



**Report to the 85th
Texas Legislature**

***Scope of Competition
in Electric Markets
in Texas***

***Public Utility Commission of Texas
January 2017***

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Public Utility Commission of Texas

January 15, 2017

Honorable Members of the 85th Texas Legislature:

We are pleased to submit to you the 2017 *Scope of Competition in Electric Markets* Report, as required by Section 31.003 of the Public Utility Regulatory Act. This report provides an overview of the current 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.

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

Sincerely,

Handwritten signature of Donna L. Nelson in blue ink.

Donna L. Nelson
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I. EXECUTIVE SUMMARY

This year marks 15 years since the opening of the Texas retail electric market in 2002, brought about by the passage of Senate Bill 7 by the Texas Legislature, which began the project of restructuring the Texas electricity market. In the 15 years since the market opening, the Public Utility Commission of Texas (Commission) has overseen the transformation of the Texas electric landscape from one of incumbent utilities to a thriving electric market in the Electric Reliability Council of Texas (ERCOT) region. This *Scope of Competition in Electric Markets* Report will provide a review of the activities the Commission has undertaken during the last two years to continue to foster market competition, improve the customer experience, and promote infrastructure to deliver electricity to power the lives of Texans.

Under the Commission's oversight, the Texas retail market remains the national leader in competitive residential, commercial, and industrial offerings, with the highest number of competitors and product variety in the country. As of March 2016, in the portion of the state that is open to customer choice, 92% of all customers had exercised their ability to switch providers.

On average, residential retail rates in the competitive areas of Texas have declined since 2014, to prices as low as 4.5 cents per kilowatt-hour (kWh), compared to a nationwide average of 13.45 cents per kWh in 2016. In addition, wholesale market prices in Texas have fallen 21% since 2013.

Alongside the Commission's work refining the retail market, the Commission has also focused on continuing to enhance the customer experience by adapting to technological changes, as well as evaluating market mechanisms to ensure that the wholesale market is as efficient and reliable as possible. To further its objective of reliable, affordable, and efficient power for Texas industry and residents, the Commission has several ongoing projects focused on promoting efficient and sustainable outcomes in the wholesale market.

On August 11, 2016, the ERCOT region broke the previous all-time record for peak demand, with customers across the region using 71,093 Megawatts (MW) of electricity, in part because of hot weather across the state. Power generation was sufficient to meet this record level of demand.

This Report summarizes the continuing trends affecting competition in the electric industry. It highlights the effects of competition on rates, customer protection and complaint issues, oversight and enforcement action, and other noteworthy Commission activities. This Report concludes with suggestions for the Legislature's consideration that may facilitate continued efficiency and promote the Commission's objective of providing high quality service to Texans.

II. STATE OF THE COMPETITIVE MARKET

A. Overview

In the 15 years since the implementation of customer choice in Texas, customers continue to enjoy the benefits of a competitive market: a plethora of retail electric providers offering innovative products designed to meet the needs of residential, commercial, and industrial customers. The diversity of retail electric providers and products has created a robust competitive market that continues to provide Texas customers with low electricity prices. With Senate Bill 7, the Texas Legislature put in place a foundation for a restructured electric market that continues to set the standard across this nation. Because of SB 7, Texas remains the national leader in competitive electric markets. The Commission will continue to oversee the competitive electric market in Texas to ensure that it stays true to the foundation created by SB 7 and that it provides Texans with the reliable, competitively priced electricity they have come to expect.

B. Retail Market Development and Prices

1. Customer Choice

The Commission has continued to guide improvements of the Texas competitive retail electric market, in which customers are able to choose which electric rates and services best suit their needs from Retail Electric Providers (REPs), which sell electricity to the end-use customer. The number and diversity of REPs competing for customers provides an indicator of the health of the retail market. Since the publication of the 2015 *Scope of Competition in Electric Markets* Report, the number of REPs and competitive offers in ERCOT has remained stable. As of September 2016, 109 REPs were operating in ERCOT, providing 440 total unique products, 97 of which solely support electricity generated from 100% renewable sources.¹

Because of the number of providers and plans available from which customers can choose, Texas continues to be recognized as the most successful competitive retail market in North America, as demonstrated by its first-place rank for the past eight years in the *Annual Baseline Assessment of Choice in Canada and the United States*, a scorecard that compares the retail competitiveness of electric markets in the U.S. states and Canadian provinces.²

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

¹ Public Utility Commission, www.powertochoose.org.

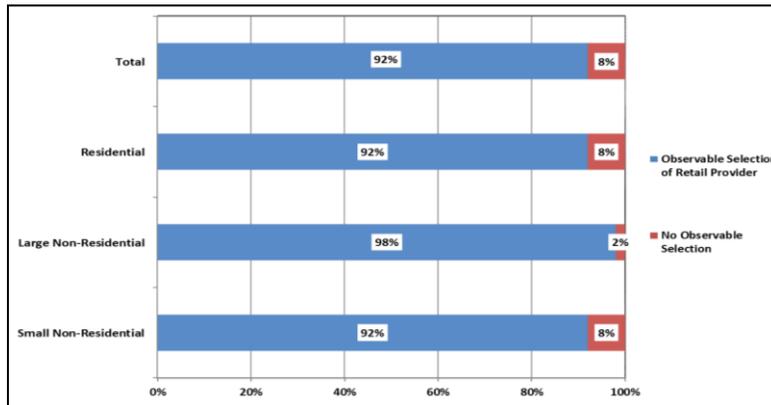
² *Annual Baseline Assessment of Choice in Canada and the United States*, Distributed Energy Financial Group, July 2015. Available at: <http://www.competecoalition.com/files/ABACCUS-2015-vf.pdf>

Table 1. Number of REPs and Products Serving Residential Customers, September 2016

TDU Service Territory ³	Residential Suppliers	Number of Products
AEP Central	52	355
AEP North	49	295
CenterPoint	55	400
Oncor	55	390
Sharyland – McAllen	14	103
Sharyland Utilities	22	155
TNMP	49	320

2. Retail Prices

Together, the REPs in the competitive market serve 6,153,293 residential customers, 1,053,032 commercial customers, and 4,336 industrial customers.⁴ In this highly competitive retail market, 92% of all customers have exercised their ability to switch REPs since the market opening in 2002. Figure 1 depicts the percentage of customers in each customer class who have switched REPs at least once since 2002.

Figure 1. Percentage of Observable Switching by Customer Class⁵

³ American Electric Power – Texas Central Company (“AEP Central”); American Electric Power – Texas North Company (“AEP North”); CenterPoint Energy (“CenterPoint”); Oncor Electric Delivery Company (“Oncor”); Sharyland Utilities (“Sharyland – McAllen” serves McAllen, Texas, and “Sharyland Utilities” serves Stanton, Brady, and Colorado City); and Texas-New Mexico Power (“TNMP”).

⁴ ERCOT *Provider of Last Resort Counts*, March 31, 2016. Available at: http://www.ercot.com/content/wcm/key_documents_lists/89277/POLR_Counts_Energy_2016_Reporting.xlsx.

⁵ ERCOT *Supplemental Information - Retail Electric Market*, April 2015–March 2016. Available at: http://ercot.com/content/wcm/key_documents_lists/89277/Observed_Selection_of_Electric_Providers_Mar_ch_2016.ppt.pptx

The success of the competitive market is highlighted in Table 2, which compares the last regulated retail rate with the current lowest 12-month fixed retail offering per 1,000 kWh in each region, adjusted for inflation. Since 2001, average retail rates across Texas have decreased 63 percent.

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

TDU Service Territory ⁶	Last Regulated Rate (2001), ¢/kWh ⁷	Last Regulated Rate, Adjusted for Inflation	Current Lowest Fixed Price ⁸	Percentage Change
AEP Central	9.6	13.1	5.6	-57.25%
AEP North	10.0	13.6	5.0	-63.24%
CenterPoint	10.4	14.1	5.4	-61.7%
Oncor	9.7	13.2	4.5	-65.91%
TNMP	10.6	14.4	5.0	-65.28%

The average lowest available residential price across the competitive market was 5.1 cents per kilowatt-hour (kWh) in September 2016, and the average across all plans available in the competitive market in Texas was 9.8 cents per kWh.⁹ Moreover, rates in ERCOT have not only decreased since Texas' transition to the competitive market, but both fixed and variable rates have continued to be much lower than nationwide averages of 13.45 cents per kWh in July 2016 and 13.62 cents per kWh in July 2015.¹⁰

Table 3 compares the current lowest fixed price available for residential service in each TDU service territory with the average price of plans available and the nationwide average, excluding Texas.

⁶ Sharyland Utilities was formed shortly before the market opening to serve part of McAllen, Texas; it is not included in this table because of its limited number of customers at that time. In Docket No. 21591, Sharyland Utilities committed that its average bundled residential rates would not exceed those of Central Power & Light Company (now AEP Central).

⁷ Association of Electric Companies of Texas. Available at: <http://www.aect.net/inside-the-charts-prices-available-in-the-competitive-market-today-well-below-the-last-regulated-rate/>.

⁸ The current lowest fixed price available for a residential plan in each TDU service territory as of September 2016, for a 12-month plan without time-of-use features, prepaid features, or a minimum usage fee, for a fixed month-to-month rate, for a customer who expects to consume approximately 1,000 kWh of electricity a month. Available at: www.powertochoose.org.

⁹ This average is for a residential customer expecting to consume approximately 1,000 kWh of electricity each month. Available at: www.powertochoose.org.

¹⁰ The nationwide average is for July 2016 and includes all U.S. states, except Texas. Source: U.S. Energy Information Administration, *Average Retail Price of Electricity*, Electricity Data Browser, July 2016. Available at: <http://www.eia.gov/electricity/data.cfm>.

Table 3. Current Lowest and Average Residential Plans by TDU Service Territory

TDU Service Territory	Current Lowest Fixed Price (¢/kWh) ¹¹	Current Average, All Available Plans ¹²	Nationwide Average ¹³
AEP Central	5.6	9.4	13.45
AEP North	5.0	9.4	
CenterPoint	5.4	9.1	
Oncor	4.5	8.3	
Sharyland – McAllen	5.6	9.8	
Sharyland Utilities	4.5	13.3	
TNMP	5.0	9.2	

3. Customer Complaints

The Commission’s rules permit a customer to file a complaint with the Commission about their electric service. The Commission’s staff works with the customer and electric service provider to resolve the complaints first in an informal complaint process, and then directs the customer to a formal complaint process if the customer is dissatisfied with the resolution. The Commission keeps records of these complaints, and evaluates the complaint statistics as a barometer for analyzing company behavior and its effect on customers. The Commission uses the data to identify any company-specific trends, work with companies to address any issues, or otherwise take enforcement action.

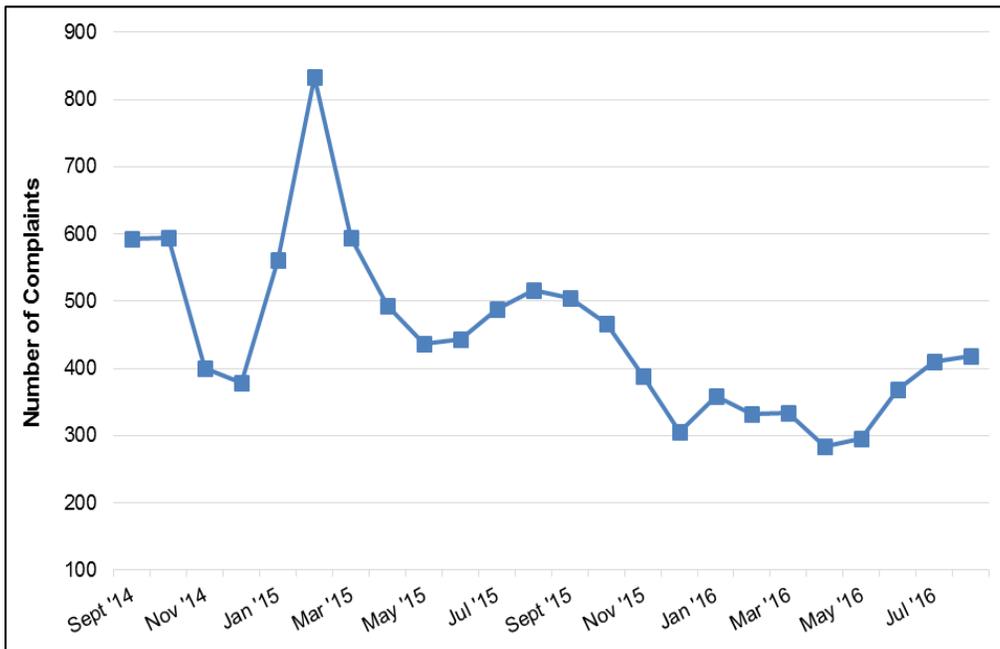
From September 1, 2014 to August 31, 2016, the average number of days to resolve a utility complaint was 18 days. The slight decline in the number of electric complaints received in 2015 through 2016 may be attributed to the mild winter weather which resulted in lower overall prices, as well as the absence of significant disruptions to electric service. Figure 2 shows the total complaints received from September 1, 2014 to August 31, 2016.

