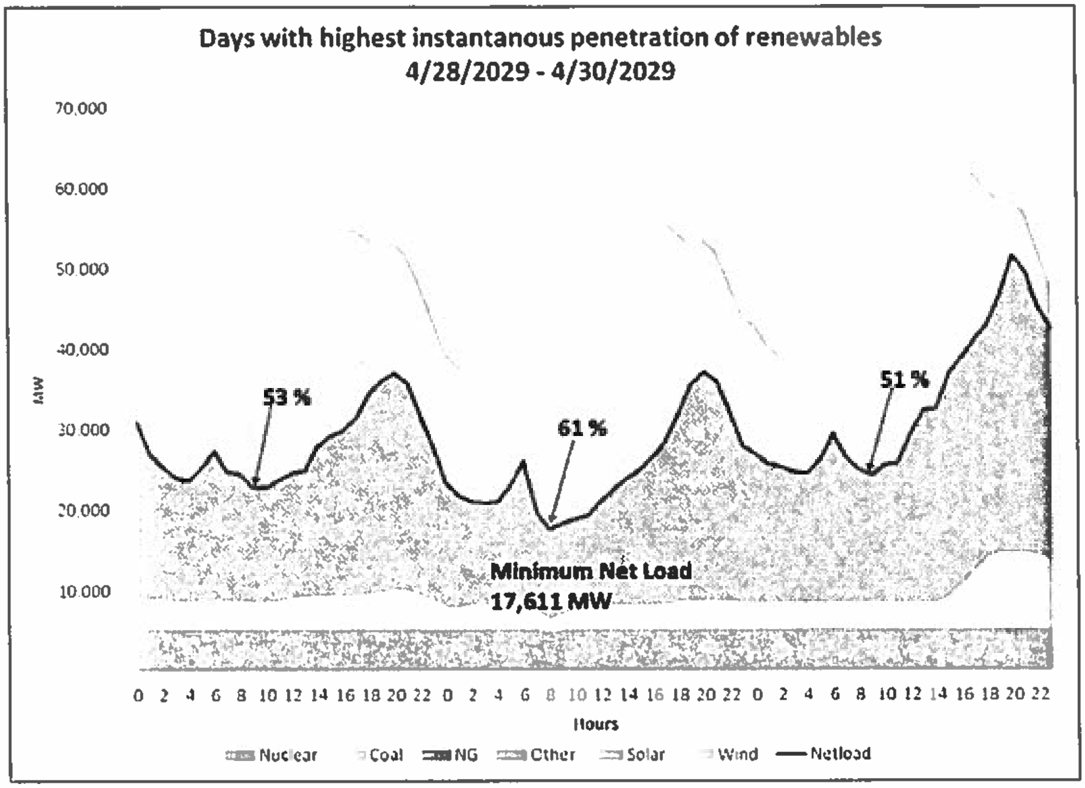

Figure 6: Days with Highest Instantaneous Penetration of Renewables

Due to load growth, the lowest net load (defined as total load minus generation from intermittent energy resources) in 2029 is higher than current record (14,809 MW in 2014 and 17,611 MW in 2029). Therefore, during low net load hours there will be no significant change compared to current operating conditions in terms of MW of thermal generation online, inertial response and frequency response available during generation trip events.

Significant increase can be seen in net load ramps compared to current experience. While the net load down ramps in 2029 are still largely defined by decreases in load at night, as is the case currently, the highest net load up ramps are defined by rapid solar production decline at sunset and simultaneous decline in wind production during evening load pick-up. Table 7 displays the maximum ramp-up and ramp-down in 2029 in the \$25/ton CO_2 scenario. Figure 7 shows wind and solar generation output and customer demand (load) on the day with the highest three hour net load ramp in 2029 from the \$25/ton CO_2 scenario.

