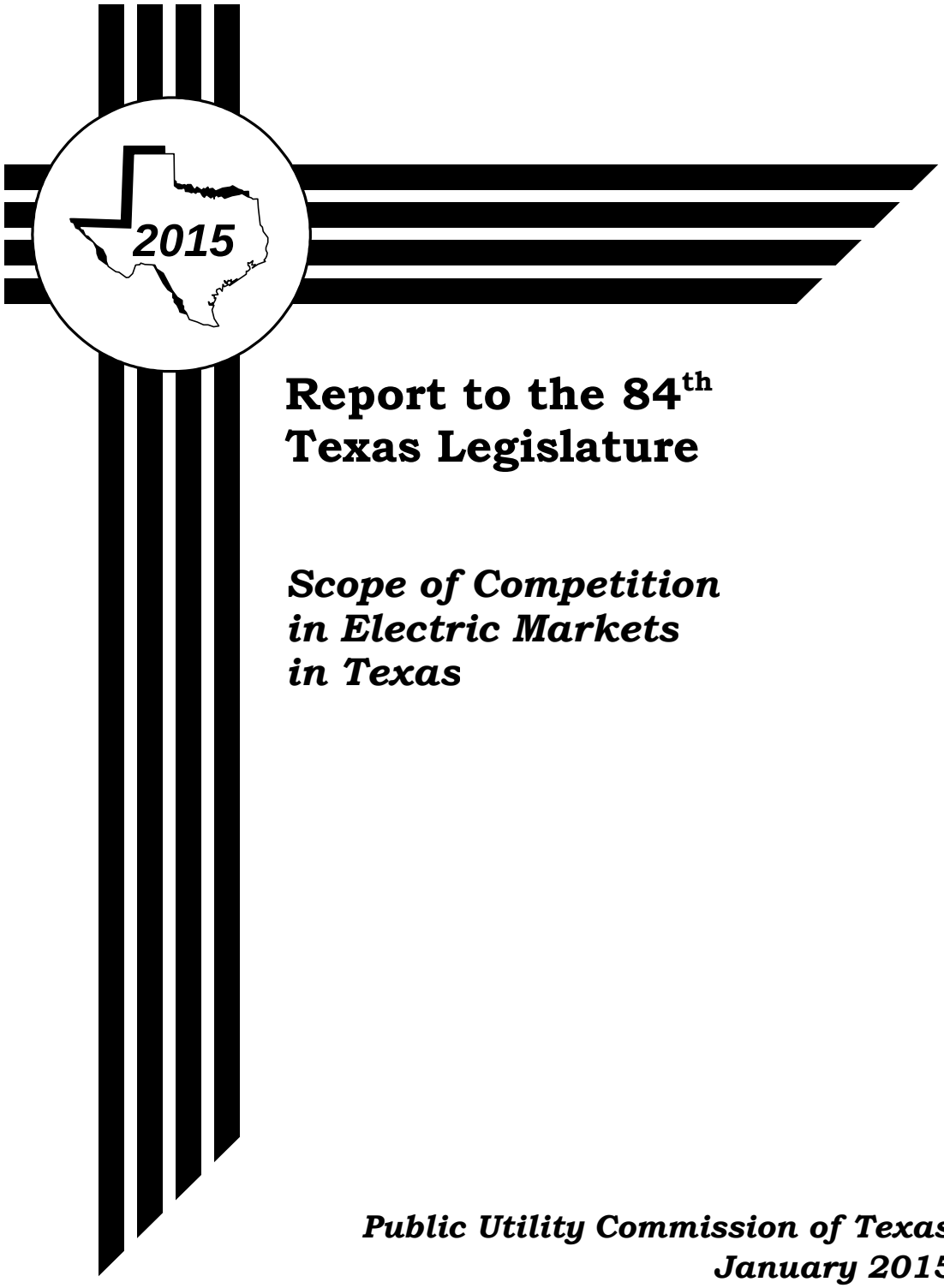

Report to the 84th Texas Legislature

Scope of Competition in Electric Markets in Texas

Public Utility Commission of Texas
January 2015

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Public Utility Commission of Texas

January 15, 2015

Honorable Members of the 84th Texas Legislature:

We are pleased to submit our 2015 Report on the Scope of Competition in Electric Markets, as required by Section 31.003 of the Public Utility Regulatory Act. This report provides an update on the status of electric competition in Texas and describes other electric industry matters for which the Commission has responsibility under State law. The report concludes with a discussion of recommendations that the Legislature may wish to consider. Additionally, attached to this report are the Commission comments to the Environmental Protection Agency regarding proposed Rule 111(d) of the Clean Power Plan, which highlight the detrimental impact of the regulations on Texas energy consumers.

We look forward to continued collaboration with the Legislature as we work together to secure a bright energy future for electricity customers, commerce, and industry in Texas. If you need additional information about the issues addressed in this report or any other PUC issues, please contact us.

Sincerely,

Donna L. Nelson	Kenneth W. Anderson, Jr.	Brandy Marty Marquez
Chairman	Commissioner	Commissioner

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I. EXECUTIVE SUMMARY

This Scope of Competition in Electric Markets Report examines the status of competition in retail and wholesale electric markets in Texas. The Public Utility Commission of Texas (Commission) has overseen a maturing competitive electric market in the Electric Reliability Council of Texas (ERCOT) region. As discussed in this Report, over the past two years the Commission has been engaged in numerous projects that improve the efficiency of the wholesale market, support a large and diverse number of competitive retail providers, protect customers, and promote high quality electric infrastructure.

The Texas retail market, under Commission oversight, remains the national leader in competitive residential, commercial, and industrial offerings, with the highest number of competitors and product variety in the country. Since the implementation of SB 7 in 2002, when Texans were given the power to choose their electricity provider, the forces of competition have created a robust marketplace today, with a diverse set of providers and offerings and an innovative and evolving product set, all with increased transparency for customers. In addition to leading the nation in diversity of product offerings and number of providers, Texas has been recognized as the market leader in its facilitation of customer choice by promoting ease of switching retail providers and by simplifying customer access to price information. Moreover, under the guidance of the Commission, the competitive market has produced average retail rates that consistently trend lower than those seen in other parts of the country in all sectors.

Alongside the Commission's work refining the retail market, much of the Commission's focus in 2013 and 2014 has been on ensuring resource adequacy in the region. To that end, the Commission has approved several enhancements to the wholesale market to support reliability. In its commitment to providing reliable, affordable, and efficient power to Texas industry and residents, the Commission has several ongoing projects focused on promoting efficient and sustainable outcomes in the wholesale market.

This Report summarizes these continuing trends affecting competition in the electric industry. It highlights the impact of competition on rates, customer protection and complaint issues, oversight and enforcement action, and noteworthy Commission activities. The Emerging Issues section of this Report underlines pending federal environmental regulations that may undermine ERCOT's competitive wholesale market, imposing substantial costs on consumers and jeopardizing resource adequacy. According to the grid operator, complying with these mandates could force the early retirement of up to 8,700 MW of coal-fired generation capacity, require significant build-out of additional transmission infrastructure, and increase energy costs for consumers by up to 20%.

The Report concludes with legislative recommendations that may facilitate continued efficiency and promote the Commission objectives of providing high quality electric service to Texans.

II. STATE OF THE COMPETITIVE MARKET

A. Overview

Over the past two years, the Commission has continued its work on retail competition by refining the rules that govern the retail market, enabling millions of Texas citizens and businesses to access competitively priced, reliable electric service. In the 12 years since the implementation of customer choice, the state has seen a proliferation of providers and products available to residential, commercial, and industrial consumers. Under the guidance of the Commission, Texas remains the national leader in competitive electric opportunities for its residents and industry.

In 2013 and 2014, the Commission, in conjunction with ERCOT, also took steps to improve the economic efficiency of the wholesale market and increase supply security in the region. The Commission's efforts included enhancing real-time price formation and increasing the precision of ERCOT's supply and demand forecast. The Commission has sought to create stronger incentives for demand response and generation investment in ERCOT, reinforcing supply adequacy in its energy-only market.

B. Retail Market Development and Prices

1. Customer Choice

The Commission has continued to improve the competitive retail electric market in Texas, in which customers are able to choose which electric rates and services best suit their needs. The success of Texas' transition to a competitive electric market is underscored by the fact that, as of September 2014, in the portion of the state that permits competition, 90% of all customers had exercised their ability to switch providers. Competition in Texas was also expanded in 2014 when customer choice was implemented in Sharyland Utilities, L.P.'s (Sharyland's) service territories in West Texas, which is further discussed in Section III.D, Rulemaking Activities.

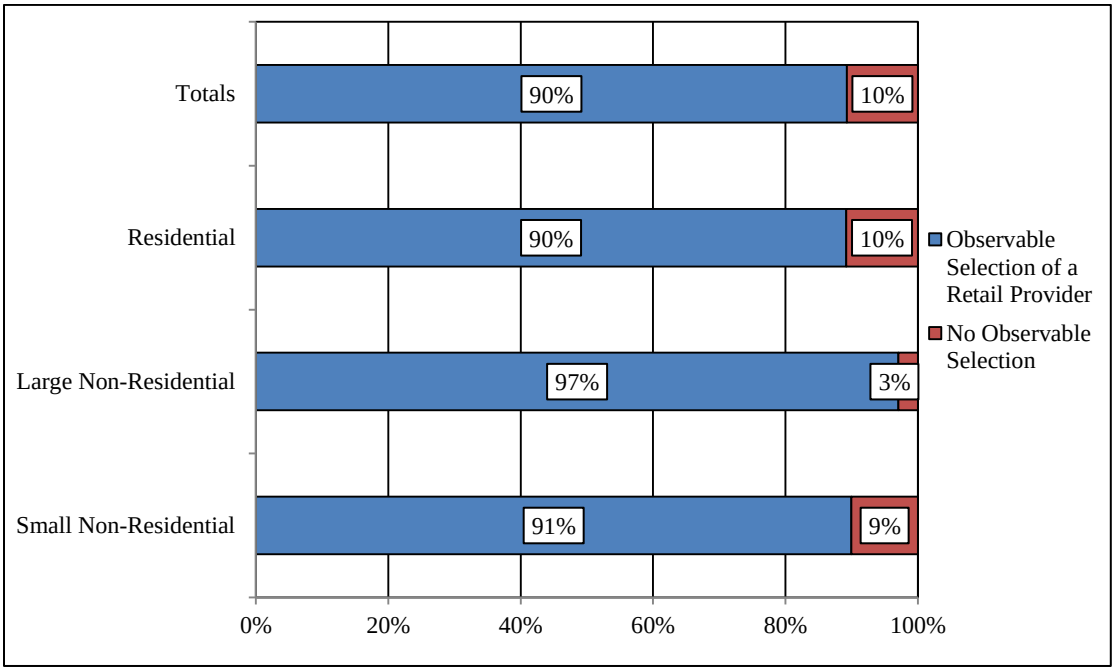
The competitive market includes 5,955,761 residential customers, 1,034,600 commercial customers, and 3,848 industrial customers. On average, residential retail rates seen across Texas have slightly increased in comparison to 2011 and 2012, rising to approximately 11.76 cents/kilowatt hour (kWh) as of October 2014 from an average of 11.37 cents/kWh in 2013, 10.98 cents/kWh in 2012, and 11.08 cents/kWh in 2011. However, prices in the state continue to trend lower than the nationwide averages of 12.12 cents/kWh in 2013 and 12.55 cents/kWh in 2014.

An important indicator of retail market competitiveness is the number and diversity of providers competing for customers. Since the publication of the 2013 Scope of Competition Report, the number of retail electric providers (REPs) and competitive offers has remained stable. As of September 2014, 114 REPs were operating in ERCOT, and over 300 products with 100% renewable content were available. Texas continues to be

recognized as the most successful competitive retail market in North America as demonstrated by its number one rank for the past seven years in the *Annual Baseline Assessment of Choice in Canada and the United States*, a scorecard developed by research group DEFG that measures the success of U.S. states and Canadian provinces in implementing a competitive retail market.[1]

Since Texas transitioned to competition in 2002, a vast majority of customers have exercised their ability to switch electric providers. The percentage of consumers who have had at least one change to their REP of record is depicted in Figure 1, broken down by customer class.

Figure 1. Percentage of Observable Switching in ERCOT by Customer Class



[1] *Annual Baseline Assessment of Choice in Canada and the United States*, Distributed Energy Financial Group, January 2014. Available online at: http://www.competecoalition.com/files/ABACCUS-2014-vf.pdf

The number of REPs serving residential customers and the associated number of product offerings by transmission and distribution utility (TDU) are shown in Table 1.

Table 1. Number of REPs Serving Residential Customers by Service Territory

TDU	Residential Suppliers		Number of Products	
	2013	2014	2013	2014
AEP Central	51	45	294	234
AEP North	45	40	269	225
CenterPoint	53	44	318	257
Oncor	52	46	322	255
TNMP	44	41	272	211
Sharyland	9	27	52	114

a. Retail Rates

The success of the competitive market is highlighted in Table 2, which depicts a comparison of the last regulated rate in ERCOT regions now open to competition with the current lowest 12-month fixed retail offering per 1000 kWh in each region (delineated by TDU), adjusted for inflation.

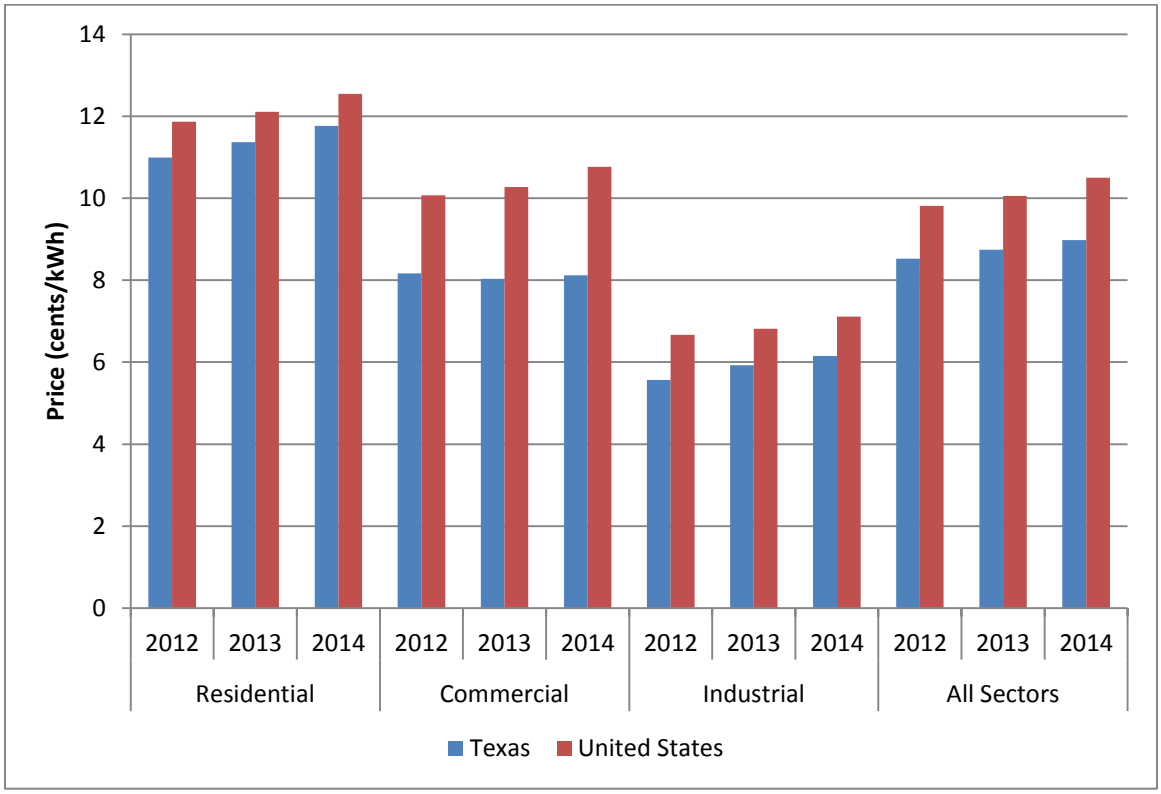
Table 2. Inflation-Adjusted Comparison of Regulated and Competitive Rates[2]

TDU	Current Price (¢/kWh)	REP	Last Regulated Rate (2001)	% Change	Inflation-Adjusted 2001 Regulated Rate	Inflation-Adjusted % Change
AEP Central	8.75	American Light & Power	9.60	-9%	12.89	-32%
AEP North	8.75	American Light & Power	10.00	-13%	13.43	-35%
Center Point	8.60	Spark Energy	10.40	-17%	13.97	-38%
Oncor	7.73	American Light & Power	9.70	-20%	13.03	-41%
TNMP	8.30	Gexa Energy	10.60	-22%	14.24	-42%

[2] Competitive rate information available as of December 2014, adjusted using Bureau of Labor Statistics Consumer Price Index rate of inflation.

In comparison to rates seen in regions outside Texas, retail electricity prices have remained competitive. Although prices have slightly increased from 2013 to 2014, this change has kept pace with increases evident in other jurisdictions. As demonstrated in Figure 2, across all sectors average retail rates seen in Texas are consistently lower than those aggregated to the national level.[3]

Figure 2. Retail Electricity Prices



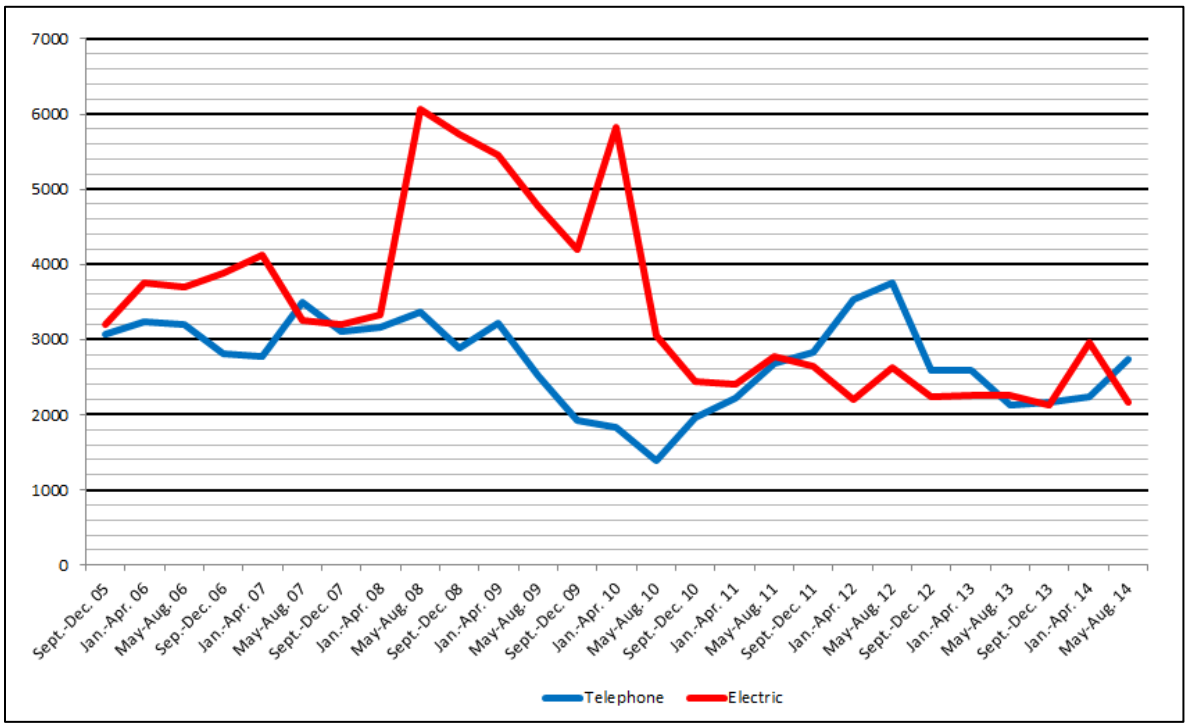
2. Addressing Customer Complaints

Commission rules permit customers to file complaints with the Commission about their utility service, and the Commission is required to keep records of the complaints. Complaint statistics serve as a barometer for analyzing company behavior and its effect on customers. These statistics, shown in Figure 3, also enable Commission management to identify company-specific trends that may lead to enforcement action or meetings with companies to address issues. While § 25.30 requires that investigations into complaints be concluded within 21 days, the average number of days to resolve a utility complaint during this report period was 16.5 days. The slight rise in the total number of complaints seen in 2014 may be attributed to the expected initial troubleshooting associated with the build-out of advanced meter infrastructure and the relatively harsh winter weather, which typically results in seasonally unexpected

[3] U.S. Energy Information Administration, *Average Retail Price of Electricity*, Electricity Data Browser, December 2014.

increased electric consumption with resulting higher bills, and which may have increased the number of temporary service interruptions.

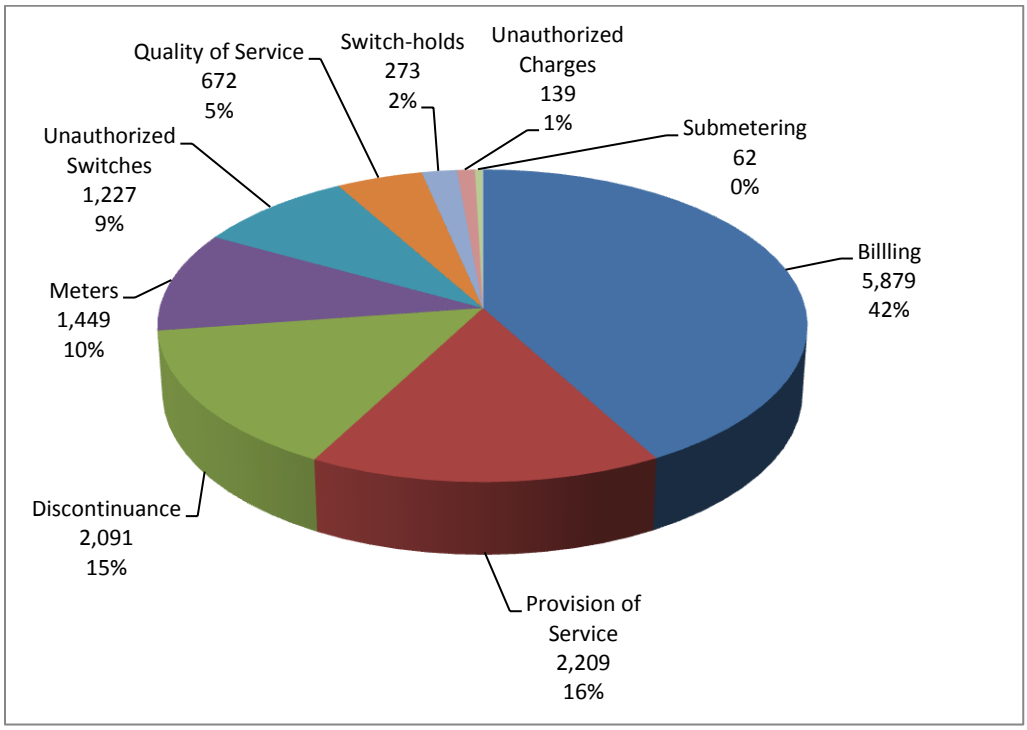
Figure 3. Total Complaints Received - September 2005 through August 2014



Rule § 22.242 sets forth the agency's procedural handling of complaints, and allows Commission staff to waive or decline to investigate a complaint for a number of reasons. A total of 14,002 electric complaints were received from September 2012 through August 31, 2014, with 511 waived in accordance with § 22.242.

Complaints are broken down by category in Figure 4. Billing complaints continue to be the leading factor in customer complaints as over 40% of all electric complaints involved billing issues. The Provision of Service category, which includes Customer Service and Refusal of Service, was the second leading cause of complaints at 16%. Discontinuance of service (power disconnection) was the third leading cause of complaints at 15%.

Figure 4. Types of Complaints Received - September 2012 through August 2014



3. Energy Efficiency

The utilities' energy efficiency programs are designed to reduce customers' electric demand and energy consumption. Energy and demand savings are achieved through the Commission-regulated energy efficiency program adopted pursuant to 1999 legislation (SB 7) and subsequent legislation in 2001 (SB 5), 2007 (HB 3693), and 2011 (SB 1125). The 2011 legislation increased the demand goal, beginning with the 2013 program year, to 30% growth in demand. Once a utility reaches this goal, the utility must achieve a reduction of four-tenths of one percent of the utility's summer weather-adjusted peak demand in subsequent years. These updated goals are reflected in Substantive Rule 25.181. The verified energy savings achieved and program expenditures for 2013 are shown in Table 3.

Table 3. Energy Efficiency Savings

2013 Verified Savings by Utility					
	Verified Savings		Goals		Expenditures
	MW	MWh	MW	MWh	
SPS	5.10	7,950.00	5.60	9,100.00	$ 2,106,000
SWEPCO	14.07	18,778.00	5.60	9,811.00	$ 4,609,804
Sharyland	2.67	1,022.00	0.95	1,664.00	$ 443,926
Entergy	19.10	36,996.00	15.50	27,156.00	$ 8,183,431
El Paso	14.19	23,394.00	11.16	19,552.00	$ 4,351,934
Non-ERCOT	**55.13**	**88,140.00**	**38.81**	**67,283.00**	**$ 19,695,095**
CenterPoint	195.97	160,106.74	54.85	96,088.00	$ 37,326,761
AEP TCC	34.14	48,954.00	12.93	22,653.00	$ 12,723,420
AEP TNC	6.93	9,087.00	4.26	7,464.00	$ 2,646,610
TNMP	10.29	16,981.00	5.108	8,949.00	$ 4,703,099
Oncor	112.70	224,666.00	54.60	95,659.00	$ 56,857,714
ERCOT	**360.03**	**459,794.74**	**131.75**	**230,813.00**	**$ 114,257,604**
Total	**415.16**	**547,934.74**	**170.56**	**298,096.00**	**$ 133,952,699**

During 2013 the utilities also cumulatively achieved 243% of the demand reduction goal, offsetting approximately 73% of growth in demand. The electric utilities' combined goal for reduction in growth in demand for calendar year 2013 was 170.56 megawatts (MW) (131.75 MW for utilities in ERCOT), and the achieved demand reduction was 415.16 MW (360.03 MW for utilities in ERCOT).

4. Customer Education Activities

Throughout 2013 and 2014 the Commission conducted significant outreach, helping customers acquire all relevant information necessary to make fully-informed retail market choices. Since its inception in February 2001, the goal for the "Texas Electric Choice" campaign has been to educate Texans about the changes and choices in the retail electric market. In 2012, the Commission re-launched its user-friendly PowerToChoose.org website for Texans shopping for a retail electric provider. Additionally, the Commission started a new statewide initiative called "Power to Save Texas," which aims to educate Texans on energy conservation during the peak times of 3 p.m. to 7 p.m.