¹¹ The current lowest fixed price available for a residential plan in each TDU service territory as of September 2016, for a 12-month plan without time-of-use features, prepaid features, or a minimum usage fee, for a fixed month-to-month rate, for a customer who expects to consume approximately 1,000 kWh of electricity a month. Source: www.powertochoose.org.

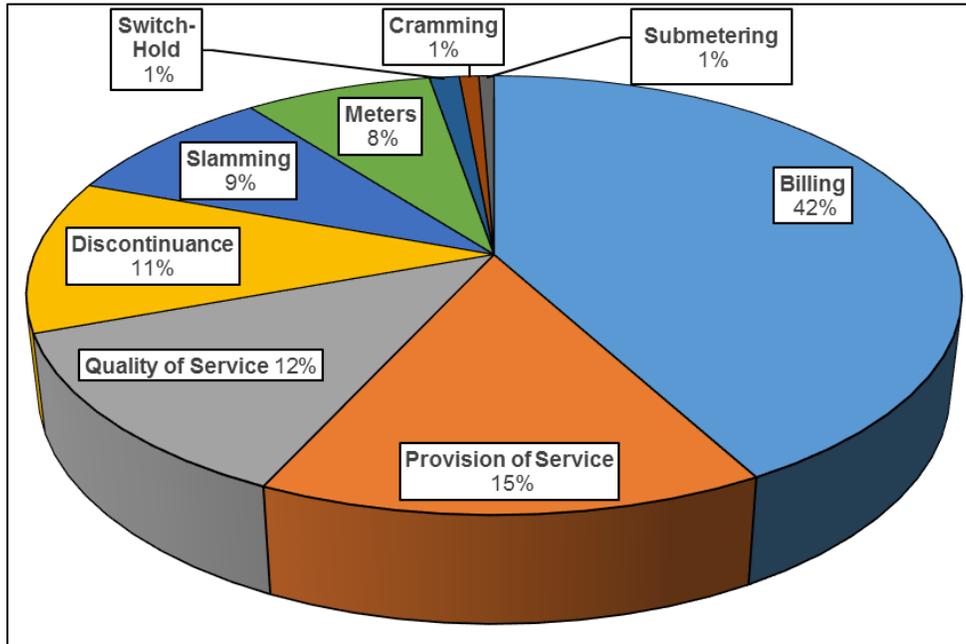
¹² The average is for a residential customer expecting to consume approximately 1,000 kWh of electricity a month. Source: www.powertochoose.org.

¹³ The nationwide average is for July 2016 and includes all U.S. states except Texas. Source: U.S. Energy Information Administration, *Average Retail Price of Electricity*, Electricity Data Browser, July 2016. Available at: <http://www.eia.gov/electricity/data.cfm>.

Figure 2. Total Electric Complaints Received, September 2014 – August 2016



From September 1, 2014 to August 31, 2016, the Commission received 4,465 electric complaints. Billing complaints continue to be the greatest cause of customer complaints, with 42% of all electric complaints concerning billing issues. Complaints relating to the provision of service, including customer service and the refusal of service, were the second highest cause of complaints at 15%. Quality of service contributed to the third-leading cause of complaints at 12%. Complaints are broken down by category in Figure 3.

Figure 3. Electric Complaints Received by Category, September 2014 – August 2016 ¹⁴

4. Energy-Efficiency Programs

Energy-efficiency programs in Texas are administered by the TDUs in ERCOT and the vertically integrated utilities outside of ERCOT, pursuant to the Public Utility Regulatory Act (PURA) §39.905. The utilities recover the cost of the energy-efficiency programs through a surcharge on electric bills, which are adjusted and approved annually by the Commission. Under the energy-efficiency programs, TDUs reduced 559,369 MWh of electricity consumption in 2015, exceeding the goal for the year by 40%. The energy-efficiency programs are designed to reduce customers' energy consumption as well as electric peak demand. In 2011, SB 1125 increased the peak demand goal reduction to a 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.

The 2011 legislation also required that the Commission develop an evaluation, measurement, and verification (EM&V) framework to promote effective program design, to provide consistent and streamlined reporting, and to retain a third-party contractor to conduct these activities. EM&V efforts for the 2015 program year focused on evaluating targeted programs for which the associated peak demand and energy savings were most uncertain. A primary component of EM&V is the statewide Technical Reference Manual (TRM), a single common reference document prepared and maintained by the EM&V contractor to estimate energy and peak demand savings resulting from the installation of

¹⁴ "Cramming" is the practice of adding unauthorized charges for any services to an electric bill without verified consent by the customer. "Slamming" is the practice of switching the customer to another provider without authorization.

energy efficiency measures sponsored by utility-administered programs in Texas. In 2015, changes made to the TRM added and updated existing deemed savings values and added standardized EM&V protocols for determining and verifying energy and demand savings, effective for the 2016 program year. Verified demand and energy savings and program costs for 2015 are shown in Table 4.

Table 4. 2015 Verified Energy Efficiency Savings¹⁵

Utility	Verified Savings		Goal		Program Cost
	MW	MWh	MW	MWh	
El Paso Electric	12.31	22,283	11.16	19,552	\$4,039,278
Entergy Texas	18.09	39,688	15.50	27,156	\$7,023,009
SPS	8.17	14,537	5.49	9,627	\$3,190,744
SWEPCO	9.88	15,262	5.60	9,811	\$3,220,359
Non-ERCOT Total	48.44	91,770	37.75	66,146	\$17,473,390
AEP Central	43.78	68,482	12.93	22,653	\$13,261,480
AEP North	4.54	12,289	4.26	7,464	\$2,727,260
CenterPoint	168.49	188,255	58.83	103,069	\$35,832,993
Oncor	115.81	178,908	69.40	121,589	\$47,438,836
Sharyland	0.60	2,528	1.00	1,752	\$633,252
TNMP	8.66	17,452	5.770	10,109	\$4,011,627
ERCOT Total	341.88	467,915	152.19	266,636	\$103,905,448
Grand Total	390.33	559,685	189.94	332,782	\$121,378,838

*Excludes Statewide EM&V contractor expenses of approximately \$3M for review of prior program year.

In 2015, the utilities cumulatively achieved 206% of the demand reduction goal (226% for utilities in ERCOT), and 168% of the energy reduction goal (175% for utilities in ERCOT).

5. Customer Education Activities

The Commission engages with residential and small commercial electric customers about retail electric competition through its “Texas Electric Choice” campaign, and also informs customers about energy conservation opportunities through its “Power to Save Texas” campaign. In addition to engaging with customers through these two campaigns, Commission staff also respond to customer inquiries and distribute literature about electricity facts and issues.

¹⁵ The non-ERCOT utilities within the state of Texas are El Paso Electric Company (“El Paso Electric”); Entergy Texas, Inc. (“Entergy Texas”); Southwestern Public Service Company (“SPS”); and Southwestern Electric Power Company (“SWEPCO”).

a. *“Power to Choose”*

The Commission educates customers about the evolving marketplace, continuing its “Texas Electric Choice” campaign, which began in February 2001 with the goal of educating Texans about the changes and choices in the retail electric market. The PowerToChoose.org website, and its Spanish-language counterpart PoderDeEscoger.org, provides a simple, one-stop shop portal for Texans who live in a service territory open to customer choice to enter in their zip code and browse through the numerous plans offered by the REPs.

b. *“Power to Save Texas”*

In addition to the “Texas Electric Choice” campaign and the PowerToChoose website, the Commission has also continued its statewide initiative, “Power to Save Texas”, together with its parallel Spanish-language initiative, “Poder de Ahorrar”, which educates Texans about conserving energy during the summer peak times of 3 p.m. to 7 p.m., when the demand for electricity tends to be the highest. The PowerToSaveTexas.org website, and its Spanish-language counterpart, PoderDeAhorrarTexas.org, provide Texans with energy saving tips for homes and businesses.

As part of the Power to Save Texas campaign, the Commission contracted with Resource Action Programs (RAP) to develop and implement a middle school energy conservation outreach program in Hidalgo, Harris, Dallas, and Tarrant counties. In the 2015 – 2016 school year, the program provided an effective energy education program which strongly supports the Texas Essential Knowledge and Skills (TEKS) curriculum standards, as well as engages students through school challenges and at-home activities.

c. *Campaign Outreach*

PowerToChoose.org and its Spanish-language counterpart, PoderDeEscoger.org, have proven valuable in educating customers about customer choice in the electricity market. The Commission conducted a number of activities to further promote the state’s official electric choice website through social media, community events, trade shows, and expos. From September 1, 2015 through August 31, 2016, nearly a million potential customers visited the PowerToChoose.org and PoderDeEscoger.org websites. Website statistics are contained in Table 5.

Table 5. Website Statistics, September 2015 – August 2016

PowerToChoose.com Unique Visitors	980,473
PoderDeEscoger.com Unique Visitors	4,652

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

Throughout 2015 and 2016, the Commission’s staff also worked with legislative offices and faith- and community-based organizations to provide educational materials and training to help their constituents better understand 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 Legal Aid of Northwest Texas, senior activity centers, and religious groups.

e. Call Center

The Commission has trained its Customer Protection Division staff, who are fluent in both English and Spanish, to answer customer calls, and to assemble and mail informational packets comparing electric plans when requested by customers without Internet access. From September 2015 to August 2016, the Customer Protection Division staff handled 7,663 calls from customers requesting assistance with shopping.

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 events, and in response to customer requests to the call center. Up-to-date fact sheets are available on the Commission's website, PowertoChoose.org, and PoderDeEscoger.org, as part of the campaign's outreach efforts. The fact sheets provide information on a number of current industry and consumer topics.

Throughout 2015 and 2016, campaign educational materials promoting the agency's programs, including Power to Choose and Power to Save Texas, were distributed at numerous community events and civic town hall events, such as Hurst-Eules-Bedford "Back 2 School" day, Dickenson Housing Family Fair, Energy Day, DFW Family Fair, Earth Day Texas, Texas Home and Garden shows in Houston, Texas Black Expo, National Night Out events, and minor league baseball games.

C. Wholesale Market Development

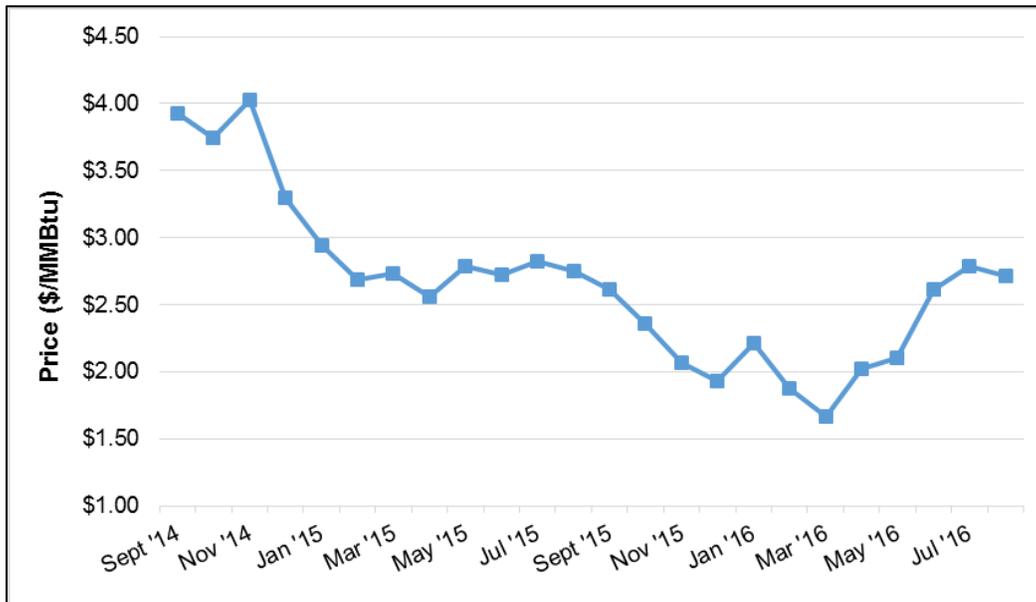
The Commission engages regularly with ERCOT to oversee market developments and ensure system supply, reliability, security, and improved price formation and market outcomes. Market design changes made as a result of this working relationship have created new opportunities for a variety of generation resources to enter the market and supported the formation of wholesale prices that reflect real-time market conditions more accurately and therefore improve the efficiency of the market.

1. Wholesale Market Prices

Wholesale market prices have fallen in comparison to prices seen in the 2012 – 2014 period. The ERCOT load-weighted real-time average price of energy in 2015 was \$26.77 per Megawatt-hour (MWh), a 34% decrease from the average price in 2014 and a decrease of 21% from the average seen in 2013.

