COMMENTS BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ), PUBLIC UTILITY COMMISSION OF TEXAS (PUCT), AND RAILROAD COMMISSION OF TEXAS (RRC) REGARDING THE FEDERAL PLAN REQUIREMENTS FOR GREENHOUSE GAS EMISSIONS FROM ELECTRIC UTLILITY GENERATING UNITS CONSTRUCTED ON OR BEFORE JANUARY 8, 2014; MODEL TRADING RULES; AMENDMENTS TO FRAMEWORK REGULATIONS; EPA DOCKET ID NO. EPA-HQ-OAR-2015-0199

Contents

I. Summary of Proposed Rule

On October 23, 2015, the United States Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule, under Federal Clean Air Act (FCAA), §111(d), for a federal plan and model rules to implement the carbon dioxide (CO_2) emission guidelines for existing fossil fuel-fired electric generating units (EGU), also known as the final Clean Power Plan (80 FR 64662). The federal plan would apply to states that either fail to submit a state plan or for which the EPA does not approve the submitted state plan. The proposal includes changes to general rules for FCAA §111(d) plans as well as two proposed model rules: a rate-based emission trading program and a mass-based emission trading program. The EPA would finalize both the rate-based and mass-based model rules, but would adopt a single approach --either the rate-based or mass-based trading program-- as the federal plan for all states for which a federal plan was required.

II. Comments

A. Electric Reliability and Energy Policy

1. The EPA should reevaluate the reliability impacts of the Clean Power Plan using the reliability assessments performed by the Electric Reliability Council of Texas (ERCOT) and similar local reliability authorities. The ERCOT Analysis of the Impacts of the Clean Power Plan (October 16, 2015) is attached for the EPA's consideration.

The analysis shows that a far greater capacity of coal is at risk of retirement in the ERCOT region than projected by the EPA. ERCOT estimates that an additional 4,000 megawatts (MW) of coal capacity incremental to the baseline case could retire by 2030 as a result of the Clean Power Plan. The EPA estimated only 600 MW of coal capacity retirements by 2030 under a rate-based plan and 1,321 MW of coal capacity retirements by 2030 in a mass-based plan.[1] The EPA should use regionally specific analyses performed by the local reliability authority rather than its Integrated Planning Model (IPM) results. Analyses performed by the local authority are more likely to reflect actual grid conditions and future market outcomes than IPM's projections. Furthermore, IPM is not an accurate model for assessing reliability because IPM assumes that lost capacity below an area's reserve margin will simply be added to fill the loss. A true reliability assessment should consider whether the reserve margin can be maintained, particularly for the ERCOT region, where the reserve margin is a target, not a mandate. The EPA should reevaluate its resource adequacy and reliability analysis in light of the analysis performed by ERCOT and other local reliability authorities. Also, as discussed in II.B.1 below, the EPA should include an effective reliability safety valve in the federal plan in light of ERCOT's analysis.

2. The proposed federal plan would implement the Clean Power Plan emission guidelines, which continue to be based upon the EPA's flawed approach to establishing the best system of emission reduction (BSER) by evaluating the electric grid and states' energy policies as a whole, instead of the individual sources that it has authority to regulate under §111(d). A state's energy generation mix is not BSER as the EPA claims; it is the direct result of a state's energy policy.

The EPA's authority under §111(d) is limited to setting "standards of performance" for emissions of air pollutants from stationary sources. Together, the EPA's final Clean Power Plan and the associated proposed federal plan are 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 CO_2 emission reductions from the proposal, in light of other worldwide CO_2 emissions. A state's renewable energy (RE) standards and the fuel mix of the fossil fuel-fired power generation fleet are not a system of emission reduction but are in fact energy policy decisions. The EPA is taking a mix of energy policies from the states, selecting the policies that it prefers, and imposing those policies onto the states by incorporating those energy policies into the state goal calculation under the guise of "BSER."

The Texas Legislature adopted a RE portfolio standard (RPS) in 1999, and increased it in 2005. Under the RPS, all entities in the ERCOT region that sell electricity are required to either directly own or purchase RE capacity. Entities that do not own or purchase RE capacity are required to purchase renewable energy credits (REC) to satisfy the RPS. The PUCT has adopted a rule establishing a REC trading program.[2] Under the REC trading program, RECs may be generated, transferred, and retired by RE power generators certified under the rule, as well as retail entities and certain other market participants. Through the RPS, the Texas Legislature mandated that a minimum amount of electric generation capacity from RE sources be installed in the state. Texas has met its existing mandates. In light of this, the Texas Legislature has not indicated a preference to increase these mandates.

The proposed federal plan and model trading rules would illegally usurp the roles of the Texas Legislature and PUCT in determining the right RE policy for Texas. If the recently adopted emissions performance rate is applied to EGUs, many EGUs will have no choice but to build new RE capacity, or pay for others to build RE capacity on their behalf. The end result amounts to the EPA commandeering the Texas RPS statutes and regulations without considering cost and reliability, which have been crucial considerations for the Texas Legislature and the PUCT in setting Texas RE policies.

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[1] U.S. Environmental Protection Agency, *Technical Support Document: Resource Adequacy and Reliability Analysis* at 30, 51 (August 2015).
[2] 25 Tex. Admin. Code § 25.173.

The ERCOT study also highlights a critical factor that the EPA has failed to consider: grid limitations. Regardless of whether Texas files a state plan or has a federal plan imposed upon it, there is a limit to the amount of intermittent RE that the ERCOT grid can accommodate due to the need for other available resources to ensure grid reliability. In 2015, 11.7% of the ERCOT power region's annual generation came from wind, and at its highest level of penetration, wind energy served approximately 45% of all customer demand. The ERCOT study forecasts that the rule will force significant growth in additional wind and solar resources, which together may comprise 27% of total generation by 2030. "Significant ramping capability and operational reserves" from fossil EGUs is required to maintain grid reliability during these periods of high RE penetration; however, at a high enough level of penetration, ERCOT will likely be forced to curtail RE output to keep the grid stable.[3] As renewable resources are curtailed, production is reduced, and it is more likely that compliance with the rule cannot be achieved—a scenario that the rule does not contemplate. These issues are among the factors that the Texas Legislature has been deliberating as it discusses Texas's existing RPS law and precisely why these issues are properly left to state legislatures and electricity regulators to decide.

B. Federal Plan

1. The EPA should include an effective reliability safety valve in the federal plan, and the use of the safety valve provision should be at the discretion of the state public utility commission and local reliability authority. Regional trading does not necessarily assure reliability.

The EPA's proposed federal plan does not include a reliability safety valve. The EPA argues that because inflexible requirements are not imposed and "the very nature of the federal plan" supports reliability by allowing companies to obtain allowances or credits, a reliability safety valve is unnecessary (80 Fed. Reg. at 64982). However, the EPA's logic is flawed because it assumes that allowances or credits will be available to a specific entity if an energy reliability situation arises that causes that entity to operate their affected units more than expected. Allowances or credits may not be available, particularly if the reliability issue occurs near the end of a compliance period. The existence of banks of credits or allowances under the Clean Energy Incentive Program (CEIP) does not guarantee that these will be available to affected EGUs as needed to ensure reliability in an emergency situation.

Furthermore, regional trading under a federal plan could have significant implications for reliability in the ERCOT region due to the nature of the ERCOT grid as an electrical island with limited capability to import or export power. If emission allowances or emission rate credits (ERC) can be traded outside the region, but electric power cannot, regional trading could raise additional reliability issues in the ERCOT region beyond those identified in previous studies. This issue becomes particularly acute under a federal plan because the state will not be able to determine its trading partners, but rather would be grouped with other states also under federal plans (or trading-ready state plans). Texas could be grouped with states with poorer renewable resources and less capacity available to shift towards natural gas-fired generation, increasing the relative requirements for the ERCOT region. Any resulting reliability issues would need to be addressed entirely within the ERCOT region, even though emissions allowances could be traded with other states.

The ERCOT region has some of the best wind and solar resources in the nation. As a result, allowance trading under a regional plan is likely to drive more renewable development in the ERCOT region than would be seen under a state-wide plan, since it will likely be cost-effective to build renewables where the resources are strongest and then trade the resulting allowances to other states. However, because the associated electricity cannot also be traded outside of the

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[3] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 13 (October 16, 2015).

region, any associated integration issues (i.e., system costs and reliability impacts due to increased variable generation and the need for additional transmission) would be addressed solely within the ERCOT region. In this way, regional trading under a federal plan could increase the challenges of reliably operating the ERCOT grid beyond the levels anticipated under a state-wide plan, and most, if not all, of the associated costs would be borne exclusively by customers in Texas.

By the same design, because Texas does have strong renewable resources and a substantial existing natural gas combined cycle (NGCC) fleet, trading with regional partners with fewer of these resources (e.g., states heavily reliant on coal-fired generation) could further decrease the allowances available to coal-fired generation in the ERCOT region. This could result in earlier and additional coal unit retirements compared to those identified in ERCOT studies. These studies have indicated likely localized transmission issues resulting from coal unit retirements, as well as potential resource adequacy challenges if retirements occur over a short timeframe, before the market has time to respond with new investment. To the extent that regional trading could exacerbate these trends, it might create additional reliability issues that must be addressed – again, wholly within the ERCOT region.

The unique nature of the ERCOT region creates different reliability challenges compared to other areas of the country. As the examples above indicate, it is possible that discrepancies between future allowance trading market regions and existing electricity market regions could result in additional reliability challenges and costs in the ERCOT region relative to compliance under a state-wide plan. The federal plan proposal states that the EPA, U.S. Department of Energy, and the Federal Energy Regulatory Commission (FERC) have agreed to coordinate efforts to help ensure continued reliable electricity generation. As the ERCOT region does not transcend state boundaries, FERC has limited authority in the region and may not be able to address reliability issues in the manner assumed by the EPA. The EPA should consider these potential issues in the design of the model trading rules and the federal plan.

The EPA requested comment on the approach of developing an allowance set-aside for emergency circumstances (80 Fed. Reg. at 64982). An allowance set-aside is not an appropriate approach for addressing energy emergencies because the EPA has no means of determining the amount of allowances that may be needed for future emergencies. The emergency allowance set-aside could be severely diminished and additional emergencies could occur during the compliance period.

Although the TCEQ does not support all the requirements for a reliability safety valve in the Clean Power Plan, the EPA should include a reliability safety valve under a federal plan since it adopted the requirement for state plans. Additionally, to promote consistency in implementing both state and federal plans, any reliability safety valve mechanism available under a federal plan should be substantially similar to the Clean Power Plan safety valve for state plans. However, under the Clean Power Plan, use of the safety valve is subject to the EPA's approval, which is not appropriate because the EPA is not in a position to determine if an electric reliability emergency is occurring. The state public utility commission and local reliability authority should make the final determination regarding an energy emergency and use of the safety valve, even under a federal plan.