These campaigns use a number of approaches in both English and Spanish to reach and inform the public of the various choices they have in not only retail electric service but also on ways to save money on their electric bills. A summary of each of the methods used during the last two years is included below.

a. *Power to Choose Outreach*

The Commission conducted a number of activities to improve the public visibility of retail electric choice, largely designed to inform electric customers of the official electric choice website of the Commission, PowerToChoose.org.

After conducting a usability study of PowerToChoose.org, the Commission directed the redesign of the website to be more user-friendly. The redesigned website allows customers to compare offers and shop for electricity providers, learn more about generating and selling renewable power, and find incentives for energy efficiency and renewable generation technology.

PowerToChoose.org and its Spanish-language counterpart, PoderDeEscoger.org, have proven vital in the customer education process, especially with the opening of Sharyland Utilities' territory to electric choice. Sharyland Utilities, which acquired Cap Rock Energy Corp., opened their area to electric choice on May 1, 2014.

Key statistics for these websites from September 1, 2012 through August 31, 2014 show an approximate increase of 72% in unique visitors to PowerToChoose.org and PoderDeEscoger.org since the last Scope of Competition Report was published. Website statistics are illustrated in Table 4.

Table 4. Website Statistics

Power to Choose Unique Visitors	3,057,279
Poder de Escoger Unique Visitors	50,227
Downloads of PUC Publications	39,406

b. *Power to Save Outreach*

In April 2012, the Commission contracted with an outside consultant to develop a campaign to educate the public on energy conservation. The campaign elements included research, branding, messaging, television and radio public service announcements, the PowerToSaveTexas.org website, video news releases, and public outreach.

The Commission launched the Power to Save Texas conservation campaign in March 2013 as a way to educate Texans on simple steps that can be done to reduce energy use during peak hours and save money. The PowerToSaveTexas.org website, and its Spanish-language counterpart, PoderDeAhorrarTexas.org, provide Texans with energy saving tips that can be utilized in homes and businesses.

Through a combination of online banners, radio and TV public service announcements, video news releases, and social media the campaign reached millions of Texans, with important messages such as "In the summer, your stove and oven heat up the house, making your air conditioner work harder, so reduce power use especially between 3-7 p.m."

As part of the Power to Save Texas campaign, the Commission has contracted with Resource Action Programs (TEAM RAP) to develop and implement a middle school energy

conservation outreach program in Hidalgo, Harris, and Dallas counties for school year 2014-2015. The program will provide an effective energy education program which will include an educational component that strongly supports Texas Essential Knowledge and Skills (TEKS) standards, as well as engaging students in school challenges and at-home activities.

Throughout 2013 and 2014, campaign materials promoting both Power to Choose and Power to Save Texas were distributed to numerous community events and civic town hall events, such as Hurst-Euless-Bedford Back 2 School day, Dickenson Housing Family Fair, Earth Day Texas, Texas Home and Garden shows in Houston and Dallas, Texas Black Expo's Juneteenth Celebration, National Night Out events, and minor league baseball games.

c. *Customer Outreach in Sharyland Utilities' Territory*

In January 2014, Sharyland Utilities mailed out notices to customers regarding five public informational meetings at five different locations to discuss the transition to retail electric competition. At the events, Commission Staff had several informational brochures on how to use the PowerToChoose.org website, description of the types of plans, a glossary of the various charges a customer may see on their electric bill, as well as a spreadsheet to help customers make an apples-to-apples comparison of different REP offerings.

After the events, Commission Staff contacted three community organizations and 24 libraries. Fifty copies of each publication distributed at the events were mailed to three community organizations (West Texas Opportunities, Central Texas Opportunities, and Community Services Inc.). Commission Staff provided libraries with 10 copies of "How to Shop for an Electric Provider," which is a guide on how to navigate the PowerToChoose.org website, and 10 copies of the LITE-UP Texas application.

Commission Staff also contacted five Veterans of Foreign Wars posts and VA hospitals to help disseminate the informational material provided at the Sharyland civic events.

d. *Low-Income/Elderly Outreach and Collaboration with Faith- and Community-Based Organizations*

Commission Staff worked with legislative offices and faith- and community-based organizations to provide educational materials and training to help their constituents gain a better understanding of the deregulated electric market and the Commission's websites. The Commission has actively participated with the Interagency Coordinating Group (ICG), which was established by the Texas Legislature to expand and improve relationships between state government and faith- and community-based organizations.

Information on customer assistance programs, such as LITE-UP Texas, was provided to community organizations such as West Texas Opportunities, Inc., senior activity centers, homeowners associations, chambers of commerce, and religious groups.

e. *Call Center*

The Commission has trained Staff in its Customer Protection Division, fluent in both English and Spanish, to answer customer calls, assemble and mail fulfillment packets

comparing electric plans (requested by customers without internet access), including brochures, a list of retail electric providers in their area, and the retail electric provider contact phone numbers. Call center activity is shown in Table 5.

Table 5. Call Center Activity – September 2012 to September 2014

Total Representative-Assisted Calls	30,676
Total Spanish-Language Calls	2,876

f. *Educational Literature*

In addition to the educational materials on the Commission's website, the Commission provides brochures, fact sheets, and other educational materials by mail and e-mail, through a network of community organizations, and through requests to the call center. Fact sheets, which can be found on the Commission's website, as well as accessed through both PowerToChoose.org and PoderDeEscoger.org, are routinely created and updated for distribution as part of the campaign's outreach efforts. The fact sheets provide information on a number of current industry and consumer topics. The Commission has distributed over 120,000 informational products over the past two years.

C. Wholesale Market Development

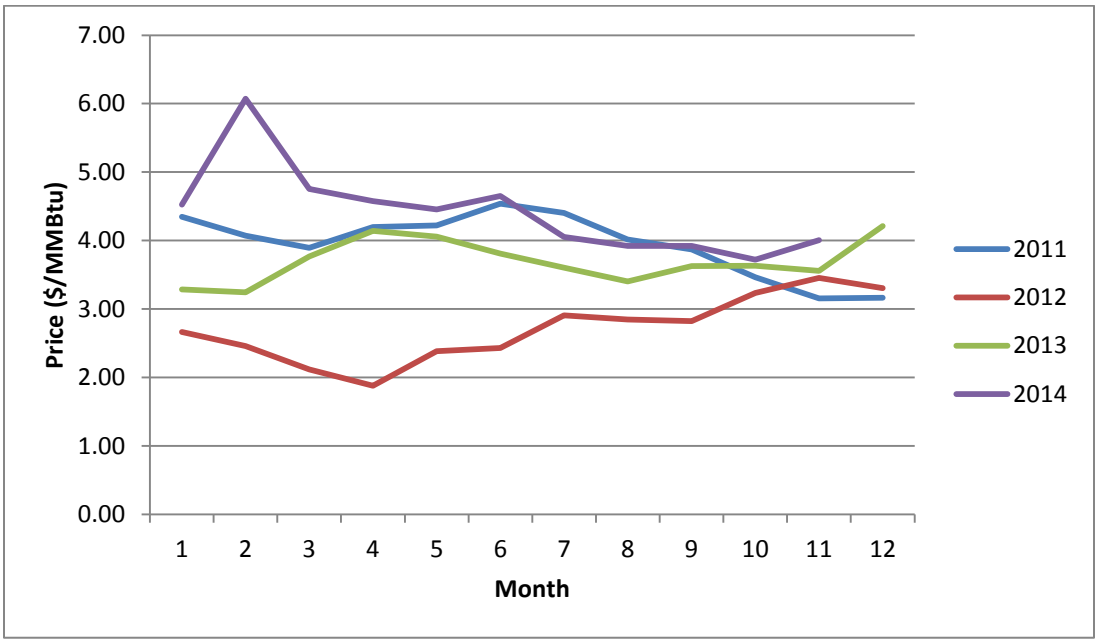
As described in Section III of this Report, the Commission has actively addressed the issue of resource adequacy within the ERCOT region and is committed to ongoing work to further improve wholesale market outcomes. Revised forecasts produced by the grid operator suggest that the Texas energy-only market is healthy. The Commission continually evaluates system supply security, and incremental improvements to the wholesale market design made by the Commission and ERCOT over 2013 and 2014 have created better opportunities for a variety of resources to enter the market and produce prices that more accurately reflect real-time market conditions.

1. Wholesale Market Prices

Wholesale market prices, tracking rising natural gas prices, have risen in comparison to those seen in 2012 but have moderated in comparison to those seen in 2011. The ERCOT load-weighted real-time hub average settlement point price of energy was $32.13/MWh in 2013, a 23% increase from the average price in 2012 and a decrease of 31% from the average seen in 2011. Through the end of November, the average settlement point price in ERCOT was $40.44/MWh for 2014.

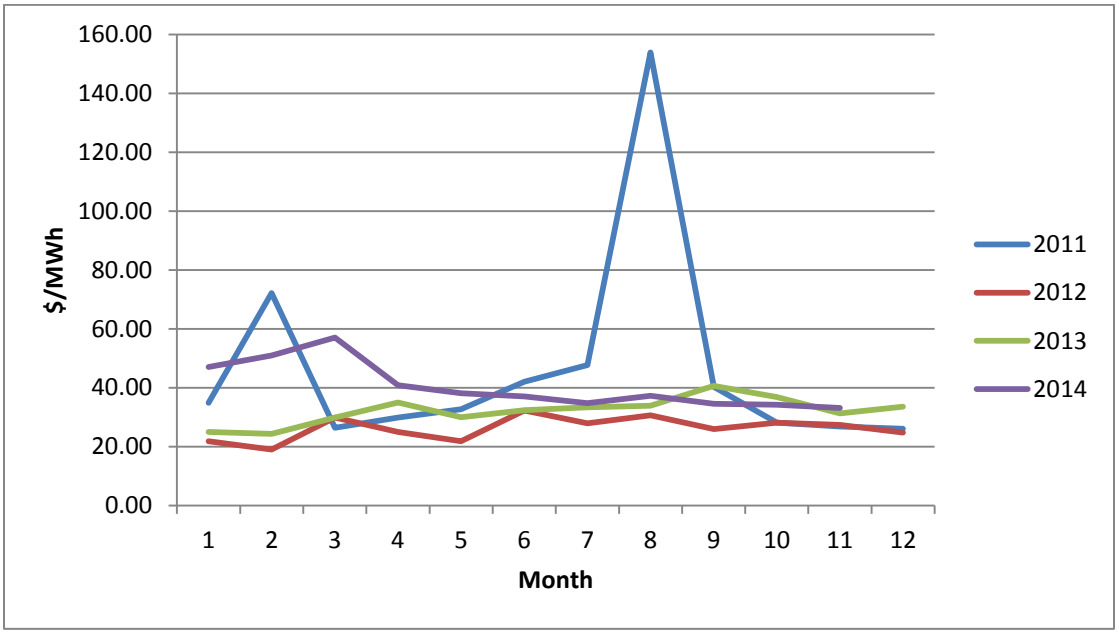
Rising wholesale prices are correlated with the rising cost of natural gas, the primary fuel of many of the region's power plants. The average Houston Ship Channel spot price for natural gas was 36% higher in 2013 than in 2012, increasing from $2.71/MMBtu in 2012 to $3.69 in 2013. Through November, the average price for 2014 has risen to $4.42/MMBtu. Natural gas price trends for 2011 through 2014 are shown in Figure 5.

Figure 5. Monthly Average Natural Gas Prices



Monthly average wholesale electricity prices are shown in Figure 6. Load-weighted prices are calculated by dividing the price at a node by the associated demand. This metric provides clarity into the actual amount paid by load at the wholesale level.

Figure 6. Load-Weighted Average Real-Time Monthly Settlement Point Prices



A component of the real-time price is the cost of transmission congestion, which occurs when there is insufficient transmission capacity to dispatch energy in an economically optimal fashion. The recent build-out of additional transmission lines in areas of high congestion has partially alleviated the cost burden in these areas, particularly in West Texas, where oil and gas

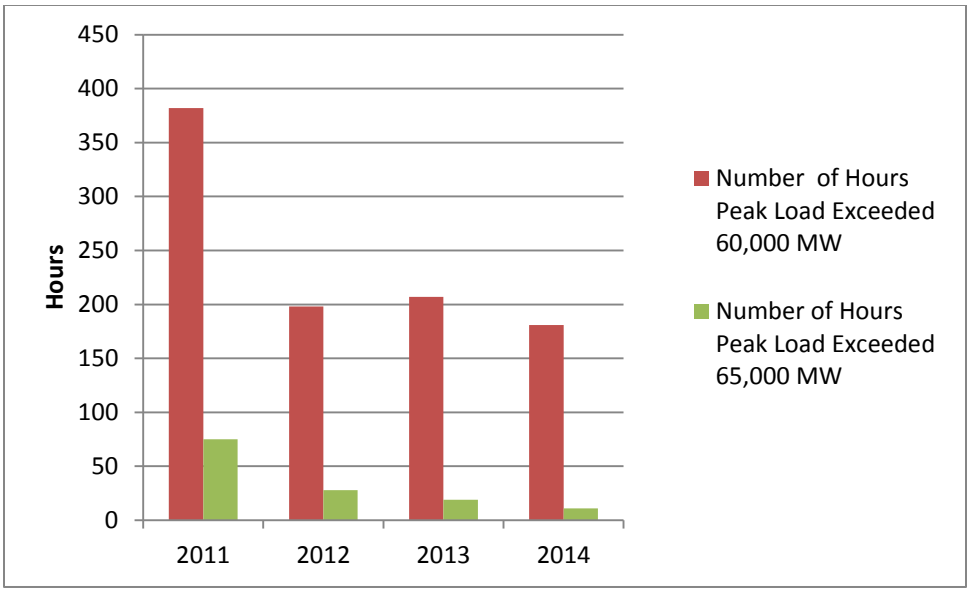
production growth has rapidly increased the demand for electricity and resulted in relatively higher zonal prices.

2. Peak Demand

In comparison to the peak demand recorded in 2011 and 2012, demand over the past two years has decreased. According to ERCOT, loads exceeded 60,000 MW for 195 hours in 2013 and exceeded 65,000 MW for 19 hours in 2013, down from 73 in 2011 and 23 in 2012. As of November, loads in 2014 have exceeded 60,000 MW for 181 hours and have exceeded 65,000 MW for 11 hours. Figure 7 indicates the relative duration of high load conditions in ERCOT.

As peak demand has comparatively lessened, the recorded availability of generation supply in the region during times of high load has increased. Physical Responsive Capability (PRC), analogous to capacity reserves available on the system at any given time, fell below 3,000 MW for 25.9 hours in 2013, down significantly from 371 hours in 2011 and 71.2 hours in 2012. As of November, the PRC in 2014 has dropped below 3,000 MW for 21.3 hours. The decreasing occurrences of extremely high demand in 2013 and 2014 may be due to more moderate weather and increasing demand response capability in the region.

Figure 7. Peak Demand Exceeding 60 GW or 65 GW from 2011-2014



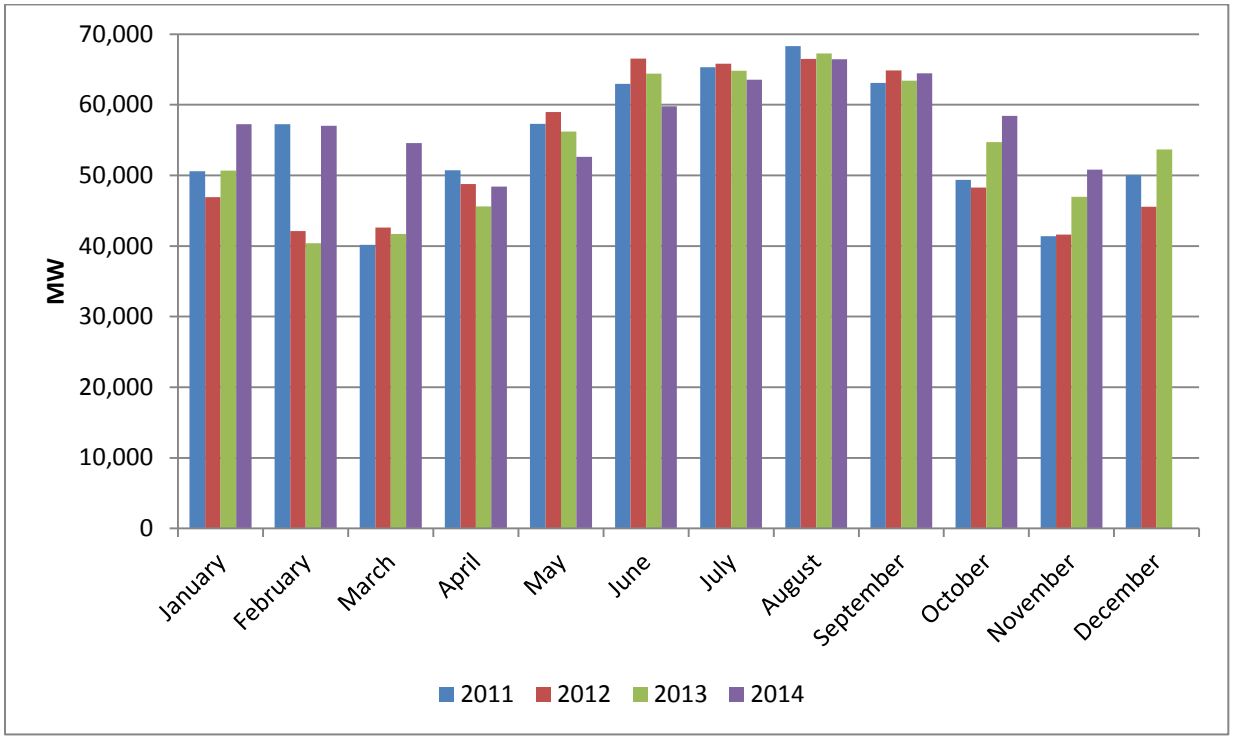
The ERCOT peak demand was 67,245 MW in 2013, up 1% from the 2012 peak. The winter season peak demand totaled 57,256 MW in 2014, the second highest winter peak ever recorded on the system. As shown in Table 6, the peak demand recorded in ERCOT for 2014 was 66,454 MW.

Table 6. ERCOT Peak Demand from 2011-2014

Year	ERCOT Peak Demand (MW)
2011	68,305
2012	66,548
2013	67,245
2014	66,454

Figure 8, seen below, shows the hourly peak load for each month in ERCOT since 2011. The first quarter of 2014 has had significantly higher peak loads than previous years, due in large part to the extremely cold weather during that time frame.

Figure 8. Monthly Peak Demand

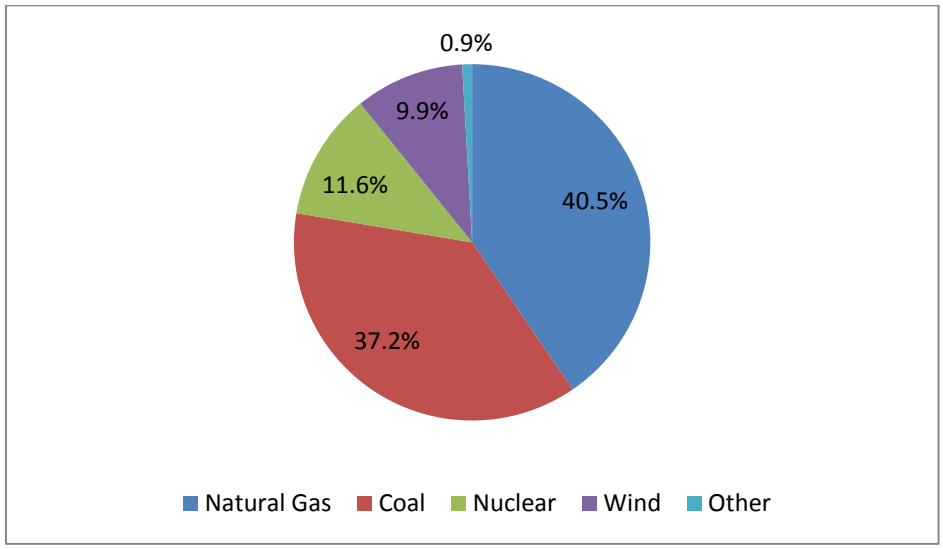


3. Generation Diversity

As consumption has increased in ERCOT, the system's generation portfolio has also seen diversification. Generators taking part in the state's renewable energy credit trading program reported a 12% increase in renewable generation from 2012 to 2013, rising from 33.9 million MWh to 38.1 million MWh, with wind representing nearly 97% of the total renewable mix. Landfill gas was the second most prevalent renewable source, representing approximately 1.4% of all renewable generation in 2013. In comparison to that seen in 2012, energy produced

from wind generation was up by 13%, and solar energy production was up by about a third to 178,326 MWh.[4] Energy use in the region by fuel type as of May 2013 is shown in Figure 9.

Figure 9. Energy Use in ERCOT



The Commission's wholesale projects are further described in Section III of this report.

[4] ERCOT News Release, "*Statewide renewable energy production up by 12 percent in 2013*," May 16, 2014. Available at: http://ercot.com/news/press_releases/show/26629

III. SUMMARY OF COMMISSION ACTIVITIES FROM 2013 TO 2015

A. Introduction

The Commission develops and modifies rules, policies, and procedures for the competitive electric market in Texas, consistent with legislative direction and in response to changes in the industry. The Commission also maintains oversight for programs that were enacted to promote energy efficiency, renewable energy, and advanced metering infrastructure. Certain areas of Texas remain subject to Commission transmission rate regulation, and the Commission continues to set transmission rates and supervise the investor-owned utilities in these areas.

B. Resource Adequacy

Both the Commission and ERCOT took several steps in 2013 and 2014 toward ensuring Texas has a reliable and diverse portfolio of resources, even as demand for electricity grows in our state. In Project No. 40000, the Commission and market participants discussed a variety of wholesale market design enhancements to address resource adequacy challenges in ERCOT, implementing measures to ensure adequate investment in generation in ERCOT and to provide efficient price signals to resources and consumers.

1. Capacity, Demand, and Reserves Report

An important starting point for the Commission's discussion of resource adequacy is the Capacity, Demand, and Reserves (CDR) report produced by ERCOT, which estimates the system reserve margin, or the percent of resource capacity available beyond peak demand requirements. This set of metrics serves to project the availability of electricity supply during the hottest summer days, when there is the greatest strain on the system.

Historically, ERCOT has used weather and economic indicators to forecast load growth for the CDR. Over time, analysis has shown a less direct correlation between electricity use and these variables. At the Commission's direction, ERCOT revised its load forecasting methodology to account for this decoupling. ERCOT's new approach, based on customer premise counts, among other things, projects larger reserve margins than previous analyses had indicated. With a more accurate load forecast, the Commission now has a better understanding of the health of the market as it relates to resource adequacy. The most recent CDR forecast, published in December 2014, is shown in Table 7.

Table 7. December 2014 Capacity, Demand, and Reserves Report

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Forecast (MW)	66,714	67,427	68,284	69,219	70,272	71,197	72,123	73,044	73,963	74,884
Resources (MW)	77,166	78,947	80,654	80,654	79,814	80,054	80,354	80,354	80,354	80,354
Reserve Margin	15.7%	17.1%	18.1%	16.5%	13.6%	12.4%	11.4%	10.1%	8.6%	7.3%

2. Operating Reserves Demand Curve

In addition to achieving a more accurate picture of market reliability conditions as indicated in the updated CDR, the Commission worked to improve the formation of real-time wholesale prices during supply shortage conditions. Efficient price signals should reflect the increasing value of capacity as supply diminishes, and accurate scarcity prices are essential to creating not only the right incentives to invest in generation, but also the right incentives to reduce demand for electricity. In pursuit of this aim, the Commission directed ERCOT to implement the Operating Reserves Demand Curve (ORDC), based in part on a proposal by Dr. William Hogan, research director of the Harvard Electricity Policy Group. Implemented on June 1, 2014, the ORDC produces wholesale price adders that approximate the true value of reserves (the opportunity cost of incremental demand) during shortage conditions.

To improve the economic efficiency of pricing outcomes (i.e., to create prices that better fit the actual supply and demand of electricity), the Commission also established a gradual increase to the System-Wide Offer Cap, raising it from $5,000/MWh in 2013, to $7,000/MWh in 2014, and to $9,000/MWh on June 1, 2015. Along with the ORDC, higher offer caps translate into higher wholesale prices during periods of low reserves, which more accurately reflect the market value of capacity. Higher prices during these infrequent scarcity conditions are expected to drive investment in generation resources and the development of demand response in ERCOT, ultimately improving the resiliency of supply during periods of high demand with minimal administrative intervention.

3. Evaluation of the Reliability Standard

In its ongoing effort to ensure resource adequacy, the Commission initiated Project No. 42302 to review all aspects of the reliability standard employed in ERCOT. The reliability standard is a measure of how often retail electric consumers will be involuntarily interrupted because of inadequate available installed generation capacity. Once determined, the reliability standard sets a target level of resource adequacy against which the actual system reserve margin is compared.

ERCOT (and most other North American markets) currently employs a 1-in-10 reliability standard, implying one loss of load event due to capacity shortage (i.e., involuntary load shedding) in ten years, without regard to the magnitude or duration of the event. Currently

the Commission is researching a range of other reliability criteria, including those based on least-cost principles and those that specify expected annual unserved energy due to inadequate generation supply. By selecting a reliability standard that represents the most appropriate balance of economics and reliability, the Commission can more accurately estimate resource adequacy and make market improvements to achieve its target.

4. Other Wholesale Market Improvements – Transmission Congestion and Loads in SCED

In 2012 and early 2013, transmission congestion, which occurs when insufficient transmission infrastructure exists to serve load in an economic fashion, was a source of comparatively high prices in the West load zone due to a rapidly increasing demand for electricity associated with oil and gas production. Increased build-out of high-voltage transmission lines in affected areas has reduced these charges, and several ongoing projects will further alleviate high congestion costs around these areas with inadequate transmission infrastructure.

Additionally, the Commission has a long-standing project open to examine and enhance the capability of customers to voluntarily curtail their electricity usage, or offer demand response services to the market. On June 1, 2014, ERCOT and its stakeholders implemented a demand response initiative called Loads in SCED (an acronym for "Security Constrained Economic Dispatch"). SCED is ERCOT's real-time evaluation of supply and demand that dispatches electricity based on a least cost solution constrained by transmission capacity. SCED calculates not only what the wholesale price of electricity at any given moment must be, but also maintains reliability by precisely balancing how much electricity is being generated with how much electricity is being used. "Loads in SCED" allows certain types of customers to offer to reduce their consumption during peak periods of demand for electricity, when prices are high in real-time. This would enable ERCOT to match the electricity supply with demand not only by selecting the most economic supply of generation, but also by permitting these customers to adjust their demand to reflect their willingness to curtail based on price signals.