Falling wholesale prices are correlated with the current trend of lower natural gas prices, the primary fuel of many of the region's power plants. The average Houston Ship Channel spot price for natural gas was 41% lower in 2015 than in 2014, decreasing from \$4.37/MMBtu in 2014 to \$2.58 in 2015. Through March, the average price for 2016 has fallen to \$1.92/MMBtu. Natural gas price trends from September 2014 through August 2016 are shown in Figure 4.

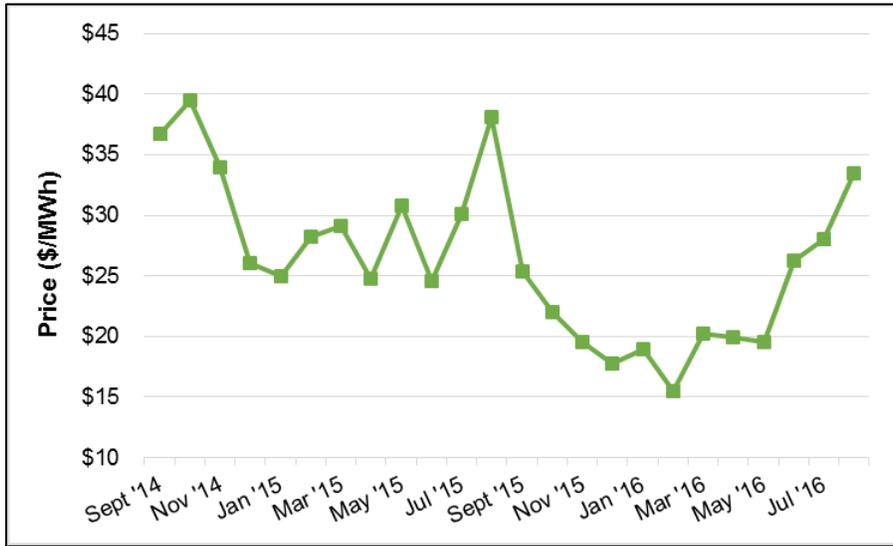
Figure 4. Monthly Average Natural Gas Prices, September 2014 – August 2016



Monthly average wholesale electricity prices are shown in Figure 5. Load-weighted prices are calculated by dividing the price at a load zone by the associated demand. This metric provides a useful proxy for the actual wholesale prices paid by load.¹⁶

¹⁶ It is worth noting that most power in ERCOT is sold through various bilateral arrangements that are designed to hedge daily real-time market price risk.

Figure 5. Load-Weighted Average Real-Time Monthly Settlement Point Prices, September 2014 – August 2016



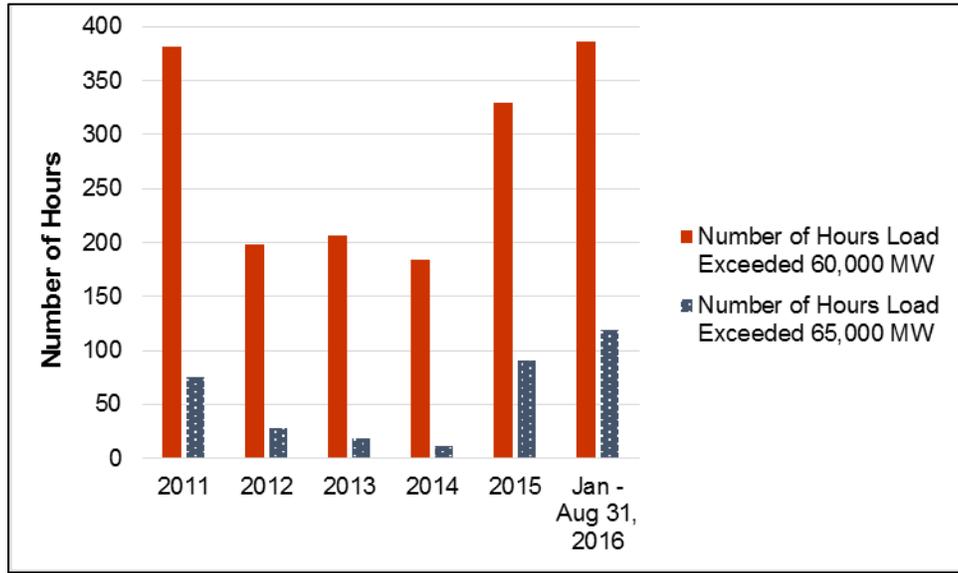
Another component of the real-time price of electricity is the cost of transmission congestion. Transmission congestion occurs when there is insufficient transmission capacity to dispatch energy in a least-cost fashion. The recent build-out of additional transmission lines in areas of high congestion has partially relieved the cost burden in these areas, particularly in West Texas, where oil and gas production growth rapidly increased the demand for electricity, resulting in relatively higher zonal prices.

2. Peak Demand

After the very high peak demand levels during the hot summer of 2011, peak demand in ERCOT was lower in 2012 through 2014. In 2015, peak demand again increased, though not to 2011 levels, with load exceeding 60,000 MW for 330 hours and exceeding 65,000 MW for 91 hours, as shown in Figure 6 below. In 2016, ERCOT experienced a record week in August which saw the previous record peak demand broken six times, and the ERCOT region hit its all-time peak demand of 71,093 MW on August 11, 2016.

As peak demand has increased, the recorded availability of generation supply in the region during times of high load has decreased slightly. Physical Responsive Capability (PRC), analogous to the amount of reserves available on the system at any given time, fell below 3,000 MW for 26.9 hours in 2015, up slightly from 21.3 hours in 2014 and 21.5 hours in 2013, but well below the 371 hours recorded during the 2011 summer.

Figure 6. High Load Hours in ERCOT, 2011 – 2016



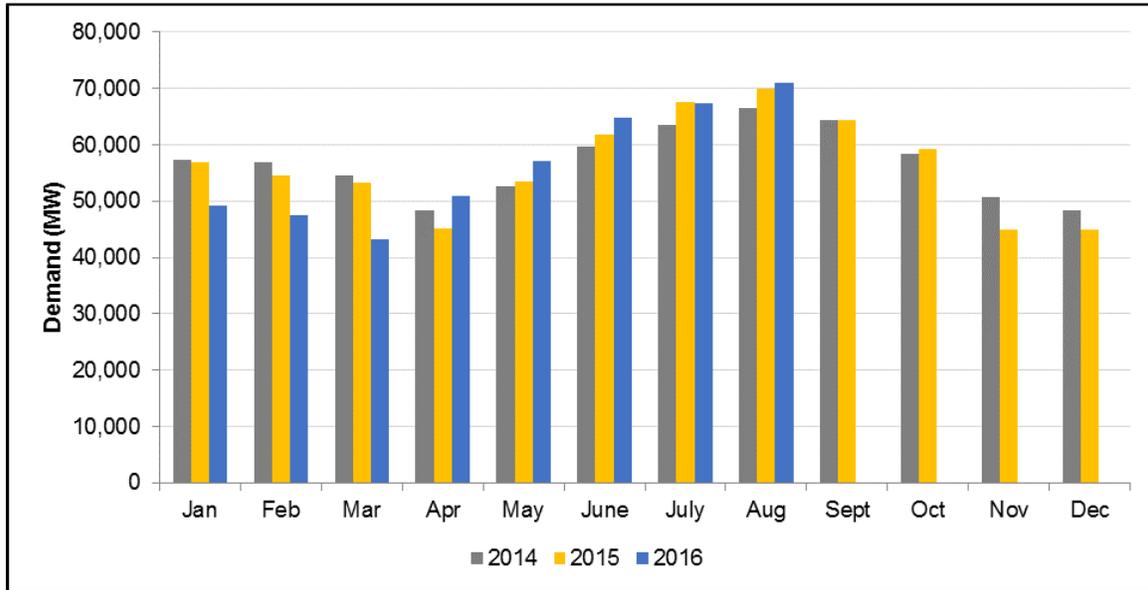
As shown in Table 6, the ERCOT system peak demand was 69,877 MW in 2015, up 5% from the 2014 peak, and the 2016 ERCOT system peak demand increased 1.74% from the peak demand of the previous year.

Table 6. ERCOT Peak Demand, 2012 – 2016

Year	ERCOT Peak Demand (MW)	Percentage Change from Prior Year
2012	66,548	—
2013	67,245	1.05%
2014	66,454	-1.18%
2015	69,877	5.15%
2016	71,093	1.74%

Figure 7 shows the hourly peak load for each month in ERCOT from January 2014 to August 2016.

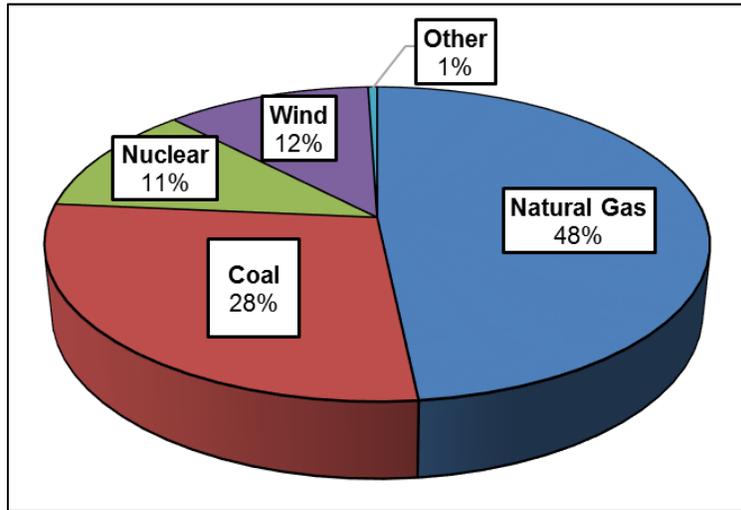
Figure 7. Monthly Peak Demand in ERCOT, January 2014 – August 2016



3. Generation Diversity

As electricity consumption has increased in ERCOT, the diversity of the system's generation portfolio has also increased. Generators participating in the state's renewable energy credit (REC) trading program reported an 11% increase in renewable generation from 2013 to 2015, rising from 37.6 million MWh to 46.9 million MWh, with wind representing 96% of the total renewable mix. Landfill gas was the second most prevalent renewable source, representing approximately 1.2% of all renewable generation in 2015. Energy produced from wind generation was up by 13% in 2015 from 2013, and solar energy capacity more than doubled, from 121 MW in 2013 to 288 MW in 2015. Coal-fired generation has been steadily shrinking as a proportion of total generation, declining from 37% of electricity produced in 2014 to 28% in 2015. Energy use in the ERCOT region by fuel type for 2015 is shown in Figure 8.

Figure 8. Energy Use in ERCOT by Resource Type, 2015



The Commission's projects are further described in the following section of this report.

III. SUMMARY OF COMMISSION ACTIVITIES FROM 2015 TO 2016

A. Introduction

The Commission develops and modifies rules, policies, and procedures for the competitive electric market in Texas in response to the technological advances in the industry, and the evolving needs of customers. The Commission also continues to carry out oversight of programs with which the Legislature has tasked it – such as energy efficiency, renewable energy, and advanced metering infrastructure. Within the ERCOT region, the monopoly wires-and-poles companies that provide transmission and distribution services throughout the grid remain subject to traditional rate regulation by the Commission. The Commission continues to set rates for these utilities, as they are not subject to the forces of market competition. This section provides an overview of the Commission’s activities in its oversight of the wholesale and retail electric markets, as well as its governance over regulated electric utilities.

B. Resource Adequacy

Resource adequacy is the long-term ability of the system to serve demand reliably when consumption is highest, given the available installed capacity, load resources, and the operational reliability of the system. Assessing resource adequacy requires comparing the system’s forecast installed capacity and load resources against the forecast peak summer load. The difference between the forecast of available generation and load resources and the forecasted demand for electricity is referred to as an “installed capacity reserve margin,” which is an indicator of the ability of the system to meet customer demand during peak conditions. In addition to evaluating the forecast reserve margin, assessing resource adequacy includes evaluating the system’s operational reliability. The system’s operational reliability depends on the ability of generators to manage plant operations successfully, as well as the grid operator’s ability to manage the system to avoid or to mitigate load curtailment. During 2015 and 2016, the ERCOT system performed well with respect to resource adequacy. The Commission has devoted significant attention to ensuring that ERCOT maintains an adequate installed capacity reserve margin and a high level of operational reliability, developing a wholesale market design that allows consumers to continue to receive low-cost and reliable electricity over the long term.

1. Capacity, Demand, and Reserves Report

The Capacity, Demand, and Reserves (CDR) Report, published by ERCOT semi-annually, is a snapshot estimate of long-term supply and demand and the associated annual reserve margin for peak summer and winter conditions. While the CDR Report is not a forecast of any particular outcome, it provides insight into possible resource adequacy trends.

The May 2016 CDR Report shows estimated reserve margins well above the current target reserve margin of 13.75%. Installed capacity reserve margin estimates taken from this CDR Report are shown below in Table 7.