2. Rather than finalizing only a single approach (i.e., either mass-based or rate-based) for the federal plan, the EPA should finalize both approaches and evaluate the best approach for each state on a case-by-case basis upon promulgation of the federal plan in each state.

The EPA's proposal indicates that although the EPA intends to finalize the model trading rules for both approaches, only one will be available to states under the federal plan. The best approach for each state will depend on that state's unique electrical grid system. Finalizing both approaches would allow for each state to participate in the program that works best for its energy infrastructure. While prior EPA rules targeting the electric utility sector may have had impacts to a state's electrical grid and reliability, the CO_2 emission guidelines for existing power plants effectively establish an emission performance standard for the state's entire electrical grid. Multiple state agencies must be involved in the analysis of the emission guidelines and the decision-making process to determine the best approach for the state. By the time the EPA finalizes this federal plan, planning for a potential state submittal would already be well underway, regardless of whether the state intends to submit a complete state plan or request an extension in 2016. The uncertainty of the federal plan's trading approach would impact the state's planning and further complicate its decision regarding whether to submit a state plan or not. If a state ultimately decides that the best approach is not the same one that is finalized in the federal plan, the state's options for participation in the federal trading program would be limited.

3. If only a single approach is finalized for the federal plan, that should be made clear in the final rule, especially if the EPA's intention is to only provide public notice of a federal plan as part of a finding of failure to submit a state plan or disapproval of a submitted state plan. Effectively, this final rule would serve as the only federal plan proposal.

The EPA refers to its "staged approach" as finalization of one or more model trading rules on the one hand and finalizing federal plans on the other. Thus, the approach that is finalized in this rulemaking would be the only notice to states regarding which of the approaches (i.e., either mass-based or rate-based) would be used in the federal plan. Again, this decision will impact the state's planning and its decision of whether to submit a state plan or not. Further, if a state chooses an approach that is different from the federal plan, it will not have the option of participating in interstate trading with those states included in the federal plan. It is therefore necessary for the EPA to make clear which approach will be used for the finalized federal plan.

4. The federal plan should make clear the criteria states must use and the steps needed to transition from the federal plan to an approvable state plan and allowance tracking system.

The proposed federal plan indicates that states retain the flexibility to modify certain aspects of the federal plan or to eventually transition to a state plan. It would be appropriate for this transition to occur at the conclusion of a federal plan compliance period. However, the rulemaking, following an appropriate notice and comment process, should also clarify *how* this transition would need to occur. These clarifications should include: what specific provisions would have to be included in an approvable state plan to facilitate this transition; if the state plan involves a different compliance approach such that the state will no longer participate in the federal trading program, any federal requirements that would continue to apply to affected EGUs; and a description of how affected EGUs would exit the federal trading program. Additionally, these requirements should be finalized so as to minimize complications, delay, and burdens for states and affected EGUs.

The proposal also indicates states may use an EPA-designated allowance tracking system that is interoperable with an EPA-administered allowance tracking system. The EPA should provide guidance to states of what an interoperable system may comprise such that the incentive to create eligible generation in the last compliance period, from eligible EGUs under the output-based allocation set-aside subject to the federal plan, is not potentially diminished or ultimately lost. Such guidance would provide states with the ability to proactively determine if states wish to replace and how and when states may choose to replace a federal plan with a state plan.

5. Contrary to the EPA's claims, the proposed federal plan will not result in a reduction of 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 Clean Power Plan 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 previously detailed in the TCEQ's comments on the Clean Power Plan proposed rule, the expected reduction in CO_2 in the United States will be greatly exceeded by the increases in CO_2 emissions from other countries, most notably China. The EPA projects that the proposed federal plan will reduce annual CO_2 emissions in the United States by between 413 – 415 million metric tons per year by 2030, assuming all states of the contiguous United States will be regulated under a federal plan or will adopt the model rule. The total increase in annual CO_2 emissions from countries that are not members of the Organization of Economic Co-operation and Development, including China and India, from 2010 to 2030 is projected to be 9,988 million metric tons per year, 24 times the total annual CO_2 reductions the EPA expects from the Clean Power Plan by 2030. 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.

6. The EPA has not provided a single concrete benefit of the proposed federal plan. 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.

Just as it did for the Clean Power Plan final rule, the EPA has only provided monetized climate benefits of the CO_2 reductions from the proposed federal plan 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 have any quantifiable effect on global climate (Regulatory Impact Analysis for the Proposed Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations). Furthermore, even though the EPA used the global SCC factor for calculating monetized benefits from the CO_2 reductions of the proposed rule, 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.

7. The proposed federal plan would implement the Clean Power Plan emission guidelines, which require the use of net generation to demonstrate compliance with the state goals. This reliance on net generation does not consider the source-specific actual operation of facilities that have installed pollution control equipment that increases onsite parasitic load.

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. The use of net generation only penalizes companies that have had to install controls for compliance with other regulations that have increased parasitic loads due to installing pollution control equipment. The EPA's reliance on net generation to develop state goals ignores source-specific performance variability and the fact that some affected sources, suffering from increased parasitic load due to other EPA regulations, must increase generation output to maintain the same supply to the electric grid to meet demand, ultimately resulting in increased CO_2 emissions. By expressing the state goals and reporting requirements in terms of gross generation, this would allow for a more equitable treatment of all affected sources by observing the ratio of CO_2 emissions to electric generation for all sources before parasitic load, thus normalizing for other EPA regulations that target certain affected sources.

C. Rate-Based Implementation Approach

1. The EPA should not limit options to generate ERCs in the federal plan from the full list of options discussed in the emission guidelines.

The eligibility requirements discussed in section VIII. K. of the emission guidelines allow states to choose from multiple options to generate ERCs. The emission guidelines list options like biomass, combined heat and power (CHP), and waste heat and power (WHP) that are eligible to be used to generate ERCs. The TCEQ supports inclusion of these options in the federal plan. States that would be subject to the federal plan should be able to readily take advantage of CO_2 emission reductions that result from options like biomass, CHP, and WHP.

D. Mass-Based Implementation Approach

1. Zero-emitting EGUs, such as RE and nuclear sources, should be provided allowances as part of the output-based allocation approach so that states can take advantage of already existing units in the state's fleet.

As stated below in II.E.7., the EPA is overlapping the two parts of §111(b) and §111(d) in both the Clean Power Plan and the proposed federal plan by imposing leakage requirements on the mass-based approach. If the EPA had established BSER consistent with prior precedent under §111, then the leakage issue would not exist. However, if states are forced to adapt to the concept of leakage and must comply with requirements associated with the issue, the EPA should provide for greater flexibility to comply with the proposed federal plan requirement.

The EPA proposes to provide allowances to existing NGCC capacity to create a set-aside bank aimed at mitigating leakage. As part of this output-based set-aside bank, existing RE sources should be eligible to receive allowance allocations. If the EPA disallows states from capitalizing on existing renewable generation as eligible generation to receive allowances from this proposed set-aside, the EPA would not only undermine its own claim that states have broad flexibility in choosing which measures to use to satisfy the state goals, but it would also severely discriminate against states that have already heavily invested in RE resources and that already have a diversified portfolio of generation. Texas' current installed wind power capacity, as of fall 2015, is approximately 16,000 MW, which is more than 2.5 times the current installed wind power capacity of the state with the next highest capacity. Texas is also seventh in the nation in terms of installed solar photovoltaic (PV) system capacity and tenth in terms of average cost of solar systems on a dollar per watt basis. If the EPA adopts an output-based set-aside to address leakage under the mass-based approach in a federal plan, it should allocate allowances earned per megawatt-hour (MWh) for RE sources similarly to its proposed methodology for existing NGCC units, but with either no capacity-factor threshold or a lower capacity-factor threshold than proposed for NGCC units. Because RE generation such as wind and solar may not possess the same dispatch capability as NGCC generation, the EPA should account for this variability by providing allowances to eligible EGUs by either eliminating a capacity-factor threshold or by establishing a capacity-factor threshold lower than 50%.

2. A mass-based trading program itself will not incentivize new and existing low- and zero-emitting generation and, in particular, the construction of new RE

generation. Simply creating a set-aside of allowances designated for a specific source type will not cause the construction of that source type such that states can further use those new sources to mitigate leakage.

The EPA fails to appropriately explain why and how a mass-based trading program in and of itself provides incentive for new and existing low- and zero-emitting generation, i.e., how a mass-based trading program in particular incentivizes the construction of new RE sources, and why the results of such a mass-based trading program should be used to mitigate leakage. If states are forced to adapt to the concept of leakage and must comply with requirements associated with the issue, the EPA should explain the reasoning it relied upon to conclude that a mass-based trading program would encourage investment in the construction and operation of new RE sources solely based on an allowance trading mechanism. This explanation should address the factors that are critical to the evaluation of a state's true potential for RE development and inherent constraints on RE generation, such as resource availability. Critical factors may include capital and annual costs associated with the planning, construction, and continued operation of RE generation. Furthermore, the EPA fails to fully address how exactly the approach of the RE set-aside would address leakage from existing sources covered under the proposed federal plan to new sources not covered under the proposed federal plan.

The EPA claims that the RE set-aside is expected to address leakage by lowering the marginal production costs of clean energy technologies thus making sources like RE more competitive against new sources. This seems to ignore the potential differences in economies of scale associated with advanced NGCC generation and the fact that as capacity demand increases, NGCC generation may become more economically attractive. Theoretically nothing prohibits owners or operators of new advanced NGCC from utilizing such units, and increasing utilization of such units, to meet demand, especially if such units are owned or operated by the same entities that own or operate existing units.

3. The EPA should inform states of how much time it will need to review eligibility of projected MWh for distribution of RE set-aside allowances.

The EPA should provide states with an enforceable schedule for when it expects to review and approve the documentation of eligibility and the projection of MWh before a project can become eligible for a distribution of the RE set-aside allowances. Such a timetable would allow the RE providers in a state, particularly in Texas given the vast number of potentially eligible RE providers, the ability to plan for RE generation so that the renewable generation can be eligible based on projected generation. This will become especially important as states may choose to exit a federal plan and replace the EPA's federal plan with a state plan so that states do not lose any potential allowances associated with eligible generation. This anticipated knowledge would further allow RE providers in states to appropriately consider the economics of constructing new RE sources and allow states to consider the availability of existing or planned transmission infrastructure; relative reliability or time-of-production of power; local, state, regional, or national policies; and the location or magnitude of current and potential electricity loads.

The time for review and approval could affect how and when the state or stakeholders make a demonstration of the appropriateness of new measure types such that a new measure type could be considered eligible for the RE set-aside.

