November 22, 2011

Chairman Jon Wellinghoff
Commissioner Philip D. Moeller
Commissioner Marc Spitzer
Commissioner John R. Norris
Commissioner Cheryl A. Lafleur
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket No. AD12-1 Reliability Technical Conference – ERCOT's Reliability Impact Studies and Declaration

Dear Chairman and Commissioners:

Electric Reliability Council of Texas, Inc. (ERCOT) appreciates the Federal Energy Regulatory Commission's (FERC) examination of the relationship between reliability impacts and the effect of recent and proposed Environmental Protection Agency (EPA) rules.

In December 2010, the chairman of the Public Utility Commission of Texas asked ERCOT to analyze the effect of proposed EPA rules on generation facilities in ERCOT. When ERCOT completed its analysis in spring 2011, Texas was not included in the proposed Cross-State Air Pollution Rule (CSAPR). ERCOT was asked to re-analyze the impacts of this rule and in September 2011, ERCOT concluded its revised CSAPR analysis and subsequently provided a declaration for legal proceedings.

Attached are ERCOT's reliability impact studies, including ERCOT's declaration of concerns with the Cross-State Air Pollution Rule (CSAPR – Docket No. EPA-HQ-OAR-2009-0491).

Sincerely,

/s/ H. B. "Trip" Doggett
H. B. "Trip" Doggett
President and Chief Executive Officer

cc: Public Utility Commission of Texas Chairman and Commissioners

Attachment: ERCOT's Reliability Impact Studies and Declaration

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Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System

Revision 1

June 21, 2011

Executive Summary

On December 15, 2010, the Chairman of the Public Utility Commission of Texas (PUCT) requested that ERCOT evaluate the potential impacts of proposed environmental regulations on generation facilities in ERCOT. The Chairman described four potential rule changes:

- Clean Water Act – Section 316(b), regarding new requirements for cooling-water intake structures;
- Clean Air Act – new emission limits for Hazardous Air Pollutants (HAP);
- Clean Air Transport Rule (CATR); and,
- Coal Combustion Residuals (CCR) Disposal regulations.

In order to assess the potential impacts of these regulatory changes, ERCOT reviewed published studies of the nation-wide impacts of these proposed regulations, and ERCOT met with environmental experts from several of the generating entities in the ERCOT region. Using information obtained from this review, ERCOT developed scenarios based on likely compliance requirements and future market conditions and evaluated the economic value of affected generating units. Following a rules-based approach, units that did not have sufficient market value under assumed market conditions in each scenario were assumed to be retired. These retirement decisions were based solely on market economics; a requirement to maintain adequate generation (plus a reserve margin) to serve forecasted peak loads in the ERCOT region was not imposed on the analysis, and an evaluation of the market potential for generation expansion was not included in the scope of this study.

This scenario analysis indicates that coal generation in ERCOT maintains sufficient market value to justify investment in additional environmental control technologies. It is unlikely that a significant amount of coal-fired generation will be retired unless several factors, such as low natural gas prices and carbon emission fees, combine to significantly reduce the economic viability of these units.

Older gas steam units that are subject to retrofit requirements are more likely to be retired. In many cases, this generation is less efficient and less flexible than new quick-start gas-fired generation, and many of these generating units are nearing the end of their useful life. Any requirement to upgrade these old inefficient units is likely to cause unit retirements; generation owners are much more likely to invest capital in new, more efficient generation. Based on the analysis included in this study, the imposition of closed-loop cooling tower requirements as part of the changes to Section 316(b) of the Clean Water Act is likely to result in the retirement of almost 10,000 MW of gas-fired generation, with a majority of these units being located in or near the urban centers of Dallas/Fort Worth and Houston. Without additional replacement generation (the analysis of which was not included in the scope of this study) the retirement of this gas-fired generation would reduce generation reserve margins below 0% in 2016.

The amount of replacement generation developed by private investors will depend on the market viability of new capacity, as determined by individual generation developers. As the gas-fired generation identified in this study to be at risk is being dispatched to provide peaking capacity, it would seem reasonable for replacement generation to serve the same role. Yet development of new gas-fired peaking capacity will require sufficient hours of scarcity pricing to justify new investment. As another consideration, if there is sufficient market interest in new generation capacity, there may be a system reliability need should the timing of the new regulatory requirements not allow sufficient lead-time for favorable market conditions to develop and new generation to become operational.

A preliminary analysis of localized transmission system impacts indicates that the potential loss of this gas-fired generation would have impacts on transmission reliability in the Houston and Dallas/Fort Worth regions, likely requiring additional reactive devices and new import pathways into both regions. Redevelopment of existing generation sites in these urban areas with new generating units could reduce or delay the need for additional transmission infrastructure and would likely lead to substantial savings to the overall ERCOT system.

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Appendices

This June 21, 2011, version includes revisions to pages i, iii, 7, 8, 12, 17, 18, and 20 to reflect updated unit data.

Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System

1. Introduction

On December 15, 2010, the Chairman of the Public Utility Commission of Texas (PUCT) requested that ERCOT evaluate the potential impacts of proposed environmental regulations on generation facilities in ERCOT. The Chairman described four potential rule changes:

- Clean Water Act – Section 316(b), regarding new requirements for cooling-water intake structures;
- Clean Air Act – new emission limits for Hazardous Air Pollutants (HAP);
- Clean Air Transport Rule (CATR); and,
- Coal Combustion Residuals (CCR) Disposal regulations.

In order to accomplish this review, ERCOT undertook several activities.

- ERCOT reviewed several published studies of the nation-wide impacts of these proposed regulations, each of which led to significantly different conclusions, to develop an understanding of the key assumptions or analytical methodologies that led to the differences in results. Summaries of these studies in provided in Section 3.
- ERCOT consulted with environmental experts from several of the generating entities in the ERCOT region whose facilities were most likely to be affected by the proposed regulations. The purpose of these meetings was to gather insight on the likely impacts of the regulations from the viewpoint of the entities that would be required to make the investment or retirement decisions for affected generating units and to gather any specific plans for meeting the new requirements.
- ERCOT compiled a list of the types of emissions controls that are currently installed on many of the generating units that may be affected by the pending regulations and that are above a certain size threshold. ERCOT also compiled a range of potential costs for emissions control technologies.
- ERCOT evaluated the economic impact of compliance with the pending regulations relative to market prices under several different scenarios of compliance requirements and market conditions.
- ERCOT developed a preliminary assessment of the system reliability impacts of identified potential retirements.

2. Environmental Regulations

The United States Environmental Protection Agency (EPA) is currently reviewing four regulations that could have an impact on compliance requirements of generating units across the United States. Proposals for two of these regulatory changes were issued in late March, 2011. The two published proposals are under court-ordered schedules; the release dates for the other two regulatory changes are not known at this time.

Section 316(b) of the Clean Water Act requires that cooling-water intake structures utilize best available technology, and that these structures minimize adverse environmental impacts to fish populations. The EPA has developed revisions to the requirements for cooling-water intake structures for existing facilities; proposed regulations were signed by the EPA Administrator on March 28, 2011. These regulations are designed to reduce fish entrainment and impingement caused by the use of cooling water by industrial facilities and electric generation plants. While the proposed regulations provide for flexibility and development of site-specific solutions, the strictest implementation of these revised regulations would require that closed-loop cooling tower (CL-CT) systems be installed at all existing facilities that currently utilize once-through cooling.

On March 16, 2011, the EPA also released proposed revisions to the emissions standards for hazardous air pollutants (HAP) from coal- and oil-fired electric generating plants pursuant to Section 112 of the Clean Air Act. These revisions are being promulgated in accordance with the February 8, 2008, ruling by the United States Court of Appeals for the District of Columbia Circuit that the EPA issue emissions limits for hazardous air pollutants, most notably, for mercury and acid gases, based on current Maximum Achievable Control Technology (MACT).

The proposed HAP regulations establish different limits for mercury emissions from boilers designed to burn lignite and those designed to burn sub-bituminous and bituminous coals. The mercury emission limit for lignite units is 0.04 pounds per GWh; the limit for non-lignite-fired coal units is 0.0008 pounds per GWh. Even though the limit for lignite-fired units is higher than for other coal units, this limit is labeled a “Beyond-the-Floor” limit in the EPA proposal, meaning that it is more stringent than has been shown to be achievable by existing commercial environmental control technologies. Control of mercury emissions is further complicated by the varying concentrations and chemical speciation of mercury in different types (and sub-types) of coals. Emission limits based on the effectiveness of best-available control technologies for one type (or sub-type) of coal may be difficult to achieve for other types of coal.

With these considerations, based on the proposed regulations, it is expected that control of mercury and acid gases emissions from lignite-fired plants will require installation of a wet limestone scrubber (WLS) and a baghouse (BH) with activated carbon injection (ACI). Selective non-catalytic reduction (SNCR) may also be required to alter the chemical speciation of the mercury in the flue gas. Due to the reduced mercury content of sub-bituminous coals used by coal-fired generation in ERCOT (mostly imported from the Power River Basin region of Wyoming), it is likely that control of mercury and acid gases emissions from non-lignite-fired coal units will require installation of dry sorbent injection (DSI) and baghouse (BH) with activated carbon injection (ACI).

The Clean Air Transport Rule (CATR) is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). As currently proposed, generating units in Texas would be required to reduce their NO_x emissions during the summer (ozone season) months. While finalizing the CATR program, the EPA is considering whether to allow interstate trading of emissions allowances, and whether to impose plant-specific emissions limits. As Texas is only included in the CATR program for peak-season NO_x emissions, compliance with this proposed rule would likely not require installation of selective catalytic reduction (SCR) equipment on all electric generating units. Rather, sufficient reductions in NOx emissions would likely result from plants that currently have SCR technology, along with additional installations of less expensive selective non-catalytic reduction (SNCR) technology, over-fired air (OFA), low-NOx burners (LNB), and other good combustion practices.

Coal Combustion Residuals (CCR) Disposal regulations: Under section 3001(b)(3)(A)(i) of the Resource Conservation and Recovery Act (known as the Bevill exclusion), ash products generated from the combustion of coal are excluded from handling and disposal requirements in the Act pending a determination from the EPA that such requirements are justified. In 1993 and 2000, the EPA determined that regulation of ash from coal combustion under RCRA was not justified. In June 2010, the EPA issued a new proposal to address the risks associated with coal ash disposal by either reversing its earlier Bevill regulatory determinations and classifying coal ash as a "special waste" under Subtitle C of the Act, or by maintaining its previous Bevill determinations but issuing national minimum criteria regarding the proper disposal of coal ash waste under Subtitle D of the Act. In either case, the EPA proposal would limit ash disposal options and require additional monitoring of ash disposal facilities. The EPA proposal could also limit options for the beneficial use of coal ash products.

In addition to these proposed regulatory initiatives, recent changes in the national ambient air quality standards for ozone could result in additional counties in the ERCOT region being declared non-attainment zones. Six counties are currently under review, namely Hood, Gregg, Rusk, Smith, Travis and Bexar. The EPA is expected to issue a determination of the non-attainment status of these counties in the spring of 2011. Revisions to the State Implementation Plan (SIP) for non-attainment zones may include additional restrictions on NO_x emissions from electric generating units in or near these six counties, potentially resulting in requirements that specific units be retrofitted with selective catalytic reduction (SCR) equipment.

Based on the current understanding of the pending regulations, this analysis is based on the assumption that all lignite-fired generation will require a wet-limestone scrubber, a baghouse with activated carbon injection, and selective non-catalytic reduction equipment. Non-lignite fired generation will require dry-sorbent injection, and a baghouse with activated carbon injection. These requirements are evaluated with and without installation of closed-loop cooling tower systems for all subject generation facilities to achieve Clean Water Act compliance.

3. Prior Studies

Several studies have been completed analyzing the national impacts of proposed environmental regulations. Three studies of particular importance are those completed by the Brattle Group, by the Edison Electric Institute (EEI), and by the North American Electric Reliability Corporation (NERC). Each of these studies assessed the potential cumulative impacts of these proposed environmental regulations on electric generating units, using different assumptions and methodologies. These three studies were completed prior to promulgation of the proposed hazardous air pollutant rules and the cooling tower requirements in late March.

The Brattle Group study, "Potential Coal Plant Retirements Under Emerging Environmental Regulations," dated December 8, 2010, focuses on impacts of pending regulations on coal-fired generation.[1] The Brattle analysis is based on a comparison to generation unit replacement costs for units owned by regulated utilities, and on expected market returns of unit retrofit investments deregulated generation investments. The study concludes that pending regulations are likely to lead to the retirement of 50 – 66 gigawatts (GW) of coal generation capacity nationwide, and from 9 – 12 GW of coal generation capacity in ERCOT.

The EEI study, "Potential Impacts of Environmental Regulations on the U. S. generation Fleet, conducted by ICF International and dated January, 2011, utilizes the same Integrated Planning Model (IPM) used by the Environmental Protection Agency to evaluate impacts from proposed regulations. This study evaluated numerous scenarios, including sensitivities on the price of natural gas and the impacts of regulation of carbon emissions. For the primary scenario, the study found a likely retirement of as much as 50 GW of coal capacity nationwide, with retirement of 2.3 GW of coal capacity in ERCOT. Other scenarios led to the retirement of 36 to 96 GW of coal generation capacity nationwide, and 0 to 4 GW of coal generation capacity in ERCOT. The study also concluded that between 2 and 5 GW of natural gas fired capacity would likely retire in the ERCOT region.

