STP000029
May 31, 2011

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

**May 11, 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 over 8,000 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 to below 2% in 2015.

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

# 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:

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- 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

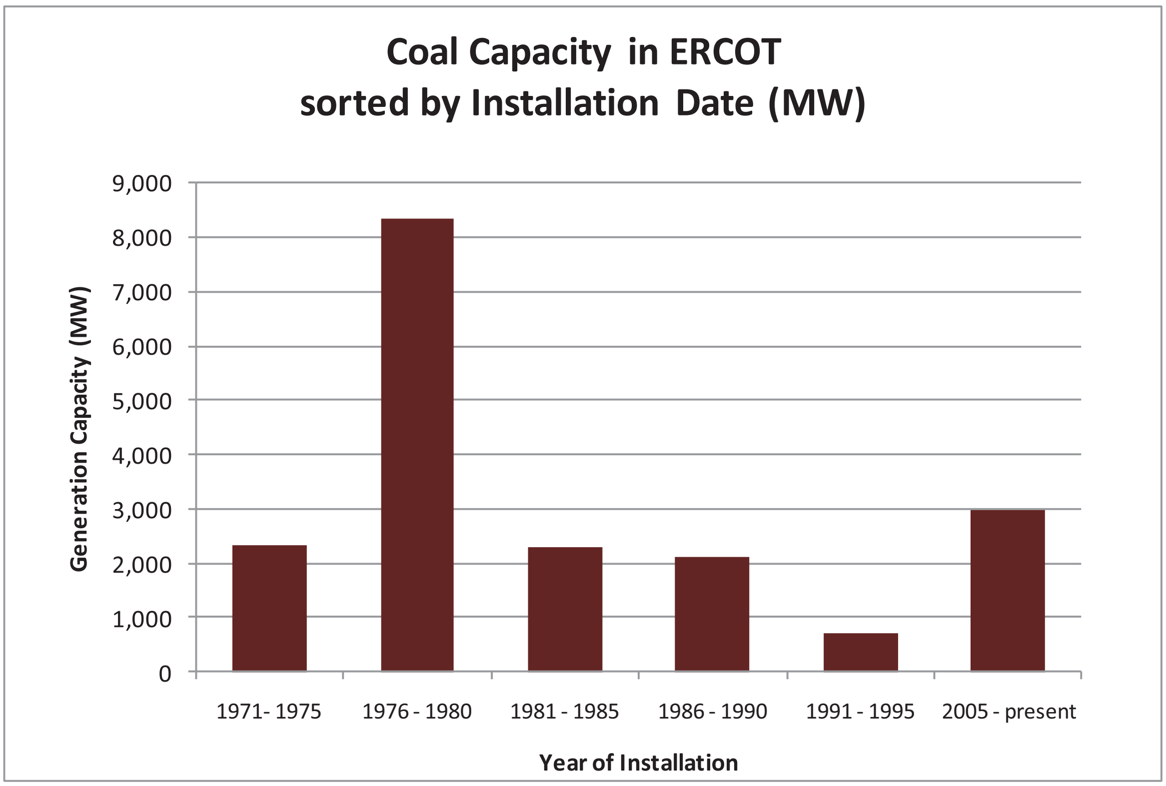
 