Table 7. May 2016 Capacity, Demand, and Reserves Report Forecast

Forecast	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load (MW)	68,548	69,409	70,795	71,420	72,098	72,792	73,482	74,168	74,864	75,704
Total Capacity (MW)	80,995	87,019	87,238	87,407	87,678	87,738	87,738	87,728	87,728	87,728
Reserve Margin	18.2%	25.4%	23.2%	22.4%	21.6%	20.5%	19.4%	18.3%	17.2%	15.9%

2. Operating Reserve Demand Curve

In ERCOT, the price signals produced by the energy-only wholesale electric market should provide incentives to promote short-term reliability as well as induce optimal long-run investment in new resources. If the prices are efficient and reflect the full cost of dispatching resources to meet demand, the benefits that accrue to both consumers and producers can be maximized at the least cost, and new generating capacity (or load resources) should develop to maintain the equilibrium as old resources retire or demand increases.

The Operating Reserve Demand Curve (ORDC), implemented at the Commission's direction in June 2014, improves price formation by allowing prices to more fully reflect the value of operating reserves. The ORDC assigns an economic value to operating reserves, or the amount of extra capacity available to maintain system reliability on a daily basis.

As part of its ongoing review of resource adequacy in ERCOT, the Commission is currently evaluating the accuracy of the inputs to the ORDC to ensure that its contribution to price formation appropriately reflects the costs of meeting demand and the underlying needs of the system.

3. Transmission Congestion

Although competitive power producers and regulated transmission providers form two distinct segments of the market, transmission buildout has a direct effect on wholesale power prices. When there is insufficient transmission capacity to dispatch energy in a least-cost fashion, the system operator takes action to ensure that the physical limits of the transmission system facilities are not violated. The re-dispatch of generation because of transmission limits results in disparate prices at different locations on the system. In comparison to prior years, transmission congestion in ERCOT has lessened, because of the large increase in transmission investment and the reduction of high demand related to oil and gas production in West Texas. ERCOT and the Commission continually evaluate the need for cost-effective additional transmission investment to manage congestion.

4. Wholesale Market Design Initiatives

While the ERCOT wholesale market has been successful in attracting new resource investment and also maintaining competitive prices for consumers, certain improvements to the market design could yield additional benefits in terms of efficient price formation and opportunities for entry of new technology. Initiatives already in place in many other regions, such as real-time co-optimization and multi-interval real-time resource dispatch, may allow existing capacity to be used more effectively and create opportunities for the integration of additional load resources to serve electric demand. The Commission continues to work with ERCOT and interested stakeholders to determine the value of implementing such enhancements, particularly as ERCOT's resource mix changes over time.

5. Reliability Standard

In early 2014, the Commission opened a project to review its use of a target installed capacity reserve margin based on a reliability standard equivalent to one loss-of-load event every ten years. In this project, the Commission received written comment from interested parties, conducted a public workshop, consulted with independent experts, and reviewed the application of reliability standards in other regions. As a result of this review, future reliability metrics to be estimated in ERCOT will include the market equilibrium reserve margin, the economically-optimal reserve margin, and the associated levels of expected unserved energy. The Commission believes that publishing these metrics represents an improvement over reporting a one-event-in-ten-years standard by enhancing insight into expected outcomes in ERCOT's energy-only market.

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 would not result in fair competition and reliable service, because of the lack of an independent organization to coordinate the electric system and the concentration of ownership in the generation sector in some of those areas. Consequently, SB 7 included provisions recognizing the difficulty of implementing retail competition in areas outside of ERCOT. Therefore, the utilities outside of the ERCOT region remain vertically integrated, owning generation, transmission, and distribution assets, as well as selling power to end-use customers. These vertically integrated utilities remain subject to traditional regulation, including rates set by the Commission, and customer choice is not offered in the service territories of these utilities.

The Commission does continue to monitor ongoing activities in the non-ERCOT portions of the state. In 2015, the Legislature granted the Commission the authority to retain counsel and consulting experts in order to participate in legal proceedings at the Federal Energy Regulatory Commission (FERC), which has regulatory jurisdiction over wholesale power sales and transmission rates outside of ERCOT. This authority has

permitted the Commission to participate more effectively in FERC proceedings affecting Texas' utilities located outside of ERCOT.

1. Southwest Power Pool

The Southwest Power Pool (SPP) is the Regional Transmission Operator (RTO) for areas of Northeast Texas and the Texas Panhandle. In Texas, the utilities Southwestern Electric Power Company (SWEPCO), Southwestern Public Service (SPS), and several electric cooperatives and municipally owned utilities are in SPP. In addition to these areas of Texas, the SPP footprint includes parts of New Mexico, Arkansas, Missouri, Nebraska, Louisiana, and all of Kansas and Oklahoma. In 2015, SPP became the RTO for the Integrated System and neighboring areas, which includes parts of Iowa, Minnesota, North Dakota, South Dakota, Wyoming, and Montana. SPP has spent extensive time and resources over the last two years to integrate these new areas successfully. The expansion added 5,000 MW of peak demand, 7,600 MW of generating capacity and 9,500 miles of transmission lines.¹⁷

In 2014, SPP launched its new Integrated Marketplace which provides a Day-Ahead Market, a Real-Time Balancing Market and Congestion Hedging Markets, mechanisms similar to those available in ERCOT. The implementation of the Integrated Marketplace resulted in a savings of \$422 million in 2015. As a result of the Integrated Marketplace, SPP's planning reserve margin will be reduced from 13.6% to 12%, a change expected to save about \$90 million annually.

Chairman Donna L. Nelson represents the Commission as a voting member on SPP's Regional State Committee (RSC). The RSC provides collective state regulatory agency input on a variety of issues. In addition, the RSC has authority over 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 meets more frequently if necessary.

2. Midcontinent Independent System Operator

The Midcontinent Independent System Operator (MISO) is an RTO that serves all or part of 15 states in the central U.S., one Canadian province, and the portion of eastern Texas served by the vertically integrated utility Entergy Texas, Inc. MISO provides a Day Two market which has a variety of functions and services, including 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 2015.

Like SPP, MISO is in the Eastern Interconnection which crosses state boundaries, and is therefore subject to FERC jurisdiction. A number of recent FERC proceedings have

¹⁷ 2015 Southwest Power Pool Annual Report. Available at: <https://www.spp.org/documents/37800/2015%20southwest%20power%20pool%20annual%20report.pdf>

affected the portion of Texas that is in the MISO footprint. The Commission, through outside counsel, has been an active party in such FERC proceedings. FERC Docket No. ER14-1174 addressed in part a dispute regarding the availability of transmission capacity under the Joint Operating Agreement between MISO and the SPP. Ultimately, FERC approved a settlement agreement under which MISO will compensate SPP and its members for using their or other entities' transmission systems.

In a related pending docket at FERC, Docket No. ER14-1736, parties are addressing how the cost of these payments will be allocated among MISO market participants. Parties in this proceeding are engaged in settlement discussions. In addition, in Docket No. ER14-75-000, FERC approved a settlement agreement among the participating Entergy Operating Companies and their retail regulators to terminate the Entergy System Agreement, effective August 31, 2016. The settlement terms prohibit any post-termination payments that roughly equalize production costs among the operating companies after December 31, 2015, terminate certain specific cross-purchase power agreements between Entergy Texas and former Entergy Gulf State Louisiana, and permit the continuation of several other purchase power agreements.

Commissioner Kenneth W. Anderson, Jr., represents the Commission as a voting member in the Organization of MISO States (OMS), the purpose of which is to coordinate regulatory oversight among the states in the MISO region and to make recommendations to MISO, FERC, and other entities. Commissioner Anderson also represents the Commission as a voting member of the Entergy Regional State Committee (ERSC), which has certain FERC-approved authority for five years after the Entergy integration with regard to cost allocation for Entergy transmission projects and adding transmission projects to the Entergy construction plan. The ERSC meets quarterly.

3. Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is a Regional Entity whose region includes the area surrounding El Paso 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 in between. WECC is the Regional Entity responsible for Bulk Electric System reliability in the Western Interconnection and associated compliance monitoring and enforcement. WECC does not have organized markets outside of California, but is organized into 38 separate balancing authorities. 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. In Texas, El Paso Electric Company is a member of WECC.

D. Rulemaking Activities

The Commission has continued to adopt new rules and modify existing rules in order to further the continued successful operation of the competitive retail and wholesale markets, and to comply with statutory changes made to PURA by the Legislature. This

section of the Report provides a high-level overview of the Commission's key rulemaking activities, highlighting the market improvements made in 2015 and 2016.

1. Cost Recovery and Rate Adjustment

The Commission adopted new rule 16 TAC §25.246 on June 29, 2016, to implement Section Nos. 1 through 3 of House Bill 1535 of the 84th Legislature. The new rule only applies to a utility that operates solely outside of ERCOT, and allows for the use of an update period beyond the test year for which the utility initially files estimated information. The rule clarifies that all information originally estimated must be updated with actual information, and also provides requirements for a post-test-year adjustment for a natural gas-fired plant. A non-ERCOT utility also is required to initiate a new base rate case on or before the four year anniversary of the final order in the utility's most recent comprehensive base rate case, or if the commission determines that the utility has materially earned more than its authorized rate of return in two consecutive years. The rule also provides requirements and procedures for the relation back of final rates to an effective date 155 days after the filing of the rate application.

2. Changes to Certificates of Convenience and Necessity and CREZ Rule

The Commission conducted a rulemaking to implement changes pursuant to Legislative mandates in SB 776, SB 933, and HB 1535 of the 84th Legislature. SB 776 required municipally owned utilities to apply for a certificate of convenience and necessity (CCN) before constructing transmission facilities outside the boundaries of the municipality that owns the municipally owned utility. SB 933 also requires persons to obtain a CCN before interconnecting a tie line into the ERCOT grid. HB 1535 requires the Commission to issue a final order within 181 days for a non-ERCOT utility requesting a CCN for an existing electric generating facility, and 366 days after a non-ERCOT utility files a CCN for a newly constructed generating facility. In addition, the Commission also determined in this rulemaking that all future transmission projects in a Competitive Renewable Energy Zone (CREZ) must meet the need criteria of PURA §§ 37.056(c)(1) and (2), rather than being exempt. Finally, the Commission determined that the CREZ project established in 2008 was complete following the installation of a second circuit on a Sharyland line.

3. Use of Handheld Device for Enrollment

As the market evolves, the Commission evaluates market changes, balancing its desire to encourage customer-focused innovation with its concern for customer protection against potential abuses. In Docket No. 44518, the Commission granted a REP a temporary, 12-month waiver from its rules requiring the marketer to obtain telephonic verification of the customer's desire to switch REPs, as well as a waiver from certain authorization disclosure requirements, among other stipulations the Commission placed upon the REP. The Commission then opened Project No. 45625 to study the issue of REPs utilizing hand-held devices for customer enrollment more broadly and engage with market representatives, consumer representatives, and other stakeholders. The Commission anticipates considering an amendment to its rules in the spring of 2017.

4. Smart Meter Texas Portal

The electric utilities in Texas that have advanced metering systems (AMS) jointly own and operate a single web portal known as Smart Meter Texas (SMT).¹⁸ SMT fulfills two requirements imposed by the Commission’s advanced metering rule on a utility with AMS: (1) provide to the retail customer, the REP serving the customer, and other entities authorized by the customer access to such retail customer’s consumption data; and (2) allow devices at the customer’s premises to communicate through a home area network with the advanced meter at the premises. SMT also facilitates near real-time, on-demand reads of a customer’s meter that aids prepaid service offered by certain REPs.

In Project No. 42786, *Review of Advanced Metering System Web Portal*, Commission staff and stakeholders examined options for the long-term operational structure, governance, and funding of SMT. The Commission determined that ownership of SMT should remain with the TDUs because they can operate the portal at a lower cost than transferring the data repository to ERCOT. The Commission opened two rulemakings, one to ascertain the appropriate governance, performance, and funding of SMT, and a second to determine the appropriate access for third parties, ensuring that customers have the freedom to grant and give third parties access to their data if made knowingly while also securing customer privacy.

E. Sharyland Utilities

In early 2015, customers of Sharyland Utilities, the smallest investor-owned transmission and distribution utility in ERCOT, began to file with the Commission a significant number of complaints regarding high electricity bills. In response, the Commission opened Project No. 44592, *Relating to a Project Regarding Sharyland Utilities*, to provide for a more formal process for Commission review of the large number of complaints. As part of this project, Commission staff prepared a report to evaluate the electricity rates and electric bills in the operating area of Sharyland Utilities that was previously part of Cap Rock Energy.