The NERC study, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations," dated October, 2010 was conducted by Energy Ventures Analysis, Inc.[2] This study evaluated the individual and cumulative impacts of the four pending regulations. This study concluded that between 46 and 69 GW of generation capacity nationwide was at risk of retirement due to the proposed regulations. In ERCOT, the study found that 5 GW of generation capacity, all natural-gas-fired, was at risk. The NERC study predicted that no coal generation in ERCOT would be retired as a result of the pending regulations.

4. ERCOT Region Generation

The generating capacity in the ERCOT Region contains a mix of generation technologies, fueled by coal (both lignite and sub-bituminous), natural gas, nuclear, water, wind, and other sources. The following table provides current generation capacities in ERCOT by fuel type (data in this table is based on the 2010 Report on the Capacity, Demand, and Reserves in the ERCOT Region, Winter Update). These capacity amounts include generation that can switch between supplying the ERCOT region and supplying other markets, but do not include mothballed generation resources or generation capacity that may be available from private-use networks.

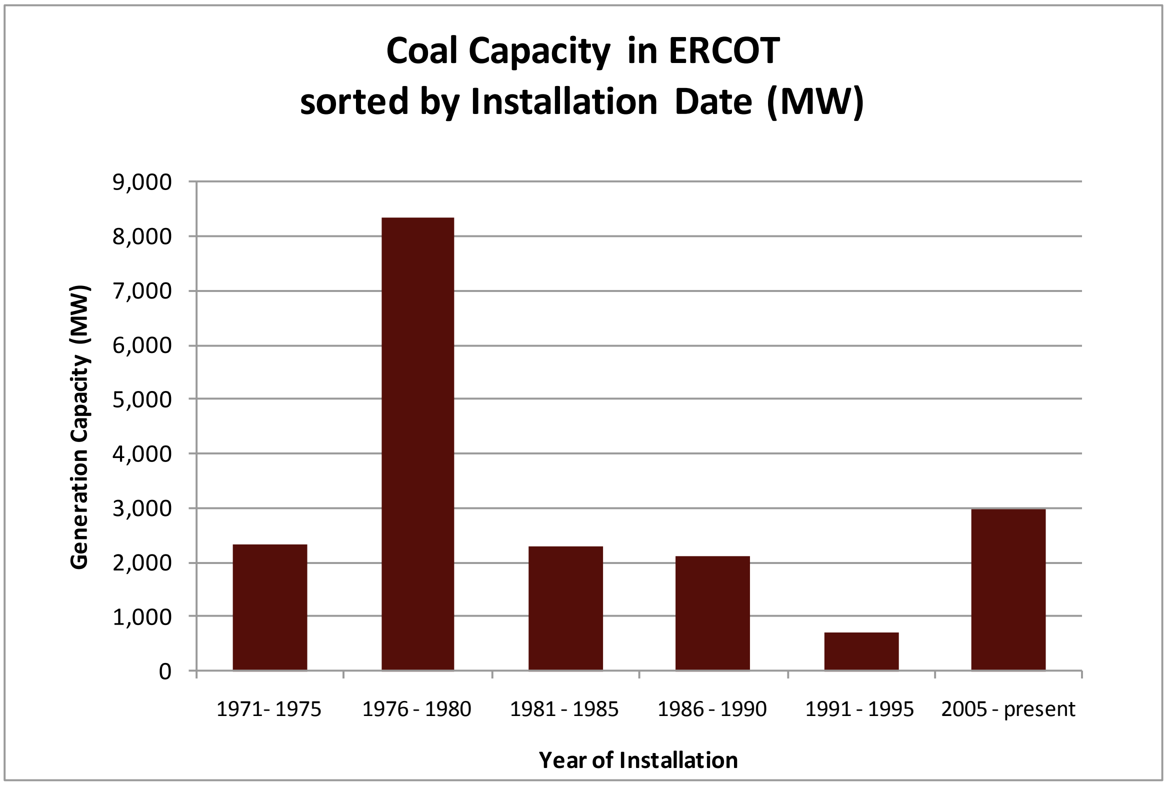
[1] http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf
[2] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

Table 1: Current Generation Capacity in ERCOT by Fuel Type

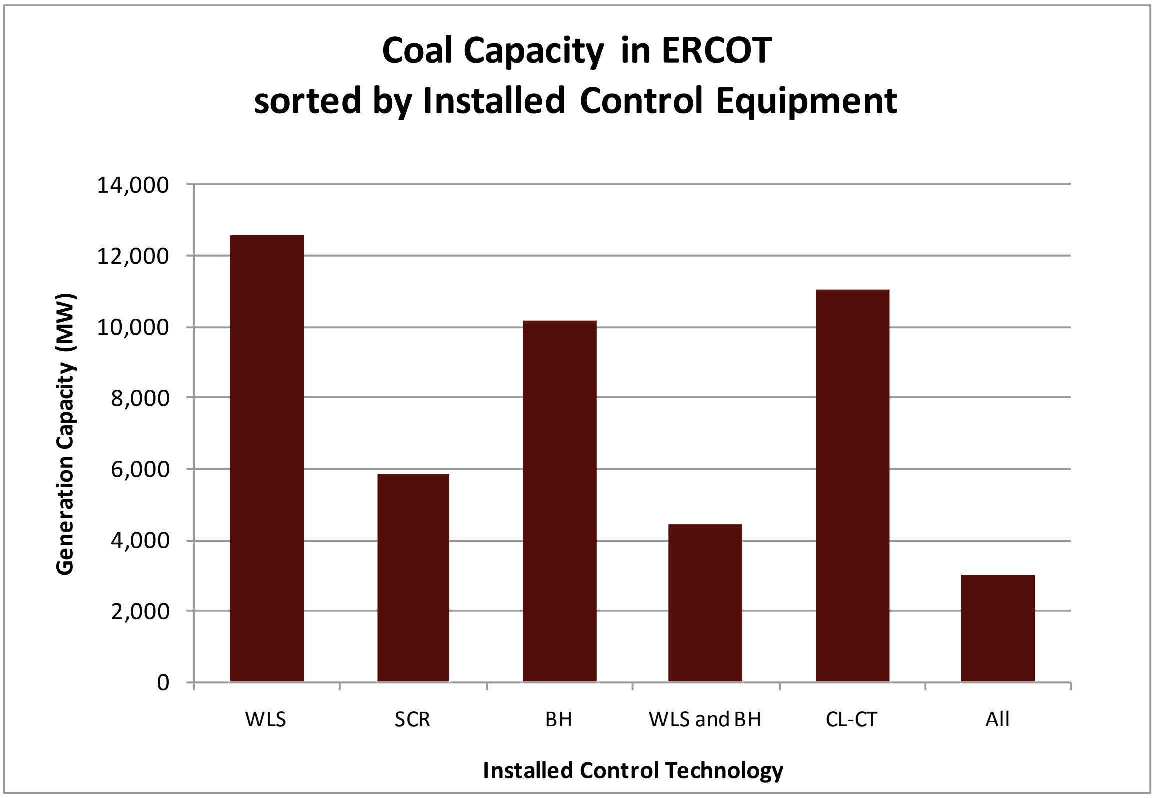
Fuel Type	Installed Capacity (MW)
Nuclear	5,131
Gas	42,732
Coal	18,772
Wind	9,527
Hydro	561
Other	234

As noted in Section 2, coal-fired and gas-fired generation is the specific focus of this study.

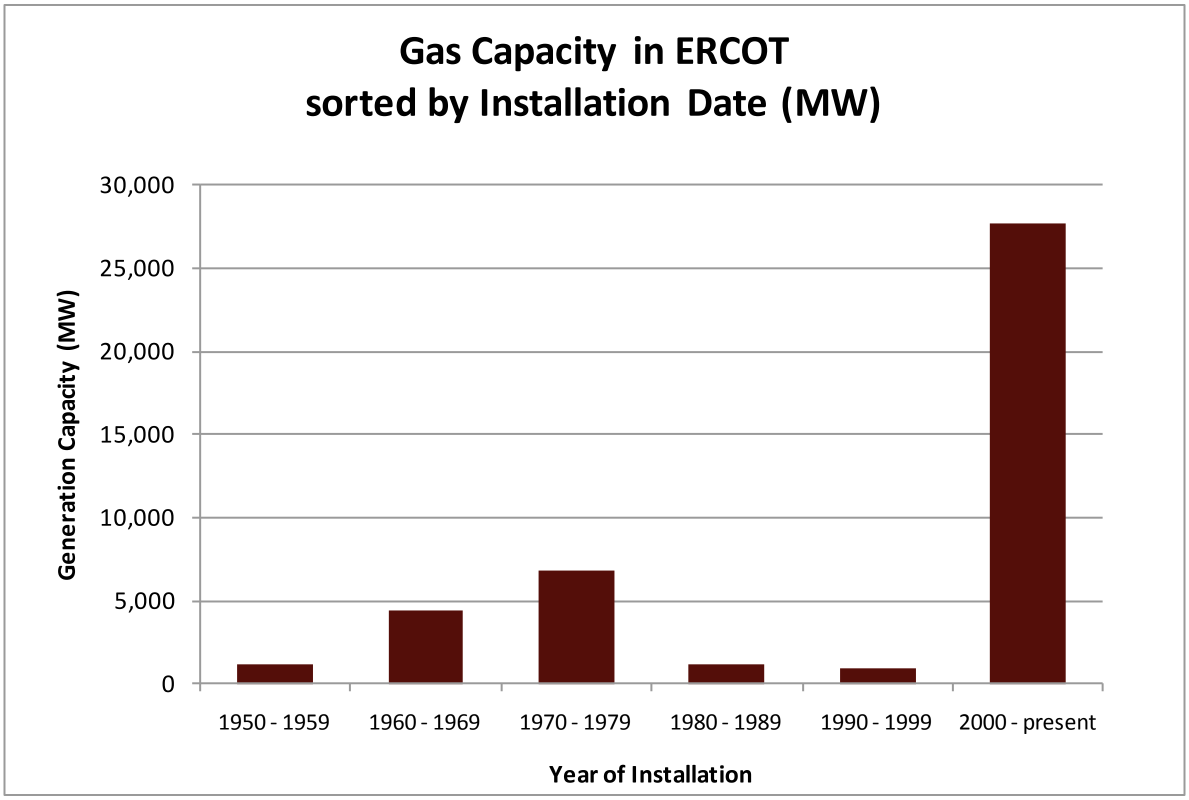
Much of the coal-fired generation capacity in ERCOT was installed in the 1970s, as depicted in the following chart.



Even though a majority of the coal-fired capacity in ERCOT has been in operation for more than 30 years, much of the coal capacity in ERCOT is equipped with best-available emission control technologies. Of the 31 coal plants in ERCOT, 19 have a wet limestone scrubber (WLS) installed, while 18 have a baghouse (BH). Eight of the coal units have a selective catalytic reduction (SCR) device installed, and 19 have closed-loop cooling towers (CL-CT). Generation capacities sorted by control technology are depicted the following chart. As noted in Section 2, proposed mercury emissions restrictions may require a combination of wet-limestone scrubber, baghouse, and activated carbon injection.

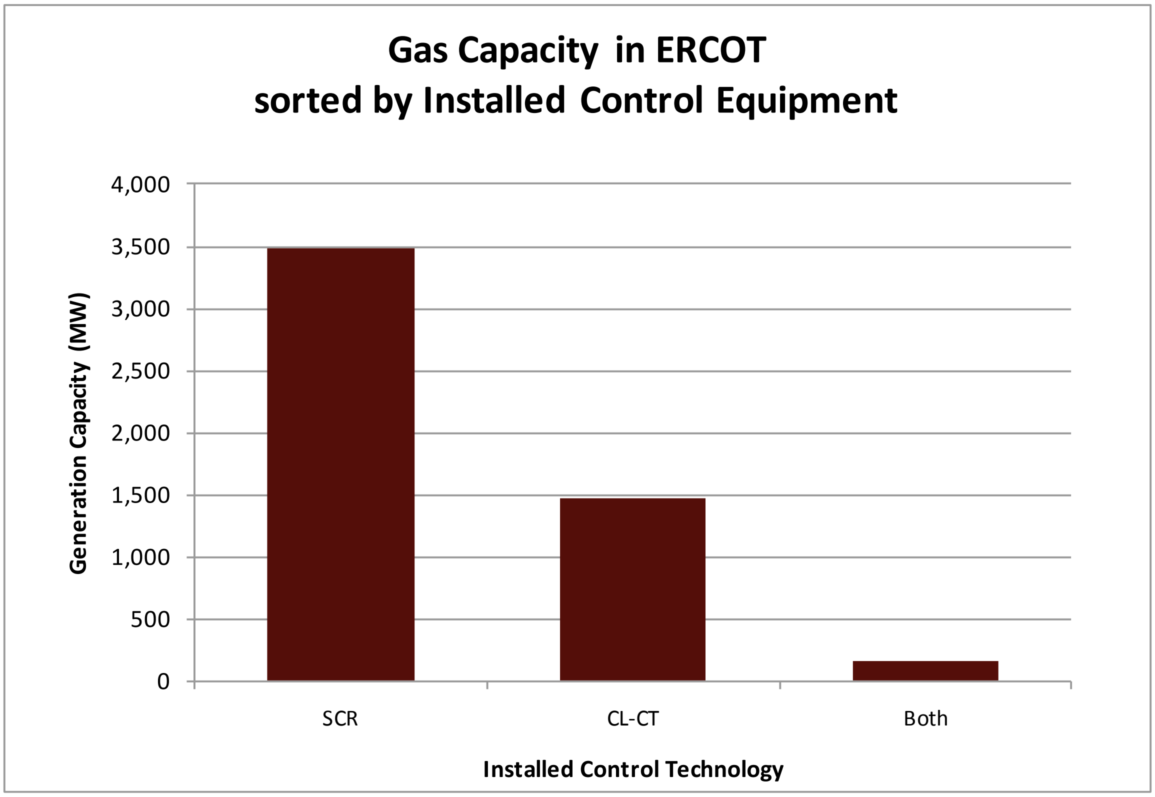


In contrast, much of the gas-fired capacity in ERCOT is less than 10 years old, as depicted in the following chart.