C. Non-ERCOT Utilities: Market Development Activities

SB 7, the law that introduced retail competition to the Texas market in 1999, granted the Commission authority to delay retail competition in an area where deregulation in accordance with Chapter 39 of PURA would not result in fair competition and reliable service. Because of the lack of an independent organization and the concentration of ownership in the generation sector in some of those areas, SB 7 included provisions recognizing the difficulty of implementing retail competition in areas outside of ERCOT. While the Commission monitors ongoing activities in the non-ERCOT portions of the state, the Commission has not certified that any area within the state boundaries but outside of ERCOT has met the competitive criteria under PURA.

1. Southwest Power Pool

The Southwest Power Pool (SPP) is the Regional Transmission Operator (RTO) for areas of Northeast Texas and the Texas Panhandle as well as all or parts of New Mexico,

Arkansas, Oklahoma, Missouri, Nebraska, and Kansas. SPP also manages transmission access, energy markets and maintains the reliability of the electric system in these areas.

The SPP Board of Directors recently voted to support the addition of the Integrated System (which includes some areas of the Western Area Power Administration, Basin Electric, and Heartland Consumers Power District) as members of SPP. The Integrated System will add approximately 378,000 square miles of service territory to SPP and will include all or parts of Iowa, Minnesota, North Dakota, South Dakota, and Montana.

On March 1, 2014, SPP launched its new Integrated Marketplace which provides a Day-Ahead Market, a Real-Time Balancing Market, and Congestion Hedging Markets to the SPP members. This new market is expected to yield up to $100 million in annual net benefits to SPP's RTO region.

The Federal Energy Regulatory Commission (FERC) issued its Order 1000 in July 2011, introducing competitive bidding for transmission construction to Regional Transmission Organizations (RTOs), such as SPP. Transmission facilities that meet the criteria contained in SPP's compliance tariff and are approved for construction or endorsed by the SPP Board of Directors after January 1, 2015 will be subject to competitive bidding. As a result, certain transmission facilities approved for construction in the Texas portion of the SPP territory would be built by entities selected through a competitive selection process.

The Commission is a voting member of the SPP Regional State Committee (RSC) and the PUC Chairman, Donna Nelson, served as the President of the RSC through the end of 2014. The RSC provides collective state regulatory agency input on a variety of issues, including the cost allocation methodologies for transmission upgrades, allocation of Financial Transmission Rights and the approach used for resource adequacy across the SPP region. The RSC regularly meets on a quarterly basis and more frequently if necessary.

2. Midcontinent Independent System Operator

Entergy Texas, Inc. (ETI) completed its operational integration into the Midcontinent Independent System Operator (MISO) on December 19, 2013. MISO is a regional transmission organization authorized by the Federal Energy Regulatory Commission (FERC). The MISO region now includes 16 states in the central portion of the U.S., providing a variety of functions and services including reliability, energy and ancillary service markets, economic dispatch, congestion management, financial transmission rights, and transmission planning. The MISO Independent Market Monitor concluded that the MISO wholesale markets were competitive in 2013, although ETI only participated in the markets for the last 11 days of that year.

The Commission is a voting member in the Organization of MISO States (OMS), whose purpose is to coordinate regulatory oversight among the states in the MISO region and to make recommendations to MISO, FERC, and other entities as appropriate. The Commission continues to be a voting member in the Entergy Regional State Committee (E-RSC), which has certain FERC-approved authority for five years after Entergy integration with regard to (a) cost allocation for Entergy transmission projects and (b) adding transmission projects to the Entergy construction plan.

3. Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is a regional transmission organization whose region includes the area surrounding El Paso, Texas and extends from Canada to Mexico, including the provinces of Alberta and British Columbia, the northern portion of Baja California, and all or portions of the 14 Western states between. WECC is the Regional Entity responsible for Bulk Electric System reliability in the Western Interconnection and associated compliance monitoring and enforcement. WECC is geographically the largest and most diverse of the eight Regional Entities in the United States with delegated authority from the North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission.

D. Rulemaking Activities

During 2013 and 2014, the Commission adopted new rules and modified existing rules to facilitate the continued successful operation of the competitive retail and wholesale markets. This section of the Scope of Competition Report lists the Commission's key rulemaking activities, highlighting the variety of market improvements enacted in 2013 and 2014, both as directed by the Legislature and as initiated by the agency in response to market issues.

1. ERCOT Emergency Operations Plans

On May 30, 2014, the Commission amended Substantive Rule 25.53, relating to Emergency Operations Plans, and § 25.362, relating to ERCOT governance, to update ERCOT's Emergency Operations Plans. The amendments were based on experience gained from emergency situations since the rule's last update in 2008, as well as on state-of-the-art recommendations from an expert consulting group hired by the Commission. The salient recommendations adopted by the Commission include:

- Allowing ERCOT to conduct generator site visits to review compliance with weatherization plans and obtain any information from generators concerning water supplies for generation purposes, including contracts, water rights, and any other related information;

- Requiring applicable entities to include in their emergency operations plan specific information plans that:

    - Address severely hot and cold weather;
    - Address known equipment critical failure points, including effects of weather design limits;
    - Address emergency water shortages;
    - Identify potentially severe weather events, including, but not limited to, tornadoes, hurricanes, severely cold weather, severely hot weather, and flooding;
    - Plans for the inventory of pre-arranged supplies for emergencies; and
    - Plans for alternative fuel testing if the facility has the ability to use alternative fuels.

- Requiring entities to notify the Texas Division of Emergency Management District Coordinators of any utility drills or exercises.
- Requiring certain personnel to take the Federal Emergency Management Agency (FEMA) National Incident Management System training.

2. Disconnection of Service for Non-submetered Master Metered Multifamily Units

The Commission adopted amendments to § 25.29 and § 25.483, pursuant to HB 1772. The purpose of these changes was to update the responsibilities of retail electric providers and vertically integrated electric utilities to provide notice when electric power to a non-submetered master metered multifamily property is disconnected for non-payment, and to establish a mechanism by which a municipality may provide the Commission with the contact information of the municipality's authorized representative for such notice of service disconnection.

3. Providers of Last Resort - Eligibility of Affiliates

The Commission has a system in place to require a designated Provider of Last Resort (POLR) to provide electric service when the customer's chosen retail electric provider is unable to continue service. POLR service is intended to be temporary and used only in rare circumstances. The Commission routinely designates Large Service Providers to act as the designated POLR in a given territory.

In January 2014, the Commission approved an amendment to § 25.43 to allow retail electric providers that are designated as Large Service Providers to request the Commission to designate one of its affiliates to provide POLR service on behalf of the LSP. The Large Service Provider's affiliate is required to meet certain criteria including the same financial, technical, and managerial qualifications that the Large Service Provider must meet under § 25.107.

4. Vegetation Management

Rule § 25.96 provides the Commission with information necessary to assess the distribution system vegetation management activities of electric utilities in determining their effectiveness in enhancing reliability and protecting public safety.

5. Commission Cease and Desist Orders

With the passage of HB 1600, the 83rd Legislature granted the Commission authority to issue cease and desist orders in specific, limited circumstances to electric market participants and required the Commission to adopt rules to implement the legislation. Pursuant to this directive, the Commission adopted a new § 25.54 in April 2014.

The new rule follows the statutory requirement that a cease and desist order may only be issued under the following circumstances: if the conduct of a market participant poses a threat to continuous and adequate electric service, is hazardous, creates an immediate danger to public safety, or is causing or can reasonably be expected to cause an immediate injury to a customer of electric services and that the injury is incapable of being repaired or rectified by monetary compensation. The Commission emphasized that issuing a cease and desist order is an

extraordinary remedy to be exercised with great prudence. The cease and desist authority has not been exercised since its implementation. The new § 25.54 addresses how to delegate this authority to the executive director, and outlines specific procedural steps to issue such an order.

6. Advanced Meter Opt-Out

The Commission adopted new rule § 25.133 and amended § 25.214 on August 9, 2013, allowing customers to opt-out from advanced meter installation. While the advantages of advanced meters are numerous for customers and utilities alike, certain customers have refused installation. Therefore, the TDU must have a written acknowledgement signed by the customer clearly stating the numerous negative consequences arising from opting out of the advanced meter service. Customers opting out will have a separate charge for the additional costs incurred by the utility.

7. Interconnection of On-Site Distributed Generation

The Commission amended § 25.211 for Distributed Generation, which refers to the interconnection of small power generation facilities that are at or close to the end users of power. The amended rule incorporated a Pro-Forma Distributed Generation Interconnection Agreement and Tariff into the rule, with options regarding indemnification and choice of law for parties entering into an agreement with a federal agency, as well as a requirement that the owner of a distributed generation facility report to the utility any change in ownership and the cessation of operations of the facility.

8. Metering for Certain Distributed Renewable Generation

On May 18, 2012, the Commission adopted amendments to § 25.211, relating to Interconnection of On-Site Distributed Generation and § 25.217, relating to Distributed Renewable Generation. The amendments to § 25.211 defined a distributed natural gas generation facility, recognized third party Distributed Generation ownership, and added a new limitation of the applicability of the rule regarding electric cooperatives.

The amendments to § 25.217 revised the definition of Distributed Renewable Generation Owner to include retail electric customers that contract with third parties and clarified that this definition applies statewide and added a section that specifies which Distributed Renewable Generation Owners are not required to register with or be certified by the Commission for purposes of Distributed Renewable Generation. Also, in 2014, the Commission amended § 25.213, relating to Metering for Distributed Renewable Generation to conform to PURA § 39.554 for utilities outside the ERCOT region.

9. Purchased Power Capacity Cost Recovery Factor

The Commission adopted § 25.238 to provide a mechanism, outside of a base-rate proceeding, by which an electric utility could seek to recover certain reasonable and necessary purchased power capacity costs incurred in the course of providing reliable electric service to ratepayers. The rule enables a utility to apply to establish a Purchased Power Cost Recovery Factor (PCRF) rider with the requirement that it be adjusted once a year to reflect appropriate

costs, changes in demand, over- and under-recoveries, and changes in revenues resulting from load growth.

The rule provides for the reconciliation of costs recovered through a PCRF at least once every three years, in conjunction with a fuel reconciliation proceeding, and also provides a process wherein a utility may seek Commission review of an arrangement for the purchase of power capacity, including purchases from affiliates of the utility, prior to the utility seeking recovery of the associated capacity expenses in a PCRF proceeding. The new rule increases regulatory certainty, reduces regulatory lag, and balances the occasionally disparate interests of the affected parties.

10. Nuclear Decommissioning Funding and Requirements for Power Generation Companies

Pursuant to HB 994, the Commission amended § 25.304 to establish the terms for Power Generation Companies that are licensed by the Nuclear Regulatory Commission for using a Power Generation Company's decommissioning trust to satisfy the financial assurance requirements for decommissioning a nuclear generating unit. This rule also delineates the rights and obligations of Power Generation Companies electing to use a Commission-approved method for providing funds from Texas customers for decommissioning a nuclear generating unit, as a means of complying with nuclear decommissioning financial assurance requirements.

11. Program for Veterans Severely Burned in Combat

The amendments to § 25.21, § 25.28, and § 25.471 implement SB 981, Bill Payment Assistance Program for Veterans Severely Burned in Combat. These amendments allow a voluntary electric utility bill payment assistance program for veterans severely burned in combat.

12. Pro-Forma Retail Delivery Tariff

On June 20, 2014, the Commission adopted an updated Pro-Forma Retail Delivery Tariff, which is used by TDUs to govern their responsibilities to competitive retail electric providers. The new tariff updates various terms and conditions of retail delivery service, including delivery service to a Retail Customer at transmission voltage; updates certain market notices; requires TDUs to provide Interval Data from certain electric meters on a daily basis; and improves the organization and layout of the standardized TDU specific offers.

13. Certification of Retail Electric Providers

The Commission adopted an amendment to § 25.107, relating to Certification of Retail Electric Providers (REPs), effective May 1, 2014. The amendment clarifies the Commission's requirements for applications for REP certificates by requiring an affidavit identifying all principals and current employees of the applicant REP that have previously been employed by a REP that experienced a mass transition of that REP's customers to a Provider of Last Resort, and by including additional complaint and disciplinary records.

14. Code of Conduct and Co-Branding for Electric Utilities and Affiliates

The Commission adopted an amendment to § 25.272, relating to the code of conduct for electric utilities and their affiliates, effective on June 26, 2014. The amendment deleted a disclaimer provision that had expired in 2005, modified the compliance audit requirement for electric utilities without affiliates by allowing these companies to file an affidavit, and updated a marketing provision to avoid customer confusion when a utility is co-branding its retail electric services with its electric transmission services on the affiliates' websites and social media platforms.

15. Privacy of Advanced Metering System Information

On April 23, 2014, the Commission adopted new rules §§ 25.44 and 25.500, relating to privacy of advanced metering system information, to implement the portion of HB 1600 that enacted, among other things, PURA 39.107(k). The rules, which closely track the legislative language, prohibit electric utilities, including transmission and distribution utilities, from selling, sharing, or disclosing information from an advanced metering system, except for the purpose of providing electric utility service to the customer or for other customer-approved services.

E. Sharyland – Migration to Competition

As detailed in the 2013 Scope of Competition Report, the Commission approved an unopposed non-unanimous Stipulation to open the Brady, Celeste, Colorado City, and Stanton divisions of Sharyland to competition on May 1, 2014.

All of the customers were transitioned to either a selected retail electric provider or a default retail electric provider in May 2014, with approximately 70% of the customers selecting their retail electric provider. As of June 2014, the Commission's Power-to-Choose website showed there were 14 retail electric providers operating in Sharyland with over 90 offerings.

F. Oversight and Enforcement Actions

The Commission's enforcement of statutes, rules, and orders applicable to entities under its jurisdiction serves to protect consumers, the electric markets, the reliability of the electric grid, and to promote fair competition. The Commission's enforcement efforts in the electric industry focus on violations of PURA, the Commission's Substantive Rules, and ERCOT protocols.

During the period from January 2013 through December 2014, the Commission assessed $4,025,150 in penalties to electric market participants.

Table 8 provides a summary of electric industry Notices of Violation since January 2013. During 2013 and 2014, Commission Staff opened 266 investigations for the electric industry and closed 198 investigations.

Table 8. Notices of Violations

Violation Type	Penalty Amount
Retail Market Violations	$2,037,450
Service Quality Violations	$860,700
Wholesale Market Violations	$1,127,000
TOTAL	**$4,025,150**

In addition to the administrative penalties assessed, in 17 cases the Commission also revoked, or the retail electric providers (REPs) relinquished, certificates to operate. Table 9 below provides a breakdown of the number of certificates revoked or relinquished. Appendix B contains a complete list of all certificates revoked or relinquished.

Table 9. Certificates Revoked or Relinquished

Type	Number
Number of Certificates Revoked	2
Number of Certificates Relinquished	15

G. Low-Income Discount: System Benefit Fund

The 83rd Legislature appropriated $612,649,273 for FY 2014 for the System Benefit Fund for the purpose of providing low-income discounts in September 2013 and May through August 2014. It also appropriated $115,613,295 for the FY 2015, for low-income discounts in September 2014 and May through August 2015. Of the funds for FY 2013, 2,744,871 discounts were distributed to 877,277 separate households equating to $73,667,802 in discounts given. In 2014, 2,664,042 discounts were distributed to 735,865 unique households, amounting to $392,409,318 in discounts. The larger cumulative discounts seen in 2014 are related to the increase in the discount amount from 16.5% of the POLR in 2013 to 82% in 2014. Each household that is deemed eligible may receive up to five months of discounts depending on when they submit their application. The System Benefit Fund discount is based on the POLR rate in effect, which was $0.138 per kWh in 2013 and $0.145 per kWh in 2014. In Section V of this report, the Commission sets forth a legislative recommendation to address the balance remaining in the System Benefit Fund.

H. Advanced Metering Infrastructure

Texas legislation enacted in 2005 encouraged the adoption of advanced meters, recognizing that "new metering and meter information technologies have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of transmission and generation assets, and provide more choices for consumers."

In ERCOT, deployment of advanced meters is 95% complete, with over 6.7 million meters installed. Five utilities (Oncor Electric Delivery, CenterPoint Energy Houston Electric, AEP Texas Central Company, AEP Texas North Company and Texas New Mexico Power

Company) have received approval for cost recovery and deployment through orders approving settlements.

The Commission recently amended § 25.133, allowing customers to opt-out from advanced meters. The rule requires the TDU to obtain a written acknowledgement signed by the customer clearly stating the numerous negative consequences arising from opting out of the advanced meter service. Customers opting out will have a separate charge for the additional costs incurred by the utility.

I. Homeland Security

The Commission recently began work to assist in the development of a task force, composed of state law enforcement, PUC staff, ERCOT, and electric utility industry partners in Texas, including those inside and outside the ERCOT footprint, that would address physical security and cybersecurity issues. This group will better facilitate the coordination of security preparedness and security incident response among utilities and state law enforcement and emergency management officials.

IV. EMERGING ISSUES

Impact of the Environmental Protection Agency's Clean Power Plan

An emerging issue for the legislature's consideration is the recent publication of the EPA's proposed Clean Power Plan (CPP), intended to enforce a seldom-used provision of the Clean Air Act, § 111(d), to regulate and reduce carbon dioxide emissions from existing generating units. With the currently proposed CPP, the EPA attempts to mandate a national energy policy that would cost consumers billions of dollars and jeopardize electric grid reliability, given its unworkable timeline and the extent to which it undermines the efficiency of the competitive power generation market.

As of the date of the publication of this report, the proposed CPP would allow states to implement a "Best System of Emission Reduction" (BSER) through four proposed "building blocks": improvements in heat rate, changing dispatch from coal-fired plants to natural gas plants, increasing the penetration of renewable energy technology, and implementing energy efficiency measures. Though these building blocks are not mandatory, the EPA has used each component of the building block to calculate a mandatory goal for each state.

Under the proposed rule, the goal is divided into an interim goal, to be met in 2020, and a final goal, to be met in 2030. Texas would need to reduce its carbon dioxide emissions to 853 pounds of CO_2 per megawatt-hour by 2020, and reduce it further to 791 pounds of CO_2 per megawatt-hour by 2030. This would have the effect of reducing Texas' carbon dioxide emissions by 30 percent relative to 2005, though the proposed CPP relies on 2012 data for its actual reduction baseline.

Apart from the stringency of the goal the CPP proposes for Texas, an issue of particular concern is the aggressive timeline imposed by the EPA. The proposed CPP would be finalized in June 2015, and would require state implementation plans to be due to the EPA by June 2016. This proposed timeline creates an issue for the legislature if legislation is required to implement a state implementation plan for Texas, as the deadline would be a full year before the 2017 regular legislative session. The PUC and the Texas Commission on Environmental Quality (TCEQ) have raised their concerns with the EPA on this point and other matters in the proposed CPP in their jointly filed comments of December 2014, with the Railroad Commission filing a letter in support of the comments.

The currently proposed CPP would also have a harmful effect on Texas' competitive marketplace, especially for power producers that have a significant portion of coal-fired plants in their generation portfolio. These entities may have to retire these facilities before the end of their useful life, resulting in stranded costs that would have to be absorbed by plant owners or uplifted to customers in the non-competitive areas of the state. Data supporting the Commission's concerns can be found in ERCOT's *Analysis of the Impacts of the Clean Power Plan*, which asserts that, combined with the EPA's other environmental regulations, multiple coal plants would likely be forced to retire within the 2020 – 2022 timeframe concurrent with

the beginning of the compliance period.[5] These early retirements could result in a significant capacity shortfall, jeopardizing system reliability.

The Commission notes that ERCOT's report also expresses serious concerns about how the displacement of conventional generation by renewable energy technology may impact electric grid reliability, particularly regarding the difficulty and cost of integrating new transmission to support the renewable generation necessary to meet the proposed regulations within the proposed required timeline. Both the North American Electric Reliability Corporation (NERC), the entity tasked with setting national electric grid reliability standards, and the Southwest Power Pool (SPP), which manages the electric grid in the northern and eastern portions of the state, echoed these concerns in their reliability assessments of the proposed CPP.

The Commission's comments submitted to the EPA on proposed Rule 111(d) of the Clean Power Plan are attached to this Report as Appendix C.

[5] *ERCOT Analysis of the Clean Power Plan*, November 17, 2014. Available at: http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf

V. LEGISLATIVE RECOMMENDATIONS

A. Retail Electric Providers

1. Commission Authority to Prohibit Repeat Offenders from Re-entering the Market

PURA § 39.352 currently authorizes the Commission to establish criteria for applicants seeking entry into the competitive retail electricity market. PURA §§ 36.356 and 39.357 provide remedies available to the Commission for violations of PURA or Commission rules by REPs, including administrative penalties and/or revocation, suspension, or amendment of a REP's certificate. Consistent with this authority, the Commission certifies only those REP applicants that have the requisite financial, technical, and managerial resources required under PURA, and the agency enforces these ongoing requirements for existing REPs.

However, in the case of certain principals of REPs that have exited the market after substantial violations of state law and PUC rules, or serious repeat offenders, it may be appropriate for the legislature to enumerate specifically further requirements for certification and enforcement regarding applicants, REPs, and the individuals associated with them, including a temporary or permanent ban from doing business in the Texas retail electric market. While to date such wrongdoers have voluntarily agreed to stay out of the market, the Commission's authority to require such an outcome in absence of an agreement may be challenged in the future without legislative clarification. Such extraordinary remedies should be accompanied by additional due process requirements.

B. Transmission

1. Treatment of CREZ Transmission Lines

When the Commission is considering an application for a transmission project intended to serve a competitive renewable energy zone (CREZ), PURA § 39.904(h) states that the Commission is not required to consider two particular criteria for approval that are required of non-CREZ transmission projects set forth in § 37.056(c)(1) and (2). The two additional criteria are the adequacy of existing service and the need for additional service. While the Commission interprets this language as only being applicable to the original set of CREZ projects authorized in 2008, the language may be construed to prevent the Commission from being able to reject proposed transmission to a CREZ area even if existing service were already adequate and there were no showing of need for such additional service.

Repeal of PURA § 39.904(h) would clarify the legislature's intent that future proposed transmission projects within a CREZ area are to be evaluated by the Commission using the same adequacy and need criteria as non-CREZ projects.

2. Require a Commission Finding that New DC Ties are in the Public Interest

The interconnection of new large DC ties between the ERCOT system and neighboring regional transmission organizations could have a significant impact on price formation, resource dispatch practices, reliability, the quantity and cost of ancillary services, and resource adequacy.

During times of system stress and high prices, ERCOT could use the DC ties as resources, importing power over the tie to alleviate strain on the system and moderate prices. When prices are low, exports over DC ties could provide broader markets for power producers in ERCOT. The impacts of new large DC ties on consumers and producers are varied and must be formally assessed.

Given this potentially significant impact on the ERCOT region, the Commission could be given the authority to review such DC ties and their impacts on the public interest, and set conditions for the interconnection of the DC tie to the ERCOT system, or deny such interconnection.

3. Commission Approval of Transmission Lines Built by a Municipally Owned Utility Outside of its Service Area

Most electric utilities in Texas must receive approval (of a change to their Certificate of Convenience and Necessity, or "CCN") from the Commission for the construction of electric transmission lines. However, when using the municipal utility's condemnation rights the utility is not required to obtain a CCN from the Commission even if it is constructing lines outside of its service territory or for purposes other than serving its own retail customers. This gap in the Commission's authority could result in landowners outside of a municipality who are affected by these lines having no recourse regarding the routing or operation of the lines should they object to the municipal utility's preferred route.

The legislature could clarify PURA §§ 37.051 and 37.052 to state that municipally owned utilities must, like other electric utilities in Texas, receive a Commission-approved CCN for the construction of transmission facilities outside of their designated retail service territory.

C. Proceedings before FERC

PURA § 39.4525 authorizes the Commission to use outside consultants, auditors, engineers, or attorneys to represent the Commission in "a proceeding before the Federal Energy Regulatory Commission" (FERC) for matters relating to Entergy Texas, Inc. This provision includes an annual expenditure limit of $1.5 million, and expires in 2017. This provision has been an important tool for the Commission to respond to complex matters in the federal arena to enable it to protect the public interest in Texas. FERC proceedings tend to be very specialized, lengthy, and complicated proceedings that require specialized legal and consulting services. The authority to retain these specialized services and the recovery mechanism provided for by PURA § 39.4525 is consistent with authority that the Louisiana and Arkansas utility regulatory commissions have been granted by their respective legislatures.

The Commission is currently a party to 21 separate FERC proceedings related to Entergy Texas, and anticipates that these proceedings and subsequent appellate actions will continue well beyond 2017. Because these issues do not affect other Texas ratepayers and the precise issues that may arise are difficult to forecast, the funding mechanism in § 39.4525 has proven to be a much more effective and appropriate mechanism for recovery of these costs as compared to general revenue appropriations. As such, the Commission believes it critical that

these existing sunset dates in § 39.4525 be extended or eliminated to ensure that the PUC can continue to retain necessary legal and consulting services to ensure that Entergy's Texas ratepayers are adequately represented before FERC.

Additionally, the Commission has found a need to be increasingly active in FERC proceedings related to other non-ERCOT utilities; namely Southwestern Public Service Company and Southwestern Electric Power Company. Similar to the matters pertaining to Entergy, these issues are technically and legally complex and neither the Commission nor the Office of the Attorney General have internal resources versed in these areas. As such, the Commission requests that the legislature authorize similar retention of counsel and consulting experts for these two utilities in the event proceedings arise that will affect these Texas utilities and their ratepayers. This would be accomplished through the insertion of provisions similar to PURA § 39.4525 into Subchapters I and K of Chapter 39 of PURA.

D. Environmental Compliance Costs

To maintain compliance with federal environmental policies, affected electric utilities have undertaken significant capital investment in their operating facilities. Recently passed and pending Environmental Protection Agency (EPA) regulations are likely to require additional capital investment or substantially change the manner in which utility power plants operate if the regulations are ultimately upheld by the federal courts. The impacts of some of these EPA proposals on the Texas market are further described in the Emerging Issues section of this report.

Because of the potential magnitude of the compliance costs associated with these federal environmental regulations, it is the Commission's understanding that certain vertically-integrated utilities may seek legislative authorization to use securitization as a means of financing these types of capital investments. Securitized cost recovery provides for a type of financing that, in comparison to conventional financing, lowers the amount of interest charges paid by ratepayers. The legislature has previously authorized securitization for other types of emissions reduction investments, stranded costs, regulatory assets, and hurricane restoration costs.[6] To date, the Commission has approved, and Texas utility companies have securitized, over $1.5 billion of weather-related infrastructure damage costs, with associated present-value savings of approximately $660 million.

E. Incentive Program for Natural Gas Generation and Mandate for Renewable Energy

1. Natural Gas

PURA § 39.9044 establishes natural gas as "the preferential fuel" in Texas for electricity generation and requires the Commission to adopt rules to establish a system of natural gas

[6] PURA §§ 39.262, 39.301-39.313, 39.458-39.463, and 36.401-36.406.

energy trading credits. The majority of all new, non-renewable electricity generation constructed since 2000 has used natural gas as a primary fuel and this trend is expected to continue. The thresholds used to trigger the natural gas energy trading credit system in PURA § 39.9044 have not been reached and they are not expected to be reached in the foreseeable future.