4. The EPA should reevaluate the proposed deadlines for submission of state allowance-distribution methodologies to replace federal plan allowance-distribution provisions.

Allowing a state to submit a state allowance-distribution methodology to replace federal plan allowance-distribution provisions and having an established schedule for affected sources and states to follow so they know their requirements and deadlines will assist program implementation. However, the EPA has still not yet determined which approach it intends to finalize, further complicating what states can reasonably anticipate in terms of planning for electric generation, transmission, distribution, reliability, and emergency events. Based on the proposal's description of potential alternative approaches (in which it could "hold off" on recording EPA-determined allocations), the EPA has indicated that it could operate with a compressed schedule to review a state-determined methodology and to subsequently record allowances. Therefore, the deadlines for submission should be reconsidered to allow states additional time to develop and finalize their own allowance-distribution methodologies so that states are better able to efficiently exit the federal plan and enter a state plan or replace federal provisions with state-determined provisions. When setting the submission deadlines, the EPA should reconsider the time needed for its review while also providing sufficient time to states to analyze all affected EGUs in the state to tailor a customized allowance-distribution approach for those affected units.

E. Legal Authority

1. The EPA's attempt to force reductions in the use of coal and natural gas-fired EGUs through the proposed federal plan and model trading rule is beyond its legal authority and is inconsistent with Texas's approach to electricity regulation, which relies on market forces to incentivize efficient development and operation of power plants. The EPA's proposed federal plan and model trading rules would require Texas to fundamentally reorganize its electric grid in the way it generates and transmits power. By unlawfully rationing the amount of electricity that can be produced by fossil-fueled generation assets and forcing expenditures on transmission infrastructure that would otherwise not be necessary, the federal plan and proposed trading rules would result in increased prices and reduced reliability.

The PUCT has previously raised numerous concerns with the EPA's proposed Clean Power Plan. The PUCT's prior comments to the EPA explained in detail that it's attempt to control the nation's electricity markets though the Clean Power Plan was an unlawful intrusion into areas it has neither the authority nor the expertise to regulate and would create significant reliability problems in Texas. While the final Clean Power Plan differs in some respects from the proposal, it nevertheless *still* unlawfully seizes jurisdiction over wholesale and retail electric utility policy from the states and the FERC and will require fundamental and significant changes to the extremely successful competitive electricity market that serves the vast majority of Texas. The Clean Power Plan will also negatively impact reliability in the ERCOT region and cause significant economic disruption and reliability risks in the markets overseen by the FERC in which other Texas utilities operate. These concerns remain under the proposed federal plan and model trading rules. The EPA lacks the legal authority and expertise to address reliability and other electric market issues impacted by its proposed federal plan and model trading rules including electricity market design, generation resource planning, operation and dispatch, RE portfolio standards, as well as transmission planning, siting, and certification, all of which are under the authority of state legislatures, state utility commissions, and/or the FERC.

The ERCOT power region is unique in that it is wholly intra-state and not directly (or synchronously) connected to the two other U.S. grid interconnections (the Western and the Eastern Interconnections). Import and export of power from the ERCOT power region is limited to the capacity of five asynchronous ties linking ERCOT and other interconnections: two between the ERCOT power region and the Eastern Interconnection (with a combined capacity of 820 megawatts), and three between the ERCOT power region and the electrical grid in Mexico (with a combined capacity of 430 megawatts). Flows on these asynchronous ties are scheduled in advance of real-time operations by market participants; however, support from neighboring power regions can be received across these ties during grid emergency events. Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT power region is an island that must independently ensure its own electric reliability. In its comments on the proposed existing source rule, the PUCT explained the unique challenges and difficulties of implementing the Clean Power Plan in Texas. Implementing the EPA's proposed federal plan and model trading rules in Texas will be no less difficult, complex and challenging. According to ERCOT, by 2030, wholesale market prices in the ERCOT power region will rise by up to 39% due to the loss of EGUs that would otherwise continue to operate, and that estimate does not include the costs of adding transmission infrastructure, additional ancillary services, and potential reliability must-run contracts.

2. The EPA does not have the authority to regulate "outside the fence" through FCAA §111(d) in either the newly finalized existing source rule, or in this proposed federal plan. In finalizing the existing source rule and, thus, in this proposal, the EPA has interpreted BSER too broadly. Section 111 applies to sources within a discrete identified source category. The EPA's proposed rule continues the illegal establishment of CO2 emission guidelines for existing EGUs based upon regulating the entire energy sector under §111(d).

Section 111 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 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." 42 U.S.C. § 7411(a)(1). 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 Ass'n v. Ruckelshaus*, 486 F2d 375 (D.C. Cir. 1973).) BSER cannot be read as broadly as the EPA finalized for existing sources, and perpetuates in the proposed federal plan. Section 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 RE 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. The EPA offered, and continues to offer, no reasonable explanation for abandoning that approach in both the Clean Power Plan and the proposed federal plan.

In response to EPA questions for states on §111(d) plan requirements, the TCEQ and PUCT warned the EPA that it did not have broad discretion under the FCAA in setting these standards.[4] 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 TCEQ, PUCT, and RRC also provided comments on the proposed Clean Power Plan opposing the EPA's determination

[4] 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 of the TCEQ, and Brian H. Lloyd, Executive Director of the PUCT, to Gina McCarthy, EPA Administrator (January 14, 2014).

of BSER.[5] The TCEQ, PUCT, and RRC reiterate their comments and oppose the proposed federal plan which relies on this illegal determination of BSER.

By effectively regulating one source category out of existence through re-dispatch and increasing RE production, the EPA exceeds its delegated authority by making energy policy rather than environmental policy. The state goals established by the EPA recognize the diverse nature of the energy production sector 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 usually under exclusive state control through state utility regulators.

The EPA's attempt to backstop its lack of legal authority for its interpretation of BSER is based on the principle that reduction in generation at the affected EGUs is itself BSER. However, the EPA's argument is fundamentally flawed. Reduction in generation is not the application of any system; it is an effect resulting from other activities. While 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 primary basis for the regulatory requirement.

The EPA's 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 proposed federal plan relies upon a final BSER determination that will force companies to reduce operations or cease business operations altogether based solely on the EPA's decision that the product that company produces can be produced using a different technology which the EPA finds more 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." It would be irrational of the EPA to assume that Congress's intent was that 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 finalized for existing sources under §111(d) and for new sources under §111(b) and is perpetuating in this proposed federal plan.

The EPA's expansion of BSER to the electric grid is unreasonable because it would bring about an enormous and transformative expansion in the EPA's regulatory authority without clear Congressional authorization. The Supreme Court most recently rejected such an expansive EPA regulation of CO_2 emissions, holding that "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." *Util. Air. Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2444 (2014).

The EPA's clear and documented history of applying BSER to the sources of emissions dates back to the early 1970s. Forty years after enactment of the FCAA the EPA now claims that the word "system" applies beyond the source.

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

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5 Comments from the TCEQ, PUCT, and RRC on Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule; EPA Docket ID No. EPA-HQ-OAR-2013-0602, tracking number 1jy-8fvt-czdh, available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-23305 (December 1, 2014).

sales by granting that power to the 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 D.C. Circuit in *Elec Power Supply Ass'n v. Federal Energy Regulatory Commission, 753 F.3d 216 (D.C. Cir. 2014)*, holding that FERC Order 745 violates states' jurisdiction over retail power markets. Because the EPA's Building Blocks 2 and 3 were based on (and ultimately would require) assumed action by the states in these areas, they violate states' jurisdiction over retail power markets and therefore cannot be used by the EPA in adopting a federal plan relying on the state goals that were finalized based on those blocks.

The EPA has not provided a rational basis for its authority under the FCAA to require states to regulate any matters subject to Building Blocks 2 and 3 and cannot "bootstrap" authority by relying upon BSER utilizing emission reductions attributable to measures under Blocks 2 and 3 that are subject to state authority unrelated to the FCAA. Similarly, the EPA cannot adopt a federal plan that relies upon BSER that will require it to enforce measures that it does not have authority to require independently under the FCAA.

3. 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 is determined to regulate CO_2-emitting sources under FCAA §111, despite the fact that the sources—in this case EGUs—are already regulated under FCAA §112. Section 111(d) prohibits the EPA from regulating under 111(d) "any air pollutant . . . emitted from a source category which is regulated under [§112]." 42 U.S.C. § 7411(d)(1)(A)(i). The plain meaning of this provision is unambiguous and excludes from §111(d) any EGU that is subject to regulation under §112. The term "air pollutant" is also unambiguous, given the context of §111(d). As the Supreme Court has stated, "EPA may not employ [§111(d)] if existing stationary sources of the pollutant in question are regulated . . . under [§112]." *Am. Elec. Power Co., Inc. v. Connecticut*, 131 S. Ct. 2527, 2537 n.7 (2011).

The EPA's basis relies on two competing amendments to §111 adopted as part of the 1990 amendments to the FCAA. 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. [6]

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 acknowledged 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]." U.S. Environmental Protection Agency, *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units*, at 9-10.

This abbreviated history of §111(d)—consisting of EPA guidelines recommending technology-based limits for a few specific emission points within narrow industry categories that

[6] *See* Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 15,994 (March 29, 2005).

significantly emit an otherwise unregulated pollutant by only one or two industries—is consistent with the EPA's long-expressed understanding of the limited role that §111(d) plays 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 state implementation plan (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 the 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 FCAA, 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, the 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 new source performance standards (NSPS). It is quite another to impose uniform technology-forcing measures on existing sources. For existing sources, §111(d) requires the EPA to establish a SIP-like process 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 a very limited role for §111(d): technology-forcing of controls on existing sources.

4. 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 newly finalized rule under §111(b), the EPA should withdraw the proposed federal plan until the §111(b) rule is legally resolved.

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). While the EPA has newly finalized a rule to regulate new sources under §111(b) significant legal concerns have been raised regarding whether that final rule will withstand judicial review. Without an effective and legally final §111(b) rule regulating carbon pollution from new sources, the EPA lacks authority to finalize this proposed rule.

5. The 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 the 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 greenhouse gases (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 this proposal, the EPA continues to rely on the assumptions it made in the §111(b) and (d) proposals, which were significantly flawed as discussed below.

In both §111(b) and §111(d) proposals, the EPA assumed that because an existing source category was 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. Again, a standard of performance is defined as ". . . a standard for *emissions of air pollutants* which reflects the degree of emission limitation achievable through . . .." 42 U.S.C. § 7411(a)(1)(emphasis added). Because the EPA originally 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) (emphasis added). No other endangerment requirement under the FCAA requires such a finding of *significant* contribution. In the proposed federal plan, the EPA simply asserts 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 U.S. emissions of GHGs, and EGUs were the single largest stationary source category of CO_2 emissions. This assertion was not an appropriate substitute for a properly conducted endangerment finding. The EPA has not provided an endangerment determination, 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 the EPA made a proper finding that U.S. emissions of CO_2 specifically from fossil fuel-fired EGUs are significant contributors to climate change.