As is depicted in the chart above, over 27,000 MW of gas-fired generation capacity has been installed in ERCOT in the last 11 years, and it is unlikely that the proposed regulations will result in retirement of this newer fleet of efficient combined-cycle and combustion turbine gas-fired units. Of the units installed before 2000, there are approximately 3,166 MW of units that are smaller than 100 MW, ranging in size from 5.6 to 88 MW. Due to their limited operation, it is not expected that the proposed regulatory changes will have a significant impact on these units, and to the extent that some of this capacity is retired, the small size of the units will limit impacts to grid reliability. As such, gas-fired generation units that were installed after January 2000 and units that are smaller than 100 MW in capacity are not evaluated in this report.

Excluding these units, there are 12,630 MW of gas-fired capacity that could be affected by the proposed regulations. Natural-gas-fired generation does not emit significant amounts of SO2, particulates, or mercury. The primary mechanism to reduce nitrogen oxides emissions is selective catalytic reduction. As shown in the following chart, approximately 3,500 MW of potentially affected natural-gas-fired generation already has selective catalytic reduction (SCR) equipment installed. Given current information regarding pending regulations, it is unlikely that additional existing natural gas-fired generation will be required to be retrofitted with SCRs. However, only 1,500 MW of potentially affected generation has an installed closed-loop cooling tower (CL-CT) system. It is possible that the remaining natural-gas fired units will be required to have CL-CT equipment installed.



The unit-specific data regarding size and installed control technologies on generating units included in this study are provided in Appendix A.

These considerations aside, based on these discussions and a review of unit-specific emission control data, it is apparent that the fleet of coal-fired generation in ERCOT generally consists of relatively well-controlled units. Given the current prevalence of natural-gas fired generation in ERCOT, coal units represent a hedge against volatile natural gas prices. Retirement of some of the existing coal fleet would likely increase the value of the remaining units as a source of fuel diversity. As such, it is unlikely that a significant proportion of the coal units that already have one or more of the potentially necessary environmental controls in ERCOT will be retired as a result of the pending environmental regulations.

The large number of new, efficient, natural-gas-fired combined-cycle units in ERCOT represents significant competition for older steam-turbine gas units. In a market with adequate reserve margins, gas steam units may not provide sufficient market revenue to justify retrofitting with closed-loop cooling towers. If proposed regulations require that these retrofits be completed in order for gas-fired steam units to continue operations, they may force the retirement of a significant percentage of the older gas-fired fleet of units.

5. System Impact Analysis

With respect to system reliability, both the compliance requirements of the pending regulations and the compliance schedules will have a significant impact. There are three categories of potential reliability concerns: resource adequacy, capacity availability during outages, and transmission system reliability issues resulting from retirements.

While generation owners may determine that some of the units will provide sufficient market revenue to offset additional investment, other generation units may be retired. If sufficient capacity is retired, the generation reserve margin in ERCOT may fall below the current target level of 13.75% absent installation of replacement capacity. A robust wholesale energy market should provide sufficient new sources of generation to replace retired units if there is adequate time for changing market conditions to incent new investment.

The installation of additional emissions controls may require an extended outage for each of the associated generating units. If the compliance schedule to implement the required controls is overly restrictive, a significant number of units may be unavailable at the same time, resulting in insufficient remaining capacity being available to serve system demand, even though sufficient capacity will be available once the upgrades are complete.

Finally, unit retirements could lead to increased system congestion. It may not be possible, in specific areas of the grid, to reliably serve forecasted customer demand (for example, areas dependent upon local generation facing multiple generation retirements may be at risk of load shed). Reliability-must-run service from the generator might not be reasonable in this situation. Development of new generation at locations where generation is retired would minimize local impacts to grid congestion and local reliability. Reuse of existing generation sites is a reasonable expectation given the availability of transmission, water, and, in most cases, a natural gas pipeline connection and/or railroad access. However, it is unknown whether the owners of the retiring plants' locations would decide to develop new units at those locations.

5.1. Retrofit Technologies

As noted in Section 2, based on a review of the currently available information on the proposed environmental regulations, the expected regulatory scenario consists of all lignite-fired coal units in ERCOT being required to have at least a wet limestone scrubber, a baghouse with activated carbon injection, and selective non-catalytic reduction equipment. All non-lignite-fired coal units in ERCOT would be required to have at least dry sorbent injection and a baghouse with activated carbon injection. In addition, it is possible that all generating plants in ERCOT (both coal-fired and natural gas-fired) could be required to have a closed-loop cooling tower system.

Retrofit costs for these technologies were reviewed from several sources. In general, retrofit costs for smaller units are higher on a cost per kilowatt of capacity basis due to economies of scale. Cost estimates from published studies are provided in Table 2.

Table 2: Cost Estimates for Control Technology Retrofits

Control Technology	Cost Estimate ($/KW)
Wet Limestone Scrubber	450 - 573
Dry Sorbent Injection	39
Selective Non-catalytic Reduction	10
Baghouse with Activated Carbon Injection (ACI)	197 - 316
Closed-Loop Cooling Tower	200

These cost estimates have been used to estimate, by unit, the potential cost of retrofits under the expected control scenario described. Under this scenario, costs per unit for environmental retrofits would range from $0/kW to $696/kW. Details are provided in Appendix A. As a comparison, current Energy Information Agency data indicates that the overnight capital cost for a new combustion-turbine generating plant is approximately $679/kW[3]. For the cost of installing all of the potentially required environmental controls on an existing unit, one could instead build a brand new unit in its place. In addition, units that are retrofitted with new controls will likely see a reduction in their maximum output, as environmental controls increase unit station service.

5.2. Scenario Development

At the time ERCOT interviewed generation owners as part of this study, none had developed a specific compliance strategy for the proposed regulations. Future investment in additional control technologies will be evaluated by generation owners with regard to forecasted return on investment based on expected market conditions. So there are two levels of unknowns at this time: until the regulations are finalized, unit-by-unit retrofit requirements cannot accurately be assessed. In addition, each generation company will develop their own assessment of future market conditions, which will be used to forecast potential market revenues and return on potential investments.

Decisions regarding whether to retrofit or retire generation units will be further complicated by uncertainty regarding future natural gas prices (natural gas is a significant driver of market clearing prices in ERCOT), potential future regulations limiting or taxing emissions of carbon dioxide, and potential implementation of additional State or Federal incentives for development of renewable generation capacity. Each of these factors, or the expectations thereof, may have a significant impact on these retire or retrofit decisions.

For this study, ERCOT developed four scenarios to assess the impacts of the proposed environmental regulations under different market conditions. The first scenario was designed to represent the continuation of current market conditions. Average delivered coal prices are approximately $2.40/MMBtu, varied to reflect specific plant locations (all prices are in 2017 dollars). The average delivered natural gas price in this scenario is $5.10/MMBtu. The second scenario is based on similar market conditions but with an average delivered price for natural gas of $8.00/MMBtu. The third scenario adds a

Assumptions to the Annual Energy Outlook, 2010. Energy Information Agency, Report # DOE/EIA-0554(2010) carbon emissions allowance price of $25/ton to the cost of generating unit operations to the base scenario, and the fourth scenario adds this same carbon allowance cost to the scenario with $8.00/MMBtu natural gas price.

5.3. Study Methodology

Using parameters developed for these four scenarios, the fleet of generation units in ERCOT was dispatched using a unit commitment and dispatch model to serve forecasted loads for the year 2017. This software was used to provide expected hourly market clearing prices and operating costs and revenues for each generating unit. Generating unit operating assumptions (generic unit efficiencies, variable and fixed costs, and operating constraints) are available for review on the ERCOT web-site[4]. Unit revenues and costs from the model simulations were used to determine the expected financial return consistent with the deregulated energy-only wholesale generation market from expected unit upgrade requirements.

The financial analysis was conducted using a pro forma type analysis, given financial assumptions consistent with non-regulated industries (debt/equity ratio: 55%/45%; cost of debt: 8%; cost of equity: 15%). The financial model used to conduct this analysis is available on the ERCOT web-site[5]. Unit operating revenues and costs derived from the system simulation model were assumed to continue throughout the useful life of each unit. Generating units were assumed to have a useful life of 50 years. Those units nearing the end of their useful life were assumed to have no less than ten serviceable years. It should be noted that, as derived, the resulting hurdle rate for investment in environmental control technologies is higher than would expected for municipal authorities and electric cooperatives. However, this consideration is not expected to significantly impact the results of this analysis.

The results of the financial analysis were used to determine which units were likely to be retrofitted and which were likely to be retired in each of the scenarios. These retirement decisions were based solely on market economics; a requirement to maintain adequate generation (plus a reserve margin) to serve forecasted peak loads in the ERCOT region was not imposed on the analysis. In addition, an evaluation of the potential for generation expansion was not included in the scope of this study. Specific unit retirements, by scenario, were then evaluated using a steady-state transmission power-flow simulation to determine areas of the transmission system that could be adversely affected by potential unit retirements.

6. Results

6.1. Generation Retirements

Each of the four scenarios was analyzed using the methodology described in the previous section under two sets of regulatory requirements. Due to the uncertainty regarding the need for closed-loop cooling tower equipment, and the possibility of site-specific less expensive options to reduce entrainment and impingement, each scenario

[4] http://www.ercot.com/content/meetings/lts/keydocs/2011/0503/Generic_Database_Characteristics_REV_1.xls
[5] http://www.ercot.com/content/meetings/lts/keydocs/2011/0503/New_Build_Financials.xls

was evaluated with and without requirements to have closed-loop cooling tower systems, yielding eight sets of results. These results are provided in Tables 3 and 4.

The generation reserve margins listed in Tables 3 and 4 are based on the assumption that the retirements listed in these tables occur by 2016, and no additional generation beyond what is currently expected is developed. Forecasted load and generation resources used to develop these reserve margin estimates are provided in the December update of the ERCOT Capacity Demand and Reserves Report (CDR).[6]

Table 3: Expected Unit Retirements by Scenario Without Closed-Loop Cooling Tower Requirement

Scenario	Coal-Fired Generation Retired (MW)	Gas-Fired Generation Retired (MW)	Total Number of Units Retired	Resulting Generation Reserve Margin (%)
Base Scenario	0	0	0	13.57
High Gas Scenario	0	0	0	13.57
Base Scenario with Carbon Fee	4,400	0	8	7.2
High Gas Scenario with Carbon Fee	0	0	0	13.57

Table 4: Expected Unit Retirements by Scenario With Closed-Loop Cooling Tower Requirement

Scenario	Coal-Fired Generation Retired (MW)	Gas-Fired Generation Retired (MW)	Total Number of Units Retired	Resulting Generation Reserve Margin (%)
Base Scenario	1,200	9,800	28	-2.3
High Gas Scenario	0	9,800	26	-0.5
Base Scenario with Carbon Fee	5,600	9,800	36	-8.6
High Gas Scenario with Carbon Fee	0	9,800	26	-0.5

In the scenarios resulting in significant retirements of existing generation, it is expected that much of the retired generation would be replaced with new generation capacity. Analysis of potential generation expansion was not included in the scope of this analysis. For new generation development to occur, wholesale prices in the region would need to increase to a high enough level to provide adequate incentive. In other words, scarcity pricing would need to be experienced for a sufficient number of hours. However, even with these higher prices, it is anticipated that these existing generating units would be retired, except in some specific circumstances where the units are in unusually good condition due to previous renovations, since it would be more economic to spend investment capital on new, more-efficient units rather than implementing the required retrofits on the existing generation which is nearing the end of its useful life.

6 http://www.ercot.com/content/news/presentations/2011/ERCOT%202010%20Capacity,%20Demand%20and%20Reserves%20Report%20-%20Winter%20Upd.xls

6.2. Transmission Needs Analysis

Reserve margin data provided in the previous section indicate that, in certain future scenarios, the proposed environmental regulations have the potential to affect the adequacy of generation resources to reliably serve expected peak loads. However, even at system reserve margin levels at or near the current target reserve margin for ERCOT of 13.75%, it is possible that unit retirements could result in significant local congestion. Generation within urban load centers can be operated during peak load periods to limit the amount of power provided by distant generation. The retirement of intra-urban generation resources would result in the need to import more power to serve load, leading to potential overloads and increased reactive power requirements.

This study uses steady-state reliability transmission models produced by ERCOT for the 2010 Five-Year Transmission Plan study. System topology, peak loads, and generation resources (except for the retirements under study) were consistent with that recently-completed study. All ERCOT Board of Directors endorsed transmission improvements were included in the system topology studied. Following the methodology used to develop the Five-Year Plan, this analysis was performed on a regional basis, with transmission impacts of expected retirements being evaluated in four studies, one for each of the following zones.