Because natural gas-fueled facilities have been the most commonly built new generation in Texas for many years and are expected to continue to be, there is no need to establish incentives for natural gas generation. The PUC recommends that the legislature consider repealing PURA § 39.9044 because it is no longer necessary.

2. Renewable Energy

PURA § 39.904 establishes goals for renewable energy. Subsection (a) mandates the installation of 5,880 megawatts of renewable energy by 2015, and Subsection (b) establishes a renewable energy credits (REC) trading program to implement the mandate. The 5,880 megawatts mandate in Subsection (a) was met in 2008. While the Commission believes the renewable energy credits trading program may provide the state with economic benefits through revenue generated in the interstate REC market, and that the trading program is needed for retail electric providers to validate renewable energy marketing claims, the Commission believes the 5,880 megawatts mandate in Subsection (a) is no longer necessary.

F. System Benefit Fund

HB 7, 83rd Legislature, Regular Session, contemplated the expenditure of all remaining funds in the System Benefit Fund (SBF) by September 1, 2016 through provision of a rate reduction not to exceed 82% in fiscal year 2014, 15% in fiscal year 2015, and 15% in fiscal year 2016. Enrollment numbers, electricity usage, and Provider of Last Resort rates have all been lower than expected, resulting in an inability to expend fully the appropriation for fiscal years 2014 and 2015. Consequently, the PUC currently estimates that at the end of fiscal year 2016, a balance of approximately $247 million will remain in the fund. Appropriation of the remaining balance for additional low-income electricity rate discounts is consistent with the intent of HB 7 that all remaining funds be spent for that purpose.

The Commission requests an extension on the life of the SBF to 2017 and authorization of a discount to spend the remaining fund balance. In the alternative, the Commission requests an amendment to PURA § 39.9039 to raise the cap on the discount in 2016 or permit a full year discount.

G. Advisory Opinions

Many regulatory agencies in Texas have the authority to issue informal guidance to the persons that they regulate, particularly with respect to outlining whether a particular course of conduct would, in the agency's view, be consistent with the laws and regulations that the

agency administers.[7] The issuance of an advisory opinion can provide regulatory clarity to a company before making significant investments or conducting operations the permissibility of which may be unclear under state law. The legislature may want to consider granting the Commission the authority to issue advisory opinions. In the electric industry, providing clarification to a company concerning issues such as the purchase of assets or the acquisition of another company could allow it to avoid expensive regulatory proceedings, without impairing the Commission's authority. The following state agencies have statutory authority to issue advisory opinions:

- Texas Ethics Commission; [8]
- Texas Medical Board; [9]
- State Board of Dental Examiners; [10]
- Texas Board of Nursing; [11]
- Texas Board of Professional Engineers; [12]
- Texas Lottery Commission; and [13]
- Texas State Securities Board. [14]

H. Administrative

1. Gross Receipts Assessment

The Commission gross receipts assessment is authorized by PURA § 16.001, which provides that "To defray the expenses incurred in the administration of this title…", an assessment of one sixth of one percent is collected from public utilities, electric cooperatives, and retail electric providers' gross receipts from consumers. Funds from this assessment are remitted to the general revenue fund, but have not been explicitly dedicated to funding the Commission. In contrast, similar assessments on water utilities, insurance companies, and other regulated entities have traditionally been used to fund explicitly the underlying regulatory programs at their respective agencies. Currently, the Commission is one of four Article VIII agencies that is not designated as self-funded (SOAH, Health Professions Council, OPUC, and the PUC).

Implementing this recommendation would require the PUC to be included in the Appropriations Limited to Revenue Collections rider located in the Special Provisions Relating to All Regulatory Agencies section of the General Appropriations Act. The Comptroller's

[7] In addition, certain federal agencies such as the Federal Communications Commission, Internal Revenue Service, Securities and Exchange Commission, and Federal Election Commission have authority to issue advisory opinions.

[8] Government Code § 571.091.

[9] Occupations Code § 162.107.

[10] Occupations Code § 258.157.

[11] Occupations Code § 301.607.

[12] Occupations Code § 1001.601.

[13] Occupations Code § 2001.059.

[14] Tex. Rev. Civ. Stat. Ann. arts. 581-28-1 & 581-35; 7 Tex. Admin. Code § 101.2.

Biennial Revenue Estimate for fiscal years 2014 and 2015 estimates the Commission's gross receipts assessment will generate in excess of $54.0 million in fiscal year 2015. The Commission's 2015 general revenue (GR) appropriation is approximately $4.7 million. The agency's GR base for fiscal years 2016 and 2017 will be approximately $13.4 million each year. Designation as a self-leveling agency would require the Commission to set the gross receipts assessment at a rate sufficient to generate revenue in the amount of the agency's GR appropriation each fiscal year instead of the current statutory rate of one-sixth of one percent. This would require a statutory change to PURA § 16.001(b). Based upon the agency's GR base, authorizing its self-leveling designation would result in an overall tax reduction of $40.6 million per year, or 75.2%.

2. Alternative Ratemaking Approaches

In 2011, the legislature adopted provisions regarding streamlined recovery of distribution investments for companies both inside and outside the ERCOT region. Under the current law, however, these provisions expire in January 2017. The legislature may wish to extend this expiration date or, alternatively, grant to the Commission the authority to develop other, additional methods of streamlined recovery.

Other states have adopted mechanisms that provide alternative ways of reviewing and setting rates for regulated utilities. Certain language in Chapter 36 of the Utilities Code could be construed as preventing the Commission from adopting alternative ratemaking methods even if the Commission were to find that they provided comparable oversight of utilities in a more efficient manner. The legislature could grant the Commission broad authority to adopt these streamlined or alternative ratemaking structures if the Commission found it was in the public interest to do so.

3. Annual Interest Rate Determination

Texas Utilities Code § 183.003 requires the Commission to meet each year on December 1st to set the annual interest rate for the next calendar year. Amending this statute to allow the agency to meet on any date in the fourth quarter before December 1st to set this rate would offer important logistical flexibility to the Commission regarding the posting and scheduling of open meetings of the agency.

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VI. APPENDICES

Appendix A – Acronyms

AEP	American Electric Power
AMS	Advanced Metering System
CenterPoint	CenterPoint Energy Houston Electric, LLC
CPD	Customer Protection Division
DG	Distributed Generation
DRG	Distributed Renewable Generation
DRGO	Distributed Renewal Generation Owner
DPS	Department of Public Safety
ERCOT	Electric Reliability Council of Texas
E-RSC	Entergy Regional State
ERS	Emergency Response Service
ETI	Entergy Texas, Inc.
FTR	Financial Transmission Rights
IMM	ERCOT Independent Market Monitor
kWh	Kilowatt-hour
LMP	Locational Marginal Pricing
LSP	Large Service Provider
MISO	Midwest Independent System Operator
MMBtu	One million British Thermal Unit (BTU)
MW	Megawatt
MWh	Megawatt-hour
Nodal	Texas Nodal Market Design
ORDC	Operating Reserve Demand Curve
PCRF	Purchased Power Cost Recovery Factor
PGC	Power Generation Company
POLR	Provider of Last Resort
PURA	Public Utility Regulatory Act
REP	Retail Electric Provider

RSC	Regional State Committee
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
Sharyland	Sharyland Utilities, L.P.
SBF	System Benefit Fund
SPP	Southwest Power Pool
TDU	Transmission and Distribution Utility
TNMP	Texas-New Mexico Power Company

Appendix B – REP Certificates Revoked or Relinquished

Certificates Relinquished
AEP Energy
APNA Holdings
Bose Energy
Devonshire Energy
DTE Energy Supply
E-Now
ExTex Retail Services
Gateway Energy Services
Occidental Power Services
Pepco Energy Services
Reach Energy
Smartcom Energy Services
Texas Power
Trademark Merchant Energy
TXI Power Company
Certificates Revoked
Proton Energy
TexRep1

Appendix C – Comments to the EPA

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

I. EXECUTIVE SUMMARY

The Public Utility Commission of Texas (PUCT) provides these comments on the Environmental Protection Agency's (EPA) proposed rule on *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Rule 111(d)).[15] The PUCT's primary concerns with Proposed Rule 111(d) are:

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

[15] 79 Fed. Reg. 34,830 (June 18, 2014).

- $10-$15 billion total annual compliance costs by 2030;[16]
- total electricity-related costs in Texas alone could be in excess of $10 billion;[17]
- increased energy costs for consumers in ERCOT of up to 20% in 2020, which does not include additional costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT.[18]
- $3 billion per year to comply with the energy efficiency mandate alone.[19]

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

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

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

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

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

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

Glossary

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

- TDU Transmission and Distribution Utility (ERCOT only)
- WECC Western Electricity Coordinating Council

II. INTRODUCTION

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

The legal infirmities alone dictate withdrawal of this rule in favor of a legally supportable approach to reducing CO_2 emissions. Simply put, Rule 111(d) effectively seeks to unlawfully seize jurisdiction over fundamental wholesale and retail electric utility policy from states and the FERC. This rule goes far beyond EPA's authority to regulate Electric Generating Units (EGUs) under the Clean Air Act (CAA). Furthermore, Rule 111(d) contemplates regulation of significant "outside the fence" activities that, if adopted, would require fundamental and significant changes to Texas's extremely successful competitive electricity market that serves the vast majority of Texas,[20] and would cause equally significant economic disruption and risks to reliability in the markets overseen by the Federal Energy Regulatory Commission (FERC) in which other Texas utilities operate.

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

EPA vastly underestimates both the cost of the proposed rule as well as the potential threats to system reliability. ERCOT has performed an analysis of the impacts of Rule 111(d) on grid reliability and electricity costs in the ERCOT region. The results of ERCOT's analysis are discussed throughout these comments and ERCOT's report is

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

attached hereto as Appendix A. ERCOT is currently working on a more complete analysis of the impacts on ERCOT of Rule 111(d) and other environmental rules including MATS, CSAPR, the Regional Haze program, the 316(b) Cooling Water Intake Structures rule, and the coal ash rules which will be released in mid-December 2014. Unfortunately, due to time and resource constraints, ERCOT was unable to complete this analysis before the December 1 comment deadline. The PUCT will file ERCOT's final analysis with EPA as soon as it is complete and urges EPA to consider this report as it finalizes Rule 111(d).

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

Proposed Rule 111(d) is unworkable. The rule establishes completely unachievable timelines for this fundamental remaking of the power industry, creating great threats to the ability of Texas to manage and operate our electricity system. The policies that Rule 111(d) seeks to force upon Texas would require substantial changes to Texas state law, PUC regulation, and protocols of the ERCOT, MISO, and Southwest Power Pool (SPP). The rule would also require intense coordination with other states connected to these power grids. It is unreasonable to require states to accomplish these

tasks by the proposed deadline for submitting State Plans (SPs) in June of 2016. This is particularly acute for states like Texas with Legislatures that only meet every other year, and will not be able to even consider the necessary changes arising from a final rule until 2017.

Finally, Rule 111(d) also has an unreasonable and disproportionate effect on Texas. Texas produces 11% of the electricity in the United States, but its proportion of total carbon dioxide reduction required by Rule 111(d) by 2030 is 17.87%.[21] Texas is by far the country's leading producer of renewable energy capacity, but is required to increase its renewable energy output by 150%. EPA has based Texas's renewable energy requirement on the renewable energy portfolio standard of Kansas, a state whose electricity production is one-tenth that of Texas. In these and other ways discussed herein, Rule 111(d) arbitrarily penalizes Texas.

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

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

For the reasons outlined herein, the PUCT respectfully requests EPA to withdraw proposed Rule 111(d). In the alternative, the PUCT urges the EPA to revise the proposed rule to address the concerns raised herein. Chief among the PUCT's concerns is Texas's interim emissions rate requirement of 853 lbs. CO_2/MWh. The interim mandate would be phased in over a ten year period between 2020 and 2029. However, in order for Texas to meet its interim mandate, approximately 77% of its CO_2 reductions must be

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

accomplished by 2020, as the interim mandate is averaged over the 10-year period from 2020 to 2029.[22] If Texas is too far above the interim mandate in the early years, it will not successfully meet EPA's interim goal without extremely over-controlling its carbon dioxide emissions in the latter part of the decade. For the numerous reasons enumerated below, this is a completely unrealistic and unattainable goal for Texas. The PUCT therefore requests that, at a minimum, EPA eliminate the interim goal from the rule.

On August 15, 2014, the PUCT, together with the TCEQ and the Railroad Commission of Texas (RRC)[23], held a joint public workshop in which numerous industry stakeholders provided comments on Rule 111(d). At the workshop and in post-workshop comments stakeholders provided useful information on the effects that Rule 111(d) would have on Texas. The PUCT will cite and discuss some of these stakeholder presentations and comments in its comments below.

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

A. The PUCT Agrees With The Comments Of TCEQ

The numerous legal and practical problems with Rule 111(d) are thoroughly outlined in the comments of the TCEQ.[24] For example, TCEQ has correctly concluded that EPA lacks the legal authority to regulate "outside the fence" activities included in

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

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

(Available at: https://www.sunset.texas.gov/public/uploads/files/reports/Railroad%20Commission%20Staff%20Report%202013%2083rd%20Leg_0.pdf).

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

Blocks 2-4. TECQ also rightly argues that the EPA cannot regulate power plant emissions under CAA §111(d) because these plants are already subject to regulation under the Mercury and Air Toxics Standards (MATS) rule adopted under CAA §112. TCEQ also discusses the numerous other legal problems with the proposed rule. The PUCT supports and agrees with the arguments raised by TCEQ in its Rule 111(d) comments.

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

In addition to the comments of TCEQ, the PUCT objects to the attempt by the EPA through Rule 111(d) to seize jurisdiction from state public utility commissions regarding the planning, operation, and resource decisions made in electricity markets. It has long been the law of the land that authority over retail electricity markets nationwide and wholesale markets in ERCOT are the sole province of state public utility commission, except where the Federal Power Act (FPA)[25] authorizes FERC regulation.[26] Environmental regulation has been limited to specific requirements on specific power plants, and has never been interpreted to grant EPA broad authority to dictate the operation of the entire electricity system. The manner in which power markets are dispatched, how much and how renewable energy should be integrated, and how end-use customers should use electricity has never been under the purview of the EPA. Rather these decisions are left best to states and the FERC, as experts in these areas. The

[25] 16 U.S. Code § 824 *et.seq*.

[26] As discussed in more detail below, ERCOT is the only Independent System Operator (ISO) in the country that is wholly contained within one state and is not synchronously interconnected to the remainder of the United States. ERCOT is unique among the nation's ISOs in that it is subject to very limited and specific jurisdiction by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA). The transmission of electric energy occurring wholly within ERCOT is not subject to FERC's rate setting authority under FPA sections 205 or 206 nor is it subject to FERC's sale, transfer and merger authority under section 203 of the FPA**.** (See: http://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp). Pursuant to FPA section 215, FERC does have jurisdiction to establish and enforce reliability standards for users of the bulk power system within ERCOT. Finally, under FPA sections 210, 211 and 212, FERC has limited jurisdiction to order certain entities within ERCOT to interconnect and provide transmission service. Historically, FERC orders issued under FPA section 212 that are applicable to entities in ERCOT have expressly stated that the utilities in ERCOT that are not currently public utilities under the FPA will not become public utilities and therefore subject to FERC jurisdiction for any purpose other than carrying out the provisions of FPA sections 210, 211 and 212. *See e.g., Kiowa Power Partners*, LLC, 99 FERC ¶ 61,251 (May 31, 2002).

policies that EPA seeks to force through Rule 111(d); namely renewable energy portfolio standards, energy efficiency standards, and cap-and-trade carbon emissions systems have ***always and only*** been implemented by deliberation in state legislatures or public utility commissions. The failed American Clean Energy and Security Act of 2009[27] was an attempt by the U.S. Congress to authorize and impose these policies on the nation as a whole. EPA cannot now do what the elected representatives of the American people declined to authorize simply by reinterpreting long-extant statutes to suddenly provide such authorization.

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

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

While Block 1 of Rule 111(d), though flawed as will be explained below, may arguably be within the scope of EPA's authority under the CAA,[28] Blocks 2-4 clearly go well beyond the EPA's authority under the CAA. EPA could certainly permit states to consider tools consistent with Blocks 2-4 in lieu of the "inside the fence" requirements in Block 1, but it cannot compel them to do so as it seeks to do under Rule 111(d). Blocks

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

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

2-4 (dispatch of natural gas plants, renewable energy portfolio standards and energy efficiency programs) are clearly areas over which states and their state utility commissions, not EPA, have jurisdiction. EPA has provided no convincing legal authority for mandating the sweeping changes to electricity markets made in the proposed rule.

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

Blocks 3 and 4 are also clearly outside of any legal authority given to the EPA to mandate or assume in developing state emission standards. Renewable energy and energy efficiency standards are, by definition, resources that do not emit any emissions, including greenhouse gases. EPA therefore has no regulatory authority to regulate the use of these sources.[29]

Use of renewable energy, energy efficiency, and decisions on the types of power plants that should be built to meet retail customer demand have never been within the domain of the EPA's authority. Rather, states have always used a suite of tools from integrated resource planning, renewable portfolio standards, market forces, and other legislative or regulatory tools to make these decisions. While the EPA has authority to

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

dictate the types of emissions controls that certain types of power plants must have, it does not have the authority to order them not to be used. The claim of authority that EPA now asserts to do so is breathtaking in its scope, not only as it relates to electricity markets, but also implies that EPA could do so for *any* business whose production process include regulated emissions.

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

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

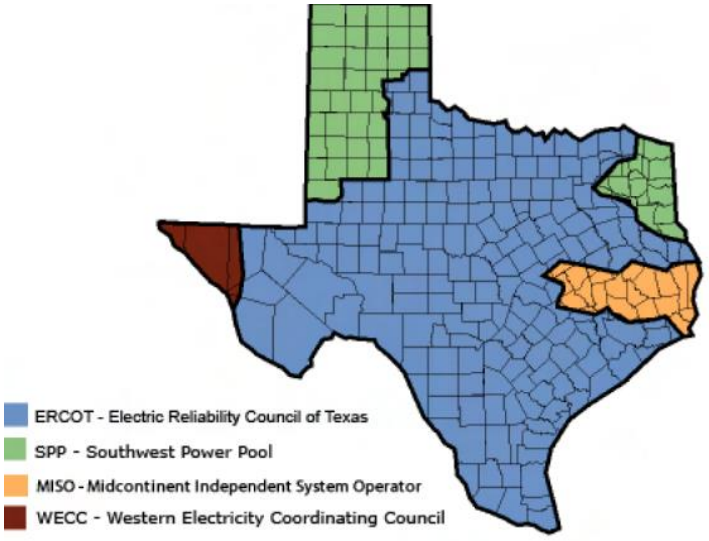
Texas is unique among all states in the fact that a large portion of the state operates in a vibrant and extremely successful competitive wholesale and retail electric market (ERCOT), while other portions of the state operate within 3 distinct competitive wholesale markets that are overseen by the Federal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

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

switching for 6.7 million premises in competitive choice areas.[30] A map of ERCOT's footprint is provided below in Figure 1.

Figure 1: Map of ERCOT Footprint

Figure 2: Map of RTO Interconnections in Texas



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

As shown in Figure 2 above, the remaining 10% of electric consumption takes place in areas outside of ERCOT served by cooperatives and vertically integrated, investor-owned utilities whose retail rates and terms of retail service are regulated by the PUCT. The IOUs operating in Texas are each part of multi-state utility systems. The non-ERCOT areas of Texas are located in far West Texas, North Texas, and far East Texas. All of the electricity markets in the non-ERCOT areas of Texas operate in multi-state competitive wholesale electricity markets that are overseen by FERC. Investor-owned El Paso Electric Company (EPE) serves far west Texas, including the City of El Paso, and operates within the Western Electricity Coordinating Council (WECC). While it is not a FERC-approved RTO, WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC also assists its members in the development of reliability standards and the coordination of the operating and planning activities of its members. WECC is geographically the largest and most diverse of the eight Regional Entities with delegated authority from the North American Electric Reliability Corporation (NERC) and FERC. WECC's service territory extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico,[31] and all or portions of 14 Western states.

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

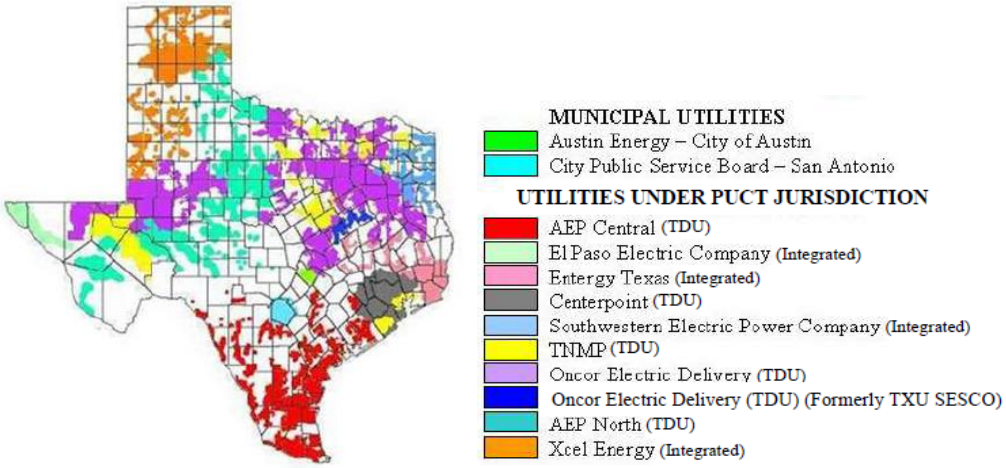
Finally in far East Texas, Entergy Texas, Inc. (ETI), an investor-owned utility, operates in the Midcontinent Independent Transmission System Operator (MISO). MISO is an independent, not-for-profit RTO responsible for maintaining reliable transmission of

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

power in 15 states in the mid-continental U.S. and the Canadian province of Manitoba. All of the Texas utilities (public or private) located in the eastern interconnection are members of SPP or MISO.

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

Figure 3: Municipal, Investor Owned, & TDUs in Texas[32]



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

V. RELIABILITY IMPACTS OF RULE 111(d)

ERCOT's primary concern with the Rule 111(d) is that, given the ERCOT region's market design and existing transmission infrastructure, the timing and scale of the expected changes needed to reach the CO_2 emission goals could have a harmful impact on reliability. Specifically, implementation of the Rule 111(d) in the ERCOT region, particularly to meet the rule's interim goal, is likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges. There is a natural pace of change in grid resources due to advancing cost effective technologies and

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

changing market conditions. This pace can be accelerated, but there is a limit to how fast this change can occur within acceptable reliability constraints. It is unknown, based on the information currently available, whether compliance with the proposed rule can be achieved within applicable reliability criteria and with the current market design. Nevertheless, there are certain grid reliability and management challenges that ERCOT will face as a result of the resource mix changes that the proposed rule will induce:

- The anticipated retirement of up to half of the existing coal capacity in the ERCOT region will pose challenges to reliable operation of the grid due to the reduction in dispatchable generation capacity and loss of reliability services provided by these resources.
- Integrating new wind and solar resources will increase the challenges of reliably operating all resources, and pose costs to procure additional regulating services, improve forecast accuracy, and address system inertia issues.
- Accelerated resource mix changes will require major improvements to ERCOT's transmission system, posing significant costs not considered in EPA's Regulatory Impact Analysis.
- Rule 111(d) could require substantial changes to ERCOT's energy market design with accompanying implementation costs.

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

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

EPA does not address how or even whether the proposed emissions standards could or should be relaxed or temporarily waived in the event of electric grid emergencies, including natural disasters, terrorist attacks, and forced outages. There is nothing in the proposed rule that allows a state to suspend the requirements of a state plan in an energy emergency. While the state could exercise enforcement discretion in such situations, utilities would still be potentially vulnerable to private citizen lawsuits for non-compliance with a CAA requirement. If Rule 111(d) is adopted, it must include

some sort of reliability safety valve (RSV) that would allow states to suspend the operation of the rule in energy emergencies.

The ISO/RTO Council (IRC)[33] has outlined the parameters of a possible reliability safety valve (RSV) that could be incorporated into Rule 111(d).[34] The PUCT understands that the IRC provided its RSV proposal to EPA staff before proposed Rule 111(d) was drafted. The IRC's proposal seeks to ensure that any federal CO_2 rule or related State Implementation Plan (SP) "includes a process to assess, and, as relevant, to mitigate, electric system reliability impacts resulting from related environmental compliance actions."[35] If EPA adopts Rule 111(d), the PUCT strongly urges the EPA to consider inclusion of some form of RSV in its adopted Rule 111(d). In its Rule 111(d) comments to the EPA, the SPP has also recommended that a reliability safety valve be incorporated into the rule.[36] In addition, NERC supports a reliability backstop as well as other measures to maintain reliability. [37]

B. Impact Of Unit Retirements[38]

ERCOT's modeling results raise two reliability concerns associated with implementation of Rule 111(d) in ERCOT. These concerns are associated with the impacts of unit retirements and increased levels of renewable generation on the ERCOT

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

[34] IRC-- *EPA CO2 RULE – ISO/RTO COUNCIL RELIABILITY SAFETY VALVE AND REGIONAL COMPLIANCE*

MEASUREMENT AND PROPOSALS, (Jan. 28, 2014) (available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf).

[35] *Id*. at 1.

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

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

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

grid. The model retired between 3,300 and 5,700 MW of coal-fired capacity in the carbon scenarios, relative to the baseline. However, these results represent a lower bound on the number of potential coal unit retirements due to the logic used to retire units in the model, generic unit cost information, and the impacts of other factors not considered by the model. ERCOT directed the model to retire capacity at the point when generic operating and fixed costs exceed revenues. However, in the modeling results for the carbon scenarios, there are several units operating at low revenues and/or low capacity factors that would likely be retired, especially when other non-modeled factors are taken into account. One important factor not considered in the modeling is the capital and operating cost impacts of other pending environmental regulations including the Mercury and Air Toxics Standard, the Regional Haze program, the 316(b) Cooling Water Intake Structures Rule, and the coal ash rules.

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

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

The model also predicted the retirement of 1,300 to 1,600 MW of natural gas steam capacity in the carbon scenarios, which is less than the 2,000 MW retired in the baseline scenario. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, which improves the economics of natural gas steam units during this

period. However, as with coal resources, there are a number of factors that may result in additional natural gas steam unit retirements compared to those found by the model. ERCOT estimates that an additional 1,500 to 4,500 MW of natural gas steam capacity may be at risk of retirement based on low net revenues in the model results combined with the need to comply with the 316(b) rule, CSAPR, and other environmental regulations.