As in the NSPS proposal, the EPA's "rational basis" argument for regulating CO_2 from existing fossil-fueled EGUs was flawed. The EPA did not concede that §111 requires an endangerment finding to justify regulating GHG from fossil-fired EGUs, but instead claimed that EPA was only required to "have a rational basis for promulgating standards for GHG emissions from electric generating plants . . .." The EPA concluded, ". . . 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. Even if CO_2 emissions from EGUs represent a substantial fraction of overall nationwide GHG emissions, the global concentration of GHG in the atmosphere is 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 provided no compelling evidence to show that the United States' contribution of EGU CO_2 emissions affected global concentrations of GHG or temperature change. The EPA provided neither a proper endangerment finding nor a statutorily-derived rational basis for regulating one GHG, i.e., CO_2, from EGUs.

6. The EPA's proposal to add new plan revision authority in §60.27(l) and error correction authority in §60.27(k) is unsupported, unworkable, and without legal basis for emission guidelines promulgated under FCAA, §111(d), particularly for the Clean Power Plan.

The EPA provides no explanation for the need for this authority, its appropriateness in the context of the scope and structure of FCAA, §111(d), the basis of its legal authority to take such actions under §111(d), or its appropriateness in the context of the scope and structure of the specific requirements of the Clean Power Plan, which is a unique emission guideline different from any previous emission guideline promulgated by the EPA.

Section 111(d) authorizes the EPA to prescribe procedures similar but not identical to SIP requirements under FCAA, §110 for §111(d) plan submittals, as well as federal plan requirements in the event of a state's failure to submit a state plan. It also grants authority to enforce state plans. Section 111 does not provide the EPA unilateral authority to prescribe other requirements of the FCAA, including §110 requirements, to §111 obligations. If the EPA was to exercise its plan revision or error correction authority at some unknown future time after a state plan was implemented, states and utilities would be subjected to unjustified risks to reliability and additional costs of compliance resulting from instability and uncertainty which would necessarily be passed on to electricity consumers. At best, this illustrates the EPA's misunderstanding of the interrelated and complex responsibilities of the electric market structure, particularly deregulated markets. Similarly, the EPA has not justified, nor provided necessary transition or implementation mechanisms for partial state plans and federal plans. The plain language of §111(d) contemplates that the EPA would have authority to provide for procedures similar to SIP requirements only for plan submittals, not for the EPA's review and/or action on those submittals.

7. While the EPA's requirement to address leakage in the final Clean Power Plan was in response to comments, the EPA has not provided states and the public with adequate opportunity to comment on the leakage requirement for mass-based plans. The EPA is exceeding its legal authority by attempting to affect the operation of new units in any manner via FCAA §111(d).

The EPA did not provide adequate opportunity to comment on the requirement in the final Clean Power Plan to address leakage to new units under mass-based plans, and compounds its error by requiring leakage to be addressed under mass-based plans in the proposed federal plan. The EPA's logic that the interconnected nature of the electric utility grid creates this possibility under mass-based plan is flawed. The possibility of leakage to new units is due to the EPA's faulty approach to setting the BSER in a manner that ensures standards for existing units are more stringent than the standards for new units. If the EPA had established BSER consistent with prior precedent under §111, then the leakage issue would not exist. Also, the EPA exceeded its legal authority by attempting to indirectly affect new units under §111(d) via the leakage requirements. Section 111 is clear: emission performance for new units is covered under §111(b) and existing units under §111(d). However, the EPA conflates the two parts of §111 in both the Clean Power Plan and the proposed federal plan by imposing leakage requirements on the mass-based approach. Furthermore, the EPA's approach under the proposed federal plan would incentivize keeping older, less efficient units online longer, thereby decreasing the installation of new units in the future which would be more efficient and result in fewer emissions.

8. The EPA should not propose rules that are not enforceable. The EPA has no practical mechanism to enforce BSER as finalized in the Clean Power Plan, and

relied upon in this proposed federal plan, which would open the door for citizen suits against the EPA.

The EPA does not have authority to enforce or compel RE electric generating production or re-dispatch of NGCC EGUs in lieu of electrical generation by coal-fired EGUs under the FCAA or Texas law. Instead, as discussed previously in comments II.A.2 and II.E.1, the federal government has limited authority over wholesale and retail electric utility markets, and that limited authority is not granted to EPA. If the EPA were to issue a federal plan for Texas, there is no practical mechanism to enforce the components of BSER finalized in the Clean Power Plan, and relied upon in this proposed federal plan, which could result in citizen suits against the EPA. Because it does not have authority, the EPA would be illegally imposing on States to address the practical compliance mechanisms necessary to enable the federal plan, through the federal plan.

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

"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 . . ."

F. General Comments

1. The EPA has not adequately demonstrated that a trading program satisfies the FCAA requirement for states to consider the remaining useful life of existing sources that would be subject to this rule.

The EPA asserts that its approach to setting the emission guidelines and use of a federal trading program adequately accounts for the remaining useful lives of affected EGUs. However, the ability to purchase credits or allowances in lieu of installing controls does not address the issue of early retirement of coal-fired EGUs or other units that may be forced to retire early or limit generation to comply. Instead, the trading program will require states and EGUs to focus exclusively on the type(s) of generation and whether the total generation mix can operate under or within a trading budget. The modeling results contained in the attached ERCOT *Analysis of the Impacts of the Final Clean Power Plan* indicate the potential retirement of at least 4,000 MW of coal-fired capacity due specifically to compliance with the Clean Power Plan, occurring starting in 2025. The final emission guidelines underestimate this potential coal capacity retirement for Texas, and multiple unit retirements could occur in a short timeframe. The use of a federal trading program does not sufficiently address this inherent issue built into the EPA's final emission guidelines, which preclude the state from considering the remaining useful life of these units. Instead, in promulgating the final emission standards, the EPA has made assumptions that eliminate the states' ability to meet their statutory duty to consider remaining useful life of individual emission units.

2. The EPA should move forward with its proposed interpretation that FCAA, §111(d) would not apply to existing sources that modify or reconstruct. Instead, these sources should be subject to the NSPS regulations under FCAA §111(b) as a new source and not as an existing source under §111(d).

At proposal of the Clean Power Plan, the EPA proposed to require that modified or reconstructed sources would remain subject to the requirements of the FCAA §111(d) rule, contrary to all prior precedent under §111. However, the EPA removed that requirement from the final Clean Power Plan rule. With the proposed federal plan, the EPA is requesting comment on the proposed interpretation that, when an existing source modifies or reconstructs in such a way that it meets the definition of a new source, it becomes a new source and is no longer subject to §111(d) program (80 Fed. Reg. at 65039). The EPA's proposed interpretation that modified or reconstructed sources would not remain subject to the requirements of Clean Power Plan §111(d) rule is consistent with the plain language of FCAA §111 and prior §111(d) regulatory actions by the EPA.

3. The EPA should allow RE and energy efficiency (EE) projects implemented on or after September 6, 2016 to be eligible for the Clean Energy Incentive Program (CEIP).

States for which the EPA promulgates a federal plan should be able to award early action ERCs or allowances for projects built on or after September 6, 2016 instead of the proposed date of September 6, 2018. This is already an option for states that finalize their own state plan by the September 6, 2016 deadline. Similarly, this should be an option for states who receive an extension to submit their plan after the initial deadline and for states under a federal plan. The ability to award early action ERCs or allowances at an earlier date can lead to important incentives in developing RE and EE projects sooner. It also prevents RE and EE projects that are scheduled to be implemented between September 2016 and September 2018 from being deemed ineligible for early action ERCs or allowances. Since the purpose of the CEIP is to encourage and reward early investments in RE generation and EE, projects implemented prior to September 6, 2018 should be credited for their contribution to early reductions in CO_2.

The eligibility of projects to receive early action ERCs or allowances should not be contingent upon insignificant or arbitrary dates but instead upon the project's real impact and contribution to early CO_2 emission reductions. Establishing restrictions on the periods in which projects can be implemented or when CO_2 emission savings occur limits the ability of qualified RE and EE projects to generate equitable early action ERCs and allowances. Since the CEIP is an early incentive plan, eligible projects in states under the federal plan should be credited for contributing to early reductions in CO_2. The EPA should allow for emission reductions achieved before the proposed regulatory schedule to be eligible for generating early action ERCs or allowances.

4. The EPA should expand the scope of CEIP-eligible projects beyond just wind and solar RE and low income EE, as it has provided no reasonable justification for limiting CEIP eligibility to only these measures.

The EPA has proposed to establish an account to match ERCs or allowances for the states that are participating in the CEIP either through their state plan or for states that are subject to the federal plan. This pool of additional ERCs or allowances will be distributed so that states with greater reduction obligations will be able to secure a larger proportion of the pool for those projects which are eligible. Eligible projects are limited to RE investments that generate metered MWh from any type of solar or wind power, and demand-side EE projects for low income communities that reduce energy demand during 2020 and/or 2021. As the nation's leader in RE production in wind power, Texas supports the creation of a federal pool of matching ERCs or allowances for states participating in the CEIP. However, the scope of eligible projects should be expanded to include other measures that contribute to early emission reductions like hydroelectric, biomass, geothermal, and other EE programs, all of which contribute to reductions in CO_2. By reserving a portion of the pool for a specific group of projects, the EPA could be creating a scenario in which there are unused matching ERCs or allowances that could have been used were they not reserved. Instead, the pool of matching ERCs or allowances should be unfettered and allow for a state to choose the type of projects that would best fit its needs.

ERCOT Analysis of the Impacts of the Clean Power Plan

Final Rule Update

ERCOT Analysis of the Impacts of the Clean Power Plan

Final Rule Update

In August 2015, the U.S. Environmental Protection Agency (EPA) released the Clean Power Plan (CPP) final rule, which sets limits on carbon dioxide (CO_2) emissions from existing fossil fuel-fired power plants. EPA had originally proposed the rule in June 2014, and the Electric Reliability Council of Texas (ERCOT) subsequently evaluated the potential implications for the resource mix and grid reliability in the ERCOT Region.[1] However, the final rule made adjustments to the emissions limits, as well as to the deadlines for compliance. Because the timing and magnitude of the required reductions for Texas have changed in the final rule, ERCOT updated its CPP analysis to reflect these changes.