1. North-North Central weather zones (NNC)
2. South – South Central weather zones (SSC).
3. West – Far West weather zones (WFW).
4. East and Coastal weather zones (EC).

Given the locations of the potential generation retirements caused by the pending regulations, the two areas of specific concern for transmission reliability are the Dallas/Fort Worth region and the Houston region.

Dallas/Fort Worth Region (North-North Central Weather Zones)

In the scenarios in which closed-loop cooling towers are required, a significant amount of older-gas fired generation is expected to be retired. This generation includes several units in the Dallas Fort Worth area. With these units removed from the simulation, over 2,000 MVArs of additional reactive devices were required in order to maintain adequate voltage levels even without evaluating contingencies of system equipment. This reactive power requirement could also be provided by converting some or all of the retired generation into synchronous condensers (separating the generator from the remainder of the unit and using grid power to keep the generator synchronous with grid frequency). With these additional reactive devices included in the simulation, the system was still significantly strained, with numerous contingencies resulting in non-convergence (likely voltage collapse). Additional contingencies resulted in voltage at buses that were below established acceptable criteria. Significant system improvements would be required, given this level of unit retirement, in order to maintain system reliability.

Steady-state contingency analysis indicates that the expected retirements cause significant reliability implications in the Dallas/Fort Worth region. However, it does not indicate how much generation could be retired without excessively straining the existing transmission system. A transfer analysis was conducted to evaluate the impact of increasing amounts of unit retirements. Units that were determined to be economically "at risk" from the base scenario with closed-loop cooling tower requirements were included in a group, the generation output of which was reduced in a step-wise fashion until voltage collapse was noted. The most severe contingencies noted from the steady-state analysis were evaluated.

The transfer analysis indicates that not more than approximately 3,000 MW of generation capacity can retire from the North and North-Central zones (the greater Dallas/Fort Worth region) before the system becomes unreliable under peak-load conditions. Given the assumptions in this analysis, the most severe voltage conditions were noted in the area south of Dallas. As noted above, evaluation of potential generation expansion was not included in the scope of this study. Without generation replacement, the retirement of generation in and around Dallas/Fort Worth would result in increased import of power mainly from South and Houston zones. Given current system import limits from the South and Houston zones to North zone, these increased import requirements would lead to significantly reduced voltages at the intermediary buses. The result stated above serves as an indicative result only – a more detailed analysis, with an assessment of units actually proposed for retirement and a more thorough review of contingencies of concern, would be required to develop an accurate assessment of the point of voltage collapse.

Houston Region (East and Coastal Weather Zones)

Expected retirements in the Houston region for the base scenario with closed-loop cooling tower requirements led to a significant need for additional reactive devices in the Houston region. Much of this need could be met by converting all retired generation into synchronous condensers; several additional dynamic reactive devices were added to achieve stable system performance without contingencies. However, even with these reactive devices, reduced bus voltages were noted at five 345-kV buses and twenty-five 138-kV buses, with some as low as 0.83 per unit under contingency conditions.

A detailed study would be required in order to determine the most cost-effective improvements to maintain transmission system reliability in the Houston region following a significant retirement of generation capacity. It is possible that additional dynamic reactive capability could be sufficient, but results from this study indicate that it is likely that the retirements in the Houston area, as modeled, would require an additional import pathway.

System conditions were considerably worse in the Base Scenario with Carbon Fee with the closed-loop cooling tower requirement. In this scenario, the combined loss of several large coal plants in the South Zone and retirement of gas generation in the Houston zone led to significant overloads on the existing import pathways into the Houston area, in addition to the problems noted above. In this scenario, it is likely that at least two new import pathways into the Houston region would be required to maintain system reliability.

7. Discussion

This study is based on an analysis of four different pending regulations: revisions to the hazardous air pollutant emissions requirements for electric generating plants; revisions to cooling water intake requirements for electric generating plants and industrial facilities; proposed limits on interstate transport of air pollutants; and possible revisions to the requirements for storage of ash waste products. Proposals for the first two of these regulatory changes have been published; the latter two regulatory changes have not yet been formally proposed. In addition, even though the proposed cooling water regulations have been published, it is not clear what impact they will have on existing generating units. There is sufficient discussion in the regulations about site-specific solutions to indicate that power plants that are operated infrequently to maintain system reliability under peak load conditions may not be required to install expensive closed-loop cooling equipment.

The hazardous air pollutant regulations, as published, also present an amount of uncertainty. The mercury limit for lignite-fired units is a “Beyond the Floor” limit, indicating that it is more severe than most or all of the emissions rates at existing lignite-fired plants. It is not known at this time whether the environmental retrofits specified in this study (wet limestone scrubbers, baghouse with activated carbon injection, and selective non-catalytic reduction) will allow lignite-fired plants to meet these standards.

In addition, both of these proposed regulations may be revised before they are finalized sometime this fall, following public comment periods and regulatory review. Formal proposals for the remaining two pending regulatory changes were not available to be included in this study. For the purposes of this study, given that Texas will only be regulated for peak-season NOx emissions, it was considered unlikely that the rules limiting interstate transport of air pollutants would result in any additional requirements for environmental controls on existing electric generating units. The impact of pending ash disposal regulations was also considered unlikely to change the economic value of existing coal-fired generation.

Given the impact of just the closed-loop cooling tower requirements on older gas-fired generation in ERCOT, the results of this analysis must be reviewed in the context of the current uncertainty surrounding the proposed regulations.

The analysis conducted in this study indicates that the proposed environmental regulations are expected to affect two types of generation in ERCOT – coal-fired generation and older gas-steam units. In most scenarios, the impact to coal-fired generation is expected to be minimal. Given the prevalence of gas-fired generation in ERCOT, existing coal-fired generation maintains significant market value even with current natural-gas prices. Gas-fired generation sets market clearing prices in a majority of market intervals, causing the market value of coal generation to be highly dependent on current and forecasted spot price of natural gas in Texas.

As was noted by several parties interviewed as part of this study, in aggregate the coal-fired generation in ERCOT is generally larger, newer, and generally more environmentally controlled than the average of coal plants across the country. Even with these considerations, subject to significant environmental retrofit requirements, the least efficient coal plants may be considered only marginally economic, and the resulting retirement analyses may depend on the overall mechanical condition of the unit. The potential for increased coal transportation costs due to higher petroleum prices would also be a concern for the economic viability of these units.

This analysis indicates that the risk of future carbon emission fees also has a significant impact on the market value of coal generation. Every megawatt-hour of generation from a coal plant creates approximately 1 ton of carbon dioxide emissions; the same megawatt-hour of generation from a natural gas fired plant creates approximately one-half ton of carbon dioxide emissions. With gas-fired generation setting the market price, carbon emission fees can be expected to reduce the operating profit of coal-fired generation by one-half of the fee.

The base scenario with carbon emissions fee is unlikely to occur, but was included in this analysis in order to show the potential combined impact of low natural gas price and carbon emissions fee on coal generation. In this scenario, the carbon emissions fee of $25/ton was sufficient to make some of the coal units in ERCOT, mostly the smaller units that burn sub-bituminous coals, more expensive to operate than the combined-cycle gas-fired plants. As a result, in this scenario, the unit dispatch model indicated that the lower-cost coal units operated throughout the year, as did many of the combined cycle plants, while the higher-cost coal units operated less than half of the time, mostly during peak months. Under these market conditions, a similar impact to the dispatch of coal- and gas-fired units would be seen throughout the country – with coal plants that relied on fuel transported significant distances on rail or ocean vessel being more expensive than gas-fired combined-cycle generation. Should such a carbon emissions fee be imposed, the increased use of natural gas would likely lead to higher prices for this fuel, resulting in higher prices, which would then increase the output and economic viability of coal-fired generation.

Much of the older gas generation determined to be at risk in this study has limited market value and is likely to be returning little beyond payment of fixed costs and recurring capital requirements. In many cases, this generation is less-efficient than new quick-start generation, and less flexible. As shown in Appendix A, much of this generation is nearing the end of its useful life. Any requirement to add significant capital investment into these old inefficient units is likely to cause unit retirements. New capital would likely be diverted to newer, more efficient generation projects. In the scenario evaluated as part of this study, installation of closed-loop cooling towers would also increase unit station service (i.e., would reduce the net output of affected units), further reducing the market value of the retrofitted units.

Older gas-steam generation typically has significant range between maximum and minimum output, but it cannot start and stop quickly in response to changing market needs. The integration of variable generation in ERCOT has led to increased value in quick-start generation. This trend is expected to become more pronounced when the transmission improvements designated for the Competitive Renewable Energy Zones (CREZ) is complete, currently scheduled for late 2013. The analysis in this study does not assume any increase in wind generation, so impact of the CREZ build-out would further erode market value of older gas-steam generation.

The amount of replacement generation developed by private investors will depend on the market viability of new capacity. As the generation identified to be at risk is being used to provide peaking capacity, it would seem reasonable for replacement generation to serve the same role. Yet development of new gas-fired peaking capacity may require sufficient hours of scarcity pricing to attract new investment. Further, construction decisions may lag system needs for reliable operation. In other words, regulatory requirements may cause retirements, and real reliability concerns, before market signals can incent adequate investment in new generating stations.

As another consideration, if there is sufficient market interest in new generation capacity, there may be a system reliability need if the timing of the new regulatory requirements is such that there is insufficient lead-time for favorable market conditions to become apparent.

The transmission analysis indicates that the potential impact of the closed-loop cooling tower requirement on gas-fired generation could have a significant impact on transmission reliability in both the Dallas/Fort Worth and Houston regions. It should be noted that if plants are retired due to environmental non-compliance, reliability-must-run contracts may not be an option, or may be very costly if possible. This reliability analysis included the potential change of existing generation into synchronous condensers; even with this consideration the need to import real power into the urban centers resulted in potential system overloads and reduced voltage conditions. Given these results, the redevelopment of existing urban generation sites with new generation would be likely to result in a significantly lower overall cost to society.

8. Conclusions

ERCOT has reviewed the potential impacts of the following pending environmental rule changes:

- Clean Water Act – Section 316(b), regarding new requirements for cooling-water intake structures;
- Clean Air Act – new emission limits for Hazardous Air Pollutants (HAP);
- Clean Air Transport Rule (CATR); and,
- Coal Combustion Residuals (CCR) Disposal regulations.

The review conducted by ERCOT includes an overview of the pending EPA regulations and the potential range of resulting requirements and costs, provides information on the existing generation resources in the ERCOT Region including the emissions control technology currently installed on these units, identifies the key factors and uncertainties that will drive the decisions by generating unit owners to retire those units or to retrofit the units with additional control technologies, and provides an assessment of the implications of those pending regulations on generation and system reliability in the ERCOT Region.

This review indicates that there is still substantial uncertainty regarding the compliance requirements and schedules of the proposed regulations. However, given recently published proposals for the Hazardous Air Pollutants rule and the cooling water intake structures rule, ERCOT developed an assessment of possible retrofit requirements for electric generating units, and given these requirements, evaluated market viability of affected generating units in four potential future scenarios.

This scenario analysis indicates that it is unlikely that a significant amount of coal-fired generation will be retired, unless a combination of low natural gas prices and carbon emission fees significantly reduce the economic viability of these units. Older gas steam units that are subject to retrofit requirements are more likely to be retired; the imposition of closed-loop cooling tower requirements is likely to result in the retirement of almost 10,000 MW of gas-fired generation. Without additional replacement generation, the retirement of this gas-fired generation would reduce generation reserve margins below 0% in 2016.

The potential loss of this gas-fired generation would also have localized impacts on transmission reliability in the Houston and Dallas/Fort Worth regions. Both regions would likely require additional reactive devices and new import pathways. Redevelopment of existing generation sites in these urban areas with new generating units could reduce or delay the need for additional transmission infrastructure, and would likely lead to substantial savings to the overall ERCOT system.