Table 7: Maximum Ramp-up and Ramp-Down

Net Load	Maximum 60-min Ramp-up (MW/60Mins)	Maximum 60-min Ramp-down (MW/60Mins)	Maximum 180-min Ramp-up (MW/180Mins)	Maximum 180-min Ramp-down (MW/180Mins)
2011 Net Load (actual)	6,267	-6,124	16,058	-18,985
2012 Net Load (actual)	6,563	-7,019	14,997	-15,977
2013 Net Load (Jan-May) (actual)	6,247	-5,446	12,200	-14,373
2029 Net Load (modeled \$25/ton CO_2 scenario)	11,074	-11,938	22,221	-22,560

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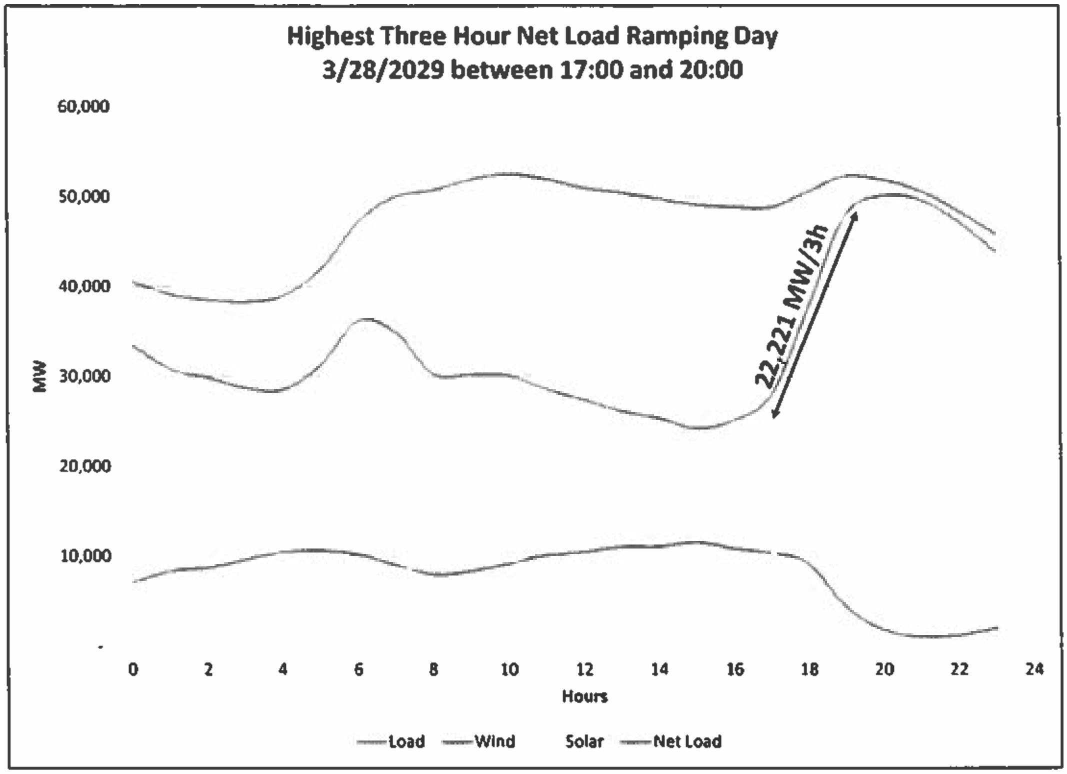

Figure 7: Highest Three Hour Net Load Ramping Day

The simulation model assumes perfect foresight and ensures that there is sufficient amount of thermal generation with sufficient ramping capability committed to follow such rapid net load ramps. In real time operation, however, accommodating the maximum ramps resulting from simultaneous solar and wind generation decline would be more challenging. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. It is important that market mechanisms are adopted so that the need for flexible generation (with short start-up times and high ramping capability) is reflected in real-time energy prices. Market mechanisms to include dispatchable load resources could also help to address flexibility needs. Enhancing wind and solar forecasting systems to provide more accurate wind and solar generation projections will become increasingly important. Regulation and Non-Spinning reserves will need to be increased to address increased intra-hour variability and uncertainty of power production from wind and solar. Tools available to system operators must be enhanced to include short-term (10-min, 30-min, 60-min, 180-min) net-load ramp forecasts and simultaneous assessment of real-time ramping capability of the committed thermal generation to assist operators in maintaining grid reliability.[16]

Though all solar capacity additions predicted by the model were utility-scale, it is likely that a significant portion of future solar generation capacity will be embedded in the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels). ERCOT does not currently have visibility of these resources. To produce accurate solar production forecasts, ERCOT would need to have information regarding the size and location of distributed solar installations. Additionally, to ensure grid

[16] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013. Available from http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_CAISO_VG_Assessment_Final.pdf

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reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems.[17]

Based on ERCOT's modeling, the majority of new renewable generation resource additions are anticipated to be solar. However, if instead ERCOT sees a large amount of wind resource capacity additions, then the reliability impacts may be more severe. Wind production in West Texas results in high renewable penetration during early morning hours, when load is lowest. An expansion in wind production, rather than solar, may result in lower net loads and significant reliability issues. If ERCOT cannot reliably operate the grid with these high renewable penetration levels, then production from these resources will be curtailed to maintain operational reliability. Should this occur, it would reduce production from renewable resources, leading to possible non-compliance with the proposed rule deadlines.