Staff’s report found that a number of factors contributed to the comparatively high bills for many of Sharyland-Cap Rock’s customers. First, Sharyland’s small size and its low customer density result in high TDU rates for all customers relative to other TDUs. In particular, Staff’s report found that Sharyland-Cap Rock’s rates for distribution service are up to three times higher than those of other TDUs in Texas. In addition to Sharyland-Cap Rock’s high costs for distribution service, higher wholesale transmission costs also contributed to the rate increases charged to Sharyland-Cap Rock’s customers. These transmission costs are the result of increased transmission investment in recent years throughout Texas that has increased transmission costs for all distribution providers,

¹⁸ The participating Texas TDUs are AEP Texas Central Company and AEP Texas North Company (jointly “AEP”), CenterPoint Energy Houston Electric, LLC (“CenterPoint”), Oncor Electric Delivery Company LLC (“Oncor”), and Texas-New Mexico Power Company (“TNMP”) collectively referred to as the “Joint TDUs”. Operation of an AMS web portal was addressed in the orders approving particular utilities’ deployment of AMS and approving surcharges for AMS cost recovery. While Sharyland Utilities filed comments in the proceeding, it did not participate as it had not fully completed its AMS deployment at the time.

including Sharyland Utilities. Second, the comparatively colder winter of 2014 – 2015, which was the time period generally consistent with the timeframe in which the Commission began receiving complaints, appeared to result in higher electricity usage than normal. This combination of high TDU rates and the higher electricity usage led to higher bills for customers.

Staff's report also noted that in Sharyland-Cap Rock's last rate case in 2014, the approved rates reflected movement towards more cost-based rates for all customers, including some customers that previously had been heavily subsidized by other customers. Additionally, in the process of standardizing Sharyland-Cap Rock's customer classification with the classifications of the other TDUs in Texas, some customers may have experienced a move from one class that previously was paying below-cost rates to another class that was now paying above-cost rates. For some of these customers, the combined effects of the movement towards cost-based rates and the change to a different class may have contributed to a significant change in the customers' rates. Regardless of any cost-shifting between customer classes, Sharyland's rates remain two to three times higher than those of other TDUs in Texas for all customers in all classes.

On December 4, 2015, the Commission signed an order directing Sharyland to file an application for a comprehensive rate review by April 30, 2016. Sharyland filed its rate application on April 29, 2016, in Docket No. 45414, *Review of the Rates of Sharyland Utilities, L.P.* On October 10, 2016, the Commission ordered Sharyland to file an amended application as soon as practicable, but no later than January 1, 2017, to reflect the unique aspects of the company's organizational structure as a real estate investment trust (REIT). At the time of publication, Sharyland is expected to file its amended application in December 2016.

F. PowerToChoose Website

As part of its ongoing evaluation of the competitive market, the Commission opened Project No. 45730 to evaluate the functionality and usability of its PowerToChoose website, which allows customers to select a REP and an electric plan based on their zip code. In the process, the Commission received significant feedback from customers stating that the Commission's PowerToChoose website was an important tool that plays a fundamental role in their shopping process. In response to the feedback received from industry representatives and consumers, Commission staff changed how the website sorts and filters retail electric plans, adding a filter to allow customers to unselect plans that contain minimum usage fees or credits. This filter is now a default setting, and plans with minimum usage fees and credits are not shown unless the customer actively selects to search for such plans. In addition, Commission staff made other changes to increase the clarity of the REP complaint rating. The Commission continues to evaluate other changes to improve the customer experience of the PowerToChoose website and provide transparency for retail electric plans.

G. Report on Alternative Ratemaking Mechanisms

In 2015, the Legislature enacted SB 774, which requires the Commission or its consultant to conduct a study and make a report to the Legislature analyzing the alternative ratemaking mechanisms adopted by other states. In addition, SB 774 extended the authorization for the Periodic Rate Adjustment (PRA) mechanism from 2017 to 2019, which the Legislature had authorized in 2011 (SB 1693) as a version of an alternative ratemaking mechanism that provides to utilities a means for expedited recovery of distribution infrastructure costs. Pursuant to SB 774, the Commission retained a consultant to produce the report, and the consultant's recommendations included streamlining the ratemaking process to reduce procedural costs, providing for a periodic review of the prudence of the costs, and using certain types of alternative ratemaking mechanisms that decouple the recovery of costs from variations in load. The Commission held a public hearing to receive comments on the report from stakeholders and, after consideration of those comments, has provided to the Legislature the consultant's report together with its own discussion of the report.

H. Request for Purchase of Oncor Electric Delivery Company

In March 2016, the Commission approved with conditions an application by an investor group led by Hunt Consolidated, Inc., the owners of Sharyland Utilities, to acquire control of Oncor Electric Delivery Company (Oncor), the largest transmission and distribution utility in Texas, from Oncor's parent company, Energy Future Holdings, which is in bankruptcy. The Commission approved the request subject to certain conditions, including stipulations regarding the organization of the new entities and treatment of tax benefits. The investor-led group subsequently declined to pursue the transaction that was approved by the Commission.

In September 2016, NextEra Energy, which owns Florida Power & Light, received approval from the United States Bankruptcy Court in Delaware for its plan to purchase Oncor. In October 2016, NextEra Energy filed an application with the Commission in Docket No. 46238 for approval of the proposed transaction. The Commission will evaluate the application to determine if the transaction is in the public interest.

I. Integration of Lubbock Power and Light

In March 2016, the Commission opened Project No. 45633 to study and identify the issues related to the request of Lubbock Power and Light, the state's third-largest municipally owned utility, to be integrated into ERCOT. The Commission is currently working with stakeholders, ERCOT, and SPP to determine the cost and benefits of any potential switch by Lubbock Power and Light into ERCOT, and whether such a switch is in the public interest.

J. Desalination Project: ERCOT Studies

In 2015, the Legislature passed HB 4097, which directed the Commission and ERCOT to study whether existing transmission and distribution planning processes are sufficient to provide adequate infrastructure for seawater desalination projects, and to study the potential for desalination projects to participate in demand response opportunities in the ERCOT market. Pursuant to that direction, ERCOT staff have prepared a report on the feasibility of interconnection of large desalination projects and on opportunities for such projects to participate in ERCOT's demand response programs, which is attached to this Report in Appendix B.

K. 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 rules, and ERCOT protocols.

During the period from January 2015 through August 31, 2016, the Commission assessed \$3,258,500 in penalties against electric market participants. Table 8 provides a summary of electric industry Notices of Violation since January 2015. During 2015 and 2016, Commission staff opened 212 investigations for the electric industry and closed 177 investigations.

Table 8. Notices of Violations

Violation Type	Total Penalty Amount
Retail Market Violations	\$539,000
Service Quality Violations	\$451,500
Wholesale Market Violations	\$2,268,000
TOTAL	\$3,258,500

In addition to the imposition of administrative penalties, the Commission uses other enforcement mechanisms in exercising its enforcement duties, including revoking a company's certificate to operate. In addition, some companies may be required to relinquish a certificate as part of a settlement after enforcement action has proceeded. Table 9 provides a breakdown of the number of certificates revoked or relinquished. In 2016, the Commission revoked the certificate of the REP TruSmart Energy.

Table 9. Certificates Revoked or Relinquished

Type	Number
Certificates Revoked	1
Certificates Relinquished	0

The Oversight & Enforcement division also issues warning letters to companies in the electric market when it determines that a violation occurred, but given the circumstances surrounding the violation and other mitigating concerns, no administrative penalty is warranted. During 2015 and 2016, the Oversight & Enforcement division issued 50 warning letters. Finally, the Commission generally seeks to reimburse money directly to customers when appropriate. In 2015 and 2016, the Commission ordered the reimbursement of \$85,435.96 to Texas electric customers.

Table 10. Warning Letters

Warning Letter Type	Number
Retail Market Warning Letter	8
Service Quality Warning Letter	1
Wholesale Market Warning Letter	41
TOTAL	50

In addition to its enforcement activities, the Commission also enters into voluntary mitigation plans with generators that request one through a contested case proceeding pursuant to PURA §15.023(f) and 16 TAC §25.504(e). The Commission entered into one voluntary mitigation plan during 2015 and 2016 in Docket No. 44635.

L. Low-Income Discount: System Benefit Fund

The System Benefit Fund (SBF) was originally established in 1999 to fund discounts to low-income customers, customer education activities, energy-efficiency and weatherization, and electric market oversight, through a nonbypassable surcharge on retail electric bills. HB 1101 of the 84th Legislature provided that the SBF be sunset on September 1, 2017, by which time the SBF is intended to be exhausted. In the 2016 Fiscal Year (FY), \$325,521,250 was appropriated in the SBF to provide a 25–31 percent discount to low-income customers over a 12-month period.

To assist the drawdown of the remaining balance, HB 1101 authorized the Commission to use any unexpended SBF balance in FY 2017 to assist low-income customers. The Commission estimates that the remaining SBF balance will be approximately \$1.7 million by August 31, 2017. The Commission has determined that this amount is insufficient to fund the rate reduction program; however, the Commission will spend approximately \$100,000 to continue automatic enrollment in the program to provide REPs a list of customers eligible to receive late fee waiver and deposit installment benefits. These two ancillary benefits of the rate reduction program will continue for the duration of FY 2017.

M. Homeland Security

The Commission assesses the efforts of ERCOT and utilities to defend against, mitigate, and respond to the variety of risks that the modern electricity system faces. The Commission also meets with ERCOT, utilities, and governmental entities on an ongoing basis to discuss preparation for everything from hurricanes and other severe weather to cyber-threats and threats of physical damage to the grid from accidents or intentional malfeasance. In addition, the Commission monitors industry and federal programs that address homeland security issues.

The Commission serves as an information liaison between state government and electric utilities during emergencies. The Commission's main roles include:

- Conveying outage and service restoration information from electric utilities to state government;
- Conveying service restoration priorities (hospitals, water treatment facilities, etc.) from state government to electric utilities; and
- Facilitating the clearance of downed power lines in disaster re-entry areas and facilitating entry of electric utilities into disaster areas.

The Commission's Emergency Management Response Team (EMRT) provided staff at the State Operation Center for the May 2015 and April 2016 flooding events in Texas, as well as additional staffing for severe winter weather.

N. Demand Response

ERCOT staff have begun to report annually on the participation of customers in REP-sponsored demand response programs. These programs, which have been facilitated by the deployment of smart meters throughout the competitive areas within ERCOT and by many municipal and cooperative electric utilities, take the form of rebates for reduction in usage during peak period, time-of-use pricing, real-time volumetric price compensation for load reduction, and direct control of customer load, among other plans.

These programs have seen dramatic increases in participation since ERCOT began to gather this information in 2013. From 2013 to 2014, the number of residential customers participating in these programs increased from 151,793 to 721,273, and the number of commercial and industrial customers participating rose from 30,275 to 50,205. The Commission continues to monitor ERCOT's stakeholder process for efforts relating to the integration of demand response.

IV. LEGISLATIVE RECOMMENDATIONS

A. Determination of Low-Income Customer Eligibility

In 2015, HB 1101 required that all remaining funds in the System Benefit Fund (SBF) be expended, that the fee that funded the program as a nonbypassable surcharge on electric bills be set at zero, and that the SBF be sunset on September 1, 2017. Per the provisions of HB 1101, the SBF fee was set at zero in September 2016, concluding the funding for the program. The sunset of the SBF program also concluded the relationship between the Texas Health and Human Services Commission (HHSC) and the Commission, in which the HHSC provided to the Commission eligible electric customers for the SBF low-income discount. Because of the termination of the relationship with HHSC with the termination of the SBF, the Commission will no longer be able to determine easily an electric customer's eligibility for other low-income programs, such as late penalty waivers and the option of paying an electric deposit over multiple months.

The Legislature may wish to consider easing low-income customers access to these low-income programs by facilitating the process used to determine eligibility. The Commission offers four possible approaches in which the Legislature could continue these low-income programs:

- (1) Authorize HSSC to provide identification of eligible low-income customers to the Commission;
- (2) Allow retail electric providers (REPs) to provide such low-income programs using the Low Income Discount Administrator's (LIDA) Telecommunications Lifeline Service Program list to identify low-income customers;
- (3) Require REPs to offer such low-income programs, with customers self-enrolling and REPs verifying income eligibility; or
- (4) Allow REPs to voluntarily provide such low-income programs at their own discretion.

B. Outside Counsel for Proceedings before Regional Transmission Organizations

Regional Transmission Organizations (RTO) manage the power grid across wide regions of the United States. Most of Texas is inside the ERCOT region, however there are significant portions of East Texas, and the Panhandle that are in the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). Issues arise in these other RTOs that have significant impact on Texas ratepayers, such as how transmission infrastructure costs will be shared. These tend to be very lengthy and complicated proceedings that require specialized legal and consulting services.

PURA § 39.4525 currently authorizes the Commission to use outside consultants, auditors, engineers, or attorneys to represent the Commission in proceedings before the Federal Energy Regulatory Commission. 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. The PUC recommends that the Legislature expand the language in this statute to include the ability to hire outside assistance for proceedings before other RTOs to provide those same protections to Texas ratepayers in those areas.

C. Repeal of Natural Gas and Renewable Energy Mandates

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 energy trading credits. The majority of all new, non-renewable electricity generation constructed since 2000 for Texas has used natural gas as a primary fuel and this trend is expected to continue in the foreseeable future. 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) requires the installation of 5,880 megawatts of renewable energy by 2015, and Subsection (b) establishes a renewable energy credits trading program to implement the requirement. The 5,880 megawatts mandate in Subsection (a) was met in 2008. While the Commission believes the renewable energy trading credit 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.