Appendix A – Unit Capacity and Environmental Control Information

Table A1: Coal-Fired Units

Unit Name	Capacity (MW)	Installation Date	Primary Fuel	Installed Control Technology	Potential Retrofit Cost[7] ($ M)	Potential Retrofit Cost ($/KW)
Big Brown 1	600	1971	Lignite	LNB, OFA, SNCR, ESP, BH	391	651
Big Brown 2	595	1972	Lignite	LNB, OFA, SNCR, ESP, BH	387	651
Coleto Creek	640	1980	Sub-bit	LNB, OFA, BH, CL-CT	25	39
Fayette Power Project 1	608	1979	Sub-bit	WLS, LNB, OFA, ESP	241	397
Fayette Power Project 2	608	1980	Sub-bit	WLS, LNB, OFA, ESP	241	397
Fayette Power Project 3	445	1988	Sub-bit	WLS, LNB, OFA, ESP	201	451
Gibbons Creek 1	470	1982	Sub-bit	LNB, OFA, ESP, CL-CT	136	290
J K Spruce 1	555	1992	Sub-bit	WLS, LNB, OFA, BH	111	200
J K Spruce 2	785	2010	Sub-bit	WLS, SCR, LNB, OFA, BH, CL-CT	0	0
J T Deely 1	440	1977	Sub-bit	LNB, OFA, BH, CL-CT	17	39
J T Deely 2	440	1978	Sub-bit	LNB, OFA, BH, CL-CT	17	39
Limestone 1	831	1985	Lignite	WLS, LNB, OFA, ESP, CL-CT	172	207
Limestone 2	858	1986	Lignite	WLS, LNB, OFA, ESP, CL-CT	178	207
Martin Lake 1	805	1977	Lignite	WLS, LNB, OFA, ESP	328	407
Martin Lake 2	810	1978	Lignite	WLS, LNB, OFA, ESP	330	407
Martin Lake 3	810	1979	Lignite	WLS, LNB, OFA, ESP	330	407
Monticello 1	565	1974	Lignite	LNB, OFA, SNCR, ESP, BH	393	696
Monticello 2	565	1975	Lignite	LNB, OFA, SNCR, ESP, BH	393	696
Monticello 3	760	1978	Lignite	WLS, LNB, OFA, SNCR, ESP	302	397
Oak Grove 1	820	2011	Lignite	WLS, LNB, OFA, SCR, BH, CL-CT	0	0
Oak Grove 2	796	2011	Lignite	WLS, LNB, OFA, SCR, BH, CL-CT	0	0
Oklaunion 1	650	1986	Sub-bit	WLS, LNB, ESP, CL-CT	128	197
San Miguel 1	391	1982	Lignite	WLS, OFA, ESP, CL-CT	127	326
Sandow 4	573	1980	Lignite	WLS, LNB, OFA, SCR, ESP, CL-CT	113	197
Sandow 5	570	2010	Lignite	CFB, WLS, SNCR, BH, CL-CT	0	0
Twin Oaks 1	156	1990	Lignite	CFB, BH, CL-CT	0	0
Twin Oaks 2	156	1991	Lignite	CFB, BH, CL-CT	0	0
W A Parish 5	645	1977	Sub-bit	LNB, SCR, BH, CL-CT	25	39
W A Parish 6	650	1978	Sub-bit	LNB, SCR, BH, CL-CT	25	39
W A Parish 7	565	1980	Sub-bit	LNB, SCR, BH, CL-CT	22	39
W A Parish 8	610	1982	Sub-bit	WLS, LNB, SCR, BH, CL-CT	0	0

[7] Based on a regulatory scenario that would require all lignite-fired coal plants to have a wet limestone scrubber, selective non-catalytic reduction, a baghouse with activated carbon injection, and a closed-loop cooling tower system; all sub-bituminous coal plants required to have dry sorbent injection, a baghouse with activated carbon injection, and a closed-loop cooling tower system.

Table A2: Natural-Gas-Fired Units

Unit Name	Capacity (MW)	Installation Date	Installed Control Technology	Potential Retrofit Cost[8] ($M)	Potential Retrofit Cost ($/kW)
B M Davis 1	335	1974	IFGR	67	200
Cedar Bayou 1	745	1970	SCR	149	200
Cedar Bayou 2	749	1972	SCR	150	200
Dansby 1	110	1978	OFA, CL-CT	0	0
Frontera 1	141	1999	LNB, CL-CT	0	0
Frontera 2	141	1999	LNB, CL-CT	0	0
Graham 1	225	1960		45	200
Graham 2	390	1969	OFA	78	200
Handley 3	395	1963	SFRG, SCR	79	200
Handley 4	435	1976	LNB, OFA, SCR	87	200
Handley 5	435	1977	LNB, OFA, SCR	87	200
Johnson Cnty 1	163	1997	SCR, CL-CT	0	0
Johnson Cnty 2	106	1997	CL-CT	0	0
Lake Hubbard 1	392	1970		78.4	200
Mountain Creek 6	120	1956	LNB, IFGR	24	200
Mountain Creek 7	115	1958	LNB, IFGR	23	200
Mountain Creek 8	565	1967	LNB, OFA, SCR	113	200
O W Sommers 1	420	1972	IFGR, OFA	84	200
O W Sommers 2	420	1974	IFGR, OFA	84	200
Ray Olinger 2	107	1971	OFA, FGR	21	200
Ray Olinger 3	146	1975	LNB, OFA, FGR	29	200
Sam Bertron 3	230	1959	IFGR	46	200
Sam Bertron 4	230	1960	IFGR	46	200
Sim Gideon 1	136	1965	OFA, CL-CT	0	0
Sim Gideon 2	136	1968	OFA, CL-CT	0	0
Sim Gideon 3	336	1972	IFGR, OFA, CL-CT	0	0
Stryker Creek 1	171	1958	LNB	34	200
Stryker Creek 2	502	1965	LNB, OFA	100	200
T H Wharton 3	104	1974	LNB, CL-CT	0	0
T H Wharton 4	104	1974	LNB, CL-CT	0	0
Thomas C Ferguson 1	424	1974	LNB, IFGR	85	200
Trinidad 6	226	1965		45	200
V H Braunig 1	215	1966		43	200
V H Braunig 2	220	1968		44	200
V H Braunig 3	412	1970	IFGR, OFA	82	200
W A Parish 1	174	1958		35	200
W A Parish 2	174	1958		35	200
W A Parish 3	278	1961	IFGR	56	200
W A Parish 4	552	1968	IFGR	110	200

[8] Based on a regulatory scenario that would require all natural gas-fired plants included in this analysis to have closed-loop cooling tower systems.

Abbreviations:

Sub-bit	Sub-bituminous Coal (primarily Powder River Basin Coal)
WLS	Wet Limestone (Or Lime) Scrubber
DSI	Dry Sorbent Injection
LNB	Low-NOx Burners
ESP	Electrostatic Precipitator
BH	Baghouse
ACI	Activated Carbon Injection
IFGR	Induced Flue Gas Recirculation
CFB	Circulating Fluidized Bed (With Limestone Injection)
SNCR	Selective Non-Catalytic Reduction
SCR	Selective Catalytic Reduction
OFA	Over-fired Air
SFRG	Selective Flue Gas Recirculation
FRG	Flue Gas Recirculation
CL-CT	Closed-Loop Cooling Tower System

Impacts of the Cross-State Air Pollution Rule on the ERCOT System

September 1, 2011

Executive Summary

ERCOT was asked by the Public Utility Commission of Texas (PUCT) in the Open Meeting on July 8, 2011, to evaluate the impacts of the Cross-State Air Pollution Rule (CSAPR) on the reliability of the ERCOT grid. The ERCOT analysis included meetings with representatives of the Texas Commission on Environmental Quality and the U.S. Environmental Protection Agency, review of the compliance strategies provided by the owners of coal-fired resources in the ERCOT region, and consolidation of these compliance strategies for purposes of evaluating system-wide impacts.

Based on the information provided by the resource owners, ERCOT developed three scenarios of potential impacts from CSAPR. The first scenario, derived directly from the compliance plans of individual resource owners, indicates that ERCOT will experience a generation capacity reduction of approximately 3,000 MW during the off-peak months of March, April, October and November, and 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Scenario 2, which incorporates the potential for increased unit maintenance outages due to repeated daily dispatch of traditionally base-load coal units, results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 5,000 MW during the fall months of October, November and possibly into December. Scenario 3 includes the impacts noted for Scenario 2, along with potential impacts from limited availability of imported low-sulfur coal. This scenario results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 6,000 MW during the fall months of October, November and possibly into December.

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

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Impacts of the Cross-State Air Pollution Rule on the ERCOT System

1. Introduction

ERCOT was asked by the Public Utility Commission of Texas (PUCT) in the Open Meeting on July 8, 2011, to evaluate the impacts of the Cross-State Air Pollution Rule (CSAPR) on the reliability of the ERCOT grid. The final language of the CSAPR was released by the U.S. Environmental Protection Agency (EPA) on July 6, 2011, and was published in the Federal Register on August 8, 2011.

The CSAPR is one of several environmental rules proposed by EPA that affect electric generation. The CSAPR includes three separate compliance programs: an annual SO_2 program, an annual NO_X program, and a peak season NO_X program (for emissions during the peak ozone season of May – September). In the proposed rule (then known as the Clean Air Transport Rule [CATR]), Texas was only included in the peak season NO_X program. Based on the proposed rule, an ERCOT study completed on June 21, 2011, evaluating the expected impacts of the pending regulations, did not include any incremental impacts from the CATR on the ERCOT system.

In the CSAPR rule actually adopted by the EPA, however, Texas is included in all three compliance programs - the peak season NO_X program, the annual NO_X program, and the annual SO_2 program. The implementation date for the CSAPR is January 1, 2012.

In order to accomplish this review, ERCOT undertook several activities.

- ERCOT reviewed documentation published on the EPA web-site regarding the rule.
- ERCOT met with representatives of the Texas Commission on Environmental Quality (TCEQ) and the EPA.
- ERCOT consulted with environmental experts from several of the generating entities in the ERCOT region whose facilities were likely to be affected by the CSAPR regulations. The purpose of these meetings was to ascertain the likely compliance plans for those resources owners.
- These compliance plans were aggregated so that ERCOT could evaluate the likely impacts to grid reliability.

2. Rule Description

The CSAPR is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The rule is a replacement for the Clean Air Interstate Rule (CAIR), which was implemented in 2005. The CAIR was remanded to the EPA by the United States Court of Appeals for the District of

Columbia Circuit in 2008. In the CAIR program, Texas was regulated for particulate matter emissions (annual NOX and SO2 emissions).

Under CSAPR, generating units in Texas will be regulated for annual emission of SO2 and NOX, as well as emissions of NOX during the peak season (May – September). Each unit will be given a set allocation of emissions allowances. At the end of the calendar year, resource owners must turn in one allowance for each ton of emissions or be subject to penalties. Intra-state trading of allowances between resource owners is unlimited in the rule. However, interstate trading of allowances is capped – no state can have annual net imports of allowances of more than approximately 18% of the total state allocation of allowances. If this limit is exceeded, any resource owner that contributed to the excessive use of imported allowances will be subject to penalties.

Resource owners in Texas are permitted to trade SO2 allowances with resource owners in Kansas, Nebraska, Minnesota, Alabama, Georgia and South Carolina. Trading of NOX emissions will be allowed with states as depicted on the following map.

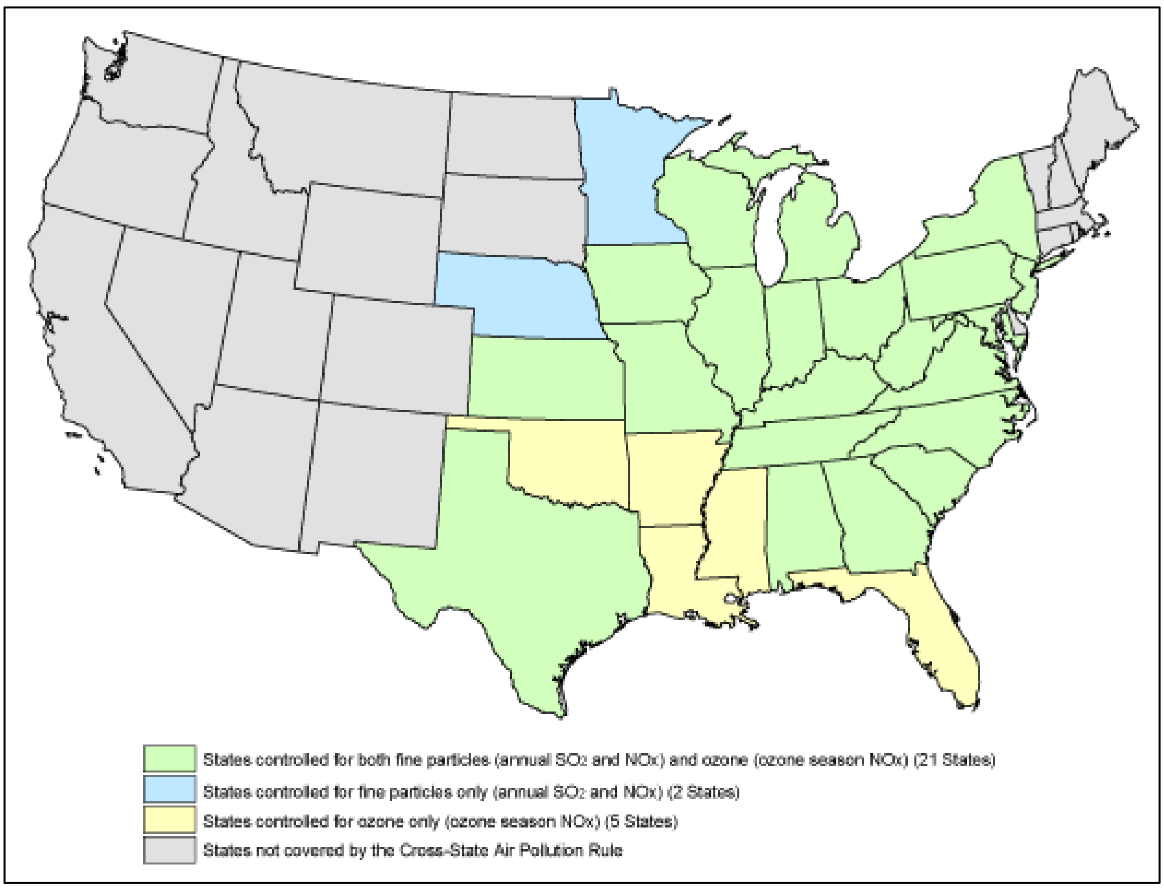


Figure 1: States Included in the Cross-State Air Pollution Rule

Resource owners who have emissions in excess of their annual allocations will have their next year's allocations reduced by one allowance for each excess ton of emissions, plus a penalty of two additional allowances for each excess ton. In addition, the Clean Air Act includes provisions for civil lawsuits in the event of non-compliance. Non-compliance penalties under the CSAPR program are substantial, and can reach up to $37,500 per violation per day. In addition to program penalties, failure to comply can subject entities to the risk of civil penalties, lawsuits by private parties, and criminal liability.