4. Impact on Transmission Infrastructure

As previously noted, ERCOT's analysis indicates that imposition of the constraints proposed in the Clean Power Plan will result in retirement of legacy base-load generation and development of new renewable generation resources. These changes to the ERCOT generation mix will likely require significant upgrades to the transmission infrastructure of the ERCOT system.

The retirement of a large amount of coal-fired and/or gas steam resource capacity in the ERCOT region would have a significant impact on the reliability of the transmission system. The transmission system is currently designed to reliably deliver power from existing generating resources to customer loads, with the existing legacy resources that are located near major load centers serving to relieve constraints and maintain grid reliability. Retirement of these resources would result in a loss of real and reactive power, potentially exceeding thermal transmission limitations and the ability to maintain stable transmission voltages while reliably moving power from distant resources to major load centers. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of coal-fired and gas steam resources were to be displaced. If new natural gas combined cycle resources were to locate at or near retiring coal-fired and gas steam resources, the impact would be lessened.

In the ERCOT region, it takes at least five years for a new major transmission project to be planned, routed, approved and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be seen at least five years in advance. Given the competitiveness of the current ERCOT market, unit retirement decisions will likely be made with only the minimum required notification (currently 90 days). Reliability-must-run contracts may provide an avenue to maintain generation resources necessary to support grid reliability, but these make-whole contracts could incur significant market uplift costs, especially if they are needed for several years or if the contracted units require capital investments in order to maintain compliance with other environmental regulations.

The growing loads in the ERCOT urban centers are causing continued growth in customer demand and a resulting need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. A new 345-kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston region, at an estimated cost of more than $590 million. Long-

[17] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013. Available from http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

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term studies indicate a potential need for further upgrades in the mid-2020s.[18] The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed project. Retirement of generation after 2018 would accelerate the need for additional transmission from the long-term horizon (6-15 years) into the near-term horizon (1-6 years).

Similarly in the San Antonio and the Dallas-Fort Worth regions there are multiple new transmission projects that are being planned to serve existing load growth. At costs of hundreds of millions of dollars, the need for these and similar projects would be accelerated by retirement of legacy units in these regions.

Growth in renewable generation would also likely have a significant impact on transmission requirements. Although ERCOT did not estimate the costs of these transmission infrastructure improvements in this study, recent projects can be illustrative of the potential costs. In early 2014, the transmission upgrades needed to integrate the Texas Competitive Renewable Energy Zones (CREZ) were completed: more than 3,600 miles of new transmission lines constructed at a cost of $6.9 billion dollars. The project took nearly a decade to complete. The CREZ project has contributed to Texas' status as the largest wind power producer in the U.S.

While the CREZ transmission upgrades provide transmission capacity beyond current generation development, these new circuits will not provide sufficient capacity to reliably integrate the amount of renewables necessary to achieve the requirements of the proposed rule. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, further significant transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve the proposed compliance requirements in the Clean Power Plan, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

5. Impact on Energy Costs

The model output included detailed cost information that can be used to characterize the impact of the Clean Power Plan on energy prices in ERCOT. This section discusses the cost impacts for the baseline, $20/ton CO_2, and $25/ton CO_2 scenarios. All cost figures are reported in nominal dollars, except capital costs, which are in real 2015 dollars.

Table 8: Locational Marginal Prices*

Locational Marginal Price	Baseline	CO_2 $20/ton	CO_2 $25/ton
2020 LMP ($/MWh)	$49.46	$66.17	$73.58
2029 LMP ($/MWh)	$72.02	$81.13	$84.28
2020 LMP % change from baseline	n/a	34	49
2029 LMP % change from baseline	n/a	13	17
2020 retail energy bill % change	n/a	14	20
2029 retail energy bill % change	n/a	5	7

*LMPs for the CO_2 limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

The inclusion of carbon prices resulted in higher average locational marginal prices (LMPs) compared to the baseline scenario, as shown in Table 8.[19] In the $20/ton carbon price scenario, the average LMP in ERCOT was $66.17 in 2020 and $81.13 in 2029 – 34% and 13% above the baseline scenario LMPs for those years, respectively. In the $25/ton carbon price scenario, the average LMP was $73.58 in 2020 and $84.28 in 2030

[18] See ERCOT's 2013 *Report on Existing and Potential Electrical System Constraints and Needs*, available from http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf.