Based on this analysis, ERCOT continues to see the potential for significant impacts on the planning and operation of the ERCOT grid resulting from compliance with the CPP. ERCOT estimates that the final CPP, by itself, will result in the retirement of at least 4,000 MW of coal generation capacity. This amount of unit retirements could pose challenges for maintaining grid reliability, and these impacts are likely to intensify and occur earlier when the effects of the CPP are combined with other environmental regulations, particularly EPA's proposed Regional Haze Federal Implementation Plan (FIP) for Texas. If ERCOT does not receive adequate notification of these retirements, and if multiple unit retirements occur within a short timeframe, there could be periods of reduced system-wide resource adequacy and localized transmission reliability issues.

A recent reliability analysis conducted by ERCOT of potential retirement scenarios resulting from compliance with the Regional Haze requirements showed that the retirement of 4,200 MW of coal-fired capacity, comparable to the amount expected to retire due to the CPP alone, would have a significant impact on the reliability of the transmission system. Model results indicated the exceedance of thermal capacities of 10 circuits (143 miles) of 345 kV transmission lines, 31 circuits (147 miles) of 138 kV transmission lines, 6 circuits (39 miles) of 69 kV transmission lines, and 11 transformers. As a general estimate, new 69 kV and 138 kV lines cost on the order of one million dollars per mile and new 345 kV lines cost on the order of three million dollars per mile. Additionally, in the ERCOT Region, it takes at least five years for a new major transmission project to be planned, routed, approved, and constructed.

As with ERCOT's analysis of the proposed rule, this study predicts a sizeable amount of renewable capacity additions, due both to the improving economics of these technologies as well as the impacts of regulating CO_2 emissions. The need to maintain operational reliability (i.e., sufficient committed and dispatchable capacity and ramping capability) could require the curtailment of renewable generation resources. Curtailment would reduce production from renewable resources, and could delay achievement of compliance with the CPP limits.

The CPP will also result in increased wholesale and retail energy costs in the ERCOT Region. Based on ERCOT's analysis, energy costs for customers may increase by up to 16% by 2030 due to the CPP alone, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, and other costs associated with the retirement or decreased operation of coal-fired capacity in the ERCOT Region. Consideration of these factors would result in even higher energy costs for customers.

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[1] Electric Reliability Council of Texas, Inc. *ERCOT Analysis of the Impacts of the Clean Power Plan*, November 2014. Available at http://www.ercot.com/content/news/presentations/2015/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf.

1. Introduction

The EPA proposed the CPP in June 2014. Under the proposed rule, Texas would have been required to meet an interim CO_2 emissions limit of 853 lb CO_2/MWh on average during the period from 2020 to 2029, and a final limit of 791 lb CO_2/MWh on average from 2030 onward. Following the publication of the proposed rule, ERCOT evaluated the potential implications of compliance with the CPP proposal for the resource mix and grid reliability. ERCOT published a report on the results of the analysis in November 2014.[2] That analysis found that implementation of the CPP *as proposed* would have a significant impact on the planning and operation of the ERCOT grid. Specifically, ERCOT estimated that the proposed rule could result in the retirement or seasonal mothballing of up to 8,700 MW of coal generation capacity, result in potential transmission reliability issues due to the loss of generation resources in and around major urban centers, and strain ERCOT's ability to integrate additional renewable generation resources.

EPA released details of the CPP final rule on August 3, 2015. In the final rule, several changes were made to the proposal, including modifications to the emissions limit calculation and the compliance deadlines. Under the CPP final rule, Texas will be required to meet a final CO_2 emissions rate limit of 1,042 lb CO_2/MWh on average from 2030 onwards, or 190 million tons of CO_2. EPA calculated these limits based on assumptions about coal plant efficiency improvements, increased production from natural gas combined cycle units, and growth in generation from renewable resources. EPA also modified the compliance deadlines in the final rule, phasing in the reductions over three interim compliance periods between 2022 and 2029, referred to as the "glidepath."

Changes to the calculation methodology make it difficult to compare the emissions rates in the final rule directly to the rates in the proposed rule, but overall the final limits for Texas are less stringent than in the proposal. Though EPA made a number of modifications in the final rule, the most impactful for the stringency of the limits for Texas is EPA's shift to a uniform national approach for setting the standards in the final rule, rather than the state-by-state approach used in the proposal.

Because the timing and magnitude of the required reductions for Texas have changed in the final rule, ERCOT updated its analysis of the potential impacts for the ERCOT Region's resource mix and grid reliability. To do so, ERCOT conducted a modeling analysis using similar assumptions and methods as the 2014 study. This report describes the results of the modeling analysis and discusses the implications for grid reliability.

2. Modeling Analysis

As with ERCOT's previous modeling analysis of the CPP, this analysis uses stakeholder-vetted planning processes and methodologies consistent with ERCOT's regional Long-Term System Assessment (LTSA) studies. This analysis is focused on evaluating the potential impacts of the CPP, in combination with the Cross-State Air Pollution Rule (CSAPR) and the currently proposed Regional Haze FIP for Texas. It does not consider the impacts of other pending environmental regulations affecting generation resources, including the Mercury and Air Toxics Standards (MATS), which have more limited or unit-specific implications and are unlikely, by themselves, to impact overall trends on the ERCOT system. However, these other regulations, in combination with the CPP, CSAPR, and the Regional Haze FIP, could result in additional grid operational impacts and reliability challenges. For example, a number of coal-fired units in the ERCOT region have compliance extensions until April 2016 from the Texas Commission on Environmental Quality (TCEQ) for MATS compliance. There remains a risk that owners may choose to

[2] Ibid.

retire the affected units rather than comply with MATS next year, especially in light of the proposed Regional Haze FIP and eventual compliance with the Clean Power Plan. The implications of potential MATS-related retirements in 2016 are *not* considered in this analysis. Information about other environmental regulations affecting generation resources is available in ERCOT's December 2014 report, *Impacts of Environmental Regulations in the ERCOT Region.*[3]

2.1. Modeling Methodology

This analysis uses the same model (PLEXOS) and modeling approach as ERCOT's environmental regulatory impact study completed in 2014. A complete description of this methodology is provided in ERCOT's December 2014 report.[4] Certain assumptions have been updated for this analysis based on more recent information currently being developed for the 2016 LTSA[5] and the Future Ancillary Services Cost Benefit Analysis,[6] including natural gas prices and renewable capacity capital costs. Figure 1 shows the updated natural gas prices, in nominal dollars, used in this analysis.

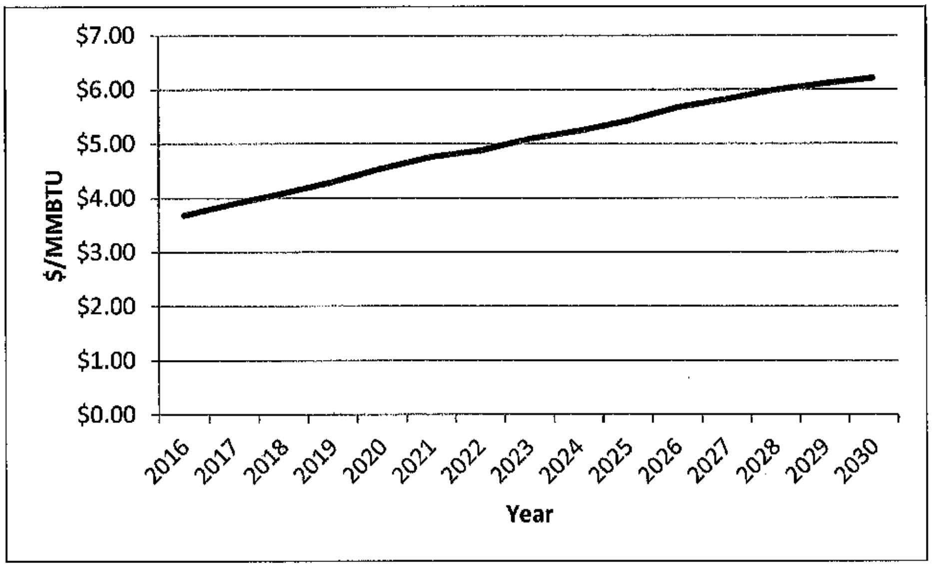

Figure 1: Natural Gas Price Assumptions

In this analysis, ERCOT models compliance with the mass-based CO_2 limits that EPA finalized for Texas. This is a departure from the 2014 study, where ERCOT modeled compliance with the rate-based standards proposed by EPA. In the final rule, EPA published both the rate- and mass-based forms of the CO_2 emissions standards, and states may choose to comply with either form of the standard. Compliance with a rate-based standard would allow overall emissions to increase as generation increases and new renewable energy and energy efficiency are added. Conversely, a mass-based standard would require emissions to remain under a set amount. Though the relative stringency of either form of the standard will depend on program design and availability of emissions reduction credits from renewable energy, energy efficiency, etc., in general modeling the mass-based form of the standard results in a slightly more stringent requirement, and thus provides a conservative estimate of

[3] Electric Reliability Council of Texas, Inc. *Impacts of Environmental Regulations in the ERCOT Region*, December 2014. Available at http://www.ercot.com/content/news/presentations/2015/Impacts%20of%20Environmental%20Regulations%20in%20the%20ERCOT%20Region.pdf.
[4] Ibid.
[5] These assumptions are available at http://www.ercot.com/content/wcm/key_documents_lists/75283/2016_LTSA_Scenario_Assumptions.pptx.
[6] Information on the proposal for a new framework for ancillary services in ERCOT and the cost benefit analysis is available at http://www.ercot.com/committees/other/fast/index.html.

the impacts of compliance. ERCOT scaled the mass limits for Texas based on the relative amount of load served in the ERCOT Region within Texas to derive ERCOT-specific limits. Figure 2 shows the mass-based emissions limits for Texas published in the CPP final rule and the ERCOT-specific limits modeled in this study.