D. Advisory Opinions

Many regulatory agencies in Texas have authority to issue informal guidance to the persons 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.¹⁹ The issuance of an advisory opinion can provide regulatory clarity to a company before making investments or conducting operations the permissibility of which may be unclear under state law. The Legislature may want to consider granting the

¹⁹ 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.

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;²⁰
- Texas Medical Board;²¹
- State Board of Dental Examiners;²²
- Texas Board of Nursing;²³
- Texas Board of Professional Engineers;²⁴
- Texas Lottery Commission; and²⁵
- Texas Securities Board.²⁶

E. Administrative

Gross Receipts Assessment

PURA § 16.001 provides for a gross receipts assessment that is used to defray the expenses incurred by the Commission to administer PURA. An assessment of one sixth of one percent is collected from public utilities, electric cooperatives, retail electric providers and interexchange carriers' gross receipts from consumers. The funds from this assessment are remitted to the general revenue fund, but currently they have not been explicitly dedicated to funding of the Commission. In contrast, similar assessments on water utilities, insurance companies, and other regulated entities have traditionally been used to explicitly fund the underlying regulatory programs at the respective agencies. The Commission is one of four Article VIII agencies that is not designated as self-funded.

The Commission recommends that the Legislature designate the Commission as a self-funded agency whereby the collected assessments would be explicitly dedicated to the funding of the agency. Implementing this recommendation would require the Public Utility Commission 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. 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 general revenue appropriation each fiscal year, which would require a statutory change to PURA §16.001(b). Based upon the Commission's baseline budget request, authorizing the PUC's self-leveling designation would result in an overall estimated tax reduction of \$45.6 million per year, or 77.4%.

²⁰ Government Code § 571.091

²¹ Occupations Code § 162.107

²² Occupations Code § 258.157

²³ Occupations Code § 301.607

²⁴ Occupations Code § 1001.601

²⁵ Occupations Code § 2001.059

²⁶ Tex. Rev. Civ. Stat. Ann. Arts. 581-28-1 & 581-35; 7 Tex. Admin. Code 101.2

V. APPENDICES

Appendix A – Acronyms

AEP	American Electric Power
AMS	Advanced Metering System
CenterPoint	CenterPoint Energy Houston Electric, LLC
DG	Distributed Generation
DRG	Distributed Renewable Generation
ERCOT	Electric Reliability Council of Texas
ERSC	Entergy Regional State
ERS	Emergency Response Service
ETI	Entergy Texas, Inc.
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
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 – ERCOT Desalination Report

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Study on the Demand Response Potential for Seawater Desalination Projects

Executive Summary

In 2015, the 84th Texas Legislature enacted House Bill (HB) 4097, which included several provisions relating to seawater desalination projects, including a requirement that the Public Utility Commission of Texas (PUC) and Electric Reliability Council of Texas (ERCOT) study the potential for seawater desalination projects to participate in existing demand response opportunities in ERCOT. There are several demand response products in which demand-side resources (i.e., consumers of electricity) can participate. These programs help to preserve system reliability, and provide economic benefits to participating demand-side resources. Seawater desalination is an energy-intensive process that removes salt and other minerals from salt water to produce fresh water for municipal consumption, industrial use or irrigation. Participation in demand response could help mitigate electricity costs for future seawater desalination projects in Texas and provide reliability benefits to the grid.

There are two main demand response reliability-based services administered by ERCOT: participation by demand-side resources in the Ancillary Services market and the Emergency Response Service (ERS). Within the Ancillary Services market, the most common service provided by demand-side resources is Responsive Reserve Service (RRS), which requires resources to respond either instantaneously or within 10 minutes in response to unplanned system emergencies. ERS is separate from ERCOT's Ancillary Services market, and allows demand-side resources and distributed generation to provide reliability services in the event of an energy emergency. Resources can qualify for either the 10-minute or 30-minute response time ERS programs.

There are several key considerations that will impact a demand-side resource's ability to participate in different demand response opportunities: response time, recovery time, predictability of electrical demand, and flexibility of operations. Considering these factors together, it appears that seawater desalination plants could be designed to meet the requirements for participation in demand response. Because the ability to meet the qualification requirements is dependent on the plant design, demand response opportunities should be considered early in a project's development if participation is desirable.

Whether project developers will choose to address these requirements will depend on the economic benefits of participation. There may be additional costs to design seawater desalination plants to operate in the manner required in order to participate in demand response. These include costs associated with additional plant design specifications, need for excess capacity and storage to make up for lost production during demand response deployment, operational costs resulting from interruptions to plant processes, and potential financial penalties if demand response deployment results in failure to meet contract demands. The interplay of the benefits of participation and these costs will determine whether it would be beneficial for a future seawater desalination plant to participate in demand response in ERCOT.

To date, participation of seawater desalination plants in demand response programs has been limited. Because the process of seawater desalination is energy-intensive, participation in demand response could help to reduce electricity costs while posing a relatively low risk to plant operations. As stakeholders in Texas continue to plan for possible future droughts in the region and identify water management strategies, consideration of demand response could play a role in mitigating some costs associated with seawater desalination, and allow seawater desalination plants to assist with maintaining electric reliability in the region.

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1. Introduction

In 2015, the 84th Texas Legislature enacted House Bill (HB) 4097, which included several provisions relating to seawater desalination projects, including a requirement that the Public Utility Commission of Texas (PUC) and Electric Reliability Council of Texas (ERCOT) study the potential for seawater desalination projects to participate in existing demand response opportunities in ERCOT. ERCOT and the PUC initiated this study to fulfill that requirement, and evaluated the operational and economic characteristics of seawater desalination plants in light of ERCOT's primary demand response products.¹

ERCOT is the independent system operator (ISO) for the ERCOT Interconnection, which encompasses approximately 90% of demand for electricity in Texas. ERCOT is the independent organization established by the Texas Legislature to be responsible for the reliable planning and operation of the electric grid for the ERCOT Interconnection. ERCOT also administers and maintains a forward-looking open market to provide affordable and reliable electricity to consumers in Texas. In collaboration with market participants, ERCOT has developed demand response products and services for customers that have the ability to reduce or modify electricity use in response to instructions or signals. These programs help preserve system reliability, and provide economic benefits to participating demand-side resources.

The process of seawater desalination removes salt and other minerals from salt water to produce fresh water for consumption, industrial processes, or irrigation. The drought-prone Texas climate, coupled with projections for increasing water demand in the state, has created interest in seawater desalination as a future water source. The 2017 Texas State Water Plan includes seawater desalination as a future water management strategy for water users in the state. However, the seawater desalination process is energy intensive, and electricity consumption can be a significant cost driver for these projects. To the extent that these plants could participate in demand response, it would help to defray these costs. Thus, there is a potential nexus between seawater desalination projects built in Texas to mitigate drought, but which have large electricity requirements, and ERCOT demand response opportunities, which could help to reduce their electricity costs and provide reliability benefits.

This study evaluates the demand response potential of seawater desalination plants based on their operational characteristics and economic drivers. The report is organized as follows:

- **Section 2** provides background on typical seawater desalination plant operations and economics;
- **Section 3** describes the current demand response opportunities in ERCOT;
- **Section 4** evaluates the characteristics of seawater desalination plants to determine their potential to participate in demand response opportunities in ERCOT; and,
- **Section 5** provides a summary of the conclusions of this study.

¹ In the course of developing this report, ERCOT consulted with several desalination experts with experience with existing or planned seawater desalination plants in the U.S. The technical experts consulted included Jorge Arroyo (Water Management Consultant), Andrew Chastain-Howley (Black & Veatch), Jonathan Loveland (Black & Veatch), Ron Parker (Black & Veatch), John Wolfhope (Freese and Nichols), and Srinivas Veerapaneni (Black & Veatch).

2. Seawater Desalination

There are two primary methods for seawater desalination: distillation (also referred to as “thermal”) and reverse osmosis. Distillation uses heat to remove salts and minerals from seawater by boiling water at high pressures. In contrast, reverse osmosis technology forces saline water through a membrane to separate water from the salts and minerals. While both distillation and reverse osmosis are energy intensive, distillation requires thermal energy to heat the water and overall has a higher energy requirement, whereas reverse osmosis requires primarily electrical energy and overall is less energy intensive – though still with significant electricity requirements.

Globally most thermal desalination plants are located in the Middle East due to low energy prices in the region. Plants located elsewhere, including in the U.S., typically use reverse osmosis technology.² There are two large existing seawater desalination plants in the U.S.: one in Carlsbad, California, providing water to the San Diego area, and one in Gibsonton, Florida, providing water to the Tampa Bay area. Both plants use reverse osmosis technology. In addition, there are several desalination projects currently in the planning stages or under development in Texas in the Corpus Christi area that would use reverse osmosis technology. For that reason, this report focuses on reverse osmosis technology in the evaluation of demand response potential of seawater desalination plants.

While there are currently no existing seawater desalination plants in Texas, there are several municipal and industrial brackish water desalination plants in the state. According to the Texas Water Development Board (TWDB), there are 46 municipal brackish water desalination plants with capacities greater than 0.025 million gallons per day (MGD) in Texas, representing a total of 123 MGD of capacity.³ The desalination of brackish water is typically less expensive compared to seawater, due to the lower relative salinity of brackish water. This study focuses exclusively on seawater desalination, consistent with the requirements of HB 4097, but it should be noted that conclusions may also apply to brackish water desalination, though at a different cost and scale.

This section provides high-level information on the operations (Section 2.1) and economics (Section 2.2) of seawater desalination plants, to inform the discussion of their demand response potential in Section 4.

2.1. Seawater Desalination Plant Operations

Seawater desalination plants typically range in capacity from less than 5 MGD up to 165 MGD. For example, the Carlsbad seawater desalination plant has a capacity of approximately 50 MGD, and the plant in Tampa Bay has a capacity of approximately 25 MGD. The associated electricity consumption ranges between 10 and 15 kWh/1,000 gallons produced, depending on the salinity of the water being processed.^{4,5,6} More saline water (e.g., seawater) requires larger amounts of electricity for desalination. Thus, a seawater desalination plant would have larger electricity consumption requirements compared to a similarly sized brackish water desalination plant.

² American Water. “Innovation Solutions within the Water Industry: Desalination.” Available at <http://www.amwater.com/files/InnovationsSolutionsWithinTheWaterIndustryDesalination.pdf>.

³ Texas Water Development Board. “Desalination Facts.” Available at <https://www.twdb.texas.gov/innovativewater/desal/facts.asp>

⁴ American Membrane Technology Association. April 2016. “Membrane Desalination Power Usage Put in Perspective.” Available at http://www.amta.org/wp-content/uploads/7_MembraneDesalinationPowerUsagePutInPerspective.pdf.

⁵ Water Reuse Association. November 2011. “Seawater Desalination Power Consumption.” Available at https://watereuse.org/wp-content/uploads/2015/10/Power_consumption_white_paper.pdf.

⁶ Ghaffour, N., T.M. Missimer, and G. Amy. January 2013. “Technical review and evaluation of the economics of water desalination: Current and future challenges for better water supply sustainability.” *Desalination* 309, pp197-207. Available at https://www.researchgate.net/publication/256693140_Technical_review_and_evaluation_of_the_economics_of_water_desalination_Current_and_future_challenges_for_better_water_supply_sustainability.

While the two existing seawater desalination plants in the U.S. were co-located with power plants to ease compliance with regulations on water intake and discharge structures and reduce costs, many other reverse osmosis desalination plants receive their electricity from the grid. However, plants may have on-site backup generation in case of a power outage. This will vary depending on the size and design of the plant and other factors. For example, the Carlsbad plant in California does have diesel backup generation to power control systems and flushing systems in the case of a power outage. The plant in Tampa Bay was not built with backup power due to potential storm surge risks from hurricanes and other storms. The plant does use uninterruptible power supply (UPS) backup to power control systems during power outages.

Reverse osmosis plants are typically designed with several “trains”, which consists of a high-pressure pump, turbine, and reverse osmosis membrane. Desalination plants are turned on or off one train at a time in a highly controlled process. The process of ramping up or down an individual train under normal operations typically takes one to two hours. While plants can be designed to handle immediate shutdowns (i.e., in a power outage), re-starting a system after an interruption would take this amount of time. In addition, the saline water must be pretreated (i.e., filtered) before going through the reverse osmosis train, and this can sometimes pose constraints on the flexibility of operations.

Demand for water is the key factor driving the level of production at seawater desalination plants. Typically, the plant will have a contract or contracts with municipal or other water users to deliver desalinated water, and is operated to meet that demand. Alternatively, if the plant is municipally owned, it would similarly be operated to meet the level of water demand, in conjunction with other available water sources. If water demands are close to a plant’s full capacity, the operator’s flexibility to adjust its electricity consumption as part of demand response may be limited. However, this does mean that plant operations are fairly predictable on a day-to-day basis, which is necessary for participation in demand response.