[19] LMPs for the CO_2 limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

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– 49% and 17% above the baseline scenario estimates. As a general estimate, if wholesale power is 40% of the consumer bill, these increases in average LMPs would result in a retail energy price increase of 14 to 20% in 2020, and 5 to 7% in 2029. The increase in wholesale and consumer energy costs compared to the baseline decreases by 2029 due to the addition of new solar capacity, which has virtually no variable costs, and the accrual of energy efficiency savings. The costs of investments in energy efficiency are not estimated in this study. In their comments to the Public Utility Commission of Texas, EUMMOT estimated the cost of achieving the level of energy efficiency savings estimated by EPA at $1.6 to $2.9 billion per year in Texas.[20]

Table 9: Fuel and Emissions Allowance Costs in 2020

Variable Costs	Baseline	CO_2 Limit	CO_2 $20/ton	CO_2 $25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	12.9	12.9	16.4	17.0
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	0	28	32
Average Fuel and Emissions Allowance Cost ($/MWh)	30.54	31.82	40.80	41.65
Emissions Allowance Costs Only (billions of dollars)	0	0	3.5	4.1
Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	21	24

Table 10: Fuel and Emissions Allowance Costs in 2029

Variable Costs	Baseline	CO_2 Limit	CO_2 $20/ton	CO_2 $25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	17.7	16.8	20.4	20.9
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	-5	15	18
Average Fuel and Emissions Allowance Cost ($/MWh)	37.07	36.60	44.28	45.49
Emissions Allowance Costs Only (billions of dollars)	0	0	3.8	4.4
Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	19	21

The LMP reflects the variable cost associated with the generation resource on the margin. Though this measure provides an estimate of wholesale energy prices for consumers, the increase in production costs for generators would differ. The model results indicate that generators' variable costs (which include fuel and emissions allowance costs) in 2020 will increase by 28 to 32% in the $20/ton CO_2 $25/ton CO_2 scenarios, respectively, compared to the baseline, as shown in Table 9. The variable costs of the carbon scenarios reflect the increased cost of natural gas generation, and the effects of energy efficiency and additional renewable generation. By 2029, these costs are 15 to 18% above the baseline for the two respective scenarios, as shown in Table 10. This increase is due in large part to the CO_2 emissions price, which in 2029 posed a cost of $3.8 billion in the $20/ton CO_2 scenario and $4.4 billion in the $25/ton CO_2 scenario, comprising 19% and 21% of total variable costs for the two respective scenarios.

Note that the information in Table 8, Table 9 and Table 10 do not include the associated costs of building or upgrading transmission infrastructure, natural gas infrastructure upgrades, ancillary services procurement, energy efficiency investments, and potential Reliability-must-run contracts.

[20] Presentation by Jarrett E. Simon, Director Energy Efficiency, CenterPoint Energy. *PUCT Workshop Project 42636: Comments on Proposed EPA Rule Regarding Greenhouse Gas Emissions for Existing Generating Units*, August 15, 2014. Available from the Public Utility Commission of Texas, Docket 42636, Item 21.

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Additionally, there will be capital costs for new generation resources built in both the baseline and carbon scenario cases. As Table 11 shows, the capital costs in the carbon scenarios are $7 to $11 billion higher in the carbon scenarios compared to the baseline, or an increase of 52 to 77%. Figure 8 displays the capital costs by fuel type. Though not directly reflected in LMPs, these costs will also ultimately be reflected in consumers' energy bills.

Table 11: Total Capital Cost Investments by 2029

Capital Costs	Baseline	CO_2 Limit	CO_2 $20/ton	CO_2 $25/ton
Total Capital Cost (billions of 2015$)	14	23	22	25
Capital Cost change from baseline (billions of 2015$)	n/a	8	7	11
Capital Cost change from baseline (%)	n/a	59	52	77