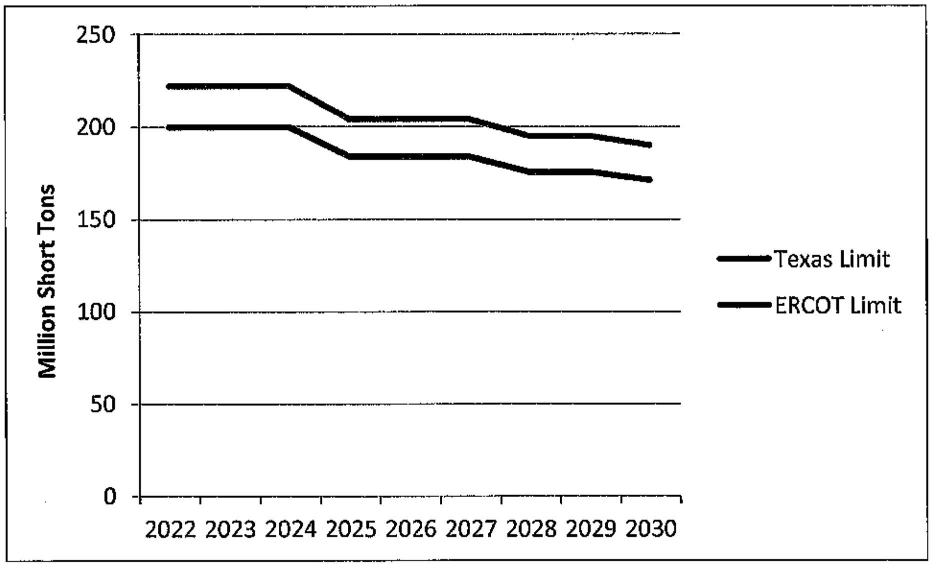

Figure 2: Carbon Dioxide Mass-Based Emissions Limits

As in the previous study, ERCOT modeled scenarios in which the CPP limits are achieved through a system CO_2 emissions constraint and a price per ton of CO_2. These scenarios were developed to evaluate the potential reliability implications of CPP compliance; they do not indicate any assessment of the policy merits or legal permissibility of either compliance approach. In addition to the CPP, the current requirements of CSAPR are included in all of the modeled scenarios, and the proposed Regional Haze FIP is included in one of the modeled scenarios.

The CSAPR program seeks to address cross-state air pollution through a cap and trade program for annual nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions, and ozone season (summer) NO_x emissions. In the 2014 study, ERCOT modeled scenarios that included CSAPR as both an emissions limit and an emissions price, but did not include CSAPR in the baseline. Since the rule came into effect on January 1, 2015, this analysis includes CSAPR in both the baseline and CPP scenarios at current allowance prices to reflect the current status of the program.[7] CSAPR allowance prices have been relatively low since the rule came into effect, and therefore the inclusion of these prices in the modeled scenarios is likely to have minimal impacts on unit operations and retirements in the modeling results.

ERCOT modeled four scenarios over the timeframe 2016 to 2030 to evaluate the implications of the CPP on reliability in the ERCOT region:

1. **Baseline** – This scenario estimates a baseline of the ERCOT system under current market trends against which anticipated CPP changes are compared.
2. **CO_2 Limit** – This scenario applies the limits in the CPP to the ERCOT system to determine the least-cost way to comply with the limits. This scenario does not place a price on CO_2 emissions.
3. **CO_2 Price** – This scenario applies a CO_2 emissions price that causes the ERCOT system to achieve compliance with the limits.

[7] ERCOT did not consider any potential future changes to the CSAPR program that could result from recent legal proceedings.

4. **CO_2 Price & Regional Haze** – This scenario adds the impacts of compliance with the proposed Regional Haze FIP to the CO_2 price scenario.

It should be noted that the CO_2 limit scenario allows the simulation model to select the least-cost way to achieve CPP compliance from electric generating resources. While this approach minimizes the overall system costs, it may not be achievable within the current electricity market design in ERCOT. Electric supply is deregulated in the ERCOT region at the wholesale and retail level. As a result, electric generation and construction of new capacity is driven by market forces, and there is no mechanism to force the ERCOT system to achieve compliance with environmental regulations in a specific manner. Resource owners will make decisions about how to operate existing resources and whether to add new capacity based on market forces. In contrast, the CO_2 price scenarios rely on price signals to obtain emissions compliance rather than direct control of plant emissions, and thus may represent a potential approach to compliance.

To ensure that the price scenarios captured operational and economic constraints not considered by the model, ERCOT reviewed capacity factors and operating revenues from the modeling results in the two CO_2 price scenarios, and assumed that any coal unit operating below a 20% capacity factor annually would retire.[8] This retirement criterion was not applied to the CO_2 limit scenario in order to allow the model to select the least-cost way to achieve compliance for the ERCOT system.

In the two scenarios that implemented the CPP using an emissions price, ERCOT calculated a price for each year that would put carbon dioxide emissions from affected units below the mass-based emissions limit for that year. As shown in Figure 3, the prices in both scenarios follow a similar trend, increasing as the emissions limits tighten in each of the performance periods. The prices required for initial compliance in 2022 are relatively low, at \$1.00/ton CO_2 in the CO_2 Price scenario. In the CO_2 Price & Regional Haze scenario, unit retirements driven by the Regional Haze requirements put ERCOT-wide emissions below the emissions limit for the first interim performance period, resulting in a \$0.00/ton CO_2 price for the first three years of compliance. These prices then increase in the subsequent performance periods as the CO_2 emissions limits become more stringent. To meet the final emissions limit in 2030, a price of \$22.50/ton CO_2 is required, or \$21.00/ton CO_2 in the scenario that also includes Regional Haze.

[8] To account for this in the 2014 analysis, ERCOT reviewed capacity factors and operating revenues in the model output to determine additional units at risk of retirement, and reported a range of potential impacts in the 2014 report.

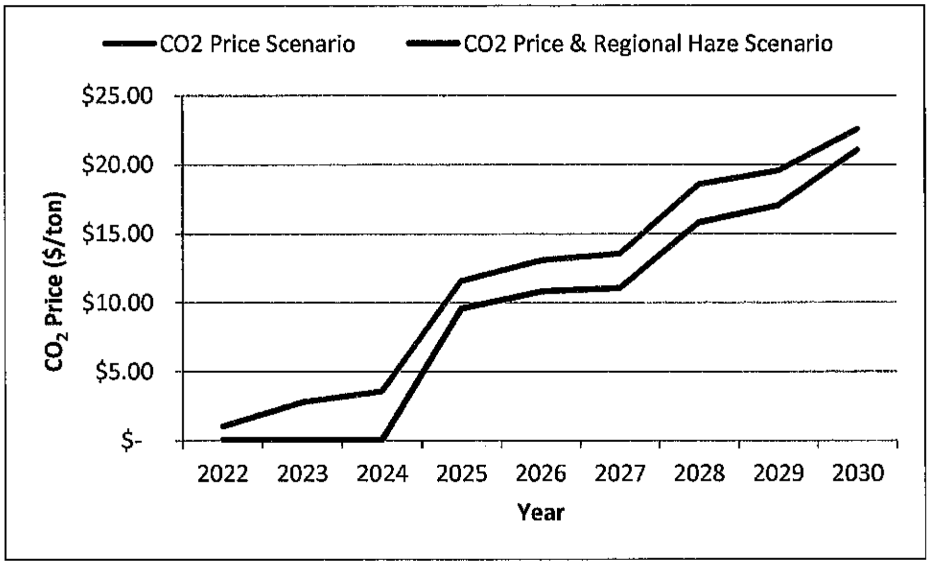

Figure 3: Carbon Dioxide Emissions Prices

In November 2014, EPA proposed a FIP disapproving portions of the Texas state implementation plan for Regional Haze, and setting SO_2 emissions limits for certain coal-fired units in Texas. EPA's proposed FIP would require seven coal-fired units in Texas to upgrade their existing scrubbers, and seven units (five of which are located in ERCOT) to install new scrubber retrofits. To model the proposed Regional Haze FIP requirements, ERCOT added the costs of scrubber upgrades and retrofits to units' fixed costs, as described in the December 2014 report.

In the 2014 study, ERCOT had modeled a 5% energy efficiency savings in scenarios that included the CPP. In this updated analysis, all four scenarios assume energy efficiency savings at 1% of load for all modeled years. At this time, it is unclear how the CPP will be implemented in Texas and how energy efficiency savings might be leveraged for compliance. If, for example, Texas becomes subject to a Federal Plan, it is unclear whether and how energy efficiency could be counted towards compliance. Therefore, the assumption that energy efficiency savings remain at current levels provides a conservative scenario for analysis, and is consistent with the current status of these programs in Texas. However, because energy efficiency remains a potentially cost-effective method for CPP compliance, ERCOT also modeled a scenario where energy efficiency may be used to help achieve compliance, discussed in Section 2.3.

2.2. Modeling Results

ERCOT's modeling of the CPP final rule suggests a different magnitude of impacts compared to the proposed rule. While these modeling results continue to indicate the potential for shifts in the generation mix away from coal and towards natural gas and renewables, the timing and magnitude of these trends differ. The modeling results indicate the potential retirement of at least 4,000 MW of coal-fired capacity due specifically to compliance with the CPP, occurring starting in 2025. However, when the impacts of the CPP are considered in combination with the requirements of EPA's proposed Regional Haze FIP, there are additional unit retirements, many of which occur before the start of CPP compliance in 2022. As with the proposed rule, the modeling predicts a sizeable amount of renewable capacity additions, due both to the improving economics of these technologies as well as impacts of regulating CO_2 emissions. Whereas the previous study saw customer costs increase as early as 2020, due to the stringency of the proposed interim compliance requirements, this analysis sees negligible increases in customer costs by 2022, but sizeable increases in 2030.

Table 1 shows the existing and planned capacity included in the model as the starting point for this analysis. The modeled scenarios resulted in different amounts of unit retirements and capacity additions relative to this baseline. Table 2 summarizes cumulative unit retirements in 2030 by scenario. The modeling results predict 2,300 MW of unit retirements in the baseline, including 800 MW of gas steam retirements and 1,500 MW of coal unit retirements.[9] The unit retirements estimated in the baseline are due to economics, and not compliance with environmental regulations. The next three scenarios consider the CPP, implemented either as a system emissions limit or an emissions fee. When the CPP is imposed as a limit, there are no additional unit retirements above the baseline scenario. When imposed as a price in the next scenario, however, compliance with the CPP results in 4,000 MW of additional coal unit retirements. These retirements occur starting in 2025, at the beginning of the second CPP interim performance period. Finally, the combined impacts of the CPP and Regional Haze result in 4,700 MW of additional coal retirements relative to the baseline. In this scenario, many of the units retire before 2022 due to the timing of the Regional Haze requirements. The number of gas steam unit retirements remains the same across all four scenarios.