The amount of flexibility in plant operations will also be impacted by the amount of water storage available. For example, if a plant has sufficient water storage on-site, or storage within the customer’s distribution system, it could provide flexibility for the plant to reduce its operations during peak hours when electricity prices are likely to be highest. It would also mitigate the impacts of interruptions to production from demand response deployments.

2.2. Seawater Desalination Plant Economics

Seawater desalination is typically more expensive than other sources of water, and a major driver of the overall cost is energy costs. In 2016, the Carlsbad plant charged rates at between \$2,131 and \$2,367 per acre-foot.^{7,8} This charge is intended to cover both the fixed costs of the plant and the variable costs to produce a unit volume of water. Typically, half to two thirds of the cost of providing desalinated seawater are accounted for by capital cost recovery, with the remainder accounted for by operations and maintenance costs, including electricity costs. Electricity costs can account for 20-25% of the total costs of seawater desalination with reverse osmosis technology.⁹

Factors affecting the capital cost of a seawater desalination plant include plant size, type of desalination process and pre-/post-treatment technologies, plant infrastructure (e.g., piping, water storage, backup power), and compliance with applicable regulations (e.g., regulations on intake structures, brine byproduct disposal). A significant driver of operating and maintenance costs is membrane replacement. Reverse osmosis membranes need to be replaced every few years, and

⁷ Source: San Diego County Water Authority. “Seawater Desalination.” Available at <http://www.sdcwa.org/seawater-desalination>.

⁸ Note that 1 acre-foot is approximately 325,851 gallons.

⁹ Based on technical input from Black & Veatch.

the rate at which they are replaced will depend on the salinity of the feedwater and how the plant is operated. Treatment and disposal of the salty brine byproduct from desalination may also incur operating costs.

Electricity costs will vary depending on a range of factors, including the size of the plant, type of desalination technology, source of electricity, and quality of the feedwater. As previously noted, more saline water requires higher amounts of electricity in desalination, and thus the amount of electricity consumption is a key difference between brackish water and seawater desalination. As a result, electricity costs comprise a significant share of the costs of seawater desalination. These costs could potentially be defrayed in part by participation in demand response initiatives.

3. Demand Response Opportunities in ERCOT

Broadly speaking, demand response can be broken down into two major categories: dispatchable or non-dispatchable. For purposes of this report, we will define dispatchable as those demand response events that are initiated by ERCOT and non-dispatchable as an event not specifically initiated by ERCOT. These non-dispatchable events may include decisions made by the end-use customer to alter its consumption pattern or may include contractual obligations with another entity, such as the end-use customer's retail electric provider ("REP"), to alter consumption patterns.

ERCOT's wholesale market is open to several types of dispatchable demand response, which are deployed to maintain system reliability. Demand-side resources providing Emergency Response Service (ERS) may offer based on either a 10 or 30-minute response time, commonly referred to as the "ramp period." Alternatively, demand-side resources may register and qualify as a Load Resource that can provide Reserves in the Ancillary Services market. The most common service provided by demand-side resources is Responsive Reserve Service which requires an under-frequency relay that can instantaneously interrupt the load during certain system reliability events. Some demand-side resources can also participate in other Ancillary Services as Controllable Load Resources that require sophisticated control systems that allow them to be deployed in a more incremental, proportional manner.

Non-dispatchable demand response in ERCOT can include a response to avoid transmission costs, where rates are based on Four Coincident Peak Pricing (4CP), response to wholesale energy prices initiated by the customer or by a REP or other load-serving entity ("LSE"), or utility-managed Load Management programs (LM).

The sections that follow provide a description of both ERCOT-dispatched (Section 3.1) and non-ERCOT-dispatched (Section 3.2) demand response. For a more detailed description of opportunities for demand-side resources to participate in demand response in ERCOT, see ERCOT's guide, *Load Participation in the ERCOT Nodal Market*.¹⁰

3.1. ERCOT-Dispatched Demand Response

There are two main demand response reliability-based services administered by ERCOT: participation by demand-side resources in the Ancillary Services market and participation in ERS. These services are dispatched by ERCOT during system emergencies.

¹⁰ Available at http://www.ercot.com/content/services/programs/load/Load%20Participation%20in%20the%20ERCOT%20Nodal%20Market_3.02.d oc.

3.1.1. Ancillary Services Markets

Demand-side resources with demand response capability that can meet a set of performance requirements can be qualified to provide Ancillary Services as Load Resources in the Ancillary Services Market. The value of having a Load Resource available to reduce load is equal to the value of having a generator available to increase its generation at a generating plant. The providers of operating reserves selected to provide Ancillary Services are eligible for capacity payments regardless of whether the Resource is actually deployed (or curtailed, in the case of the Load Resource).

ERCOT holds auctions on a daily basis for each of the following Ancillary Services: Regulation Up, Regulation Down, Responsive Reserve, and Non-Spinning Reserve.¹¹ Table 1 describes the various Load Resource types and their qualification requirements and eligible services.

Table 1: Load Resource Types and Ancillary Services

Service	Load Resource Type ^a	Qualification
Responsive Reserves (≤50% of total Reserve requirement)	Non Controllable	Under-Frequency Relay and 10-minute ramp to manual dispatch instruction
Responsive Reserves	Controllable	Primary Frequency Response and follow 5-minute dispatch instructions
Regulation-Up Regulation-Down	Controllable	Primary Frequency Response and respond to Regulation deployments
Non-Spin Reserves	Controllable	Follow 5-minute dispatch instructions

^a A Controllable Load Resource is a Load Resource capable of controllably reducing or increasing consumption under dispatch control by ERCOT.

Demand-side resources that agree to reduce load when directed by ERCOT, and that meet other metering and operational requirements as specified in the ERCOT Protocols, may participate in Ancillary Services market auctions. As noted in Table 1, the type of Ancillary Service that a Load Resource may provide will depend upon the demand-side resource's response time and metering system, as well as other requirements described in the Protocols. In the Responsive Reserve and Non-Spin Reserve markets, the Load Resource will receive capacity payments regardless of whether or not the load was actually deployed, but the load must be available for deployment at any time while providing the service.

3.1.2. Emergency Response Service (ERS)

ERCOT procures ERS to maintain grid reliability during emergency conditions and reduce the likelihood of the need for rotating outages. ERS participants may offer to provide demand response with either a 10-minute ramp period requirement (similar to Load Resources providing Responsive Reserve Service) or a 30-minute ramp period requirement. ERS Resources do not have the same telemetry and under-frequency relay requirements as Load Resources.

¹¹ Regulation Up and Regulation Down service respond to signals from ERCOT every 4 seconds to respond to changes in system frequency, full response has to be provided within 5 minutes. Responsive reserves must provide their committed capacity either instantaneously in an under-frequency event (e.g. due to a generator outage) or in energy scarcity conditions within ten minutes following an instruction from ERCOT. Non-spinning reserves must provide their committed capacity within 30 minutes based on economic dispatch instructions. Non-spinning reserve is used as replacement reserve to replenish other ancillary services and during energy scarcity.

ERS is procured through a request for proposal (RFP) process three times per year, for four-month contract terms, each of which is further split into smaller time periods based on business cycles and other factors. Demand-side resources may choose to submit offers in all time periods or only in those that best fit their unique circumstances, and may vary both the price and demand response capacity offers by time period.

Payments for ERS are performed up to 80 days after each four month contract term has ended and are subject to downward revision based upon delivered demand response capacity, and the demand-side resource's availability during the contract term.

3.2. Non-ERCOT-Dispatched Demand Response

The options listed below are not dispatched by ERCOT but they either are controlled directly by a customer or are dispatchable by another entity such as a demand response provider ("DR Provider"), REP, or a transmission and distribution utility.

3.2.1. Four Coincident Peak (4CP)

Many industrial customers are subject to transmission charges based upon a Four Coincident Peak (4CP) demand. The 4CP demand is determined by averaging the consumer's actual demand during the 15-minute settlement interval with the highest ERCOT demand during each of the four summer months (June through September). This measured 4CP demand serves as the basis for the customer's transmission tariff charges for the following year. By correctly predicting the ERCOT system peaks during the summer and curtailing load during those intervals, a consumer can help reduce the stress imposed on the electric system during peak periods of consumption and reduce its transmission charges for the following calendar year.

3.2.2. LSE or DR Provider Contracted Price Response

In the competitive areas of ERCOT, consumers can contract with their REP or a DR Provider to have their load respond to the REP's or DR Provider's instructions. The contract will usually outline the parameters of this response – at what times and frequency demand response events can be called, ramp periods, sustained response periods, compensation, etc. Because this response is a contractual matter between the REP or DR Provider and the consumer, a great deal of variety can be present in these arrangements. For example, a consumer's response may be voluntary or required; compensation could come in the form of reduced energy prices or rebate payments for each curtailment event; consumers might be notified up to a day in advance, or could have no notification at all (for automated curtailment).

In areas of ERCOT not open to competition, interruptible tariffs may be available. These tariffs will usually offer a reduced energy price for defined curtailment obligations.

3.2.3. Self-Directed Price Response

REPs may offer dynamic pricing options, or consumers within a municipality or cooperative may have their energy prices determined by a published tariff, which also may be structured based upon Time-of-Use (TOU) or have a Critical Peak Pricing (CPP) or Peak Time Rebate (PTR) component. Self-directed price response refers to consumers making an independent decision to respond to energy prices contained in a governing tariff or in either the ERCOT Day Ahead or Real Time energy markets.

TOU offerings will typically have higher energy prices during normal peak periods – for example, a TOU tariff may charge one price during Monday through Friday from 2 p.m. through 8 p.m. and another price during all other times. Customers may choose to reduce consumption during these high priced periods. Load reduction can be accomplished by load shifting (loads can be shifted by

rescheduling certain processes or by utilizing thermal storage), ending certain processes that are no longer economic, or through energy efficiency measures.

Offerings that incorporate CPP usually have prescribed high prices only during certain defined periods – for example, when load or prices are expected to reach a certain level. Response to CPP may be similar to those employed under TOU tariffs, especially if CPP is reached frequently. More often, CPP is infrequent and as such, short-term load curtailment may be the more appropriate response to meet economic objectives.

4. Demand Response Potential for Seawater Desalination

This section evaluates whether the operational characteristics and economics of seawater desalination plants would enable them to participate in one or more of the various demand response opportunities in the ERCOT Region. To date, participation of seawater desalination plants in demand response programs has been limited. Neither the plant in Carlsbad nor the plant in Tampa Bay participate in demand response programs in California or Florida, respectively. However, as will be described below, it appears that these plants can be designed and operated to meet the requirements for participation in demand response and receive economic benefit from participation in these programs.

Section 4.1 describes the operational parameters that must be met for a demand-side resource to provide ERCOT-dispatched demand response and evaluates the ability of seawater desalination plants to meet these criteria. Section 4.2 discusses the tradeoffs between payments for participation in ERCOT-dispatched demand response and potential additional costs posed to seawater desalination plants. Finally, Section 4.3 presents other opportunities for seawater desalination plants to reduce their electricity costs outside of ERCOT's reliability-based services that are open to demand response assets.

4.1. Operational Considerations for ERCOT-Dispatched Demand Response

There are several key operational parameters that impact a demand-side resource's ability to participate in different demand response services: response time, recovery time, predictability of electrical demand, and flexibility of operations. This section discusses each of these considerations as they apply to seawater desalination plants.

As discussed in Section 3.1, one of the differentiating factors between ERCOT's demand response products is the amount of time within which a demand-side resource must respond to a deployment instruction to reduce electricity consumption during an event. Participation in RRS requires an automatic response within either half a second (i.e., instantaneous) based on grid frequency, or within 10 minutes via a manual instruction. ERS requires a response time of either 10 or 30 minutes. As noted in Section 2.1, the typical time to take a reverse osmosis train on- or off-line is 1-2 hours under normal, controlled, operations. To comply with the response time requirements of RRS or ERS, a seawater desalination plant would need to be able to reduce its electricity consumption far more quickly than in normal operations. This is an element of plant design that would need to be accounted for in the specifications of the project. Considerations include the potential need for on-site backup generation including uninterruptible power supply, potential impacts to plant infrastructure (e.g., piping), reverse osmosis membranes, and pretreatment systems.

The two large U.S. desalination plants provide illustrative counterpoints in this respect. The Carlsbad plant was designed to withstand instantaneous power interruptions, and has on-site backup generation, including uninterruptible power supply to provide the ability to power control systems and flush the membranes in the event of a power loss. In contrast, the Tampa Bay plant was not

designed with on-site backup generation, and a loss of power would result in a plant shutdown and may require several days to bring the plant back on-line. Thus, it appears that it is technically possible for a seawater desalination plant to meet the response time requirements for participation in demand response, so long as this factor is considered in the design of the facility.

The time it takes a desalination train to return to operations after an event is also a consideration. Demand-side resources participating in RRS must be able to come back on-line within three hours, and those participating in ERS must return within 10 hours. Again, it appears that it is technically feasible for desalination plants to meet this requirement, so long as this requirement is considered in the plant design.