Table 1: Current Generation Capacity in ERCOT by Fuel Type

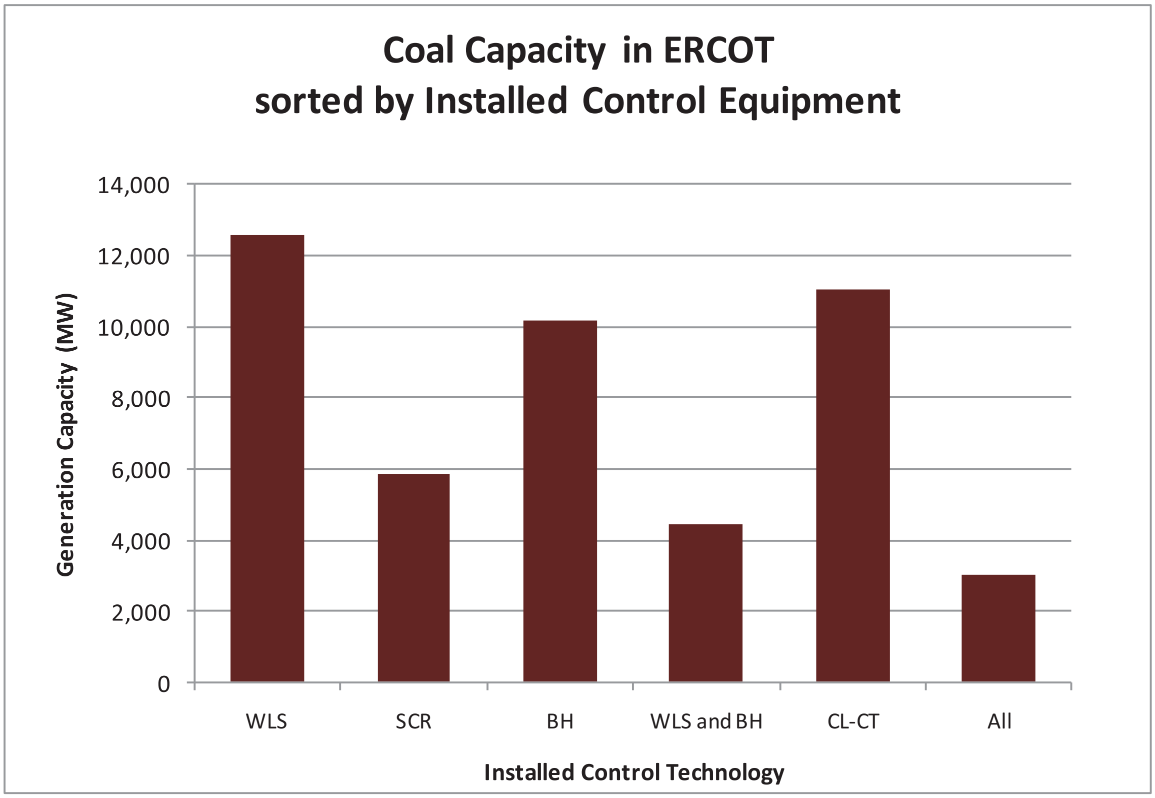
| Fuel Type | Installed Capacity (MW) |
|---|---|
| Nuclear | 5,131 |
| Gas | 42,732 |
| Coal | 18,772 |
| Wind | 9,527 |
| Hydro | 561 |
| Other | 234 |

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

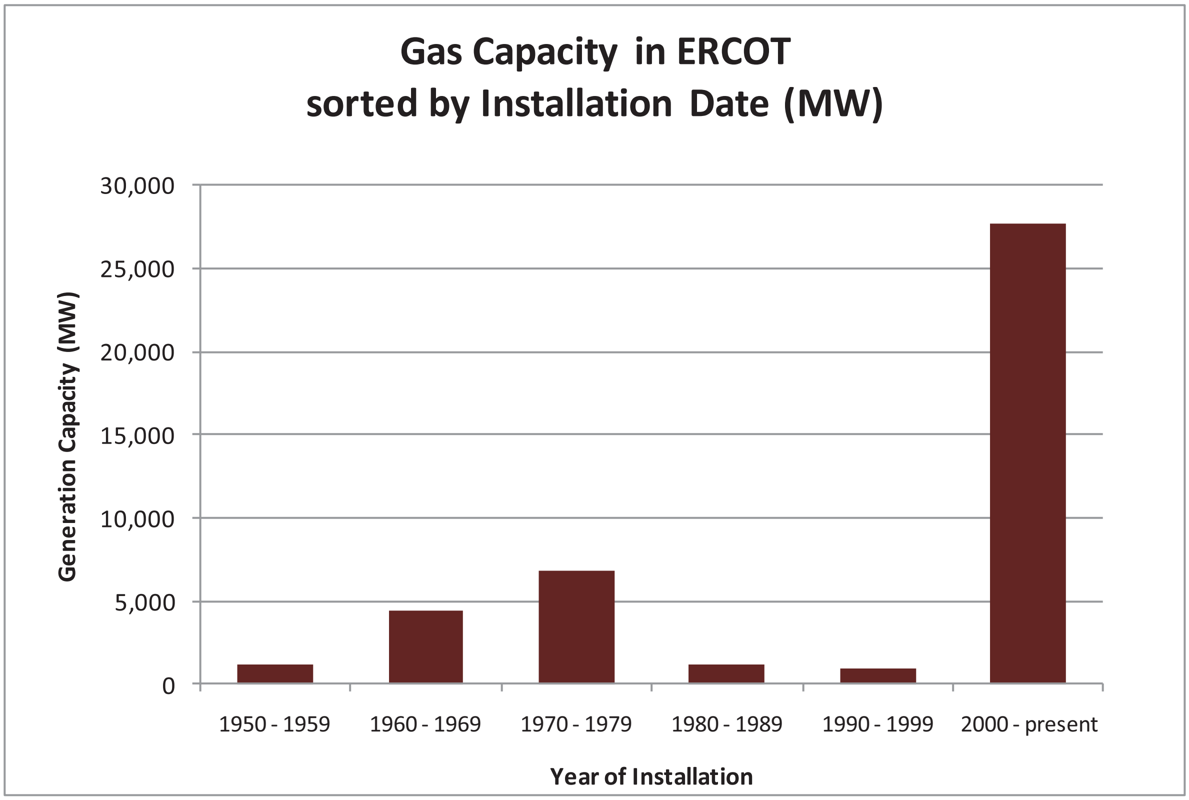
Much of the coal-fired generation capacity in ERCOT was installed in the 1970s, as depicted in the following chart.