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

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

C. Impact On Transmission Infrastructure In ERCOT[39]

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

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

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

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

or if the contracted units require capital investments in order to maintain compliance with other environmental regulations.

The growing loads in the ERCOT urban centers are causing continued growth in customer demand and a resulting need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. A new 345-kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston region, at an estimated cost of more than $590 million. Long-term studies indicate a potential need for further upgrades in the mid-2020s.[40] The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed project. Retirement of generation after 2018 would accelerate the need for additional transmission from the long-term horizon (6-15 years) into the near-term horizon (1-6 years).

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

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

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[40] *See* ERCOT's 2013 *Report on Existing and Potential Electrical System Constraints and Needs*. (Available at: http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf).

Nineteen LMPs for the CO_2 limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

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

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

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

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

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

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

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

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

> reduce carbon dioxide emissions from existing generating units, these coordination efforts may need to be revisited.[41]

While the GAO Report notes that EPA has had some consultations with FERC and the Department of Energy on other EPA rules including CSAPR, MATS, the Cooling Water Intake Structures rule, and the Disposal of Coal Combustion Residuals rule, the exact nature and extent of those consultations remains unclear. It is even less clear exactly what consultations EPA has had with FERC and DOE on Rule 111(d) since this issue was not the primary focus of the GAO Report. [42]

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

> Essentially, what I have been calling for is a more formal role for our commission as we deal with EPA on these issues, kind of an open and transparent role, so that basically we can get the engineers together to discuss the challenges involved because it really comes down to a very granular level with reliability. The laws of physics will trump regulations. There are always unintended consequences when we shut down power plants because, although they may not produce a lot of power, they may be producing other products, ancillary services that maintain reliability in the

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

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

> grid. And the location of those plants is key, and sometimes you can't replicate a plant in that location.[43]

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

> [n]o, they did not request written comments. My understanding, this is the first time I have been through the interagency review, but there were a number of staff meetings and then a, kind of a formal debrief where we made our comments over at the OMB [Office of Management and Budget] with a number of EPA people there. And we kept a memo, but we did not turn them in in writing because that has not been the practice.[44]

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

RTOs, including ERCOT, have not had sufficient time to perform a thorough reliability analysis of Rule 111(d). While ERCOT has provided its initial analysis of Rule 111(d), its complete analysis will not be completed until mid-December 2014. The PUCT will provide ERCOT's complete analysis to EPA as soon as it is available. Other RTOs, including SPP, have provided EPA their initial reliability analyses of Rule 111(d). However, additional analysis on the overall reliability impacts of Rule 111(d) still need to be performed. This is yet another reason that the EPA should withdraw the proposed

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

[44] *Id* at 41.

rule. At a minimum, implementation of Rule 111(d) should be delayed to allow the appropriate entities, including FERC, NERC and RTOs, to provide meaningful input and analysis on the reliability impacts of the proposed rule or any subsequent rule before it is adopted.

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

As explained by SPP in a recent presentation on the impacts of Rule 111(d), SPP operates regional security-constrained, economically dispatched markets. This model considers both reliability and economics. Reliability actions and generation dispatch provide regional solutions to needs over a multi-state area. These solutions are not limited to state boundaries. SPP performs regional transmission planning and directs transmission construction for its member companies. All generator interconnection requests and transmission service requests are directed to and processed by SPP. Transmission planning is a significant function of SPP and the other RTOs. Transmission planning, design, permitting and construction is very time-intensive. In SPP, planning, designing and construction of transmission lines can take up to eight and a half years.[45]

SPP has performed a reserve margin assessment as if Rule 111(d) were implemented as proposed. SPP's study was completed on October 8, 2014 and has been provided to EPA. SPP's study results indicate that Rule 111(d) will have a significant reliability impact on the SPP. SPP's minimum current reserve margin requirement is 13.6% and according to its study, SPP estimates that under Rule 111(d), its reserve margin would plummet to 4.7% by 2020—8.9% below its minimum reserve margin requirement.[46] This represents a capacity margin deficiency of approximately 4,500 MW. By 2024, SPP expects that its reserve margin would further drop to -4.0%, which represents a capacity margin deficiency of approximately 10,000 MW. Stated differently, SPP forecasts that of its 14 load serving members, 9 would be deficient by 2020 and 10

[45] Docket ID No. EPA-HQ-OAR-2013-0602—SPP comments at 8.

[46] *Id.* at 7.

members would be deficient by 2024. SPP's anticipated generation capacity deficiencies resulting from the proposed rule would be 4.6 GW in 2020 and 10.1 GW in 2024.[47]

SPP's analysis paints a grim picture of the electric grid if Rule 111(d) is adopted as proposed. As explained in SPP's Reliability Analysis of Rule 111(d), SPP developed power grid models to ascertain the effects of Rule 111(d) on reliability in the SPP region. SPP's modelling reflected the plant retirements included in EPA's Integrated Planning Models (IPMs). Part 1 of SPP's modelling assumed the plants retired in SPP would be replaced by existing unused capacity within SPP and surrounding areas. Part 2 of SPP's analysis assumed retired plants would be replaced by a combination of existing capacity and new gas fired units and wind generation.[48] Other assumptions, explained by SPP, were also part of its analysis. SPP's analysis revealed significant impacts on reliability. SPP found that the assumed plant retirements in SPP would result in significant reactive power deficiencies, the most notable of which were in the Texas Panhandle region.[49] The results of Part 2 of SPP's analysis were even more troubling as SPP noted that: "[p]ortions of the system in the Texas panhandle, western Kansas, and northern Arkansas were so severely overloaded that **cascading outages and voltage collapse** would occur."[50] The reliability impacts of Rule 111(d) might be at least partially offset by the construction of transmission line upgrades. However, planning and construction of new 345 kV transmission lines can typically take up to 8.5 years. As such, any needed transmission upgrades would almost certainly not be in place by 2020, when SPP's reserve margin is expected to drop to 4.7%.[51]

SPP's overall conclusion is that proper implementation of Rule 111(d) would require more comprehensive planning with stakeholders using new tools and metrics as well as "broader system assessments of the bulk power system and natural gas pipeline

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[47] *Id.* at 5-6.

[48] *Id.* at 2.

[49] *Id.* at 4.

[50] Docket ID No. EPA-HQ-OAR-2013-0602—SPP Reliability Impact Assessment of the EPA's Clean Power Plan at 5 (Oct. 9, 2014) (emphasis added).

[51] *Id.* at 5-6.

and storage systems based on environmental constraints…..”[52] SPP noted that it was only able to perform a preliminary reliability analysis of Rule 111(d). SPP explained that additional studies, including how the projected EGU retirements would affect reliability under potential critical scenarios such as drought and polar vortex conditions, the evaluation of the technical feasibility of implementing each of the four building blocks, and the compliance timeline under by Rule 111(d), would be needed to assess the full impact of Rule 111(d).[53] The PUCT shares SPP’s concerns, particularly given the significant adverse impacts Rule 111(d) would have on the Texas panhandle region as noted in SPP’s study. SPP’s study is further evidence of the need for EPA to withdraw Rule 111(d) and replace it with a more reasonable and achievable proposal for reducing carbon emissions.

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

At the joint PUCT/TCEQ/RRC workshop on August 15, 2014, a number of industry stakeholders provided comments on Rule 111(d)’s impacts on Texas. SWEPCO president Venita-McCellon Allen outlined various reliability concerns for SWEPCO’s approximately 600,000 retail Texas customers. SWEPCO is a non-ERCOT IOU operating in far Northeast Texas, which is located in the SPP RTO. Under EPA’s IPM, EPA projects that SWEPCO must retire its Welsh Units 1 and 3 and its Pirkey Plant by 2020.[54] This represents almost 1,700 MW or 30% of SWEPCO’s total installed capacity.[55] As explained by Ms. McCellon-Allen, this projected retirement will present major reliability impacts for SWEPCO’s customers. SWEPCO would not have sufficient capacity in Texas to make up for the forced retirement of these coal units. SWEPCO would instead be forced to purchase capacity (assuming such capacity were even available) from outside Texas to serve its customers. Because SWEPCO is located on the western seam between SPP and ERCOT, there is currently insufficient transmission from

[52] *Id.* at 6.

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

[54] *See* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Venita McCellon-Allen at 8 (Aug. 15, 2014).

[55] *Id*.

which to import the capacity that would be needed to replace its retired coal units.[56] EPA fails to recognize the significant investment in new capacity and new transmission that SWEPCO would be required to make if Rule 111(d) were adopted as proposed. This problem would be exacerbated in the winter months when natural gas curtailment issues due to weather are most likely to arise. EPA's Rule 111(d) implementation timeline provides "no recognition to the planning, approval, permitting and siting time needed to approve and install new generation and transmission."[57] Ms. McCellon-Allen further explained that the Rule 111(d) timeline fails to recognize that the East HVDC tie between ERCOT and SPP currently relies on var support from the Welsh units (slated to be retired under EPA's IPM). SWEPCO rightly noted that the final Rule 111(d) must address these unique reliability and operational concerns.

At the August 15 joint workshop, SWEPCO also outlined the conflict between Rule 111(d) and other EPA regulations. SWEPCO is currently investing approximately $750 million in its coal plants to comply with MATS. SWEPCO explained that it has already spent approximately $120 million installing emission controls on its Welsh Units 1 and 3 to comply with MATS. SWEPCO noted that this retrofit is the most economic decision for its customers, is the only solution available to allow it to meet its MATS April 2016 compliance deadline, and helps to preserve reliability of SWEPCO's system. However, in Rule 111(d), EPA has assumed that both of these units will be shut down by 2020.[58] SWEPCO further explained that if the Welsh Units are not available to serve SWEPCO's 600,000 Texas customers, reliability will be at risk. SWEPCO noted that the Welsh units should not be retired unless and until: 1) SPP has an opportunity to study the impact of these retirements on reliability; 2) SWEPCO's regulators, including the PUCT, have time to review available alternatives and issue required approvals for new transmission and generation and 3) SWEPCO has sufficient time to complete the

[56] *Id.* at 9-11. *See also* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 9 (Sept. 5, 2014).

[57] *See* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Venita McCellon-Allen, at 10 (Aug. 15, 2014)

[58] *Id.* at 11-12.

engineering, design and installation of the chosen alternatives.[59] Finally, SWEPCO explained that there is no realistic way for all of these steps to be completed before the projected 2020 retirement date of the Welsh units.[60] The PUCT is confident many other generators in Texas and throughout the nation face a similar quandary. This clearly demonstrates EPA's lack of analysis on the real effects that Rule 111(d) will have on grid reliability.

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

> Since the model must maintain adequate reserves in each region, a portion of the reduced operational capacity in the policy case is taken from reserves that currently exceed the target reserve margin and will not be needed in the future. In order to maintain resource adequacy in each region where existing resources retire, the model relies on this excess reserve reduction, additions of new capacity, and reduced total resource requirements from increases in energy efficiency.[61]

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

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

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[59] *Id.* at 12.

[60] *Id.*

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

electric service to their member distribution cooperatives. ETEC's ten electric distribution cooperatives provide retail electric service to approximately 330,000 retail customers in east Texas and Louisiana.[62]

There are significant concerns about the effect of Rule 111(d) on Texas's cooperatives like ETEC. Under Rule 111(d), four of the coal units used to serve ETEC's customers will be retired. ETEC estimates the total cost impact to its members of Rule 111(d) to be $2.9 billion. This figure includes $365 million in stranded costs and $585 million in replacement power costs.[63] In addition, the EPA fails to address many other issues, including how Rule 111(d) would work for companies, like ETEC, with power plants located in three states and operating in three different RTOs and how Rule 111(d) will apply to entities like ETEC, not currently regulated by state public utility commissions.[64] Electric cooperatives (coops) and municipally-owned electric utilities (MOUs), many of which own and operate coal plants in Texas, are subject to only limited oversight by the PUCT. This oversight does not include regulation of the generation assets of these entities.[65] However, these entities are clearly intended to be subject to and are affected by Rule 111(d). Without the requisite state law authority to regulate these entities, it is unclear how coops and MOUs can be included as part of either a state or federal plan to implement Rule 111(d).

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

The ERCOT grid has limited interconnections to the rest of country and therefore has limited ability to import power from other RTOs. There are also transmission line

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[62] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Edd Hargett, at slides 3-4 (Aug. 15, 2014).

[63] *Id.* at slides 2-3.

[64] *Id.* at slide 10.

[65] *See* TEX. UTIL. CODE ANN. §40.004 (jurisdiction of the PUCT over MOUs) & §41.004 (jurisdiction of the PUCT over electric cooperatives) (West 2007 & Supp. 2014).

limitations into the non-ERCOT Texas utilities that operate in multi-state RTOs. Planning, designing, permitting and constructing additional electric transmission lines for electric utilities operating in interstate markets is a slow and time-consuming endeavor. As noted previously, SPP's typical transmission line planning and construction timeline is typically 8.5 years.[66] Similar planning and timing issues exist in planning and building additional natural gas pipelines which would undoubtedly be required if Rule 111(d) were implemented.

In a case similar to the proposed Rule 111(d), SPS applied with the PUCT to recover costs related to EPA's Cross-State Air Pollution Rules (CSAPR). SPS was under a short time frame, (as Texas would be in order to comply with the interim goals under Rule 111(d)) and there were not a sufficient number of allowances available for SPS to purchase. To comply with CSAPR in the short term, SPS proposed "reduc[ing] the output from its coal-fired facilities and [increasing] the output from gas-fired facilities."[67] An SPS witness testified in 2011 that the effect of CSAPR on SPS's production cost would be approximately $206 million.[68] To maintain system reliability under rules that attempt to minimize the use of coal-fired plants is a difficult and expensive prospect.

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

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

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[66] *See supra* at page 27.

[67] PUCT Docket No. 39925, *Application of Southwestern Public Service Company for Authority to Revise its Fuel Factor Formulas; Change its Fuel Factors; and For Related Relief*, Direct Testimony of Dean R. Metcalf at 11 (available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39925_2_711724.PDF)

[68] *Id*. at Direct Testimony of David G. Horneck at 14. (available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39925_4_711721.PDF).

solution to the concerns raised. The MISO study did not consider the reliability impacts of Rule 111(d).[69]

MISO's general conclusions are that the compliance timeline would present significant problems with resource adequacy. MISO estimates compliance costs would be $55-90 billion on a net present value basis. MISO further concludes that many of the most economical solutions to implementing Rule 111(d) would result in an additional 14 GW of coal retirements in MISO. MISO also notes that regional compliance and carbon reduction measures beyond EPA's four building blocks provide the most economic options for meeting Rule 111(d) CO_2 reduction targets.[70]

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

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[69] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Letter of Todd P. Hillman, Vice President, MISO South Region, at 1-3 (Oct. 13, 2014).

[70] *Id.* at 2.

On November 25, 2014, MISO filed comments on Rule 111(d) which recommended that EPA eliminate the interim emission performance period and levels from the rule. MISO also recommended that the final rule provide "structured flexibility to support a variety of compliance strategies to preserve reliability of the electric system."[71] MISO echoes many of the same reliability concerns raised by NERC, SPP, PUCT and many others. EPA must consider the serious reliability impacts of the proposed rule raised by the entities charged with maintaining the reliability and integrity of the electric grid.

VI. COST IMPACTS OF RULE 111(d)

EPA has vastly underestimated the costs of Rule 111(d). EPA concludes that the costs to implement the proposed rule are approximately $7-9 billion nationwide.[72] ERCOT stakeholders have provided estimates of the cost of complying with Rule 111(d). For example, Texas Industrial Energy Consumers has estimated that the statewide total annual costs of complying with Rule 111(d) will be from $12-$15 billion by 2030.[73] A recent Energy Ventures Analysis[74] study on the impacts of Rule 111(d) together with other environmental regulations that were in effect in August 2013, estimated that the cumulative impacts on Texas of these environmental regulations would be as follows:

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

[71] Docket ID No. EPA-HQ-OAR-2013-0602—MISO Comments at 5 (Nov. 25, 2014).

[72] Docket ID No. EPA-HQ-OAR-2013-0602—EPA Regulatory Impact Analysis at ES-8, incremental cost vs. base case (2030, Option 1).

[73] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Charles Griffey at slide 12 (Aug. 15, 2014).

[74] Energy Ventures Analysis, *Energy Market Impacts of Recent Federal Regulations On The Electric Power Sector* at 27 and 38 (Nov. 2014).

Luminant, the largest generator in ERCOT, has estimated that total electricity-related costs for Rule 111(d) in Texas alone could be in excess of $10 billion.[75]

Based on its analysis, ERCOT has concluded that Rule 111(d) would result in increased energy costs for consumers of up to 20% in 2020, without accounting for the associated costs of transmission upgrades, natural gas supply infrastructure upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. Consideration of these additional factors would result in even higher energy costs for consumers.[76]

Despite the staggering costs of implementing Rule 111(d), the rule would do little to reduce worldwide CO_2 emissions. EPA has also failed to provide a single quantifiable climate benefit for implementing this rule. In its comments, TCEQ discusses both of these issues in some detail.[77] Finally, others have noted that EPA has vastly overstated the health benefits of Rule 111(d).[78]

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

[75] Docket ID No. EPA-HQ-OAR-2013-0602—Luminant Comments, NERA Economic Consulting Analysis of the Clean Power Plan at 20 (Dec. 1, 2014).

[76] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 16.

[77] Docket ID No. EPA-HQ-OAR-2013-0602--TCEQ Comments at 2-8.

[78] *See, e.g.* PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*—Partnership for a Better Energy Future at slide 34 (Aug. 15, 2014).

retiring units, or increased maintenance associated with more frequent cycling of coal-fired units.[79]

ERCOT's study concluded that the inclusion of carbon prices resulted in higher average locational marginal prices (LMPs) compared to the baseline scenario. In the $20/ton carbon price scenario, the average LMP in ERCOT was $66.17 in 2020 and $81.13 in 2029 – 34% and 13% above the baseline scenario LMPs for those years, respectively. In the $25/ton carbon price scenario, the average LMP was $73.58 in 2020 and $84.28 in 2030 – 49% and 17% above the baseline scenario estimates.[80] As a general estimate, if wholesale power is 40% of the consumer bill, these increases in average LMPs would result in a retail energy price increase of 14 to 20% in 2020, and 5 to 7% in 2029. The increase in wholesale and consumer energy costs compared to the baseline decreases by 2029 due to the addition of new solar capacity, which has virtually no variable costs, and the accrual of energy efficiency savings. The costs of investments in energy efficiency are not estimated in ERCOT's analysis.[81]

The LMP reflects the variable cost associated with the generation resource on the margin. Though this measure provides an estimate of wholesale energy prices for consumers, the increase in production costs for generators would differ. The model results indicate that generators' variable costs by 2029 will increase by 15 to 18% in the $20/ton CO_2 and $25/ton CO_2 scenarios, respectively, compared to the baseline. This increase is due in large part to the CO_2 emissions price, which in 2029 posed a cost of $3.8 billion in the $20/ton CO_2 scenario and $4.4 billion in the $25/ton CO_2 scenario, comprising 19% and 21% of total variable costs for the two respective scenarios.[82]

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

[79] *ERCOT Analysis of the Impacts of the Clean Power Plan* at 15-16.

[80] *Id.* at 17, Table 8.

[81] *Id.* at 15-16.

[82] *Id.* at 16.

baseline, or an increase of 52 to 77%.[83] Though not reflected in LMPs, these costs will also ultimately be reflected in consumers' energy bills. ERCOT's modeling results showed a decrease in the ERCOT reserve margin in the early years of the Rule 111(d) compliance timeframe. In a recently completed report prepared for the PUCT, the Brattle Group quantified the cost to consumers associated with periods of reduced reserve margins.[84] These costs include the assumed capital costs of new generation, which increase at higher reserve margins, and a range of production costs, including the cost of emergency generation, the cost of utilizing interruptible customers, the costs of utilizing all of the available ancillary services, and the impact to consumers from firm load shedding, all of which increase at lower reserve margins. Based on this report, the retirement of 6,000 MW of generation capacity would be expected to reduce the system reserve margin by about 8%. If this change occurred when the system reserve margin was approximately 14%, the increased annual production costs at the resulting 6% reserve margin would be approximately $800 million higher than would be expected prior to the regulatory impact.[85]

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

A. Stranded Costs Implications Of Block 1

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

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[83] *Id.* at 17.

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

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

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

As part of the legislation creating the competitive retail electric market in ERCOT, the Texas Legislature allowed investor-owned electric utilities (IOUs) to recover "all of [their] net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service."[86] Stranded cost claims from coal plant owners resulting from Rule 111(d) are costs that are not addressed in the proposed rule. If Rule 111(d) is adopted as proposed, the Texas Legislature would need to determine whether to change Texas law to allow recovery of stranded costs resulting from the rule. If recovery of such costs were allowed by the Texas Legislature, these costs would ultimately be borne by all Texas electricity customers.

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

EPA's Regulatory Impact Analysis indicates that two full-time staff per state will be needed to oversee implementation, assess progress, develop annual reports, and perform other necessary functions.[87] States are required to track their progress in complying with the rule and must begin submitting annual reports to EPA on July 1, 2021.

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

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[86] TEX. UTIL. CODE ANN. §39.252(a) (West 2007 & Supp. 2014).

[87] Docket ID No. EPA-HQ-OAR-2013-0602--*Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, at page 3-47.

TCEQ believes that it will require two to three full-time staff to fulfill its responsibilities under Rule 111(d).[88] While TCEQ would be responsible under Rule 111(d) for developing and submitting any State Plan to EPA, it will need assistance from the PUCT and possibly other Texas state agencies, since Blocks 2-4 involve "outside the fence" activities that are typically overseen by state public utility commissions and/or the FERC, not by EPA or state environmental agencies. For example, the PUCT has considerable experience in overseeing electric utility energy efficiency programs and would presumably need to provide assistance to TCEQ in monitoring compliance with this portion of Rule 111(d).[89] The PUCT's best estimate at this time is that assisting TCEQ in monitoring compliance with energy efficiency programs would likely require one to two additional staff members. Providing a meaningful estimate of the cost of compliance on the energy efficiency portion of the rule is difficult, however, because EPA has yet to provide guidance on the evaluation, measurement & verification (EM&V) standards for renewable energy or demand side energy efficiency programs that states must use.[90]

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

A. EPA's Proposed Building Blocks

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

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

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

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

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

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

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

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

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

EPA claims that the rule would allow states flexibility to determine what measures to implement in order to meet EPA's emission limits for each state. However, for Texas at least, this flexibility is a mirage. Because EPA has used each of the four building blocks in an extremely aggressive manner in establishing Texas's performance mandates, Texas must implement each of these goals in order to have any hope of attaining either its interim requirement of 853 lbs. CO_2/MWh or the final requirement of 791 lbs. CO_2/MWh. There are simply no other options to achieve this level of GHG

reductions in the electricity sector in Texas. Moreover, EPA has indicated that even if a state can demonstrate that a particular building block is not feasible, EPA will not adjust a state's emissions goal unless the state can demonstrate that additional controls on the other building blocks are not feasible.[91] As TCEQ explains in its comments, this is a flawed interpretation of CAA § 111(d) regarding what constitutes BSER and should be rejected.[92] Additionally, as will be explained below, there are likely no excess reductions available under any of the building blocks that can meaningfully mitigate the draconian requirements of another block.

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

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

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[91] 79 Fed. Reg. 34,893 (June 18, 2014).

[92] Docket ID No. EPA-HQ-OAR-2013-0602—TCEQ Comments at 19.

VIII. BLOCK 1: INCREASED EFFICIENCY OF COAL PLANTS

A. Texas Coal Plants Have Limited Additional Efficiency Gains Available

The EPA's proposed rule arbitrarily[93] assumes that substantial thermal efficiencies can still be obtained from coal plants in Texas. However, within the ERCOT interconnection that comprises most of Texas, there is little room for improvement in Block 1's heat rate improvement goal. Block 1 assumes that there *are* additional efficiencies available; however, the ERCOT market has forced coal-fired generators to adopt state of the art technologies available to improve thermal efficiencies in order to compete effectively, and there are few additional gains available.