3. Compliance Options

Resource owners have several near-term compliance options to meet the emissions limits established by the CSAPR. In order to reduce SO_2 emissions, lower sulfur content fuel can be used. In the case of plants that are currently burning lignite coal, or a mix of lignite and sub-bituminous coals (such as coal from the Powder River Basin [PRB] region of northwest Wyoming), increasing the use of low sulfur western coal will reduce SO_2 emissions. Units that currently are being fueled exclusively by western sub-bituminous coals can be switched in whole or in part to ultra-low-sulfur western coals.

In the near-term, the demand for lower sulfur coal is expected to exceed the mining capacity and/or the railroad capacity necessary to deliver the coal to Texas. In addition, the use of lower sulfur coals can result in unit capacity derates due to increased heat content of the fuel. Unit modifications to resolve any such derates may require modifications to the unit's air emissions permit.

Existing SO_2 control equipment, such as wet-limestone scrubbers, can be utilized more frequently than is current practice, and in some cases the effectiveness of this equipment can be increased. This option only applies to a small subset of coal plants in ERCOT, and the use of scrubbers results in a decrease in maximum net output from the affected units of about 1 to 2 percent.

The use of dry sorbent injection is another compliance option to reduce SO_2 emissions. Dry sorbent compounds, such as sodium bicarbonate and trona, can be injected into a flue duct where they react with SO_2 (and acid gases) to form compounds that can be removed using an electrostatic precipitator (ESP) or baghouse. Resource owners exploring this option anticipate that it will provide a 25 – 30% reduction in emissions of SO_2 on units without existing SO_2 control equipment. The use of dry sorbent injection may require public notice or air permit modification.

Most of the low cost options to reduce NO_X emissions have been utilized to comply with existing air quality regulations. Further reductions will likely require high capital cost unit retrofits, including the addition of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) technologies. Any such unit changes would require several years for permitting, design and construction.

The remaining option for reducing SO_2 and NO_X emissions will be reducing unit output, either through dispatching units down to minimum levels during the off-peak hours and up to maximum capacity during peak afternoon hours, or through extended unit outages. Some of the traditionally base-loaded units will experience increased maintenance outages due to this daily dispatch pattern. These same base-load units have long start-up requirements, which could make them unavailable for operation during some off-peak extreme weather events.

4. Study Methodology

In order to evaluate the potential impacts associated with implementation of the CSAPR, ERCOT met with representatives of the TCEQ and the EPA to evaluate details of the rule and its implementation. ERCOT also reviewed compliance strategies provided by the owners of coal-fired resources in the ERCOT region. ERCOT consolidated these compliance strategies for purposes of evaluating system-wide impacts.

5. CSAPR Impacts

The compliance strategies of individual resource owners were compiled and consolidated to determine the aggregate impacts on the ERCOT system. This analysis indicates that, of the three CSAPR programs, the annual SO_2 program is likely to be the most restrictive on the ERCOT system. Even though individual units may have emissions in excess of the peak season or annual NO_X limits, Texas as a whole is likely to be below the state-wide limit, indicating that resource owners can achieve compliance through trading of NO_X emissions allowances. An extended hot summer, such as the one experienced in 2011, may result in limited availability of peak season NOX emissions, and a need to obtain additional allowances from out-of-state.

In consolidating the compliance strategies from the resource owners, it became apparent that each resource owner was assuming a level of effectiveness of the various compliance options identified in Section 3. While many of these compliance plans are likely to be adequate, given the risks associated with each compliance option, it is unlikely that all of the resource owners' plans will function as designed. For example, the use of dry sorbent injection on the scale required to attain compliance at certain facilities may perform as anticipated, but its use in this context is novel and may involve unexpected complications. As a result, ERCOT has developed three compliance scenarios in order to assess the potential risks to the system based on different assumptions regarding implementation of compliance strategies.

The first scenario is derived directly from the compliance plans of individual resource owners. Based on the information that ERCOT has been given, in this scenario, the ERCOT region will experience an incremental reduction in available operating capacity of approximately 3,000 MW in the off-peak months of March, April, October and November, and an operating capacity reduction of 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Capacity reductions in the off-peak months are expected to be greater because power prices are lower during these periods, making them a more attractive time for resource owners to take extended outages to conserve allocated allowances.

The second scenario is derived from the first, but includes the additional assumption that the increased dispatching of base-load units will lead to increased maintenance outages, especially in the fall months. Over the course of the spring months it may become increasingly apparent that dispatching specific units is leading to extensive maintenance requirements. In these cases it may be cost-effective to idle these units rather than dispatch them down to minimum levels during off-peak hours. These units would likely be run through the summer peak months, but then would be idled for an extended period in the fall in order to conserve allocated allowances. Given this additional constraint, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 5,000 MW of capacity during the fall months of October, November and possibly into December.

The third scenario is derived from the second, with the added consideration of possible near-term market limitations on the availability of imported low-sulfur coals, either due to nationwide demand exceeding mine output capacity or railroad shipping capacity. In the event of such limitations, coal plant resource owners would be forced to rely on higher sulfur coals during the spring and the peak season summer months. As a result, they would be forced to further reduce unit output in the fall months, beyond what is currently included in their compliance strategy, and could be required to decommit additional capacity in October and November in order to conserve allocated allowances. As a result, given these assumptions, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 6,000 MW of capacity during the fall months of October, November and possibly into December.

6. Discussion

The scenarios analyzed in this study represent best-case (Scenario 1), and two cases with increasing impacts to system reliability. Scenarios 2 and 3 are based on the occurrence of events that are reasonably foreseeable given the circumstances facing generation resources attempting to comply with the CSAPR. Even in the best-case scenario, ERCOT is expected to experience a reduction in available operating capacity of 1,200 – 1,400 MW during the peak season of 2012 due to implementation of the CSAPR. Had this incremental reduction been in place in 2011, ERCOT would have experienced rotating outages during days in August. Off-peak capacity reductions in the three scenarios evaluated as part of this study, when coupled with the annual maintenance outages that must be taken on other generating units and typical weather variability during these periods, also place ERCOT at increasing risk of emergency events, including rotating outages of customer load.

There are numerous unresolved questions associated with the impacts of the CSAPR on the ERCOT system. It is important to note that the resource owners have had less than two months to develop compliance plans for the new rule. These plans are still preliminary and based on assumptions regarding technology effectiveness, fuel markets, impacts of altered unit operations on maintenance requirements, and the cost-effectiveness of modifying and operating units to comply with the CSPAR. The overall system impacts noted in this study will change if these individual compliance strategies are adjusted to take into account updated information.

The availability of SO_2 allowances for purchase by resource owners in Texas is a significant source of uncertainty at this time. A lack of allowances for purchase from out-of-state resources will likely increase the severity of the CSAPR rule. Many resource owners expressed their concern that parties that have excess allowances may, at least initially, hold on to their excess, in order to maintain flexibility and future compliance options. As noted in Section 2, given the penalties for non-compliance, resource owners are unlikely to exceed the number of allowances they have in hand, with the expectation that allowance markets will open up later in the year. It may be that some resource owners will keep their excess allowances until it becomes clear that they will not be needed, late in the year. Other resource owners may have to shut units down in the early fall in order to conserve allowances.

In addition, the information ERCOT has received indicates there will not be a liquid market throughout the year for allowances, which will make it difficult to determine the appropriate value of allowances to compensate resource owners for operations associated with reliability commitments, such as through the daily or hourly reliability unit commitment process. It may be necessary to administratively establish a value for these allowances through the market stakeholder review process.

It is also possible that the impacts of CSAPR will increase in 2013 and 2014. In those years, it is unlikely that resource owners will have any additional options for rule compliance. Increased dispatching of base-load units will likely continue to lead to extended maintenance outages, and delivered availability of low sulfur western coals is likely to remain limited. In addition to these factors, some resource owners will be placing units on extended outages to install emission control technologies, such as wet-limestone scrubbers and possibly selective catalytic or selective non-catalytic reduction equipment. These retrofit outages could further reduce the generation capacity available during off-peak months.

Due to the numerous uncertainties, ERCOT cannot confidently estimate a “worst case” scenario at this time. Combinations of particular events may result in reductions in operating capacity that exceed those identified in Scenario 3, and thus further increase the risk of increasingly frequent and unpredictable emergency conditions, including the potential for rotating outages. The best outcome ERCOT can expect occurs if Scenario 1 is realized (*i.e.,* all generation resources’ current plans come to fruition), and, as discussed above, Scenario 1 appreciably increases risks for the ERCOT system, in both the on-peak and off-peak months.

7. Conclusion

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

DECLARATION OF WARREN P. LASHER

1. I am the Manager of Long-Term Planning and Policy for the Electric Reliability Council of Texas (ERCOT), where I am responsible for long-range transmission planning analysis, generation reserve margin studies and analyses of potential impacts of pending regulatory changes. I have worked at ERCOT for the past seven years. I was previously employed by the Southern Company, where I worked in the Engineering and the Generation Planning and Development organizations. Prior to my employment with the Southern Company, I worked in a consulting role helping clients maintain compliance with a range of Federal and State environmental regulations. I have a Bachelors of Arts degree in Mathematics from Yale University, a Masters of Environmental Management degree from Duke University, and a Masters of Science degree in Computer Science from the University of Alabama at Birmingham. I am providing this declaration on behalf of the ERCOT ISO.

2. **<u>Background: ERCOT's Role in Managing Texas's Electric Grid</u>**

3. Founded in 1970, ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas (PUC) and the Texas Legislature. ERCOT is responsible for overseeing the reliable operation of the electric grid for the ERCOT region of Texas. ERCOT manages the flow of electric power to approximately 23 million Texas customers – representing approximately 85 percent of the state's electric load (i.e., demand for electricity) and approximately 75 percent of the Texas land area. As the independent system operator ("ISO") for the region, ERCOT schedules and dispatches power on a grid that connects approximately 40,500 miles of transmission lines and more than 550 power generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.6 million premises in competitive choice areas.

4. ERCOT is not an advocacy organization and rarely advocates for particular policies or gets involved in litigation– except in cases where its core functions, including electric grid reliability, may be affected. This is one of those cases where ERCOT believes it has a role to voice its concern that Texas will face a shortage of generation necessary to "keep the lights on" in Texas, if the EPA's Cross-State Air Pollution Rule ("CSAPR") is implemented as written. Pertinent to this declaration, it is important to note that as an ISO, ERCOT and its individual employees have no financial stake in any generator or other market participant. As stated, ERCOT's only interests are relative to its core functions, including the reliable operation of the grid.

5. ERCOT's mission is to serve the public interest by: ensuring open access to transmission and distribution systems; maintaining system reliability and operations; enabling retail choice; operating fair and competitive wholesale markets; maintaining the renewable energy credits registry; and providing leadership and independent expertise to improve system reliability and market efficiency.

6. Ensuring reliable electrical power is critical to economic stability as well as human health and safety. Businesses in Texas depend on the reliable delivery of electricity to support their operations, and individual Texans depend on electric reliability to keep them cool in the summer and warm in the winter and to provide power for their daily needs, such as refrigeration and cooking. Essential services providers such as hospitals, police departments, water and sewer utilities, fire departments, and others also depend on having reliable electricity to fulfill their necessary duties that keep people alive and protect citizens against danger.

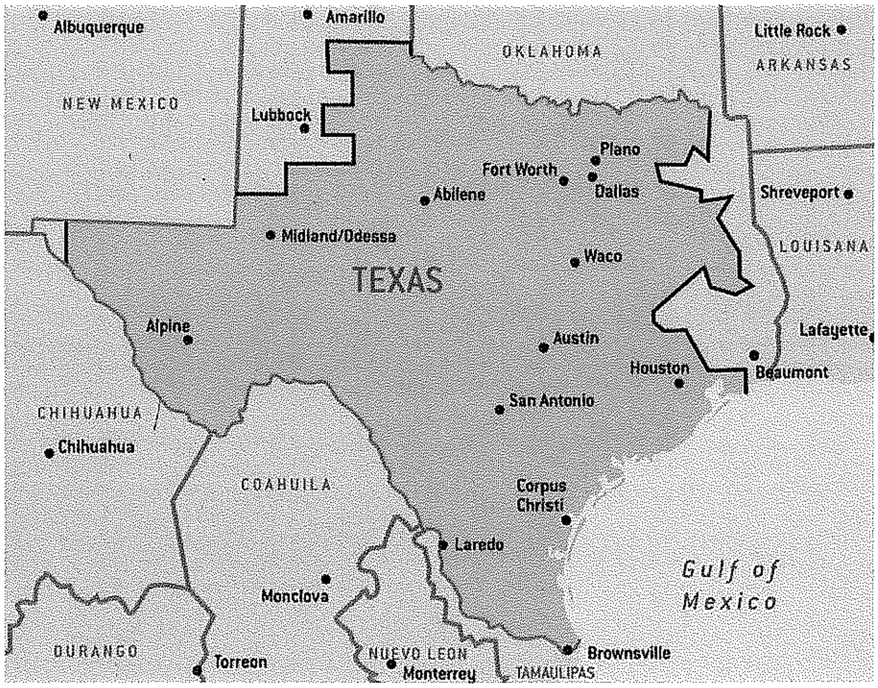
7. The federal Energy Policy Act of 2005 recognized the importance of ensuring reliability of electric grids by creating an Electric Reliability Organization ("ERO"). The ERO function is performed by the North American Electric Reliability Corporation (NERC), which oversees a vast set of reliability standards that govern operations and planning and are designed to ensure the reliability of the bulk power system. Under the NERC reliability construct, ERCOT is designated as both the Reliability Coordinator and the Balancing Authority, and as a Transmission Operator for the ERCOT Region. ERCOT is also registered for several other functions, including the key planning function of Planning Authority.