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.

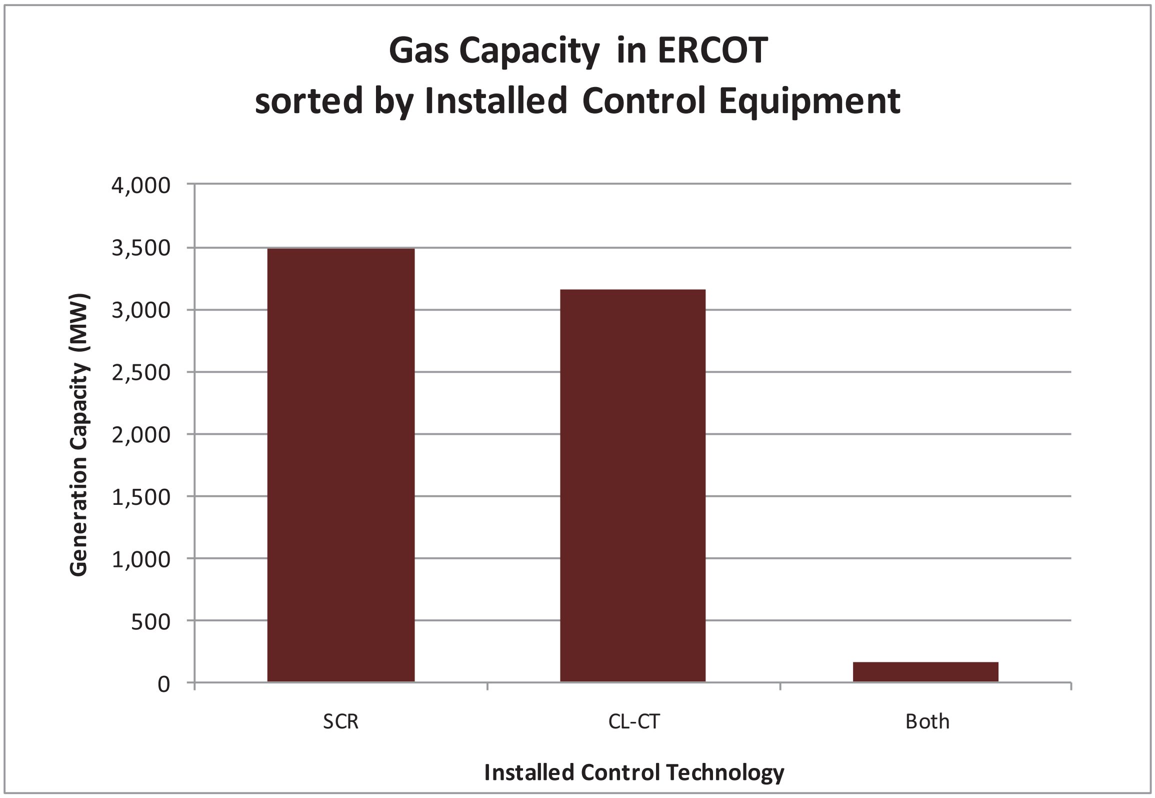



In contrast, much of the gas-fired capacity in ERCOT is less than 10 years old, as depicted in the following chart.




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 3,100 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 2017 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 | 8,100 | 28 | 0.2 |
| High Gas Scenario | 0 | 8,100 | 26 | 1.9 |
| Base Scenario with Carbon Fee | 5,600 | 8,100 | 36 | -6.2 |
| High Gas Scenario with Carbon Fee | 0 | 8,100 | 26 | 1.9 |

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 over 8,000 MW of gas-fired generation. Without additional replacement generation, the retirement of this gas-fired generation would reduce generation reserve margins to below 2% in 2015.

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, CL-CT | | 0 |
| O W Sommers 2 | 420 | 1974 | IFGR, OFA, CL-CT | | 0 |
| 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 |
| Sim Gideon 2 | 136 | 1968 | OFA, CL-CT | | 0 |
| Sim Gideon 3 | 336 | 1972 | IFGR, OFA, CL-CT | | 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 |
| T H Wharton 4 | 104 | 1974 | LNB, CL-CT | | 0 |
| Thomas C Ferguson 1 | 424 | 1974 | LNB, IFGR | 85 | 200 |
| Trinidad 6 | 226 | 1965 | | 45 | 200 |
| V H Braunig 1 | 215 | 1966 | CL-CT | | 0 |
| V H Braunig 2 | 220 | 1968 | CL-CT | | 0 |
| V H Braunig 3 | 412 | 1970 | IFGR, OFA, CL-CT | | 0 |
| 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 |