Competitive wholesale electricity markets generally operate using security constrained economic dispatch (SCED).[94] That is, every electricity generator will bid

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

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

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

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

> NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice.[95]

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

> [Heat rate improvements] may also not be achievable or justifiable at every coal-fired plant. In many cases, staff at many well-performing plants have been proactive and already implemented some of the possible improvements (e.g., steam turbine upgrades, remote monitoring centers, etc.), thus reducing the potential for further maximum heat-rate improvement.[96]

Based on the testimony at the August 15 joint PUCT/TCEQ/RRC workshop, generation owners confirmed that they have already made many if not all of the cost-effective improvements that can be made on their coal units.[97] Further mandates like those required in the proposed rule will likely require substantial investments to further

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

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

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

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

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

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

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

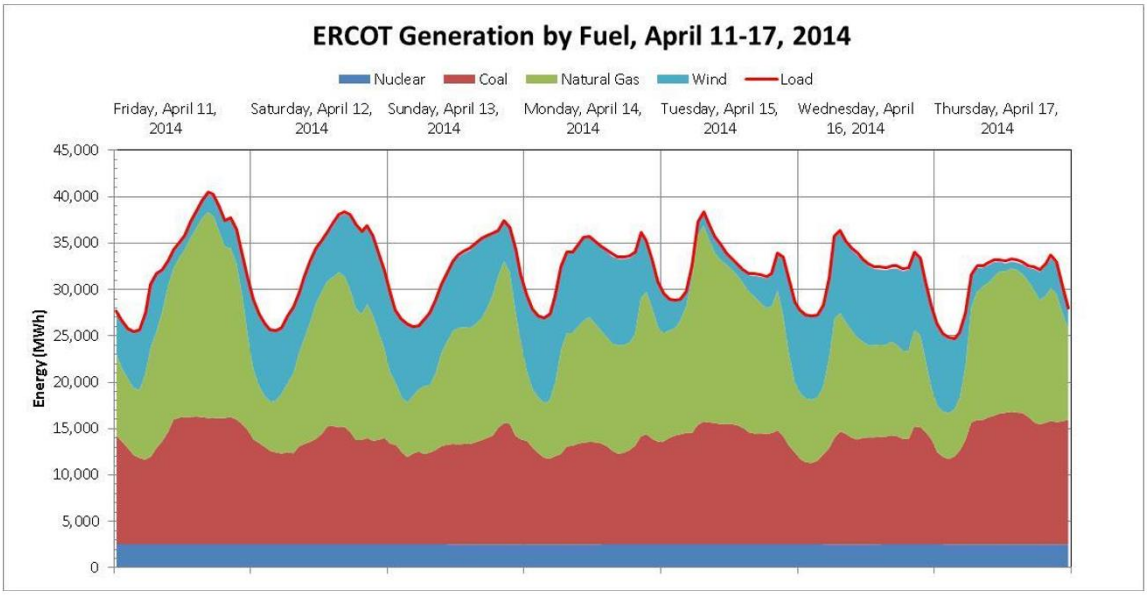

Figure 4 illustrates that Texas's 11,000 MW of wind power has substantial impacts on the operations of coal plants, particularly in the spring. This result occurs

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

While not motivated by the same competitive pressures that exist in ERCOT, electric utilities in the non-ERCOT regions of Texas have also likely made most or many of the heat rate efficiency improvements that can reasonably be made without triggering the new source review (NSR) provisions of the CAA.[98] In comments provided at the August 15 joint PUCT/TCEQ/RRC workshop, SWEPCO[99] explained:

> [M]ost of the heat rate improvement opportunities identified by EPA have already been implemented at SWEPCO's Texas units. SWEPCO plans to retire one unit at the Welsh Power Plant in 2016, and has emission control projects underway at the other two Welsh units in order to comply with the [MATS] Rule. The existing unit at Pirkey will also be equipped with activated carbon injection systems for MATS compliance. By the time the projects are completed, all of SWEPCO's Texas units will have sophisticated emission control systems that will allow them to operate for many more years and provide the fuel diversity and flexibility to respond to changing market conditions and provide a hedge against price volatility in the natural gas markets.[100]

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

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

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

In this same filing, SWEPCO detailed numerous flaws in EPA's analysis that "lead to a gross over-estimation of the potential heat rate improvements that could be reasonably and cost-effectively achieved by the fleet of coal-fired power plants that will be impacted by [Rule 111(d)]."[101] The PUCT concurs with these assessments, namely that EPA:

> (1) ignored certain of the caveats and conclusions included in the engineering reports, and the impact on heat rate of the emission control projects currently under construction to comply with other rules; (2) inappropriately assumed that heat rate variability that is not associated with unit load or ambient temperatures can be controlled through operational practices or capital improvements; (3) conducted a statistical analysis that (a) includes a number of units that will be retired prior to the initial interim compliance date, (b) uses gross heat rate data and inappropriately applies the results to a net heat rate goal, and (c) ignores additional sources of variability that are not controllable; (4) erroneously assumed that capital projects and operational practices could be universally applied to improve the efficiency of all coal-fired generating units; and (5) failed to collect any industry data on the extent to which such improvements have already been implemented and therefore are reflected in current plant efficiency values.[102]

In sum, the use of an arbitrary average 6% heat rate improvement factor in setting Texas's emissions rate is flawed because it fails to reflect that most generators in Texas have already made many of the improvements cited as rationale for that standard and fails to credit Texas for the improvement already made through use of the 2012 base year.[103] EPA must remedy this flaw through one of two options. First, rather than use an arbitrary 6% heat rate improvement requirement on all units, EPA should have instead performed an analysis as to which plants have not already implemented the improvements identified in the technical support documents and only required those power plants to implement those cost-effective and technically feasible practices. Alternatively, EPA should use an earlier date of 2002 for purposes of measuring the base from which the heat rate improvement would be calculated. Finally, EPA should account for the impacts of

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

[102] *Id*.

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

increased renewable energy generation on power grids; namely the degradation of heat rates as coal plants are ramped up and down to accommodate the intermittency of wind and solar power.

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

IX. BLOCK 2: INCREASED USE OF NATURAL GAS CAPACITY

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

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

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

utilities are set by the PUCT based on traditional cost of service principles. Block 2 also conflicts with current Texas law that requires utilities to provide power to their customers at a just and reasonable rate.[104]

Additionally, Rule 111(d) penalizes Texas for the very thing the rule will purportedly achieve: the addition of modern, efficient natural gas-fired generation. ERCOT has added substantial new efficient natural gas combined cycle generating plants over the last decade. Since 2001, ERCOT has added 14,775 MW[105] of natural gas combined cycle generating capacity and currently has more installed natural gas capacity than any other state.

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

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

A GAO report analyzed public records of interstate gas pipeline permitting processes (as FERC does not collect such data) and noted that, "for those projects that were approved from January 2010 to October 2012, the average time from pre-filing to certification was 558 days; the average time for those projects that began at the

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

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

application phase was 225 days."[106] The GAO report did not even have data for the time frames required to obtain intrastate gas pipeline permits. Interstate permitting must comply with various federal laws, including the National Environmental Policy Act, the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act. The GAO report goes on to state: "[b]oth the interstate and intrastate pipeline permitting processes are complex in that they can involve multiple federal, state, and local agencies, as well as public interest groups and citizens, and include multiple steps."[107]

Planning, permitting, and constructing such infrastructure takes time and is expensive. EPA does not appear to have taken this factor into account in the proposed rule, and instead implicitly assumes no lag time in its model for bringing natural gas pipelines online. Moreover, while EPA acknowledges that the increased use of natural gas mandated by Block 2 will result in the need for additional gas pipeline infrastructure and will increase natural gas prices, EPA failed to study existing natural gas transmission constraints, contractual arrangements, and other factors including unit design or age of equipment that could limit the feasibility, reliability, or sustainability of running individual units at such high capacity factors.[108] In short, to comply with Rule 111(d), and bring in the amount of natural gas required by the rule, will take much more time than is contemplated by the proposed rule. This creates particular risks to Texas because of the disproportionate impact that Block 2 has on Texas's interim emissions rate. Rule 111(d) assumes the entire re-dispatch is accomplished beginning in 2020, resulting in approximately 77% of Texas's final emissions reduction be achieved by 2020. Simply put, the time between the adoption of a final rule and the compliance deadline of 2020 is woefully insufficient to assess, plan, construct, and operate the infrastructure that such a dramatic shift in electricity production will require.

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

[107] *Id.* at 12.

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

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

> Dispatch of SWEPCO's EGUs within Texas is controlled by the Southwest Power Pool (SPP), according to market-based tariffs and operating agreements that are intended to capture the benefits of security constrained market-based economic dispatch across wide regions of the United States in order to secure more cost-effective operation of these collective assets for the benefit of wholesale and retail customers. 16 U.S.C. §824a(a). The operations of SPP are based on agreements of the system owners and operators, and are subject to oversight by FERC, but even FERC has no ability to compel any particular technique of coordination. *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002). SWEPCO is aware of no provision of state or federal law that would allow EPA or the state to alter those arrangements and dictate a specific technique to achieve this arbitrary level of dispatch for a specific type of unit. The energy markets recently developed in SPP have been carefully structured to achieve the least cost dispatch operation of committed generation, and to allow operators of the individual units the flexibility to respond to dynamic and constantly changing circumstances in both the supply of and demand for electricity.[109]

SWEPCO further explains that neither EPA nor the states have the authority to regulate emissions by creating preferences for one type of generation over another.[110]

B. The Paradoxes Of Building Blocks 1 & 2[111]

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

[109] *Id.* at 7.

[110] *Id.* at 8.

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

analyze the increased NO_X and SO_2 emissions increases that will result from operating coal plants in this manner.

C. The Paradoxes Of Building Blocks 2 and 3

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

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

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

Figure 5: Typical Summer Load Profile

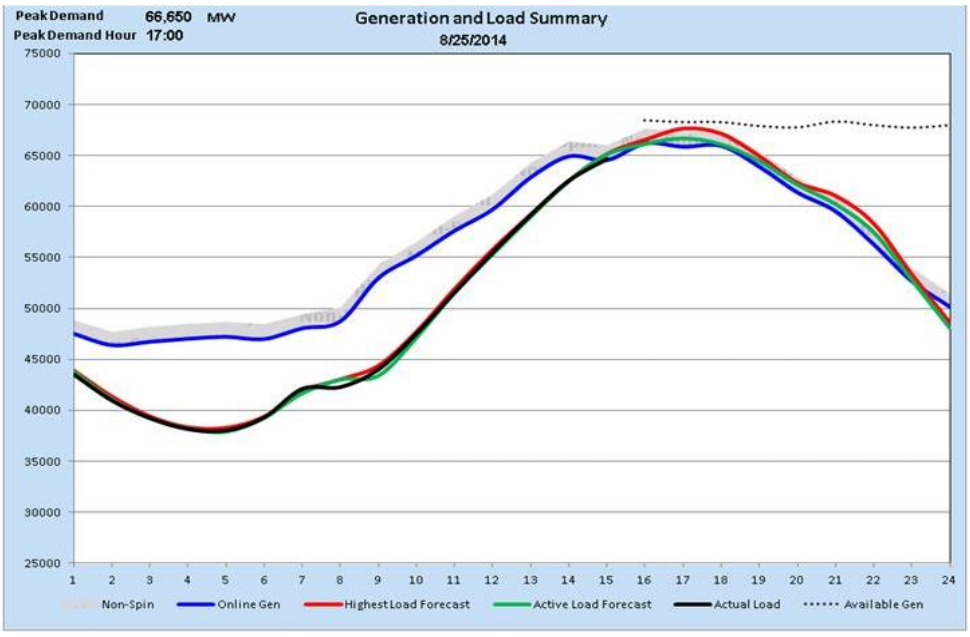


Figure 6: Spring/Fall Load Profile

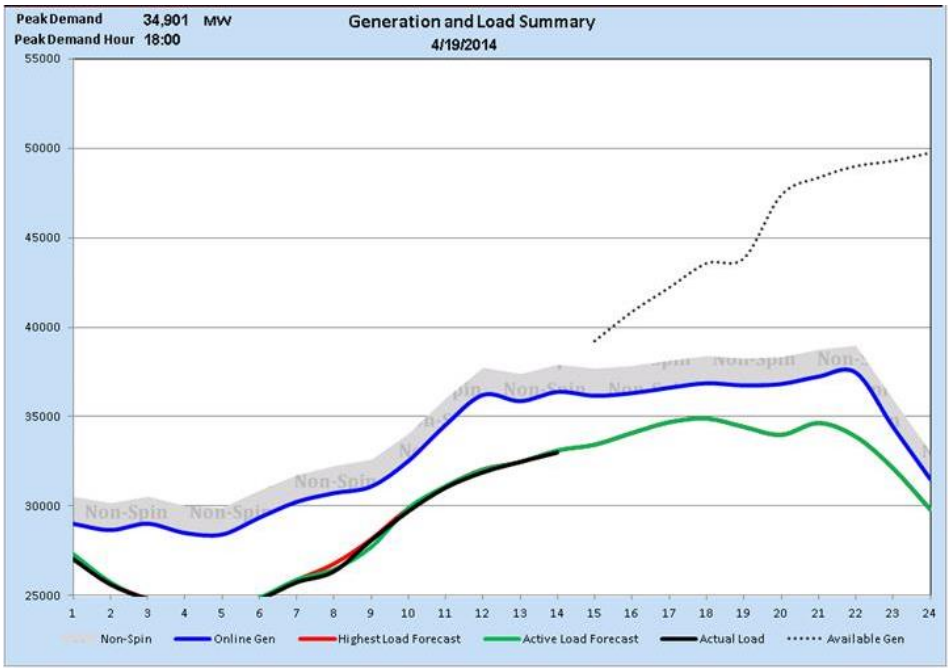


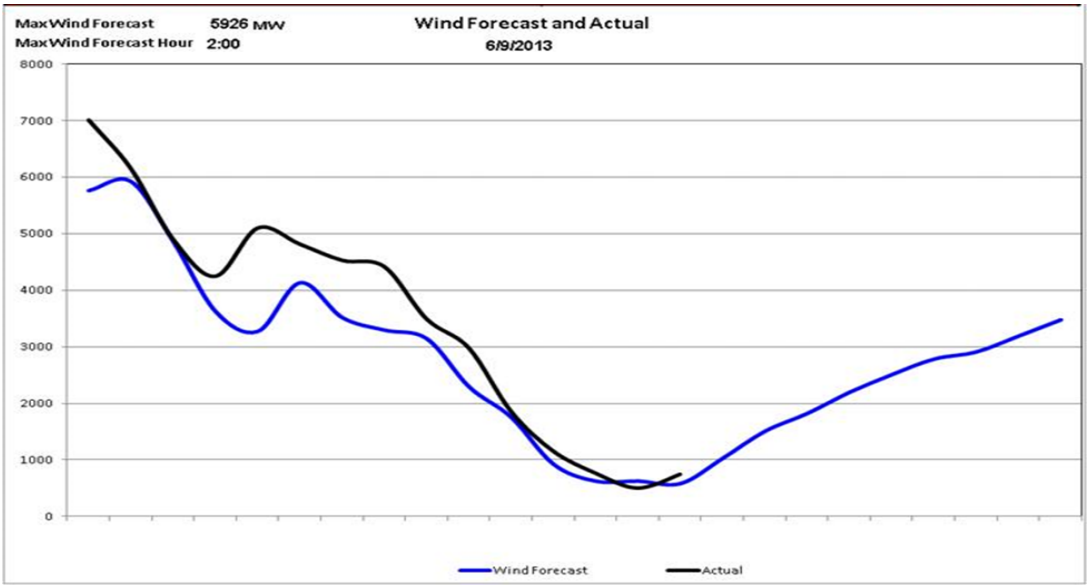
Figure 6 demonstrates a different problem that can occur with too much renewable generation as Rule 111(d) seeks to mandate through application of Block 3. Between 3:00 a.m. and 6:00 a.m. electricity consumption can drop below 25,000 MW. ERCOT previously has experienced days in which wind has provided as much as 38.4%[112] of the generation on the system**.** Rule 111(d) fails to acknowledge this reality through its use of Block 2's methodology, which creates both practical difficulties and perverse results. Wind turbines in Texas typically have a much higher capacity factor during spring and fall months. During the spring and fall a 20% renewable energy goal as proposed by the EPA under Block 3 could put more renewable generation on the grid than there is existing load. Consequently, during the early morning hours ERCOT would have to both curtail a substantial amount of the wind and back down or even shutdown much of the nuclear fleet and all other thermal generation, which would simultaneously reduce the effectiveness of both Block 2 and Block 3. As has been previously shown, coal plants

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

cannot effectively operate in a manner that would have them ramp up and down to meet load.

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

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



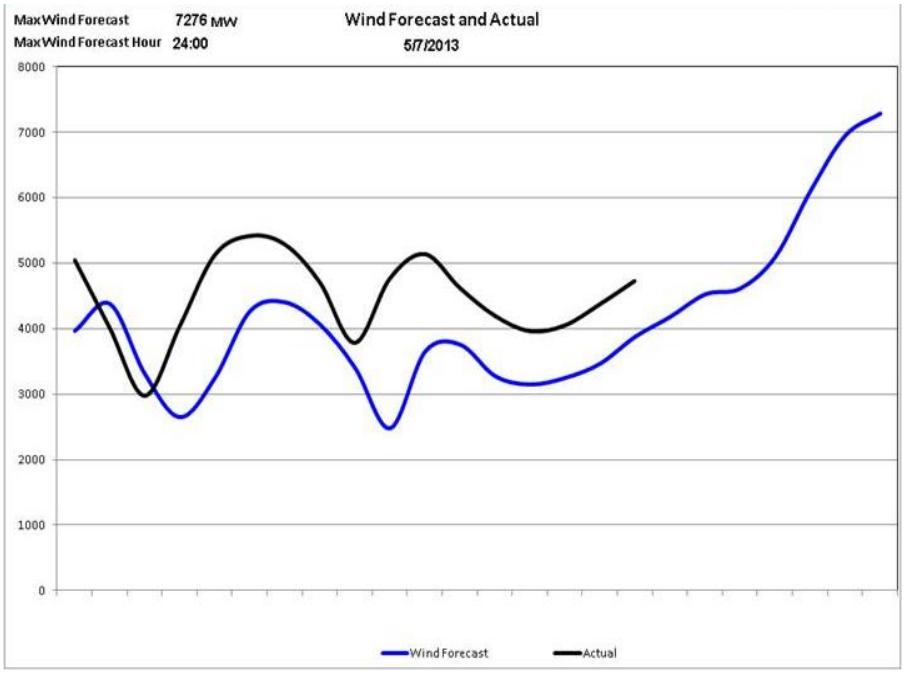
On the day referenced in Figure 7, wind generation dropped 93% (a total loss of 6,500 MW) over 13.5 hours. An over reliance on wind coupled with a possible 93% reduction of wind generation on any given day mandates an increased reliance on flexible gas generating units and less on base load units to ensure system reliability and sufficient availability of power.[113] This introduces enormous costly redundancies into ERCOT's system and likely means that nuclear generating units will be backed down when it is windy, only to be replaced with combined cycle or simple cycle gas turbine units. Because significant variability of wind and other renewable generation can occur rapidly,

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

within minutes, ERCOT's nuclear fleet cannot respond efficiently because the units are not designed for load following operations.

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

Figure 8: Variability of Wind Can Be Frequent and Extreme



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

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

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

D. 2012 Baseline Year Not Representative Of Natural Gas Prices

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

> [o]ut of all the years one could choose, 2012 is probably the least representative of likely future conditions in terms of commodity price relationships [….] the spread between coal and gas prices was less than $0.40/MMBtu during the year. […] Virtually all industry forecast expect gas prices to rise faster than coal prices relative to 2012. This fact is important because it makes the cost of generating from gas plants even more expensive than coal plants.[114]

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

> [h]istory has demonstrated the price of natural gas to be highly volatile, and multi-year forecasts have consistently been inaccurate. Establishing a mitigation goal based on an assumption of persistent low natural gas

[114] David Bellman, "EPA's Clean Power Plan: An Unequal Burden", *Fortnightly Magazine* (Oct. 2014).

prices is not a reliable or dependable approach to estimating capacity factors for NGCC plants over a long period."[115]

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

X. BLOCK 3: NUCLEAR AND RENEWABLE ENERGY

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

1. Flawed Assumptions Regarding Nuclear Energy

EPA's assumption that 5.8% of each state's nuclear fleet is "at risk" for retirement is flawed. For Texas, EPA assumed that 290 MW of nuclear capacity is "at risk" for retirement even though this does not equate to a full nuclear unit. EPA should have considered the actual size of nuclear units that were actually at risk for retirement rather than applying an arbitrary percentage to all states. EPA does not specify any type of monitoring or verification for at risk nuclear generation. Nor is it clear how or whether actual net nuclear generation would be taken into account for complying with Rule 111(d).[116] While this assumption does not appear to have a meaningful impact on Texas's emissions rate, it further illustrates the arbitrary and unreasonable manner that EPA has used in promulgating Rule 111(d).

In addition, as EPRI notes, there is "significant uncertainty as to whether the Nuclear Regulatory Commission (NRC) will extend the operating licenses for each nuclear unit as assumed. License renewal is a long and multifaceted process which is

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[115] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of the Electric Power Research Institute at 4 (Oct. 20, 2014).

[116] *See* PUCT Project No. 42636--C*ommission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of SWEPCO at 9-10 (Sept. 5, 2014).

based on submittals of complex studies to the NRC and its detailed review."[117] As with other components of the proposed building blocks, Rule 111(d) gives no consideration to the regulatory burden that is placed on the states for their nuclear fleets. EPA must consider the difficulties states face in renewing nuclear licenses.

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

Rule 111(d) establishes a drastic renewable energy goal for Texas: 20 percent of capacity. EPA makes several critical mistakes in its assumption for setting Texas's renewable energy goal. First, EPA derived this capricious and unrealistic goal by arbitrarily lumping Texas with five other states, of which only Kansas has a planned RPS. EPA states that this methodology represents "a level of renewable resource development for individual states – with recognition of regional differences – that we view as reasonable and consistent with policies that a majority of states have already adopted based on their own policy objectives and assessments of feasibility and cost."[118] On the contrary, this methodology ignores all differences between states. In this calculation, EPA ignores Texas's own statutorily mandated RPS standard of 5,880 MW of renewables capacity.[119] Instead, the proposed rule averages all existing RPS targets in a "region" and assigns the "average" to each state. There is no basis to use Kansas's RPS as the basis for a 20% energy RPS for Texas. Kansas's RPS is tailored to Kansas – a capacity-based RPS which includes biofuels and hydropower – and is inappropriate for the intermittent zero carbon dioxide emitting renewable resources of Texas. Conversion of Kansas' 20% capacity RPS to a 20% energy RPS for all states in EPA's South Central grouping is the very definition of arbitrary. The Kansas Corporation Commission recognized this in its own comments to EPA:

> EPA states that it uses only energy-based RPS standards in assigning targets. Because Kansas has a capacity-based RPS, Kansas was assigned the South Central Region's average target of 20% of generation as a

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[117] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of the Electric Power Research Institute at 5 (Oct. 20, 2014).

[118] 79 Fed. Reg. 34,866 (June 18, 2014).

[119] TEX. UTIL. CODE ANN. § 39.904(a) (West 2007 & Supp. 2014).

> default. Besides Kansas, Texas has the only other RPS target in the South Central Region. Like Kansas, Texas's RPS target is capacity-based. Because no other states in the region have RPS standards, EPA had no energy-based RPS targets in the region that could establish an energy-based target for the region. Thus, EPA used an arbitrary energy-based RPS target of 20% for Kansas and the rest of the South Central Region.[120]

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

Moreover, application of one state's renewable standard to other states is arbitrary because it does not account for the relative size of the states. Kansas's electricity sector is $1/10^{th}$ the size of Texas's electricity market, accounting for only 6 percent of the South Central state region's retail power sales, and has the third-best wind resources in the country.[121] A 20% renewable standard for Kansas implies approximately 2,800 MW of wind generation capacity (at a 35% annual capacity factor). The same standard for Texas implies over 25,000 megawatts of wind generation capacity. Such results clearly demonstrate that the Block 3 component of the emissions calculation is both disparate and arbitrary. EPRI also notes in its report: "This [regional] assumption is problematic when regions are large and encompass states with appreciably different renewable energy resources."[122]

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

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[120] Docket ID No. EPA-HQ-OAR-2013-0602--Comments of Kansas Corporation Commission at 15 (Oct. 29, 2014).

[121] Docket ID No. EPA-HQ-OAR-2013-0602--*Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 12. North American Electric Reliability Corporation (Nov. 2014).

[122] Docket ID No. EPA-HQ-OAR-2013-0602—Comments of the Electric Power Research Institute at 5 (Oct. 20, 2014).

the NODA at this time. However, based on its limited review of the NODA, the PUCT does not believe it resolves the many fundamental problems with Block 3 outlined in these comments.

In the October 30 NODA, EPA also seeks comment on ways to change the state goal calculation to make the adjustments for Blocks 3 and 4 similar to Block 2.[123] For reasons discussed in the comments of TCEQ,[124] the PUCT opposes this adjustment. The prioritized adjustment would have the effect of zeroing out all coal-fired as well as oil and natural gas steam generation for state goal calculation purposes. TCEQ estimates this adjustment would drastically alter Texas's final goal to approximately 540-550 lbs/MWh.[125] This outcome would have an even more detrimental effect on reliability than the 791 lbs/MWh emissions goal proposed in the original rule. For this and the other reasons outlined by TCEQ, the PUCT strongly urges EPA to reject this modification to the state goal calculation.

B. EPA Overestimates The Generating Capacity Of Texas Wind From A Reliability Standpoint[126]

In determining the BSER for Block 3, EPA uses a capacity factor for Texas wind of between 39% and 41%.[127] For reliability purposes, ERCOT previously assigned wind an 8.7% wind capacity factor which was the estimated availability of wind during summer peak. ERCOT recently approved a new methodology for calculating wind capacity factor. Under its new methodology, ERCOT will use historical performance of wind generation facilities in different parts of the state to predict the percentage of installed capacity ERCOT can expect during summer and winter peak conditions. The

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[123] 79 Fed. Reg. 64,552 (Oct. 30, 2014).

[124] Docket ID No. EPA-HQ-OAR-2013-0602—Comments of TCEQ at 20-21 (Dec. 1, 2014).

[125] *Id*. at 20.

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

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

installed capacity factors for non-coastal wind generation facilities (which constitute the majority of installed wind capacity in Texas) resulting from this new methodology are expected to be substantially below the capacity factor the EPA assigns to Texas wind energy.

C. Texas Receives No Credit For Previous Renewable Investments Made

Rule 111(d) as proposed also ignores the significant renewable energy development that has occurred in Texas during the preceding decade. Even with the extreme variations in wind generation that can occur over the course of the year, in 2013 Texas wind generation produced 35.917 million MWh (16.24% of the nation's non-hydro renewable generation). However, the 2012 base year selected by the EPA for the proposed Rule 111(d) does not give Texas credit for the societal and financial commitments to facilitate renewable energy. Instead Rule 111(d) punishes early movers like Texas by setting tremendous and unrealistic renewable goals. Furthermore, the early movement of renewable investment in Texas has resulted in greater knowledge and improved technology – from which other states, with reduced renewable goals, will now be able to benefit. Texas has taken on the risk of exploring renewable technology, yet will receive none of the benefit, and in fact will be penalized for having moved so early into renewables by Rule 111(d)'s aggressive goal. This penalty occurs because EPA has applied its annual growth factor of renewable energy to the base that existed in 2012. Thus states like Texas that have already expanded cost effective renewable energy are expected to add substantially more than states – even in the same regional grouping – that have little or no renewable energy today.

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

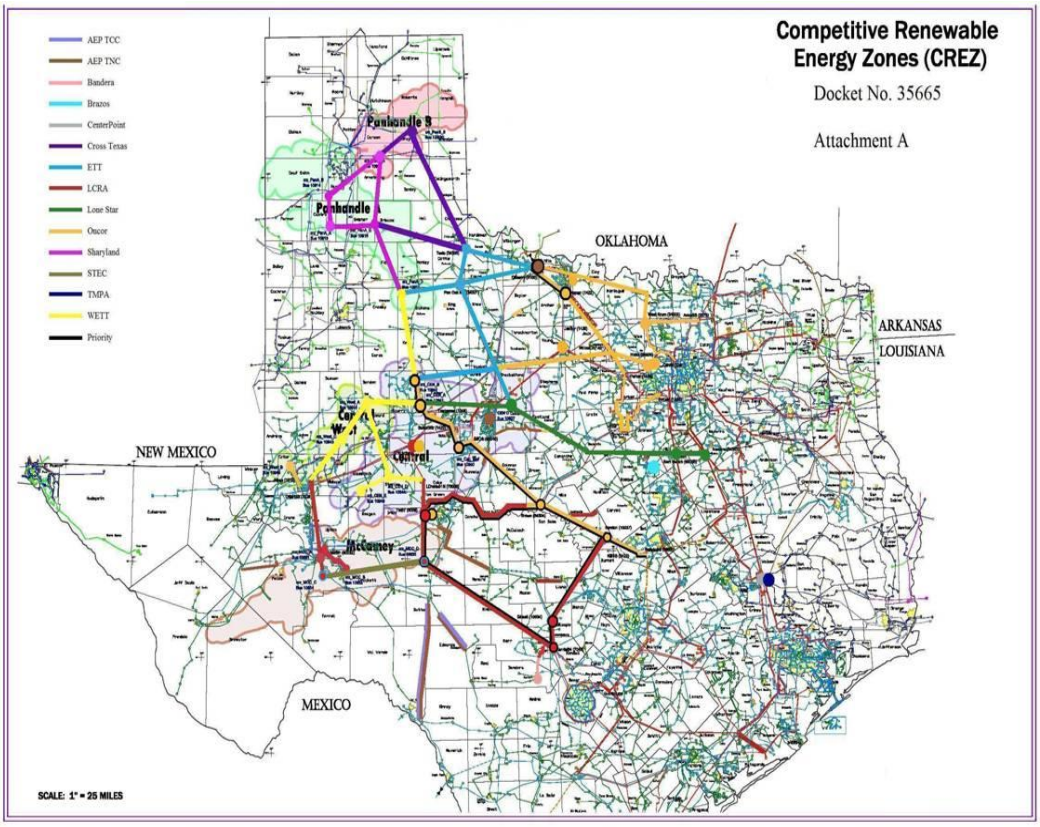
Table 1: CREZ Transmission Line Investment in Texas

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

The investment in CREZ infrastructure has contributed to a more than threefold increased contribution from wind generation to total ERCOT generation from 2007 to 2013 from 3% to 9.9%,[128] yet, as noted previously, Texas receives no credit for the growth between 2005 and 2012 because of the 2012 base year used by the EPA. Figure 9 illustrates the significance of the CREZ project in relation to ERCOT's overall transmission system.