Table 1: Baseline Capacity Assumptions

Fuel Type	Capacity (MW)
Nuclear	5,200
Coal	19,900
Natural Gas	59,300
Wind	19,400
Solar	250
Hydro	500
Other	1,000
Total	**105,500**

Table 2: Unit Retirements by 2030

Generation Technology Type	Baseline	CO_2 Limit	CO_2 Price	CO_2 Price & Regional Haze
Retired Gas Steam (MW)	800	800	800	800
Retired Coal (MW)	1,500	1,500	5,500	6,200
Total Retirements (MW)	**2,300**	**2,300**	**6,300**	**7,000**

Table 3: Capacity Additions by 2030

Generation Technology Type	Baseline	CO_2 Limit	CO_2 Price	CO_2 Price & Regional Haze
Wind (MW)	1,000	4,600	9,400	9,100
Solar (MW)	13,000	13,400	13,700	14,100
Combined Cycle (MW)	0	700	0	0
Combustion Turbine (MW)	1,100	700	2,600	2,900
Total Additions (MW)	**15,100**	**19,400**	**25,700**	**26,100**
Capital Costs of new capacity (billions of $2016)	**16**	**21**	**29**	**29**

The model added new capacity to replace retiring units and meet forecasted demand. Table 3 summarizes the cumulative capacity additions and associated capital costs (in real 2016 dollars) by 2030 for each scenario. In the baseline scenario, the model added 13,000 MW of solar capacity, 1,000 MW of wind capacity, and 1,100 MW of natural gas combustion turbines. It should be noted that this analysis assumes the expiration of the Production Tax Credit (PTC) and step-down of the Investment Tax Credit (ITC), as per current law. In the scenarios with the CPP, the model added an additional 4,000 to 9,200 MW of renewable capacity. There are also 1,500 to 1,800 MW of additional natural gas combustion turbines added in the CO_2 price scenarios.

Figure 4 summarizes the capacity additions and retirements in the modeled scenarios. The observed reserve margins resulting from these changes to the resource mix are comparable across all four scenarios.

[9] This includes the announced mothballing of CPS Energy's J.T. Deely units 1 and 2 in 2018.

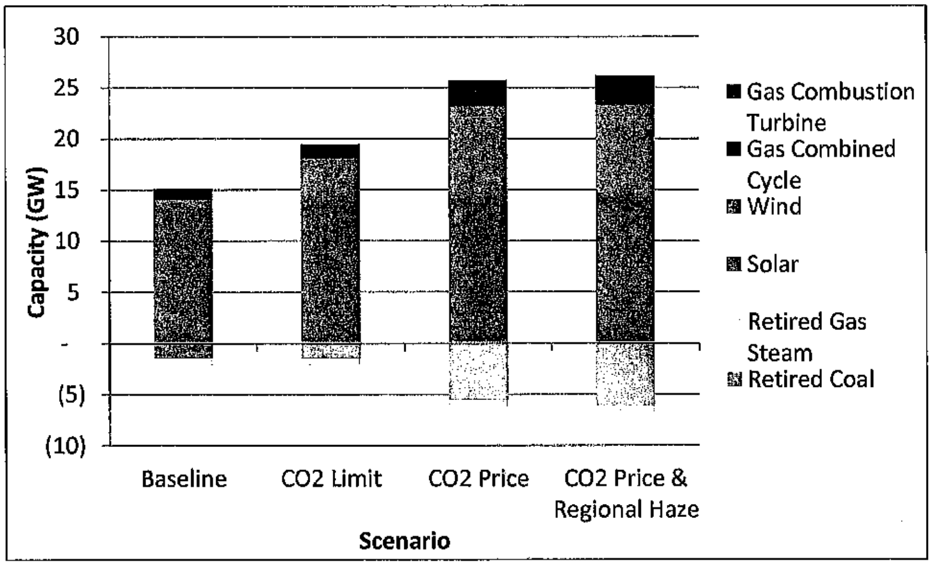

Figure 4: Capacity Additions and Retirements by 2030

Compliance with the CPP results in shifts in the generation mix away from coal and towards natural gas and renewables. Tables 4 and 5 show the annual generation by fuel in 2022 and 2030, respectively, in each of the scenarios. In 2022, the annual generation by fuel is very similar across the first three scenarios. In the fourth scenario, CO_2 Price & Regional Haze, a decrease in generation from coal is made up by increased generation from natural gas and solar resources. By 2030, the generation mix shifts more significantly as the CPP limits become more stringent. The share of generation provided by coal-fired capacity in the CPP scenarios is lower compared to the baseline, at 14 to 16%, versus 27% in the baseline. The difference is made up by increases in generation from natural gas and wind resources. As a result of increased generation from natural gas-fired capacity, in 2030 consumption of natural gas (in MMBTUs) is 14 to 18% higher compared to the baseline in the CPP scenarios.

Figure 5 shows the carbon dioxide emissions from units subject to the CPP in 2022 and 2030 for each scenario.[10] In 2022, CO_2 emissions in the baseline scenario are just above the CO_2 emissions limit for

Table 4: 2022 Annual Generation by Fuel

Fuel Type	Baseline	CO_2 Limit	CO_2 Price	CO_2 Price & Regional Haze
Natural Gas (%)	46	46	47	49
Coal (%)	27	27	26	24
Wind (%)	15	15	15	15
Solar (%)	2	2	2	3
Nuclear (%)	10	10	10	10
Other (%)	<1	<1	<1	<1

Table 5: 2030 Annual Generation by Fuel

Fuel Type	Baseline	CO_2 Limit	CO_2 Price	CO_2 Price & Regional Haze
Natural Gas (%)	43	51	50	50
Coal (%)	27	16	14	15
Wind (%)	14	16	20	20
Solar (%)	7	7	7	7
Nuclear (%)	9	9	9	9
Other (%)	<1	<1	<1	<1

[10] Figure 5 includes emissions only from those units that are subject to the CPP, it does *not* reflect total CO_2 emissions for the ERCOT generating fleet. Only existing fossil steam and combined cycle units subject to certain criteria are regulated under the CPP.

the first performance period. As noted previously, emissions in the CO_2 Price & Regional Haze scenario are below the limit in 2022 due to Regional Haze-related retirements. In 2030, the projected baseline CO_2 emissions are above the final CO_2 emissions limit, and the two price scenarios require a price of \$22.50/ton CO_2 and \$21.00/ton CO_2, respectively, to attain compliance with the limits.

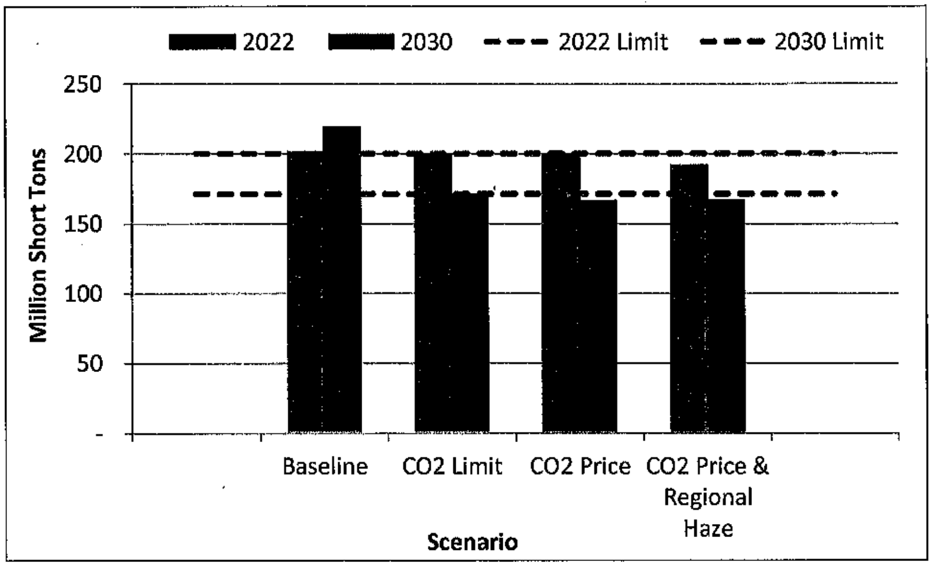

Figure 5: Carbon Dioxide Emissions from Clean Power Plan Affected Units

Compliance with the CPP will impact electricity prices in the ERCOT Region. Table 6 shows the impacts of CPP compliance on average locational marginal prices (LMPs) compared to the baseline scenario. In 2022 the average LMPs are similar across all four scenarios. By 2030 compliance with the CPP results in a 20 to 44% increase in LMPs relative to the baseline. As a general estimate, if wholesale power is 40% of the customer bill, these increases in average LMPs would result in a retail energy price increase of 8 to 18% in 2030. These results do not include the associated costs of building or upgrading transmission infrastructure, natural gas infrastructure upgrades, ancillary services procurement, or potential reliability-must-run contracts.

Table 6: Locational Marginal Prices

Locational Marginal Price	Baseline	CO_2 Limit	CO_2 Price	CO_2 Price & Regional Haze
2022 LMP (\$/MWh)	\$43.35	\$43.08	\$44.12	\$43.25
2030 LMP (\$/MWh)	\$57.20	\$68.53	\$79.78	\$82.59
2022 LMP % change from baseline	n/a	-1%	2%	<1%
2030 LMP % change from baseline	n/a	20%	39%	44%
2022 retail energy bill % change	n/a	<1%	<1%	<1%
2030 retail energy bill % change	n/a	8%	16%	18%

2.3. Energy Efficiency Scenario

As discussed in Section 2.1, energy efficiency is a potential tool that could be used to assist with CPP compliance, but at this time it remains uncertain what role energy efficiency could play in a state or Federal plan for Texas. For this reason, ERCOT did not assume any energy efficiency savings incremental to current levels in the four scenarios described in the previous section. However, because energy efficiency is a potentially cost-effective method for CPP compliance, ERCOT modeled an additional scenario in which greater deployment of energy efficiency measures may be used to help achieve compliance.

In this scenario, a cumulative energy efficiency savings of 7% by 2030 is assumed, which is consistent with the amount EPA assumed for Texas in the Regulatory Impact Analysis (RIA) of the CPP final rule.[11] To construct the energy efficiency scenario, ERCOT customized the energy efficiency assumptions used by EPA to the ERCOT load forecast. The scenario with energy efficiency savings applies the CO_2 limits in the final CPP as a system constraint, comparable to the CO_2 limit scenario.

Tables 7 and 8 summarize the unit retirements and capacity additions, respectively, for this scenario. The number of unit retirements in the energy efficiency scenario is the same as the baseline and CO_2 limit scenarios. However, the number of capacity additions is lower, due to the energy efficiency measures offsetting increases in demand. The annual generation by fuel, shown in Table 9, is similar to that of the other scenarios in 2022. The differences in the generation mix compared to the other scenarios in 2030 are, again, attributable to the reduced demand resulting from energy efficiency measures, which leads to fewer wind and solar capacity additions, and thus slightly lower generation from those technologies.

The 2022 average LMP in the energy efficiency scenario is \$43.48/MWh, which is similar to the results in the other scenarios. In 2030, the LMP is \$63.75/MWh, representing an 11% increase above the baseline or a 5% increase in retail energy prices. However, these estimates do not account for the capital costs of investments in energy efficiency measures. Although ERCOT has not estimated these costs, EPA's estimates from the RIA can be illustrative of the potential costs. Based on inflating EPA's estimates to real 2016 dollars and scaling the costs to the level of estimated ERCOT savings, the capital costs to achieve the specified savings would be approximately \$31 billion (\$2016) by 2030.