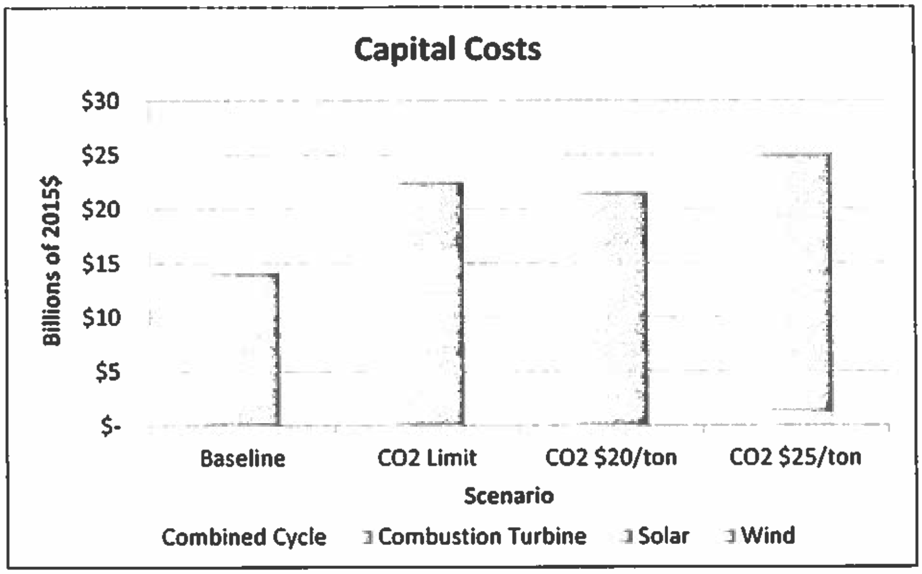

Figure 8: Capital Costs of New Capacity by Fuel Type

As previously described, the modeling results showed a decrease in the ERCOT reserve margin in the early years of the compliance timeframe. In a recently completed report prepared for the Public Utility Commission, the Brattle Group quantified the cost to consumers associated with periods of reduced reserve margins.[21] These costs include a range of production costs, including the cost of emergency generation, the cost of utilizing interruptible customers, the costs of utilizing all of the available ancillary services, and the impact to consumers from firm load shedding, all of which increase at lower reserve margins. As an example, the retirement of 6,000 MW of generation capacity would be expected to reduce the system reserve margin by about 8%. Based on this report, if this change occurred when the system reserve margin was approximately 14%, the increased annual system costs at the resulting 6% reserve margin would be approximately $800 million higher than would be expected prior to the regulatory impact.[22]

Finally, it should be noted that ERCOT used the same natural gas price assumptions in all four scenarios. With the increased consumption of natural gas anticipated not only in ERCOT but nationally, natural gas

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[21] The Brattle Group. *Estimating the Economically Optimal Reserve Margin in ERCOT*, January, 2014. Available from http://interchange.puc.texas.gov/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40000&TXT_ITEM_NO=649.

[22] See Figure 22 of the Brattle Group report (page 48).

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prices could increase beyond the levels anticipated in this modeling analysis. This would pose additional costs to consumers, which are not captured in this study.

6. Summary

Based on this analysis, it is evident that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. The proposed CO_2 emissions limitations will result in significant retirement of coal generation capacity, could result in transmission reliability issues due to the loss of fossil fuel-fired generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. If the expected retirement of coal resources were to occur over a short period of time, reserve margins in the ERCOT region could reduce considerably, leading to increased risk of rotating outages as a last resort to maintain operating balance between customer demand and available generation. The need to maintain operational reliability (i.e., insufficient ramping capability) could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed rule deadlines.

As noted previously, ERCOT supports the IRC proposal for inclusion of a reliability safety valve process in the context of the CO_2 rule, as well as the consideration of electric grid reliability during the development of State Implementation Plans. These proposals could help mitigate the potential reliability impacts of the Clean Power Plan.

The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region. Based on ERCOT's analysis, energy costs for consumers may increase by up to 20% in 2020, without accounting for the associated costs of transmission upgrades, natural gas supply infrastructure upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. Consideration of these factors would result in even higher energy costs for consumers.

ERCOT will issue the full report of this environmental regulatory impact study in mid-December 2014. The full report will include information about the impacts to ERCOT of several proposed or recently finalized environmental regulations, including MATS, CSAPR, the Regional Haze program, the 316(b) Cooling Water Intake Structures rule, and the coal ash rules. The report will also provide more details about the modeling analysis of the Clean Power Plan. As new information becomes available, ERCOT will continue to analyze the impacts of the Clean Power Plan, as well as other regulatory developments that may impact the ability to provide reliable electricity to consumers in Texas.

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