[128] Potomac Economics, LTD., *2013 State of the Market Report for the ERCOT Wholesale Electricity Markets*, at 63 (September 2014). Potomac Economics LTD. is the independent market monitor for the ERCOT market.

Figure 9: The ERCOT Transmission System



D. The Texas CREZ Experience

As EPA well knows, Texas is by far the country's leading producer of renewable capacity. As of May 2014, ERCOT had 11,182 of installed wind and solar capacity.[129] An additional 4,700 MW of renewable generation (central station wind and solar) is currently under construction. The PUCT and ERCOT therefore have more experience in planning for and integrating renewable energy onto the grid than any other state in the country and most countries in the world. The PUCT and ERCOT have learned from extensive engagement that integrating large amounts of renewable energy into ERCOT introduces a number of unique and challenging technical and operational issues. Some of these technical challenges have only recently surfaced, years after the construction and

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

energizing of renewable energy generation and the associated electric transmission lines. As further explained below, ERCOT expects to encounter additional technical and operational issues as the amount of renewable energy built in Texas increases. Finally, Rule 111(d) does not adequately address other issues associated with integrating large amounts of renewable capacity, including the impact on market prices, the need for additional ancillary services, and how any renewable energy credit program might work.

1. Integrating Renewable Resources is a Slow, Costly Process

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

Table 2: CREZ Key Statistics

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

In 2005, the Texas Legislature directed the PUCT to designate areas of the state as CREZs with the enactment of SB 20; nine years would pass until the completion of the

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

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

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

ERCOT studies have indicated several technical challenges with integrating a large amount of renewable resources in West Texas. These challenges are primarily due to two factors: 1) renewable resources in West Texas are located far from load centers requiring their power be transmitted over long distances; and 2) most renewable resources use power electronic based devices and not synchronous machines. Together, these factors induce power system challenges not previously observed on a large scale.

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

Another challenge of transferring power over long distances is handling the reactive losses in long transmission lines. Often these reactive losses become more limiting than the inherent thermal capability of a transmission conductor for long transmission lines. The solutions to this challenge include installing dynamic reactive compensation devices, building transmission lines at higher voltages (i.e. 500 kV or 765 kV), constructing more transmission lines, or installing series compensation on

transmission lines. Each of these solutions has drawbacks. Dynamic reactive devices are expensive and provide only limited benefit for long transmission lines. Construction of higher voltage transmission lines is often opposed by the public because of right-of-way issues and the aesthetic impact of these lines.

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

E. Integration Impacts of Increased Renewable Energy Generation Required By Rule 111(d)[130]

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

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

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

> **Baseline** – This scenario estimates a baseline of the ERCOT system under current market trends against which anticipated Clean Power Plan changes will be compared.
>
> **CO_2 Limit** – This scenario applied the limits in the Clean Power Plan to the ERCOT system to determine the most cost-effective way to comply with the limits. This scenario did not place a price on CO_2 emissions.
>
> **\$20/ton CO_2** – This scenario applied a \$20/ton price on carbon dioxide emissions to the ERCOT system. With a \$20/ton CO_2 price, the ERCOT system attains an emission intensity of 904 lb CO_2/MWh in 2020 and 877 lb CO_2/MWh in 2029 – above both the interim and final goals.
>
> **\$25/ton CO_2** – This scenario applied a \$25/ton price on carbon dioxide emissions to the ERCOT system. With a \$25/ton CO_2 price, the ERCOT system attains an emission intensity of 840 lb CO_2/MWh in 2020 and 792 lb CO_2/MWh in 2029 – below the interim goal and approximately meeting the final goal.[131]

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

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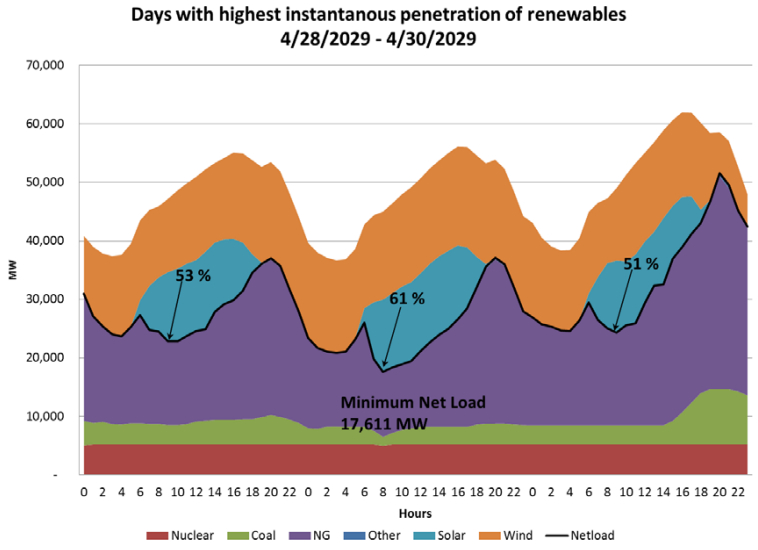
[131] *Id.* at 3. ERCOT did not attempt to calculate a carbon price to precisely meet the emissions limits. Instead, ERCOT found a carbon price range within which the system is anticipated to achieve the Rule 111(d) emissions standards.

Figure 10: Days with the Highest Instantaneous Penetration of Renewables[132]



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

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

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

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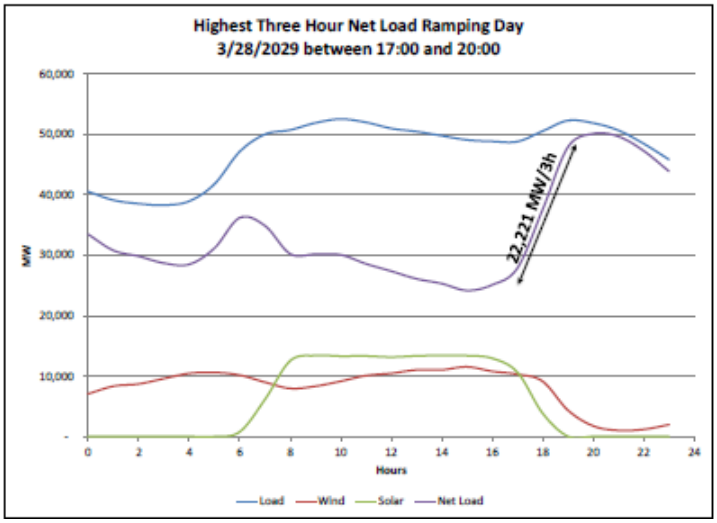
Table 3: Maximum Ramp-up and Ramp-Down[133]

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

Figure 11: Highest Three Hour Net Load Ramping Day[134]



The simulation model assumes perfect foresight and ensures that there is sufficient amount of thermal generation with sufficient ramping capability committed to follow such rapid net load ramps. In real time operation, however, accommodating the maximum ramps resulting from simultaneous solar and wind generation decline would be more challenging. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. It is important that market mechanisms are adopted so that the need for flexible generation (with short start-up times and high ramping capability) is reflected in real-time energy prices. Market mechanisms to include dispatchable load resources could also help to address flexibility needs. Enhancing wind

[133] *Id*.

[134] *Id*. at 13.

and solar forecasting systems to provide more accurate wind and solar generation projections will become increasingly important. Regulation and non-spinning reserves will need to be increased to address increased intra-hour variability and uncertainty of power production from wind and solar. Tools available to system operators must be enhanced to include short-term (10-min, 30-min, 60-min, 180-min) net-load ramp forecasts and simultaneous assessment of real-time ramping capability of the committed thermal generation to assist operators in maintaining grid reliability.[135]

Though all solar capacity additions predicted by the model were utility-scale, it is likely that a significant portion of future solar generation capacity will be embedded in the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels). ERCOT does not currently have visibility of these resources. To produce accurate solar production forecasts, ERCOT would need to have information regarding the size and location of distributed solar installations. Additionally, to ensure grid reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems.[136]

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

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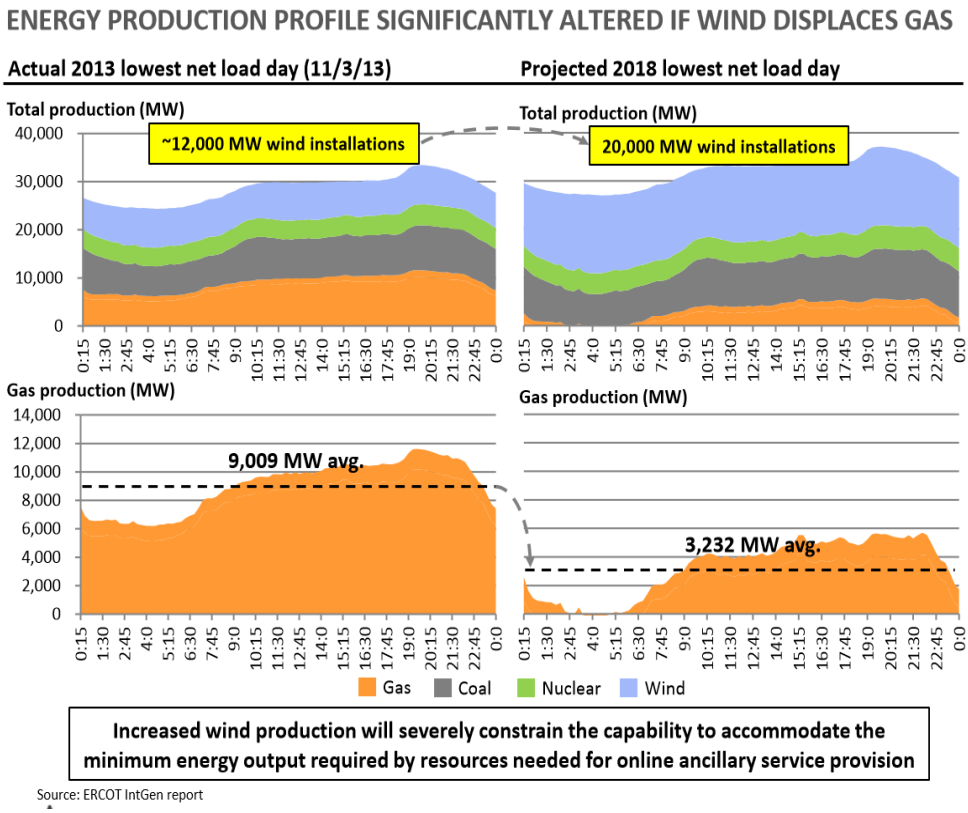
[135] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013 (available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf).

[136] *Id*.

F. Market Price Issues

Wind and solar generators tend to bid into the market at a price of zero or even negative, which reflects the value of federal production tax credits. This has a tendency to lower market prices for all generators. The bidding behavior of renewable generators also tends to reduce the run time of other generators, primarily natural gas generation, but it also tends to replace coal plants in off-peak hours. Adding the level of renewable energy required by Rule 111(d) will further distort ERCOT's energy market prices. Figure 12 below illustrates how the energy production profile is altered when wind generation displaces natural gas production.

Figure 12: Energy Production Profile if Wind Displaces Natural Gas[137]



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

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

The need for ancillary services will increase with the introduction of additional renewables on the grid. In its *Summer 2014 Energy Market and Reliability Assessment*, FERC stated, "[r]apid changes in wind and solar generation, particularly in the morning and evening, are expected to increase the need for flexible capacity for balancing and regulation."[138] Generally, ancillary services are supplemental services to the ERCOT energy market that are needed to maintain system reliability. Because the five-minute dispatch in ERCOT does not insure that appropriate resources are available to balance system generation and system load, ERCOT procures ancillary services to ensure that sufficient resources with necessary characteristics are available to balance any additional variability and to maintain system frequency through a variety of potential conditions, including unit trips, large up or down ramps, and ensuring enough capacity is available. With Texas's swath of renewables introducing variability into the grid, ancillary services are crucial to maintaining grid reliability. Rule 111(d) would introduce a level of renewables into the system that could jeopardize the security of ancillary services. NERC recognized this in its reliability assessment report on Rule 111(d):

> [t]he anticipated changes in the resources mix and new dispatching protocols will require comprehensive reliability assessment to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.[139]

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[138] FERC *Summer 2014 Energy Market and Reliability Assessment* (May 15, 2014) (available at: http://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2014/05-15-14.pdf).

[139] Docket ID No. EPA-HQ-OAR-2013-0602--*Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* at 2. North American Electric Reliability Corporation (Nov. 2014).

H. Renewable Energy Credits

Under current Texas law, renewable generators are issued a "renewable energy credit" (REC) for each MWh of energy produced. Retail electric providers (the entities who contract to buy and sell power for end users in ERCOT) must purchase RECs and turn them in to comply with their share of the renewable energy mandate. RECs are an additional subsidy to renewable generators. However, current REC prices in ERCOT are very low (less than $1 per REC/MWh) and therefore provide insignificant subsidies at this point.

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

XI. BLOCK 4: DEMAND SIDE ENERGY EFFICIENCY

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

Under existing Texas law, EPA's proposed incremental and cumulative savings targets for energy efficiency are not achievable.[140] Extensive amendments to both the statute and the PUCT's rule would be required to revise the electric utilities' energy efficiency savings goal, allow direct marketing by the utilities, and either require adoption of the EM&V framework yet to be established by the EPA or revisions to the EM&V framework enacted by the Texas Legislature in 2011. Additional amendments to the PUCT's rule would be required to adjust the cost caps for residential and commercial customers, as well as to adjust the administrative cost cap to promote increased outreach and marketing by the utilities.

Due to the time required for the Texas Legislature to pass legislation to amend current statute and for the PUCT to adopt conforming rules and approve programs, as well as the extraordinarily high cost required to implement this block, which would undoubtedly result in significant rate shock to electric consumers, the demands of Rule 111(d)'s Block 4 are simply not realistic.

B. Block 4 Would Require New and Aggressive Goals

Block 4 accelerates the state's energy efficiency improvements from 2017, based on a state's 2012 performance, incrementally up to a maximum rate of 1.5% of retail sales (Option 1) per year by 2029 or alternatively, a demand-side energy efficiency requirement that uses 1.0% savings target scenario (Option 2). The incremental energy efficiency savings as a percentage of retail sales in 2012 in Texas was 0.19% and cumulative savings as a percentage of retail sales was 1.54%. Under option 1, with a start year of 2017, Rule 111(d) requires an increase in incremental savings of 0.2% per year, with Texas reaching cumulative energy efficiency savings as a percentage of retail sales of 1.78% by 2020 and 9.91% by 2029. However, in order for these energy

[140] TEX. UTIL. CODE. ANN. §39.905 (West 2007 & Supp. 2014) and 16 Tex. Admin. Code §25.181.

efficiency measures to count toward a state's goal, Rule 111(d) also requires enforceable EM&V, although the specifics of that requirement, to date, have not been finalized.[141]

To reach the cumulative energy efficiency savings proposed in Option 1, the Joint Utilities[142] predict they will have to ramp up energy savings to approximately 6,700,000 MWh per year. Energy efficiency savings would most likely not be able to significantly ramp up until 2020. This could create a situation where the annual savings rate would have to increase at a far more aggressive rate than the already aggressive annual rate included in the proposed rule.

The scope of the utilities' energy efficiency goals will likely need to change as well. Texas's statute provides for an energy efficiency goal based on demand savings.[143] In order to decrease CO_2 emissions by increasing energy savings at the rate suggested in Rule 111(d), both the statute and the rule may need to be amended to include demand savings outside of summer or winter peak demand.[144] Furthermore, if the purpose of the utilities' energy efficiency programs is changed to include reduction in power plant emissions, consideration also needs to be given to how the addition of a specific kWh goal would contribute to meeting savings at the rate required by Rule 111(d). The utilities' current energy savings goal that requires utilities to meet an energy goal calculated from its demand savings goal using a 20% conservation load factor will not be sufficient to meet EPA's target for energy efficiency improvements. Furthermore, even if the PUCT increased the conservation load factor to 100% of the current demand savings goal, it would still not be sufficient to meet the target set by Rule 111(d).

C. The Price Tag of the Energy Efficiency Measures Required by the Proposed Rule is Astronomical

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[141] Docket ID No. EPA-HQ-OAR-2013-0602-- *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*, Chapter 5: Demand Side Energy Efficiency, 5-1 to 5-77.

[142] The "Joint Utilities" are utilities subject to the provisions of TEX. UTIL. CODE. ANN. §39.905 and 16 Tex. Admin. Code §25.181.

[143] TEX. UTIL. CODE. ANN. §39.905(a)(3) (West 2007 & Supp. 2014).

[144] TEX. UTIL. CODE. ANN §39.905(a)(3) and 16 Tex. Admin. Code §25.181.

The electric utilities in Texas spent approximately $137,776,000 on energy efficiency programs statewide in 2013. Meeting the EPA projected targets for energy efficiency will require a significant increase in statewide spending. While there may be attendant benefits to customers associated with this increased spending, these benefits would be outweighed by the dramatic increase in costs that customers will be required to pay as a result of Rule 111(d). In order to reach the EPA's energy efficiency savings growth rate of 1.5% of sales per year and the 9.91% cumulative savings target, the Joint Utilities' initial projections suggest that spending will necessarily increase to approximately $3.0 billion per year.[145] This amounts to approximately ***22 times*** the amount spent on energy efficiency in 2013. Based on historical data, the Joint Utilities assumed a current cost of energy efficiency savings of $250/MWh, close to the estimate for Texas of $260/MWh provided by ACEEE.[146,147] To achieve the magnitude of energy efficiency requirements proposed by Rule 111(d), costs will have to rise as more expensive energy efficiency programs are required to meet Rule 111(d)'s goal for Texas. As shown in Figure 13 below, the Joint Utilities' base case projection assumes that program costs required to achieve higher levels of energy savings increase gradually from $250/MWh to $450/MWh in 2029 which is consistent with costs incurred in Vermont, Massachusetts, California, and Rhode Island--all states with aggressive energy efficiency efforts that had significantly higher cumulative energy savings as a percentage of retail sales in 2012 than did Texas. The utilities' alternate estimate uses the EPA's assumed first year program cost of saved energy of $275/MWh and increases it to $385/MWh in 2029. The energy efficiency component is only one block of four prescribed for Texas in the proposed rule, and it alone would have a $3 billion impact to Texas's electric customers.

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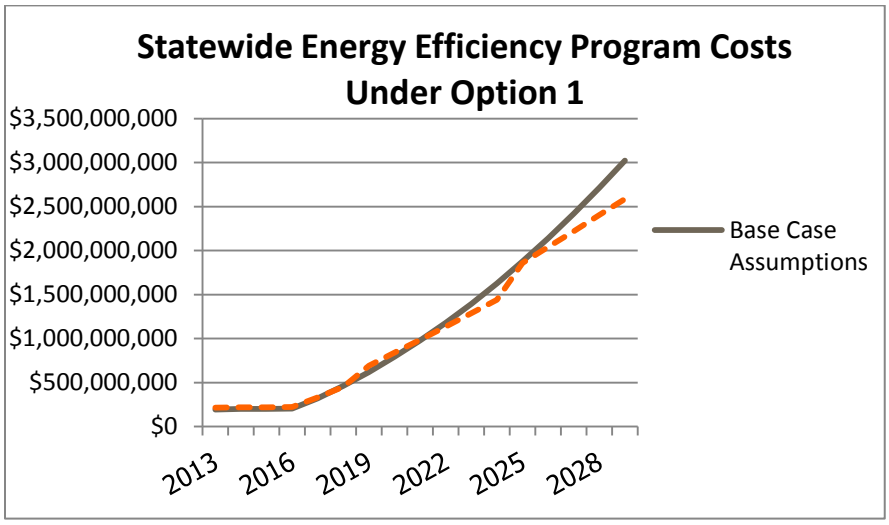
[145] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of the Joint Utilities at 8 (Sept. 5, 2014).

[146] *Id*. at 2.

[147] Molina, Maggie. "*The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.*" American Council for an Energy Efficient Economy, 18-19 (March 2014).

Figure 13: Statewide Energy Efficiency Program Costs[148]



Customer economic challenges present another barrier to increasing energy efficiency savings at the rate proposed by Rule 111(d). SWEPCO anticipated that utilities will need to place increased reliance on energy efficiency improvements that require customers to make significant capital investments in order to achieve incremental energy efficiency improvements going forward. SWEPCO stated that because their territory is perpetually disadvantaged, they expect continued difficulty motivating customers to pay for more expensive energy efficiency improvements such as HVAC upgrades and weatherization measures.[149]

Based on the Joint Utilities' cost estimates, a residential customer will see average charges for energy efficiency rise to nearly $9.00 per month, possibly higher for some customers, far more than the average monthly cost of approximately $0.80 seen in 2013. Several of the Texas utilities have little ability to raise energy efficiency savings by the magnitude required to reach the target proposed by the EPA. Sharyland Utilities, Texas New Mexico Power, and American Electric Power Texas North provide service to rural, noncontiguous areas and sparsely populated areas of Texas. Historically, these utilities have encountered difficulty attracting energy efficiency service providers who prefer

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

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

instead to work with utilities that serve contiguous, densely populated areas. These utilities face similar conditions as many of the municipally-owned utilities (MOUs) and electric cooperatives; these conditions have proved to be obstacles for these utilities in providing energy efficiency measures throughout their service territory. In addition, lack of marketing and outreach, typically performed by energy efficiency service providers, has resulted in lower customer interest in these service territories. To combat this issue, legislation in 2011 provided that, upon meeting certain demonstration requirements, an electric utility operating in an area open to competition could provide rebates or incentive funds directly to customers in rural areas to facilitate the adoption of energy efficiency measures. However, such self-delivered programs are still in their infancy and expanding the programs or initiating new programs at the rate anticipated by the EPA target is not feasible. Another utility, El Paso Electric Company, will also likely face difficulties expanding their programs at the rate necessary to achieve the EPA target. Residential customers in El Paso's territory rely very little on refrigerated air conditioning and consume far less energy than the state average, which has contributed to low participation in that sector. For these reasons, much of the burden of achieving the EPA's target cumulative savings may fall to the larger utilities serving densely populated areas that have more potential for growth in their energy efficiency portfolios. Residential customers in these areas may be faced with a monthly bill that is higher even than the average monthly bill estimated by the Joint Utilities. In order to implement Rule 111(d), not only will the Texas Legislature need to increase the utilities' energy efficiency savings goal, but PUCT will need to amend its rule to increase the cost caps for residential (set at $.0012/kWh in 2013) and commercial customers, beyond the CPI adjustment already allowed in the rule.

In addition, should the burden of reaching the savings requirement fall more to the utilities with densely populated, contiguous service areas that have more ability to expand their energy efficiency portfolios, legislation will be required that will set differing goals for the utilities. Unlike current Texas law which treats utilities consistently regarding program requirements, Rule 111(d) would introduce an important fairness issue that customers in more densely populated areas should have to pay more

for energy efficiency programs than customers living outside of these areas, all because of the aggressive requirements of Block 4.

D. Rule 111(d)'s Timing Makes Interim Goal Compliance For Block 4 Impossible

The timing mandated by Rule 111(d) is simply incompatible with Texas's legislative schedule. Like the other blocks, implementing Block 4 would require statutory changes. Even at an aggressive pace, the PUCT could likely not adopt a rule until early 2018. This would mean that any programs tailored to meet Rule 111(d)'s energy efficiency goals would not become effective until the 2019 energy efficiency program year, as the PUCT attempts to avoid adopting rule amendments mid-program year to avert complications in cost-recovery and program planning. However, it is more likely that the rule will not be adopted in time for the utilities to make the necessary program changes until the 2020 program year, the time at which Rule 111(d) contemplates Texas meeting its interim goal.

In order to meet the Block 4 target, the utilities will have to offer new programs and redesign and expand existing programs. Time is required to ramp up new programs and make program redesigns. In addition, prior to offering and making the investment necessary to launch a new program, utilities typically run a pilot program to gauge customer interest, market penetration rate, and the ability to make the program cost-effective long-term. Pilot programs, which typically run for more than one year, are not required to pass the cost-effectiveness test their first year of implementation in order to recognize program start-up costs, but are expected to pass in subsequent years. Pilot programs serve an important function in the utilities' energy efficiency portfolios by exploring the feasibility of programs designed to increase market penetration of new technologies, reach underserved customer segments, and/or explore new distribution channels. Given all of these factors, it is simply infeasible to conduct traditional deployment of the energy efficiency programs that would be required by the proposed rule under the extremely short timeline required by Rule 111(d).

E. Errors In Block 4 Goal Calculation

EPA inaccurately calculates the transmission and distribution line loss by dividing the total supply of electricity less direct use energy by retail sales using information from the EIA's United States Electricity Profile 2010. This results in EPA's proposed line loss of 7.51%. Calculating line loss by dividing estimated losses by total supply of electricity using information from the EIA's United States Electricity Profile 2012 table on the supply and disposition of electricity, provides a more accurate and timely reflection of the line loss. This calculation results in a United States line loss of 4.955%.

Additionally, EPA has failed to adjust total retail sales to remove zero CO_2-emitting generation. Zero CO_2-emitting generation would presumably grow annually as each state approaches the renewable energy percentage deemed achievable by the EPA. Adjusting for the growth in zero CO_2-emitting generation results in the Block 4 goal determination being different in each year, as the number being added to the denominator of EPA's equation would decrease each year to account for the corresponding increase in renewable energy being developed in accordance with Block 3.