8. ERCOT is primarily regulated by the PUC and the Texas Legislature. ERCOT is accountable to the Texas Reliability Entity, NERC, and the Federal Energy Regulatory Commission for federal reliability standards.

9. <u>**Most of Texas's Electric Grid is a Standalone System**</u>

10. The ERCOT region, identified in Figure 1 below, covers most of Texas and includes Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, Abilene and the Rio Grande Valley.

Figure 1 – The ERCOT Region



11. The ERCOT grid is unique in the United States in that it is wholly intra-state and essentially isolated from the two other U.S. grid interconnections (the Western and the Eastern Interconnections). The ERCOT grid is not synchronously connected outside of the state, and there is limited ability for the ERCOT region to import or export electricity. There are 5 asynchronous ties between ERCOT and other interconnections: two linking ERCOT and the Eastern Interconnection (with a combined capacity of 820 MW), and three linking ERCOT and the electrical grid in Mexico (with a combined capacity of 286 MW). Flows on these asynchronous ties are scheduled by market participants. ERCOT can request support from neighboring regions during grid emergency events. Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT region is an island that must independently ensure its own electric reliability.

12. **<u>Generation Adequacy in the ERCOT Region</u>**

13. Generating capacity in the ERCOT region consists of a mix of generation technologies, fueled by coal (both lignite and sub-bituminous), natural gas, nuclear, wind, and other sources. Approximately forty percent of the energy generation in the ERCOT region comes from coal.

14. Ensuring reliability requires a constant balance between supply and demand. Unlike gas or water, electricity cannot be efficiently stored in large quantities – it must be generated to meet demand on a real-time basis. This means generation and transmission operations must be monitored in real time, 24 hours a day, to ensure a reliable and continuous flow of electricity. Thus, it is critical that ERCOT has enough generating capacity to meet demand at every given moment.

15. ERCOT must have and maintain adequate installed capacity to cover the forecasted load on the system as well as to ensure reliability in case of events such as higher-than-projected demand (e.g., due to extreme temperatures) or unplanned generation outages (e.g., due to mechanical breakdowns), and limited generation from variable resources. Reserve margins reflect a snapshot of existing and currently planned generation resources in excess of forecasted peak demand as a percent of that forecasted peak demand. Having a sufficient reserve margin is necessary to ensure reliability in the case of these events that are outside of normal planning assumptions. In November 2010, the ERCOT board approved a minimum planning Reserve Margin target of 13.75% for the ERCOT region, based on the generally accepted industry criteria of limiting firm load shedding due to supply inadequacy to once every ten years. Firm load shedding is described in more detail below in paragraph 18.

16. ERCOT must also maintain a sufficient amount of generating capacity on-line in each hour to serve the load at that time, cover instantaneous variation in load and to instantaneously replace the generation from any generating units which suffer an unexpected maintenance disruption and are instantaneously disconnected from the electrical grid. This capacity is commonly referred to as operating reserves. When sufficient generation is not available to meet these requirements, ERCOT institutes a progressive series of emergency steps to address the problem. The initial stages focus on maximizing the use of supply resources and the later stages focus on the utilization of ancillary services provided by demand response. With respect to maximizing supply options, ERCOT notifies resource owners to make all generation capacity available and requests assistance from other grids. ERCOT's ability to import power from other regions is physically limited by the capacity of its DC ties, which is approximately 1,106 MW. However, ERCOT is not entitled to any of that capacity. ERCOT has the right to request assistance, but there must be supply available in the adjoining region. In addition, there must be transmission capacity available to accommodate the import.

17. ERCOT has two demand-response programs that can be utilized in grid emergencies to reduce the amount of load connected to the grid in order to balance load with available generation. ERCOT typically procures 1,150 MW of Load Resources (which was until recently known as "Loads Acting As A Resource," or "LAARs") and approximately 450 MW of Emergency Interruptible Load Service (EILS); these programs are utilized by ERCOT in the second and third stages of a grid emergency to maintain system stability. When all of these operational tools are exhausted, ERCOT implements firm load shedding through the use of rotating outages. The progression of these stages is indicative of increased system stress related to increasing demand against decreasing operating reserve margins.

18. In general terms, firm load shedding is the act of temporarily eliminating the supply of electricity to small areas in order to avoid system-wide blackouts. To implement firm load shedding, the transmission owners in ERCOT disconnect small portions of their system for 15 – 30 minute intervals in order to reduce their overall system load. At any given moment during a grid emergency, the number of customers affected by

rotating outages is determined by the disparity between available generation capacity and total system load. Customers in disconnected areas lose all electrical service for the duration of the outage. In some instances, equipment designed to disconnect and reconnect customers fails to operate properly, leading to an extended outage of customers in the affected area. The use of rotating customer outages enables the system operator to maintain the reliability of the electric grid – *i.e.,* to prevent cascading outages, instability and/or uncontrolled separation. Without this safety valve, system conditions could degrade to the point that generators would be forced to disconnect from the system to avoid damage, risking a domino effect of an interconnection -wide outage. In the event of such a system-wide outage, restoring service to all customers would likely require several days.

19. ERCOT administers the planning function for the ERCOT region. This function forecasts future peak demand and establishes transmission and supply requirements over the relevant period to maintain reliability of the electric grid. However, the ERCOT region, under state law, employs a competitive market construct for generation supply. In this environment, generation owners bear the risk of investment and decide when and where to build new generation, and whether to retire or idle existing generation, based on market conditions. ERCOT, the regulated transmission and distribution utilities (which provide only "wires" service and do not own or operate generation facilities), and the PUC do not have the authority to order generators to maintain or to add generating capacity. Rather, the ERCOT market is designed to provide financial signals to competitive generation companies to ensure adequate generation capacity.

20. **<u>Challenges Confronting Reliable Energy in Texas</u>**

21. Grid reliability requires maintaining sufficient generation capacity to serve load given uncertainty associated with weather variability, unit maintenance, and output from variable resources such as wind generation. Evaluating the impacts to reliability of possible changes in generation capacity requires an accurate accounting of available generation. ERCOT compiles and publishes a report on the Capacity, Demand, and Reserves in the ERCOT Region ("CDR") every six months. This document is available to all interested parties on the ERCOT web-site[1] and provides an up-to-date accurate accounting of all currently available and expected future generating capacity in the ERCOT interconnection.

22. The CDR contains a list of all generating units on the ERCOT system, and a summation of the expected contribution of these units during the peak load hours of the year. The capacity values of units that can generate into either the ERCOT region or the eastern interconnect[2] are decreased to the extent that those units have firm contracts to provide power outside the ERCOT region. The capacity value of wind generation is also discounted. Wind is a variable resource, and the peak production period for the majority of the wind on the ERCOT system is in the

[1] http://www.ercot.com/content/news/presentations/2011/ERCOT_2011_%20Capacity_Demand_and%20Reserves_Report.xls
[2] There are no units capable of generating into the ERCOT region and the western interconnect.

middle of the night or early morning hours of the fall and spring. As a result, in calculating the system reserve margin, ERCOT discounts the capacity of wind generation to its equivalent value compared to dispatchable (e.g., coal, natural gas and nuclear) generation. This discounted capacity value is based on a probabilistic analysis conducted as part of a loss-of-load probability study. Hourly wind shapes, derived through computational fluid dynamics modeling of 15 years of meteorological data, are converted to wind farm generation patterns using a generic wind turbine power curve. The resulting wind patterns are then randomly selected in an hourly simulation model to calculate the capacity value of the resulting wind profiles relative to a generic thermal generating unit. This analysis resulted in the effective load carrying capability (ELCC) of wind in ERCOT, currently 8.7% of nameplate capacity.

23. The latest ERCOT CDR (dated June 9, 2011) indicates that the current maximum generating capacity in the ERCOT region for 2011 is 73,175 megawatts ("MW"), after properly discounting for the expected availability of wind power. The expected maximum generating capacity in the ERCOT region in 2014 is 75,967 MW. Background documentation for the CSAPR provided by the EPA[3] indicates that their projection for the operational capacity in 2014 in ERCOT is 90,405 MW, a discrepancy of 14,438 MW.

24. Based on an assessment of the EPA Integrated Planning Model (IPM) input database[4], which was used by the EPA to analyze the expected impacts of the CSAPR, ERCOT believes that this discrepancy is the result of the inclusion of wind generation resources at their full name-plate capacity, and the inclusion of retired and mothballed generating capacity. ERCOT currently has approximately 9,452 MW of wind generation capacity connected to the grid. In the latest CDR, this wind generation capacity has an ELCC of 822 MW (8.7% of nameplate capacity). The discrepancy which would result from the use of the full nameplate capacity of wind versus the use of the current ELCC of wind is 8,720 MW.

25. The following table provides a list of retired units that appear to be included in the EPA analysis of available capacity in ERCOT.

[3] Technical Support Document (TSD) for the final Transport Rule Docket ID No. EPA-HQ-OAR-2009-0491: Resource Adequacy and Reliability in the IPM Projections for the Transport Rule TSD, US EPA, Office of Air and Radiation, June 2011.

[4] http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html

Retired Plant Name	Unit ID	Capacity (MW)
Collin	1	153
Decordova Steam Electric Station	1	818
Eagle Mountain	1	115
Eagle Mountain	2	175
Eagle Mountain	3	375
Handley	1A	21
Handley	1B	21
Handley	2	75
Lake Creek	1	87
Lake Creek	2	230
Laredo	1	33
Laredo	2	33
Laredo	3	105
Morgan Creek	5	175
Morgan Creek	6	511
Mountain Creek	2	30
Mountain Creek	3A	35
Mountain Creek	3B	35
North Lake	1	175
North Lake	2	175
North Lake	3	365
Permian Basin	5	115
Tradinghouse	1	565
Tradinghouse	2	818
TXU Sweetwater Generating Plant	GT01	32
TXU Sweetwater Generating Plant	GT02	72
TXU Sweetwater Generating Plant	GT03	72
TXU Sweetwater Generating Plant	STG1	64
W B Tuttle	1	50
W B Tuttle	3	100
W B Tuttle	4	154

26. These retired units represent a total capacity of 5,784 megawatts. The next table provides a list of units that are currently mothballed, i.e., unavailable to the market for an extended period due to maintenance requirements or market conditions, that appear to be included in the EPA analysis of available capacity in the ERCOT region:

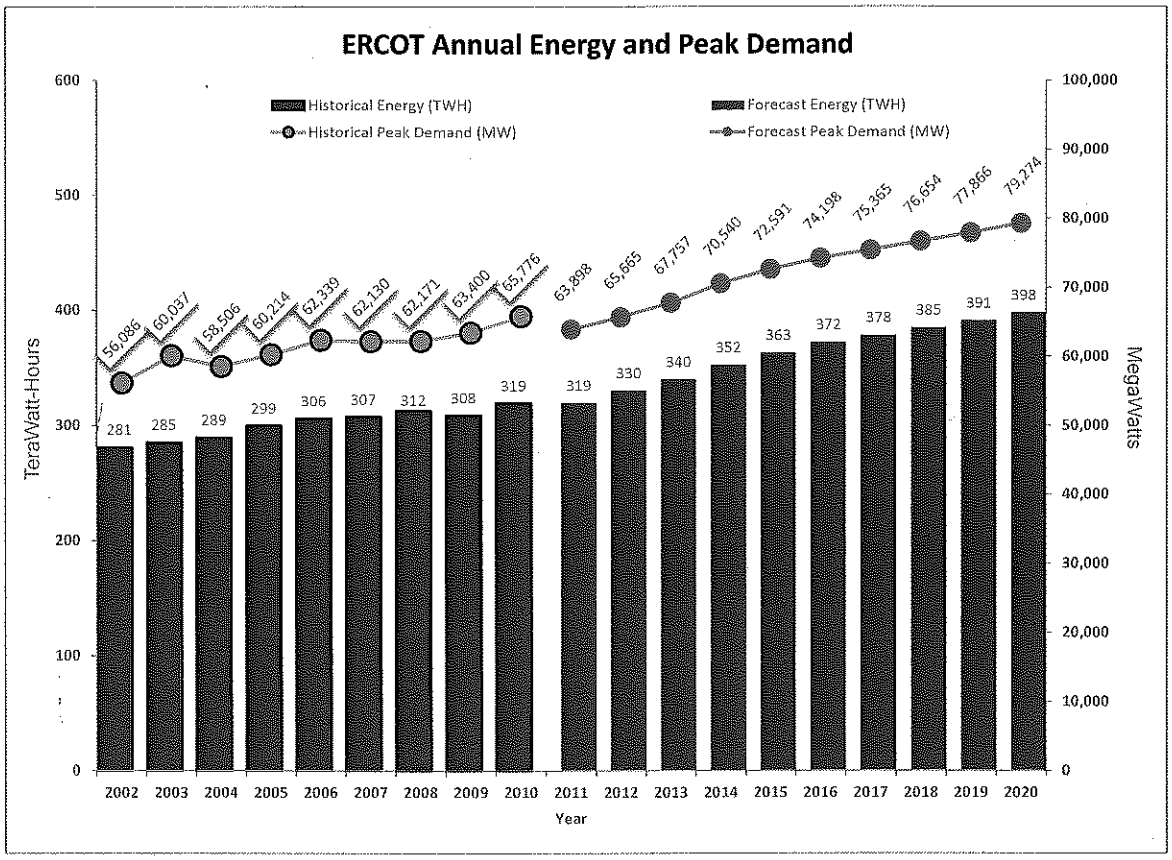
Mothballed Plant Name	Unit ID	Capacity (MW)
AES Deepwater	AAB001	140
Bryan	3	12
Bryan	4	22
Bryan	5	25
Bryan	6	50
C E Newman	BW5	41
Leon Creek	3	60
Leon Creek	4	95
North Texas	1	16.5
North Texas	2	16.5
North Texas	3	38
Permian Basin	6	540
Sam Bertron	SRB1	174
Sam Bertron	SRB2	174
Spencer	4	60
Spencer	5	65
Valley	1	175
Valley	2	550
Valley	3	390

27. These mothballed units represent 2,644 megawatts of capacity that are not available to serve load in ERCOT. The inclusion BY EPA of the full nameplate capacity of wind generation, along with the retired and mothballed generation capacity listed above, creates an unrealistically high generation reserve margin compared to expected peak loads and significantly masks the reliability implications of a potential reduction of available generation due to the CSAPR rule.