Table 7: Unit Retirements by 2030

Generation Technology Type	CO_2 Limit & Energy Efficiency
Retired Gas Steam (MW)	800
Retired Coal (MW)	1,500
Total Retirements (MW)	**2,300**

Table 8: Capacity Additions by 2030

Generation Technology Type	CO_2 Limit & Energy Efficiency
Wind (MW)	2,200
Solar (MW)	10,200
Combined Cycle (MW)	0
Combustion Turbine (MW)	900
Total Additions (MW)	**13,300**
Capital Costs of new capacity (billions of \$2016)	**14**

Table 9: Annual Generation by Fuel

Fuel Type	2022	2030
Natural Gas (%)	46	51
Coal (%)	27	18
Wind (%)	15	16
Solar (%)	2	6
Nuclear (%)	10	9
Other (%)	<1	<1

3. Discussion

As with ERCOT's 2014 analysis of the CPP proposed rule, this modeling analysis indicates that compliance with the CPP is likely to result in the retirement of existing generation capacity and require significant amounts of generation from renewable sources. Though the specific amounts of unit retirements and capacity additions differ from ERCOT's previous study of the CPP proposal – due both to changes to the emissions limits and timing in the CPP final rule as well as changing market economics – ERCOT continues to see potential challenges to grid reliability resulting from these resource mix changes, as well as associated impacts to the transmission system.

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[11] U.S. Environmental Protection Agency. *Demand-Side Energy Efficiency Technical Support Document*, August 2015. Available at http://www3.epa.gov/airquality/cpp/tsd-cpp-demand-side-ee.pdf.

3.1. Impact of Unit Retirements

The modeling results suggest that compliance with the CPP could result in the retirement of at least 4,000 MW of coal-fired capacity in the ERCOT region. In addition to these retirements, several units in the modeling results operate at low capacity factors during off-peak months, and would be potential candidates for suspended operations during those months (seasonal mothball). Though overall fewer coal units are at risk compared to the number of units under the CPP proposal, due to the differing level of stringency in the final rule, there continues to be a risk that the ERCOT Region could see multiple unit retirements within a short timeframe, which could result in implications for reliability.

The potential impacts to coal-fired generation increase when other environmental compliance requirements are considered. There are several environmental regulations for which owners of coal units will need to take actions to comply between now and 2022. With the implementation of the CPP to consider, resource owners may choose to retire units rather than install the required control technology retrofits to comply with these other rules. For more information about other environmental regulations affecting generation resources, see ERCOT's December 2014 report.

In this analysis, ERCOT included the CO_2 Price & Regional Haze scenario to assess the combined impacts of the two rules. The results of that scenario suggest that compliance with the CPP and the Regional Haze FIP could result in the retirement of at least 4,700 MW of coal-fired capacity. Model results indicate that many of the retirements will occur before the start of CPP compliance in 2022, due to the timing of the proposed Regional Haze FIP requirements. However, these results likely represent a lower bound on the number of potential coal unit retirements, in large part because the model is not requiring a competitive market rate of return for unit upgrades like investors would. Note that in the 2014 study, ERCOT considered 8,500 MW of coal-fired capacity to have some risk of retirement due to the proposed Regional Haze requirements.

If ERCOT does not receive adequate notification of these retirements, and if multiple unit retirements occur within a short timeframe, there could be implications for reliability. Coal resources provide essential reliability services necessary to maintain the reliability of the grid. The retirement of coal resources will require studies to determine if there are any resulting reliability issues, including whether there are localized voltage/reactive power control issues and the necessity of potential transmission upgrades, which is discussed in the following section.

3.2. Impact on Transmission

The modeling results indicate that the compliance requirements in the CPP could result in the retirement of at least 4,000 MW of coal-fired capacity. The retirement of legacy coal-fired generation could result in localized reliability issues and require transmission system upgrades. As part of ongoing work studying the potential impacts of environmental regulations, ERCOT recently conducted a reliability analysis that evaluated potential retirement scenarios resulting from compliance with the proposed Regional Haze FIP.[12] Though this study was focused specifically on scenarios associated with the Regional Haze requirements, the results are illustrative of the likely transmission reliability implications and associated costs of losing a substantial amount of legacy coal-fired generation over a relatively short period of time.

In the study, ERCOT retired affected units in phases – first assuming the retirement of units with scrubber retrofit requirements, and then adding to that the potential retirement of units with scrubber upgrade requirements. ERCOT evaluated the potential impacts separately for each region with affected

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[12] Additional information on this study is available on ERCOT's Regional Planning Group (RPG) website at http://www.ercot.com/content/wcm/key_documents_lists/76860/Transmission_Impact_of_the_Regional_Haze_Environmental_Regulation_Oct_RPG.pdf.

capacity (East/Coast, South/South Central, and North/North Central), using the 2015 Regional Transmission Plan (RTP) cases for the year 2020. New conventional and solar generation resources outside of the study region with a signed generator interconnection agreement (SGIA) were added to each scenario to balance the load, supply, and reserves.

The study showed that the retirement of coal-fired generation affected by the proposed Regional Haze FIP would have a significant impact on the reliability of the transmission system and would require substantial upgrades to transmission infrastructure. The study identified local transmission issues in all of the studied regions, as well as zonal transfer issues in the North/North Central region. In one scenario that assumed the retirement of 4,200 MW of coal-fired capacity, comparable to the amount expected to retire due to the CPP alone, model results indicated that the thermal capacities of 10 circuits (143 miles) of 345 kV transmission lines, 31 circuits (147 miles) of 138 kV transmission lines, 6 circuits (39 miles) of 69 kV transmission lines, and 11 transformers would be exceeded. Note that the transmission impacts of unit retirements are highly location specific. As a general estimate, new 69 kV and 138 kV lines cost on the order of one million dollars per mile and new 345 kV lines cost on the order of three million dollars per mile. Additionally, in the ERCOT Region, it takes at least five years for a new major transmission project to be planned, routed, approved, and constructed.

Growth in renewable generation would also likely have a significant impact on transmission requirements. In early 2014, the transmission upgrades needed to integrate the Texas Competitive Renewable Energy Zones (CREZ) were completed. These upgrades were intended to facilitate the integration of wind resources onto the ERCOT system and included 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. To date, more than 14 gigawatts of wind capacity have been successfully integrated onto the ERCOT grid. While the CREZ transmission upgrades provide some transmission capacity beyond current generation development, the modeling results indicate as much or more growth in renewable capacity over the next 15 years. Integrating these resources would likely require significant investments in new transmission and a substantial acquisition of new transmission line right of way, incremental to those that have already been completed as part of CREZ.

3.3. Impact of Renewables Integration

Integrating new wind and solar resources will increase the challenges of reliably operating the ERCOT grid. In 2014, 10.6% of the ERCOT region's annual generation came from wind resources. At its highest levels of instantaneous penetration, wind has provided enough energy to serve 40.58% of system load.[13] The modeling results predict further growth in both wind and solar resources, which together would constitute 27% of total generation by 2030 in the CO_2 Price and CO_2 Price & Regional Haze scenarios. However, in hourly operations, this level of renewables would result in intermittent generation serving more than 50% of load in over 400 hours of the year, and a peak instantaneous penetration of 67%. This is an increase in renewable generation compared to the results of ERCOT's 2014 study, due to the improving economics of these technologies, as reflected in the updated capital cost assumptions included in this analysis.

Further, these scenarios show significant growth in both wind and solar resources, compared to the 2014 study which predicted mostly solar capacity additions. Wind production in West Texas results in high renewable penetration during off-peak hours, when customer demand for electricity is lowest. The modeling results indicate lower net loads (defined as total customer demand minus generation from intermittent energy resources) compared to the 2014 study (14,611 MW in this analysis as compared to 17,611 MW in the 2014 study).[14] As a result, the anticipated challenges to grid reliability indicated by

[13] The current record in the ERCOT Region for wind penetration occurred on March 29, 2015 at 2:00 a.m.

[14] The current record in the ERCOT Region for net load is 14,809 MW, which occurred on March 24, 2014 at 2:25 a.m.

these modeling results may be more severe. In addition, if a significant portion of future solar generation capacity is located on the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels), as opposed to the utility-scale, it could result in additional operational impacts.

The increased penetration of intermittent renewable generation, as projected by these results, will pose challenges to the reliable operation of all generation resources. In the periods when the output of renewable generation provides a large percentage of total energy, significant ramping capability and operational reserves will be required to maintain grid reliability. If there is not sufficient ramping capability and operational reserves during these periods, the need to maintain operational reliability could require the curtailment of renewable generation resources. The ability to curtail intermittent generation resources in real-time operations is a key backstop for maintaining the reliability of the system. Curtailment would reduce production from renewable resources, and could delay achievement of compliance with the CPP limits.

4. Conclusion

ERCOT's modeling of the CPP final rule suggests impacts of a different magnitude compared to the proposed rule. Though overall fewer coal units are at risk compared to the number of units under the CPP proposal, there continues to be a risk that the ERCOT Region could see multiple unit retirements within a short timeframe. When the impacts of the CPP are considered in combination with the requirements of EPA's proposed Regional Haze FIP, there are additional unit retirements, many of which occur even before the start of CPP compliance in 2022. If ERCOT does not receive adequate notification of these retirements, there could be periods of reduced system-wide reserve margins and localized transmission reliability issues due to the loss of generation resources in and around major urban centers. A recent reliability analysis of potential retirement scenarios resulting from compliance with the proposed Regional Haze FIP indicated that the retirement of 4,200 MW of coal-fired capacity would have a significant impact on the reliability of the transmission system.

As with ERCOT's analysis of the proposed rule, this study predicts a sizeable amount of renewable capacity additions, due both to the improving economics of these technologies as well as impacts of regulating CO_2 emissions. 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. The ability to curtail intermittent generation resources in real-time operations is a key backstop for maintaining the reliability of the system. Curtailment would reduce production from renewable resources, and could delay achievement of compliance with the CPP limits.

The CPP will also result in increased energy costs for customers in the ERCOT region. Based on ERCOT's modeling analysis, energy costs for customers may increase by up to 16% by 2030 due to the CPP alone, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, 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 customers.

At this time, there is uncertainty regarding the implementation of the CPP in Texas. In the coming years, resource owners will need to make decisions about their generation units – taking into account the CPP as well as other environmental regulations – that could result in localized reliability issues and transmission constraints associated with a changing resource mix. As new information becomes available, ERCOT will continue to analyze the impacts of regulatory developments that may affect the ability to provide reliable electricity to customers in Texas.