XII. THE RULE PROVIDES AN UNWORKABLE COMPLIANCE TIMELINE

A. Rule 111(d) Would Require Implementing Extensive Coordination Among Multiple Texas State Agencies and FERC

Rule 111(d) as proposed clearly intermingles matters within the jurisdiction and expertise of the TCEQ, PUCT and the RRC. While TCEQ, as the Administrator of Texas's air quality program under the CAA, would be responsible for submitting any State Plan and monitor compliance with same, it would clearly need the assistance of the PUCT and possibly the RRC.[150] EPA has failed to address the extensive level of coordination among state agencies that would be necessary to implement this rule. For example, TCEQ would need assistance from the PUCT in implementing the energy efficiency requirements of the rule and with measurement and verification of the energy efficiency requirements. The coordination among Texas state agencies that will be

[150] For example, as the regulator of intrastate natural gas pipelines in Texas, the RRC would be responsible for permitting additional natural gas pipelines that may be necessary to comply with the increased use in natural gas in Texas and throughout the nation that is contemplated in Rule 111(d).

required by Rule 111(d) would also require changes to Texas law. Setting aside the fact that EPA has no authority to require changes to Texas law, such laws could not be amended until 2017 at the earliest. The additional state laws required to implement Rule 111(d) in Texas would in turn almost certainly require the adoption of new or amended rules by each affected state agency, including TCEQ, PUCT, and possibly the RRC and would almost certainly require interagency contracts or agreements between these agencies. EPA's compliance deadlines, particularly its interim compliance deadlines, do not account for the time needed for state agency coordination (and the associated costs) required by Rule 111(d).

Rule 111(d) will also require extensive coordination with FERC to ensure that all entities (both inside and outside of ERCOT) comply with existing FERC reliability standards.[151] This is a potentially significant aspect of compliance that EPA has not addressed in the proposed rule. Because Rule 111(d) will almost certainly impact grid reliability in Texas and throughout the nation, the compliance obligations of Rule 111(d) may conflict with the compliance obligations of entities subject to FERC reliability standards. EPA has also failed to address the cost and time implications for states and utilities in coordinating with FERC to implement Rule 111(d). In short, EPA cannot maintain its cavalier attitude to the realities of this infrastructure challenge without grave threats to the reliability of Texas's multiple power grids.

B. Rule 111(d) Provides Insufficient Time For Coordination With Partners In Multi-State Power Grids

Texas's singularly unique composition of fully-competitive service territories, with wholesale and retail markets within ERCOT that are overseen by the PUCT, and the non-ERCOT traditional integrated utilities subject to the traditional retail cost of service ratemaking jurisdiction of the PUCT, adds an additional layer of complexity and difficulty for Texas in determining how to comply with the already dizzyingly complex Rule 111(d). Particularly with respect to Texas utilities not in ERCOT, consideration of

[151] FERC regulates the interstate transmission and movement of electricity, natural gas, and oil. NERC regulates the reliability of the bulk power system in North America and assesses seasonal and long-term reliability of the U.S. power system.

a compliance plan will necessarily involve the PUCT consulting with all states in the MISO, SPP, and WECC, along with the respective grid operators. It is important to note that this consultation will need to occur even if Texas ultimately decides to file a Texas-only SP. That is because Texas, as well as all of the other states in the power grids, along with FERC and NERC, will need to understand every other state's plan in order to properly assess the reliability impacts. This process will likely need to be iterative, and the projected one year between the final promulgation of Rule 111(d) and the current June 2016 SP deadline is wholly inadequate for this purpose. Rule 111(d) also provides no clarity as to the permissions given the RTOs, especially with respect to renewable energy credit trading, evincing the lack of forethought contemplated in Rule 111(d). Finally, the proposed rule does not recognize the complex level of interaction required between the PUCT and TCEQ, as well as possibly other state agencies, that would be required – not only among four distinct RTOs, but also all the states within the footprints of those RTOs, which would result in Texas having to coordinate with almost half of the states in the country.

This also illustrates a fatal flaw in the interim goals required by Rule 111(d). States in regional power grids will not even know the final composition of all the state plans by 2020, when compliance with the interim goals begins. Again, because Texas's interim goal is not substantially different from its final goal, there will simply not be enough time under the current timeline for the planning and construction of new power plants, transmission, and gas pipelines necessitated by the rule. EPA vastly underestimates the complexity of the power system planning process and the time it takes for new infrastructure development. By point of reference, Texas's CREZ process took nearly 9 years from concept to completion – and Texas was in complete control of the execution of this process. Transmission and natural gas pipeline planning, which can require approvals from multiple states and federal agencies, will take even longer.

C. Rule 111(d) Provides Inadequate Time For Texas To Develop A State Plan

Texas's Public Utility Regulatory Act (PURA) §39.001(a) provides as follows:

> The legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, *electric services and their prices should be determined by customer choices and the normal forces of competition.*[152]

If Rule 111(d) were adopted, market prices in ERCOT would no longer be established by "customer choices and the normal forces of competition," but would instead be driven by the relative CO_2 emissions of power plants operating in ERCOT. Setting aside the issue of EPA's authority to require such a far-reaching change to Texas's electric markets, this system would require a comprehensive, time-consuming, and expensive overhaul of the ERCOT market.

In ERCOT today, only TDUs remain subject to traditional cost-of-service rate regulation by the PUCT. All ERCOT market participants, including the generators (known in ERCOT as power generation companies or PGCs) that would be subject to Rule 111(d), are required to "observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT."[153] However, nothing in PURA, the PUCT's rules, or ERCOT's protocols allows either the PUCT or ERCOT to require PGCs to implement the heat rate improvements for coal-fired units under Block 1 or the re-dispatch of existing natural gas combined cycle plants under Block 2 as is contemplated under proposed Rule 111(d).[154]

Rule 111(d), with its mandates on how coal and natural gas plants must be operated is essentially a federally-imposed integrated resource planning (IRP). In traditional cost-of-service regulated electric markets that practice IRP, utilities must obtain approval from state regulators to plan for and construct the lowest-cost generating plants that are necessary to serve their customers. However, as at least one commenter has noted, Rule 111(d) functionally imposes an IRP process without the "normal

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[152] TEX. UTIL. CODE ANN. §39.001(a) (West 2007 & Supp. 2014).

[153] *Id*. at §39.151(j) (West 2007 & Supp. 2014).

[154] As discussed in these comments, the assertion by EPA that states have "flexibility" in determining which of the four Blocks (or other measures designed to accomplish the same result) they use to achieve EPA's emission reduction limits, is a mirage, at least for Texas. In order to meet either EPA's interim or final emissions goals, Texas must implement all four Blocks.

constraints of cost, reliability, and resource adequacy."[155] The Texas Legislature has not delegated to the PUCT, or any other state agency, the authority to implement and enforce the CO_2-based IRP requirements that Rule 111(d) would impose on Texas. Adoption of Rule 111(d) as proposed would require the Texas Legislature to enact legislation authorizing some agency or agencies, to implement, oversee and enforce the restructuring of the ERCOT market. Such legislation would necessarily require more regulation of PGCs than exists today in the ERCOT market. Adoption of Rule 111(d) would require Texas law to be changed to authorize the PUCT and ERCOT to implement all "policies, rules, guidelines and procedures" necessary to impose Rule 111(d) on these entities. There is simply not enough time for Texas to complete all of these steps under the compliance timeline proposed in Rule 111(d).

D. Rule 111(d) Provides Impossible Compliance Deadlines For Texas Because Of Texas's Legislative Schedule

Under EPA's current adoption and implementation deadlines for Rule 111(d), Texas will not be able to make the numerous statutory changes necessary to submit a SP by June 2017. Some state legislatures, including Texas, do not meet every year. The Texas Legislature meets only in odd-numbered years beginning the second Tuesday of January and ending 140 days later.[156] Given the time table for Rule 111(d) adoption (June 2015) and the extremely aggressive time tables in the rule (i.e., SPs due June 2016), Texas will not be able to submit a SP until at least 2017.[157]

EPA has put Texas (and all other states) in a no-win, Catch-22 situation. Texas must either submit a SP, and thereby cede its authority over the regulation of electricity markets, or risk imposition of a FP by EPA, which would also very likely result in Texas

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[155] PUCT Project No. 42636--*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*--Presentation of Charles S. Griffey at slide 5 (Aug. 15, 2014).

[156] "The Legislature shall meet every two years at such time as may be provided by law and at other times when convened by the Governor." Tex. Const. art. III, § 5. The regular sessions of the Texas Legislature convene at noon on the second Tuesday in January of odd-numbered years. TEX. GOV'T CODE ANN. §301.001 (West 2013). The maximum duration of a regular session is 140 days. Tex. Const. art. III, § 24.

[157] *See* Gifford, Raymond, Sopkin, Gregory, Larson, Matthew, *State Implementation of CO_2 Rules—Institutional and Practical Issues with State and Multi-State Implementation and Enforcement* at 8-9 (Release 1.0—July 2014).

(Available at: http://www.wbklaw.com/uploads/file/Articles-%20News/White%20Paper%20-%20State%20Implementation%20of%20CO2%20Rules.pdf).

losing its authority over its electricity markets—both untenable outcomes for Texans. If Texas chooses to submit a SP, it must do so by June 2016 under the schedule proposed by EPA. Texas cannot submit a SP unless and until numerous state laws are amended by the Texas Legislature by 2017 at the earliest. Therefore, Texas will be unable to submit a SP by June 2016. In order to file for a one- year extension for filing a SP, a state must submit an initial plan by June 2016 that includes "commitments to concrete steps that will ensure that the state will submit a complete plan by June 2017..."[158] Moreover, the state's initial plan must also:

> include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO_2 emissions, an explanation of the path to completion, and a summary of the state's response to any significant public comment on the approvability of the initial plan.[159]

Texas will also be unable to do this because a state agency (presumably TCEQ and possibly PUCT) could not agree (as part of the SP extension process) to bind a future Texas Legislature to pass the laws necessary for Texas to implement Rule 111(d). While states can also request a two-year extension from compliance with Rule 111(d) if they are part of a regional plan, this option presents the same problem for Texas as the one-year extension request. Texas will not be in a position in 2016 to make commitments about whether Texas law will be changed in 2017 to permit Texas to implement a regional plan to comply with Rule 111(d). Moreover, since development of a multi-state regional plan would be even more complex and time-consuming than developing a state-only plan, it is unrealistic to expect states to develop a regional plan by 2018. Under EPA's current timeline for implementation of Rule 111(d) therefore, Texas would be precluded from timely filing a SP or from seeking a one year extension for filing a SP. This in turn, could result in the imposition of a FP for Texas by the EPA, under which Texas would also presumably lose jurisdiction over its electricity markets. Section 111 of the CAA

[158] 79 Fed. Reg. 34,838 (June 18, 2014).

[159] *Id.*

does not allow EPA to impose a standard that states must meet through a state plan if EPA does not have the authority to implement the standard through a federal plan.[160]

E. PUCT Rule Changes Required to Implement Rule 111(d)

Even beyond the difficulties in developing a SP in the timelines contemplated by Rule 111(d), EPA has also failed to understand the time it will take for state utility commissions and grid operators to implement a plan after EPA approval. The PUCT reviewed which PUCT regulations are potentially impacted by Rule 111(d). Some of the rule changes would also require changes in Texas law before they could be adopted by the PUCT. Possible PUCT rule changes resulting from Rule 111(d) include:

--16 Texas Admin. Code §25.51 (Power Quality)

--16 Texas Admin. Code §25.53 (Electric Service Emergency Operations Plans)

--16 Texas Admin. Code §25.54(Cease and Desist Orders to PGCs)

--16 Texas Admin. Code §25.93 (Wholesale Electricity Transaction Information)

--16 Texas Admin. Code §25.91 (Generating Capacity Reports)

--16 Texas Admin. Code §25.109 (Registration of Power Generation Companies and Self Generators)

--16 Texas Admin. Code §25.172 (Goal for Natural Gas)

--16 Texas Admin. Code §25.173 (Goal for Renewables

--16 Texas Admin. Code §25.174 (Competitive Renewable Energy Zones)

--16 Texas Admin. Code §25.181 (Energy Efficiency Goal)

--16 Texas Admin. Code §25.183 (Reporting and Evaluation of Energy Efficiency Programs)

--16 Texas Admin. Code §25.200 (Load shedding, Curtailments and Redispatch);

--16 Texas Admin. Code §25.211-213 (Rules related to Distributed Generation)

--16 Texas Admin. Code §25.217 (Distributed Renewable Generation)

--16 Texas Admin. Code §25.235 (Fuel Costs)

--16 Texas Admin. Code §25.236 (Recovery of Fuel Costs)

--16 Texas Admin. Code §25.237 (Fuel Factors)

--16 Texas Admin. Code §25.238 (Purchased Power Capacity Cost Recovery Factor)

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[160] *See* Docket ID No. EPA-HQ-OAR-2013-0602--Comments of TCEQ (Dec. 1, 2014); s*ee also* PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Luminant Energy Company, LLC and Luminant Generation Company, LLC (Luminant) at 7 (Sept. 5, 2014).

--16 Texas Admin. Code §25.251 (Renewable Energy Tariff)
--16 Texas Admin. Code §25.261 (Stranded Cost Recovery of Environmental Cleanup Costs)
--16 Texas Admin. Code §25.361 (ERCOT)
--16 Texas Admin. Code §25.365 (Independent Market Monitor)
--16 Texas Admin. Code §25.421 (Transition to Competition for a Certain Area Outside the ERCOT Region)
--16 Texas Admin. Code § 25.422 (Transition to Competition for Certain Areas in the Southwest Power Pool)
--16 Texas Admin. Code §25.501-508 (ERCOT wholesale market design rules)

Even if the Texas Legislature passed laws giving the PUCT the authority to adopt and/or amend existing rules necessary to carry out the mandates of Rule 111(d), the sheer number of rule amendments presents an impossible implementation issue for the PUCT, given the aggressive compliance timelines under Rule 111(d). Amending this many rules is an undertaking similar in scope to the rules adoption required in response to the implementation of retail electric competition in ERCOT. Implementing all of the rules needed for retail competition in ERCOT took almost 3 years (1999-2002). Completion of rule amendments necessary to implement Rule 111(d) would also likely take several years, making the timelines in Rule 111(d) impossible to meet.

F. ERCOT Protocol Revision And System Change Timelines

A separate but related implementation issue would be amendments to existing ERCOT market rules[161] or adoption of new market rules to implement Rule 111(d). Similar issues are likely to occur in power markets overseen by SPP and MISO. Again, because Rule 111(d) would involve fundamental changes to the way electricity markets operate, ERCOT would need to adopt or amend numerous market rules to move from the current competitive market to the command and control market mandated under Rule 111(d). Additionally, ERCOT would very likely need to adopt significant information technology system changes if Rule 111(d) as proposed were implemented.

[161] The market rules in ERCOT include protocols, market guides, policies, and procedures. Current market rules can be found on ERCOT's website at: http://www.ercot.com/mktrules .

Development and approval of a new market rule or an amendment to an existing market rule (*e.g.*, a Nodal Protocol Revision Request ("NPRR")) typically takes 5 to 12 months on a normal timeline or 2 to 4 months on an urgent timeline. Market rule changes may require changes to ERCOT and market participant systems. Implementation of any necessary system changes resulting from a rule change typically takes an additional 9 to 18 months on a normal timeline or 8 to 12 months on an urgent timeline. However, depending on the complexity of the change, the timelines for both rule development and system implementation can vary. The above-discussed timelines do not include market participant appeals of protocols changes to the PUCT, which is permitted under PUCT rules.[162] The appeal to the PUCT of a protocol adopted by ERCOT can take anywhere from 5 to 15 months, depending on the complexity of the protocol that is being challenged. The above-discussed timelines also do not include the appeal of a PUCT decision in court, which can take several years.

If compliance with Rule 111(d) requires substantial changes to ERCOT market rules, development and approval of the rule changes and implementation of the necessary system changes would likely take a minimum of 14 months and could take significantly longer. Two examples illustrate the process and timeline for making such changes. In September 2012, a stakeholder proposed changes to congestion revenue rights credit calculations and payments.[163] Stakeholders reviewed and discussed the proposal for five months, and the ERCOT Board of Directors ("Board") approved market rule changes in March 2013. To meet the target timeline for the most critical components, the implementation was divided into three phases. Implementation of the necessary system changes for the initial phase took 8 months. The remaining phases are targeted to begin in 2015.

In September 2013, the PUCT directed ERCOT to implement an operating reserve demand curve ("ORDC") for its real-time market.[164] Prior to directing ERCOT to implement an ORDC, the PUCT had discussed the merits of the proposal and

[162] 16 Tex. Admin. Code §22.251.

[163] *See* Nodal Protocol Review Request 484, Revisions to Congestion Revenue Rights Credit Calculations and Payments, Luminant Energy Company, LLC, ERCOT (Sept. 28, 2012).

[164] Nodal Protocol Revision Request 568, Real-Time Reserve Price Added Based on Operating Reserve Demand Curve, ERCOT (Sept. 19, 2013).

implementation details for at least 9 months. Stakeholders reviewed and discussed the changes required to implement the PUCT's direction for two months, and the ERCOT Board approved market rule changes in November 2013. Implementing the necessary system changes then took an additional 8 months. Furthermore, additional market rule changes proposed by stakeholders to implement the ORDC were deferred from the initial changes so that the ORDC could be implemented prior to the 2014 summer peak electricity demand period. Some of those additional market rule changes have been reviewed and discussed by stakeholders for 10 months, and the ERCOT Board is currently scheduled to consider them at its December 2014 meeting.[165] ERCOT has estimated that actually implementing the necessary system changes will take a further 4 to 7 months after the rule changes are approved by the ERCOT Board.

Again, EPA has vastly underestimated the regulatory and electricity system changes needed to comply with the mandates of Rule 111(d). These changes simply cannot be accomplished in the timelines required by the rule in a manner that will minimize costs to ratepayers and preserve the reliability of electric service in Texas. EPA should withdraw Rule 111(d) and meaningfully engage the nation's grid operators and electricity system regulators regarding these issues in advance of EPA's next attempt to implement a lawful rule.

XIII. RULE 111(D) HAS A DISPROPORTIONATE AND UNFAIR IMPACT ON TEXAS

Rule 111(d) raises substantial questions of fairness given that Texas is disproportionately affected by the rule. Certain aspects of the inequitable and disparate treatment that Texas would suffer under proposed Rule 111(d) have already been discussed. There are more. For example, evaluating EIA and U.S. Census data shows that, from 2000 to 2010, Texas, the second most populous state in the United States, has reduced its carbon dioxide emissions by 8.05%.[166] In comparison, over the same time

[165] *See* Nodal Protocol Revision Request 595, RRS Load Resource Treatment in ORDC, Tenaska Power Services Co., ERCOT (Jan. 29, 2014).

[166] U.S. Energy Information Administration, *State CO2 Emissions* (Feb. 25, 2014) (available at: http://www.eia.gov/environment/emissions/state/state_emissions.cfm).

period, California, the most populous state, has reduced its carbon dioxide emissions by only 4.36%.[167] On a per-capita basis, California reduced its carbon dioxide emissions by 15.49% over the same time period while Texas has reduced its carbon dioxide emissions by nearly 24% on a per-capita basis;[168] during this time Texas maintained grid reliability while transitioning to competitive (and very successful) wholesale and retail markets. Instead, Texas's heavy investment and remarkable transformation is penalized by a final target of 791 lbs. of CO_2/MWh, which could not even be met by a state-of-the-art combined cycle power plant with existing technology. Texas produces 11% of the electricity in the United States, but its proportion of total carbon dioxide reduction required by Rule 111(d) by 2030 is 17.87%.[169] EPA offers no reasonable explanation for the disparate, seemingly punitive, treatment of Texas under the proposed rule.

Significantly, both the interim 853 lbs. CO_2/MWh mandate and final 791 lbs. CO_2/MWh mandate applied to Texas are substantially lower than the CO_2 per MWh emission level required by the EPA to be achieved by new coal or gas power plants under Section111(b) of the CAA. EPA's proposal would require Texas to account for somewhere between 18 to 25% of the country's total CO_2 reductions. It is important to note that Texas's CO_2 emissions rate in 2012 is 1,284 pounds of CO_2/MWh, a rate lower than the final goal set by the EPA for 13 states.[170] In a fashion, EPA deems rates higher than Texas's *current* carbon dioxide emissions levels as satisfactory final goals for other states, for what appear to be entirely arbitrary reasons. EPA does not even apply a uniform *percentage* reduction of carbon dioxide emissions from each state's current level

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[167] *Id*.

[168] *Intercensal Estimates of the Resident Population for the United States, 2000 – 2010*, United States Census Bureau (available at: http://www.census.gov/popest/data/intercensal/state/state2010.html).

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

[170] Docket ID No. EPA-HQ-OAR-2013-0602—Table 8—the following states all have **final goals higher than Texas's current levels of CO_2 emissions**: Hawaii (1,306 lbs. of CO_2/MWH); Indiana (1,531 lbs. of CO_2/MWH); Iowa (1,301 lbs. of CO_2/MWH); Kansas (1,499 lbs. of CO_2/MWH); Kentucky (1,763 lbs. of CO_2/MWH); Missouri (1,544 lbs. of CO_2/MWH); Montana (1,771 lbs. of CO_2/MWH); Nebraska (1,479 lbs. of CO_2/MWH); North Dakota (1,783 lbs. of CO_2/MWH); Ohio (1,338 lbs. of CO_2/MWH); Utah (1,322 lbs. of CO_2/MWH); West Virginia (1,620 lbs. of CO_2/MWH); and Wyoming (1,714 lbs. of CO_2/MWH). *See* 79 Fed. Reg. 34,895 (June 18, 2014).

of carbon dioxide emissions. This is yet another example of how Rule 111(d) would subject Texas to unfair and disparate treatment.

A. Texas's Renewable Energy Mandate Under Rule 111(d) Far Exceeds The Requirement For Any Other State

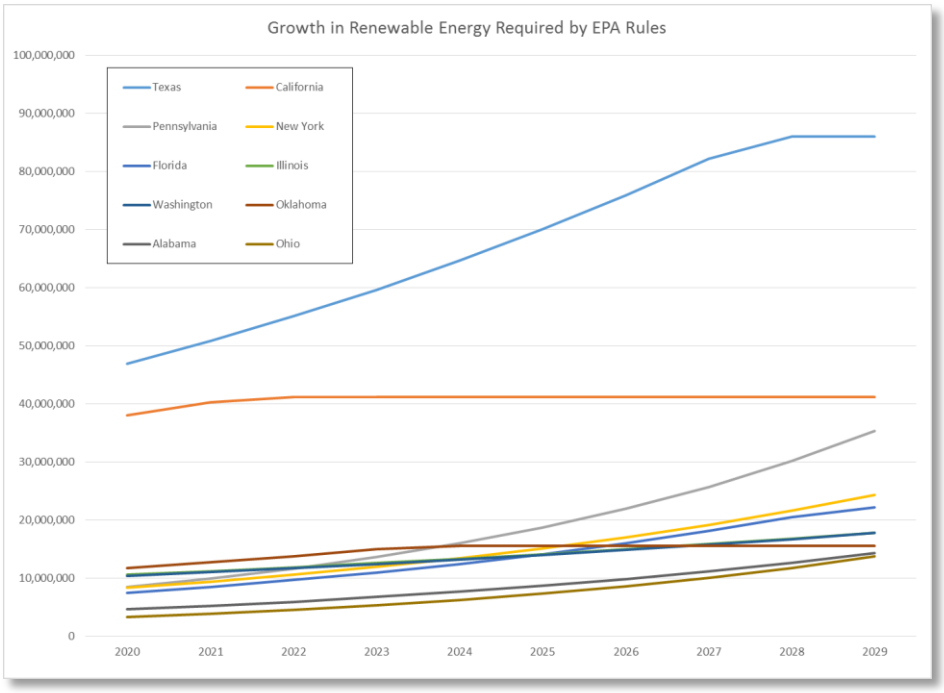
Rule 111(d) would effectively require Texas to add 52 million MWh of renewable energy by 2030. The renewable energy mandate for Texas far exceeds the renewable energy requirement for any other state. Texas, already the nation's largest renewable energy producer, would be required to increase its renewable portfolio by 153% over the next 8-14 years, while the next largest renewable energy producer, California, would only be required to increase its renewable energy portfolio by 37%.[171] The required increase in Texas's renewable energy fleet required under the rule would be greater than the increases of 29 states combined.[172] Finally, Texas's renewable energy portfolio resulting from Rule 111(d) would be larger than the present day wind and solar fleets of every country in the world, except for the U.S.[173] The magnitude of Texas's renewable energy mandate compared to certain other states is illustrated below in Figure 14. EPA offers no credible or reasonable explanation for this disparate treatment of Texas in the proposed rule.

[171] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Partnership for a Better Energy Future, at slide 28 (Aug. 15, 2014).

[172] *Id.* at slide 29.

[173] *Id*. at slide 30.

Figure 14: Growth in Renewable Energy Required by Rule 111(d)[174]



B. Rule 111(d) Disproportionally Harms Texas's Non-Profit Electric Cooperatives

Texas has a number of electric cooperatives that have been providing service since the Rural Electrification Act of 1934. These cooperatives have heavy coal-fired generation portfolios, which allow them to serve their communities at a low cost. Comments from one cooperative noted that "eliminating our coal-fired generation could increase our wholesale power costs by as much as 40 percent" with a corresponding "30 – 35 percent increase in retail electric rates."[175] This cooperative noted that coal-fired generation represented 63 percent of its fuel portfolio in 2012. Rule 111(d)'s impact on electric cooperatives would also adversely impact small businesses and rural, low-income

[174] Presentation of Brian Lloyd, PUCT Executive Director, Air Pollution Control Association Conference at slide 16 (Sept. 11, 2014).

[175] PUCT Project No. 42636—*Commission Comments on Proposed EPA Rule on Greenhouse Gas Emissions for Existing Generating Units*, Comments of Rusk County Electric Cooperative at 2 (Aug. 29, 2014).

communities that are served by these non-profit, member-owned cooperatives. Electric cooperatives in Texas serve a disproportionate number of low-income customers as well as the elderly, who are dependent on the low cost of fossil-fuel fired generation for reasonably priced electricity. Rule 111(d) would likely eliminate many coal plants owned by electric cooperatives—plants that provide jobs and economic health in Texas's rural communities. One cooperative explained that its coal-fired power plant provides good jobs to approximately 1,200 citizens and their families: "This may not sound like much in our greater metropolitan centers, but to these five northeast Texas counties, the impact on the rural economy, the local tax base, and social services would be devastating."[176]

XIV. CONCLUSION

The PUCT has outlined the numerous, significant problems, both legal and operational, with Rule 111(d). For all of the reasons discussed in these comments, the PUCT urges EPA to withdraw the proposed rule. In the alternative, the PUCT urges EPA, at a minimum, to eliminate the interim emissions goals from the final rule.

[176] *Id*. at 1.