28. At any given time, available generating capacity is typically less than the theoretical maximum, for a variety of reasons. For example, all plants have planned and unplanned maintenance outages that can render them unavailable. Available generating capacity in ERCOT changes daily and seasonally. It is lowest in the spring and fall when many plants are scheduled to be off-line for maintenance outages. On average, approximately 10,000 MW of generation capacity is unavailable during the spring and fall months due to scheduled periodic maintenance requirements. Similarly, approximately 4,000 MW of generation capacity is typically unavailable at any given moment due to unplanned forced maintenance outages.

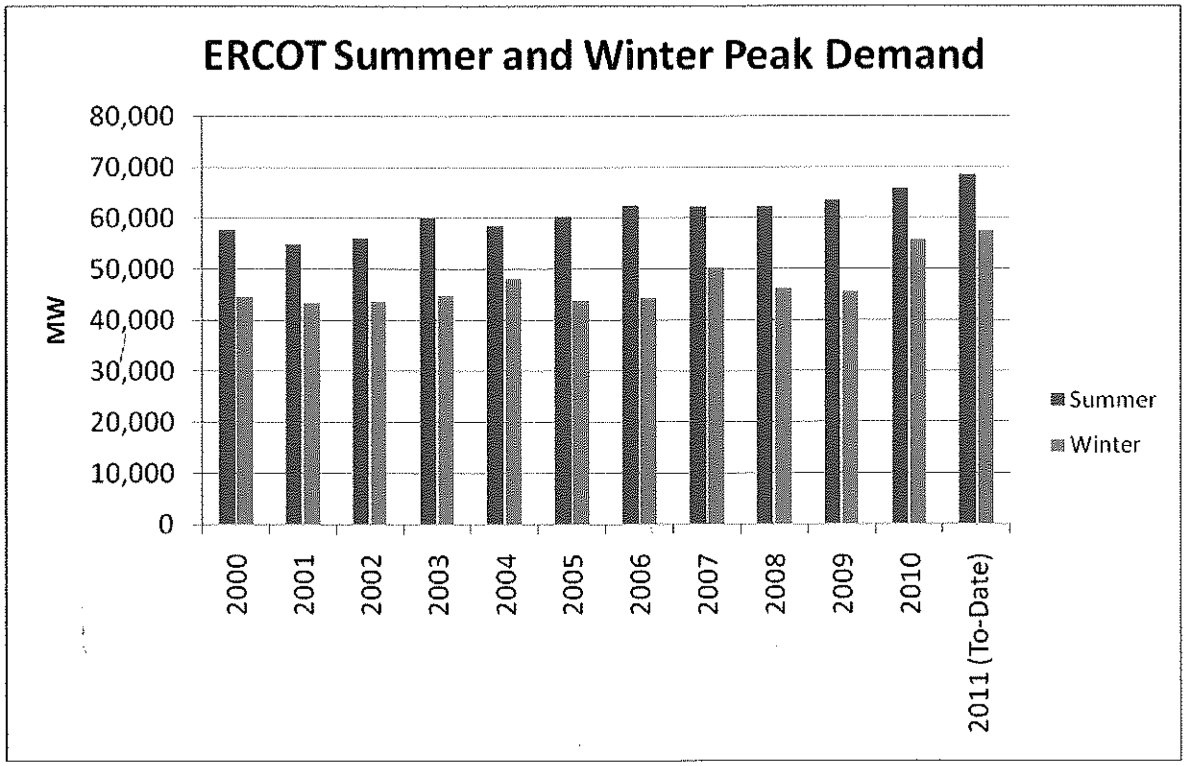
29. ERCOT typically experiences peak demand in the summer season (June – September). Demand has been consistently increasing in Texas and is projected to steadily increase through 2020.

Figure 2 – ERCOT's Historical Load Data and Long-term Load Forecast



30. ERCOT hit a new all-time peak demand for three consecutive years—2009, 2010, and 2011—and has exceeded the previous peak demand in seven of the last eleven years (2000, 2003, 2005, 2006, 2009, 2010, and 2011). Similarly, the winter peak record was broken in 2010 and again in 2011, and the previous winter peak demand record has been broken in six of the last eleven years (2000, 2003, 2004, 2007, 2010, and 2011). Figure 2 shows summer and winter peaks from 2000-2011. These record-breaking peak demands are due in part to the fact that Texas has continued to experience economic and population growth.

Figure 3– ERCOT Historical Summer and Winter Peak Demand



31. In its May 2011 CDR, ERCOT compared this steadily increasing demand to the forecast of available capacity and concluded that ERCOT will fall below its target reserve margin in the summer peak season as early as 2014, based on information that was known at that time, unless new generation capacity comes online to offset the growth in demand. This analysis did not account for the impact of EPA's CSAPR rule.

32. On August 3, 2011, the ERCOT region set a new peak demand record of 68,294 MW, breaking the record set in 2010 of 65,776 MW. The online capacity available for the ERCOT region on August 3, 2011 was 69,504 MW, meaning that total available generating capacity exceeded demand by only 1,210 MW, or less than 2%. Had the grid experienced forced outages of additional units, ERCOT might have had to employ rotating outages. The very next day, on August 4, 2011, in order to avert rotating outages, ERCOT had to deploy its Emergency Interruptible Load Service ("EILS"), which is an emergency load reduction service that involves disconnecting large customers that voluntarily agree to have their service interrupted in an electric grid emergency. If another 300-500 MWs of generating capacity had been unavailable on August 4, 2011, ERCOT would have had to order rotating outages to maintain grid reliability. The record demands from August 3 and 4 were caused by extreme heat – these were two of the hottest days in a record-breaking Texas summer. In fact, the National Oceanic and Atmospheric Administration has

classified the summer of 2011 in Texas as the "warmest summer on record of any state."[5]

33. Extreme weather conditions are expected to continue into next year. Unusually hot and dry conditions in Texas are now forecasted to persist into 2012.[6] If this prediction is correct, the continuing record drought will have an increased impact on generation resources. Currently, four generating units are being derated in order to limit the use of increasingly scarce surface cooling water resources. Operators of additional capacity have notified ERCOT that they will be at risk of derates and/or reduced hours of operation if drought conditions persist through the end of 2011.

34. The continuing drought and elevated temperatures could lead to extreme conditions again next summer. Three new dispatchable generation units (with an aggregate capacity of approximately 1,600 MW) coming on-line between now and the summer of 2012 will only cover expected load growth due to population and economic growth in the ERCOT region, leaving ERCOT in 2012 with a similar reserve margin as in 2011. Combined with persistent drought, ERCOT could face greater challenges in the summer of 2012 than for 2011 (as described above in paragraph 32).

35. Electric reliability is not just a summer problem. On February 2, 2011, extreme cold weather conditions, record electricity demand levels, and the loss of numerous electric generating facilities across the ERCOT region due to weather-related malfunctions resulted in rotating outages. On February 2, 2011, ERCOT set a new winter peak of 56,334 MW. Given generating unit outages (planned and forced) that resulted in available capacity dropping to as low as 54,000 MW that day, ERCOT had to declare an Energy Emergency Alert (EEA) Level 3 and had to shed 4,000 MW of firm load through rotating outages in order to maintain the integrity of the grid. Absent load shed on February 2, demand would have approached 59,000 MW, far outstripping the available capacity.

36. These events demonstrate that the currently installed level of generating capacity is barely sufficient to avoid rotating outages with the level of demand experienced in 2011.

37. **<u>Impacts of the Cross-State Air Pollution Rule</u>**

38. The Cross-State Air Pollution Rule (CSAPR) was issued on July 7, 2011 and requires substantial reductions in NO_x and SO_2 emissions from generating units in Texas. ERCOT was asked by the PUC on July 8, 2011, to evaluate the impacts of the CSAPR on the reliability of the ERCOT grid. ERCOT completed this analysis and issued a report summarizing its findings on September 1, 2011[7]. This report is attached.

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[5] http://www.noaanews.noaa.gov/stories2011/20110908_auguststats.html
[6] http://www.ncdc.noaa.gov/teleconnections/enso/index.php
[7] "Impacts of the Cross-State Air Pollution Rule on the ERCOT System," Electric Reliability Council of Texas,

39. In order to evaluate the potential impacts associated with implementation of the CSAPR, ERCOT met with representatives of the TCEQ and the EPA to evaluate details of the rule and its implementation. ERCOT also reviewed compliance strategies provided by the owners of coal-fired resources in the ERCOT region. ERCOT consolidated these compliance strategies for purposes of evaluating system-wide impacts.

40. Based on the information provided by the resource owners, ERCOT developed three scenarios of potential impacts from CSAPR. The first scenario, derived directly from the compliance plans of individual resource owners, indicates that ERCOT will experience a generation capacity reduction of approximately 3,000 MW during the off-peak months of March, April, October and November, and 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. These results incorporate Luminant's recently announced plan to comply with the CSAPR. Capacity reductions in the off-peak months are expected to be greater because power prices are lower during these periods, making them a more attractive time for resource owners to take extended outages to conserve allocated allowances.

41. The second scenario is derived from the first, but includes the additional assumption that the increased dispatching of base-load units will lead to increased maintenance outages, especially in the fall months. Over the course of the spring months it may become increasingly apparent that dispatching some of the traditionally base-loaded coal-fired units is leading to increased maintenance requirements. If this occurs, it may be cost-effective to idle these units rather than dispatch them down to minimum levels during off-peak hours. These units would likely be run through the summer peak months, but then would be idled for an extended period in the fall in order to conserve allocated allowances. Given this additional constraint, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 5,000 MW of capacity during the fall months of October, November and possibly into December.

42. The third scenario is derived from the second, with the added consideration of possible near-term market limitations on the availability of imported low-sulfur coals, due to nationwide demand exceeding either mine output capacity or railroad shipping capacity. Such limitations are not hypothetical – shipments of low-sulfur coals to plants in ERCOT were disrupted this past summer by floods in the Midwest. In the event of a recurrence of such limitations, coal plant resource owners would be forced to rely on higher sulfur local coals during the spring and the peak season summer months. As a result, they would be forced to further reduce unit output in the fall months, beyond what is currently included in their compliance strategy, and could be required to decommit additional capacity in October and November in

September 1, 2011.

order to conserve allocated allowances. As a result, given these assumptions, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 6,000 MW of capacity during the fall months of October, November and possibly into December.

43. The scenarios analyzed in this study represent best-case (Scenario 1), and two cases with increasing impacts to system reliability. Scenarios 2 and 3 are based on the occurrence of events that are reasonably foreseeable given the circumstances facing generation resources attempting to comply with the CSAPR. Even in the best-case scenario, ERCOT is expected to experience a reduction in available operating capacity of 1,200 – 1,400 MW during the peak season of 2012 due to implementation of the CSAPR. As noted above, the incremental loss of 300 -500 MW of available generating capacity on August 4, 2011 would have resulted in rotating outages. Off-peak capacity reductions in the three scenarios evaluated as part of this study, when coupled with the annual maintenance outages that must be taken on other generating units and typical weather variability during these periods, also place ERCOT at increasing risk of emergency events, including rotating outages of customer load.

44. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in each of the three scenarios outlined above and detailed in the attached ERCOT study.

45. If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of EEA events. These capacity reductions will, at best, present significant operating challenges for ERCOT, including increased likelihood of rotating outages as early as March 2012. If extreme drought and elevated temperatures comparable to what Texas experienced in 2011 continue in 2012, as discussed in paragraphs 33 and 34, the capacity reductions caused by CSAPR would lead to unavoidable rotating outages, possibly even recurring events, which could occur in both peak and off-peak periods, through 2012 and beyond.

I, Warren P. Lasher, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 21st day of September, 2011.