An additional consideration is the predictability of a demand-side resource's electricity consumption. Participation in the responsive reserves ancillary service market requires bidding in the day-ahead market, and thus a demand-side resource must know with great accuracy (within 95%) its electrical demand at least a day ahead of time. For ERS, auctions are held three times a year for four-month contract periods. Thus, to participate in ERS, a resource must know its forecasted electrical demand several months in advance. Because seawater desalination plant operations are driven by contracted demand for water, it is likely that a plant operator would have a good idea of the plant's electrical demand days or even weeks/months in advance, especially for summer months when demand is likely to be relatively steady. An important consideration, however, is the salinity of the water, which drives the electrical requirements, and which can be impacted by recent weather events. Similarly, reductions in demand for water during non-summer months, or wet summer days where demand may be reduced, could also impact a plant's ability to predict its electricity demand.

Finally, a seawater desalination plant must have sufficient flexibility in its day-to-day operations so that it can afford to lose several hours of production when deployed for demand response. It should be noted that demand-side resources participating in RRS and ERS are called infrequently: demand-side resources providing responsive reserves were deployed one time in 2015, and ERS was not deployed that year. However, this is an important factor to consider if a plant is operating at close to full capacity and would incur financial penalties if it fails to meet its contract obligations due to a demand response event. Including additional storage and building a plant with extra capacity could help to mitigate this risk. It should also be noted that a plant operator does not need to commit the full plant capacity to these services, but rather can specify an amount of MW that will be committed. Thus, a plant operator could mitigate issues both with predictability and flexibility of plant operations by committing only a portion of its predicted electrical demand to participate in demand response.

Considering these factors together, it appears that seawater desalination plants could be designed to meet the operational requirements for participation in ERCOT's demand response services (both RRS and ERS). Because the ability to meet the requirements is dependent on the plant design, demand response would need to be considered early in a project's development if participation is desirable. Whether project developers will choose to address these requirements will depend on the economic benefits of participation in demand response, which will be discussed in the next section.

4.2. Economic Considerations for ERCOT-Dispatched Demand Response

This section describes the economic benefits to demand-side resources from participation in ERCOT-dispatched demand response programs. The average price paid for a demand-side resource participating in RRS in 2015 was \$10.87 per MW per hour, and for ERS was \$6.45 per MW per hour for the contract periods during the 2015 program year. These payments could provide a significant financial benefit to seawater desalination plants. To give a simplified example, for a plant with an electrical demand of 10 MW operating at a 100% annual load factor (10 MW × 24 hours × 365 days), the annual benefit would be on the order of \$500,000 for ERS or \$1 million for RRS.

In 2015, demand-side resources providing responsive reserves were deployed one time for a duration of 10 minutes, and ERS was not deployed.¹² The most ERS was ever deployed in a single year was two times in 2011. Thus, participation in either program could result in a substantial payment to a seawater desalination plant with a relatively low risk of deployment and associated disruption of plant operations, although it is important to note that participation in either ERCOT service subjects demand response resources to annual unannounced testing. Other than testing, the frequency of deployment will depend on grid conditions and is a risk that should be considered.

The financial benefits of participation must be weighed against the costs of designing facilities with the capabilities to operate in this manner. These include:

- The costs to design the plant to reduce electrical demand within the required timeframes for demand response and to withstand an instantaneous interruption, if not already part of the plant design. For example, a plant may need to be designed to have backup power generation on-site. In addition, there could also be costs to restart the system after an interruption.
- The costs to build a plant with excess capacity and/or storage to make up for lost production hours when demand response is deployed. This will add to the total capital costs of the project. Land area constraints should also be considered when considering additional storage, as the space requirements for the necessary storage capacity could be significant.
- Costs associated with the impact of interruptions on plant processes (e.g., more frequent replacement of membranes, impacts to pretreatment system or plant infrastructure).
- Potential financial penalties that would be incurred if deployment as part of demand response were to result in failure to meet contract obligations to supply water.
- The loss of potential benefits in the form of cost avoidance from participation in non-ERCOT-dispatched demand response opportunities (see Section 4.3). If a plant is committed to RRS or ERS, the plant operator would lose the flexibility to take advantage of these other opportunities to reduce their electricity costs.

The interplay of these benefits and costs will determine whether it would be beneficial for a future seawater desalination plant to participate in demand response in ERCOT.

4.3. Considerations for Non-ERCOT-Dispatched Demand Response

Outside of the reliability-based services administered by ERCOT, there are other opportunities for seawater desalination plants to reduce their electricity costs. As described in Section 3.2.1, seawater desalination plants may be able to reduce the demand charges on their electricity bills through curtailing load during 4CP intervals. In addition, plant operators may adjust operations in response to real-time electricity prices to take advantage of lower off-peak prices and avoid price spikes (see Sections 3.2.2 and 3.2.3). All of these opportunities require that the plant have flexibility to reduce production during certain times of the day.

In the ERCOT region, as noted above, a portion of transmission and distribution charges are set based on the peak systemwide 15-minute interval of the four summer months (June through September), referred to as the four coincident peaks (4CP). Large customers can reduce or avoid this charge by reducing electrical consumption during these four peak intervals. AEP Central Texas and CenterPoint are the transmission providers covering the majority of the Gulf Coast in Texas.¹³

¹² ERCOT. June 2016. "Load Resource Deployment Update." Available at http://www.ercot.com/content/wcm/key_documents_lists/87098/5_RRS_Load_Resource_Deployment_Update.pdf.

¹³ It is also possible that a seawater desalination plant could be located in an area that as not opted in to competition, in which case the plant owner would need to negotiate its electricity charges bilaterally with the Non Opt-In Entity (NOIE).

Assuming a future seawater desalination plant would be connected at transmission-level voltages, the relevant 4CP charges based on the 2016 tariffs, accounting for both transmission charges and transmission cost recovery factors, would be \$4.1425 per 4CP kW for AEP Central Texas and \$4.1870 per 4CP kVA for CenterPoint.¹⁴ If a seawater desalination plant has 10 MW of load and is capable of interrupting all of it, and successfully does so for all four 4CP intervals, the savings based on the 2016 tariffs would be approximately \$500,000 per year ($\$4.1425 \times 1,000 \text{ (kW to MW)} \times 10 \text{ MW} \times 12 \text{ months}$). Thus, a seawater desalination plant that reduces its electricity use during the 4CP intervals could avert some or all of these charges.

Another opportunity for seawater desalination plants to reduce their electricity costs is through adjusting operations in response to real-time electricity prices. In 2015, the average electricity price in ERCOT was \$26.77/MWh. However, prices exceeded \$50/MWh in 254 hours (3% of all hours), \$100/MWh in 88 hours (1%), \$200/MWh in 40 hours (0.5%), and \$300/MWh in 21 hours (0.2%). Prices exceeded \$3,000/MWh for 0.21 hours.¹⁵ Depending on the desalination plant's exposure to real-time wholesale market prices (via its retail contract), the degree of high prices the plant owner is willing to avoid, and grid conditions in a given year, reducing unit operations in order to avoid high electricity prices could impact operators for anywhere between a few and several hundred hours out of the year. In addition, a plant can plan its operations to take advantage of lower electricity prices during off-peak periods (e.g., at night when generation from wind is high). For example, at least one company is marketing a modular desalination unit design intended to take advantage of low prices during periods of high renewables generation and to provide grid reliability services through demand response.¹⁶

There are several factors to consider regarding these opportunities to reduce electricity costs. The plant would need to monitor the ERCOT market, or hire a contractor to do so, in order to know when to reduce demand for electricity. These programs do not impose any requirements on response time as with RRS or ERS, and there may be sufficient warning of 4CP intervals or peak pricing to allow the plant operator to plan its operations earlier in the day with sufficient time to ramp down production under controlled conditions. However, quicker ramping capability may be desirable to respond to electricity price fluctuations.

For 4CP, because the four intervals used to set demand charges are not known ahead of time, it is likely that the plant would need to reduce its demand multiple times per summer to ensure the 4CP intervals are hit, impacting production at the facility. Timing operations to coincide with off-peak pricing or to avoid price spikes would similarly result in reduced operations during certain hours. To offset the lost production hours, the plant may need to be designed with extra capacity and water storage capability to maintain the ability to meet its contractual obligations for freshwater delivery. Because the period of reduced operations is greater than with ERCOT-dispatched demand response services, this need would be greater for a seawater desalination plant reducing load during 4CP intervals or in response to real-time electricity prices, and would increase the capital costs of the project. It should also be noted that high prices in the ERCOT Region typically, but not always, occur in summer months, when drought conditions are more likely to develop and demand for desalinated water is likely to be highest. This may limit the flexibility of the plant to time its electricity consumption to avoid high-priced hours.

¹⁴ Public Utility Commission of Texas. "Transmission and Distribution Rates for Investor Owned Utilities." Available at <http://www.puc.texas.gov/industry/electric/rates/tdr.aspx>.

¹⁵ Potomac Economics. June 2016. *2015 State of the Market Report for the ERCOT Wholesale Electricity Markets*. Available at https://www.potomaceconomics.com/index.php/markets_monitored/ERCOT.

¹⁶ Sisyuan LLC. "Demand Response Desalination." Available at <http://renewabledesalination.com/wp-content/uploads/2015/06/Demand-Response-Desalination.pdf>.

In addition, the plant's ability to participate in demand response would also be limited for those hours it is reducing load as part of 4CP response or in response to real-time prices, because the plant would not be able to reduce its electricity consumption if that demand is already committed to another demand response service. Thus, participating in demand response versus taking advantage of these other opportunities may be, to some extent, mutually exclusive.

5. Conclusion

Based on this analysis, it appears that the operational characteristics of seawater desalination plants would allow them to participate in demand response opportunities in ERCOT, so long as the necessary operational requirements are considered in the design specifications of the plant. Project developers should consider the necessary requirements early in the plant design. Whether the economic benefits of participation would provide a sufficient incentive for them to do so will depend on the costs of accommodating those operational requirements, and whether there is the flexibility available to operate the plant as necessary under these programs. Though most existing seawater desalination plants do not participate in demand response programs, it does appear that participation by these plants is possible and could result in a financial benefit. Table 2 compares the different demand response opportunities available to demand-side resources in ERCOT.

Table 2: Comparison of Demand Response Opportunities

Demand Response Opportunity	Requirements for Participation	Impacts to Plant Operations	Financial Benefit
Ancillary Services – Responsive Reserve Service (RRS)	<ul style="list-style-type: none"> • Under-Frequency Relay • Instantaneous or 10 minute response time • Recover load within 3 hours • Bid in day-ahead market 	<ul style="list-style-type: none"> • Deployed once in 2015 for 10 minutes • Subject to annual unannounced testing 	<ul style="list-style-type: none"> • \$10.87 per MW per hour (based on 2015 prices)
Emergency Response Service (ERS)	<ul style="list-style-type: none"> • 10 or 30 minute response time • Recover load within 10 hours • Four-month contract term 	<ul style="list-style-type: none"> • Not deployed in 2015; the most times ever deployed in a single year was twice in 2011 • Subject to annual unannounced testing 	<ul style="list-style-type: none"> • \$6.45 per MW per hour (based on 2015 prices)
Four Coincident Peak (4CP)	<ul style="list-style-type: none"> • Interval Data Recorder (IDR) meter • Ability to predict system-wide peak demand hours during summer months 	<ul style="list-style-type: none"> • Likely plant will need to reduce load multiple times per summer to hit 4CP intervals • Likely to be able to predict possible 4CP intervals earlier in day 	<ul style="list-style-type: none"> • Avoid ~\$48,000 per 4CP MW per year (based on 2016 tariffs) if successful in reducing during all four summer months
LSE or DR Provider Contracted Price Response	<ul style="list-style-type: none"> • Varies based on contractual arrangements 	<ul style="list-style-type: none"> • Varies based on contractual arrangements 	<ul style="list-style-type: none"> • Varies based on contractual arrangements
Self-Directed Price Response	<ul style="list-style-type: none"> • Retail contract with exposure to real-time market prices • Ability to monitor real-time prices in ERCOT wholesale market 	<ul style="list-style-type: none"> • Varies depending on number and severity of pricing events • May be able to predict peak pricing events earlier in day 	<ul style="list-style-type: none"> • Varies depending on number and severity of pricing events

Demand response programs in ERCOT provide opportunities for demand-side resources to defray their electricity costs and provide reliability benefits to the ERCOT electric grid. Because the process of seawater desalination is energy intensive, participation in demand response could help to reduce electricity costs while posing a relatively low risk to plant operations if demand response participation is factored into plant design.

Participation in non-ERCOT-dispatched demand response opportunities, such as reducing load during 4CP intervals or in response to real-time electricity prices, may also help to reduce electricity costs for seawater desalination plants in Texas. As stakeholders in Texas continue to plan for possible future droughts in the region and identify water management strategies, consideration of demand response could play a role in mitigating some costs associated with seawater desalination, and allow seawater desalination plants to assist with maintaining electric reliability in the region.