Reliability Risks Due to Coal Retirement at ERCOT

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Executive Summary

Market forces are transitioning Texas to a cleaner electric grid. Due to Texas's abundant low cost natural gas and increasing renewable penetration, coal-fired power plants are under economic strain that may be too great to overcome, even without new federal environmental regulations. Furthermore, if federal environmental regulations are added to the equation coal units will face increased cost, further worsening coal plants' economics.

Recent Brattle and ERCOT studies[1] have forecasted that due to these factors, some coal plants in ERCOT may shut down over the next few years. New gas and renewable capacity is likely to be added to replace coal plants that may retire and to meet additional electricity demand. As Texas continues this transition, the reliability of the ERCOT grid is important. It is the purpose of this study to explore reliability issues that could arise within ERCOT in the future with the retirement of existing coal plants.

We conclude that coal plant retirements are unlikely to impact ERCOT's reliability. As we discuss in this paper, there are safeguards in place to ensure that reliability issues that may arise can be addressed by ERCOT and the state. As a last resort, the US Department of Energy can prevent a unit's retirement under Section 202(c) of the Federal Power Act, if no other solution is found.

ERCOT is currently oversupplied and the forecasted additions of natural gas, solar, and wind generation should provide a cushion to absorb many of the retirements that may occur. In addition, ERCOT's market is designed to, and has to date, effectively dealt with resource adequacy needs. In an extreme scenario, such as a large number of coal plants retiring almost simultaneously, system resource adequacy could be diminished resulting in more frequent scarcity events, but this is unlikely to result in significant customer outages.

Should a large number of coal units announce to exit the market around the same time with little warning (ERCOT rules require 90-day notification), maintaining local transmission reliability is likely to be more challenging than maintaining system resource adequacy. In the past, ERCOT has dealt effectively with the local transmission reliability problems that have arisen, even when only the minimum, 90-day notice was given. To address the potential local transmission

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[1] Ira Shavel et al. Exploring Natural Gas and Renewables in ERCOT, Phase IV. May 17, 2016. Posted at http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626 and Doug Murray, 2016 LTSA Update, June 21, 2016, posted at http://www.ercot.com/content/wcm/key_documents_lists/77730/2016_LTSA_Update_6_21_2016.pptx 7,200 MW added in "Texas Recession" scenario; 11,900 MW added in "Environmental Mandate" scenario.

reliability challenge ERCOT may face over the next few years, there are a number of short- and long-term options available to ensure local reliability.

In the short term, the backstop would be a Reliability Must Run (RMR) agreement with a coal plant owner to keep the unit in service until another solution can be implemented. This would resolve the reliability issue until ERCOT is able to identify other short-term options to replace the RMR agreement in the form of Must Run Alternatives (MRA). The MRA alternatives ERCOT can look to include short-term transmission solutions, local demand response, distributed generation, and short-term contracts with new grid connected generation.

In the long term, new generation resources (gas, wind, solar, and storage), demand-side resources, and transmission upgrades can be developed to resolve the local transmission reliability issues. Brattle and ERCOT analyses have found that up to 13 GW of new solar capacity may be added by 2022.[2] In this study, we find the existing Competitive Renewable Energy Zones (CREZ) transmission system may support up to 11 GW of new solar capacity additions in West Texas.

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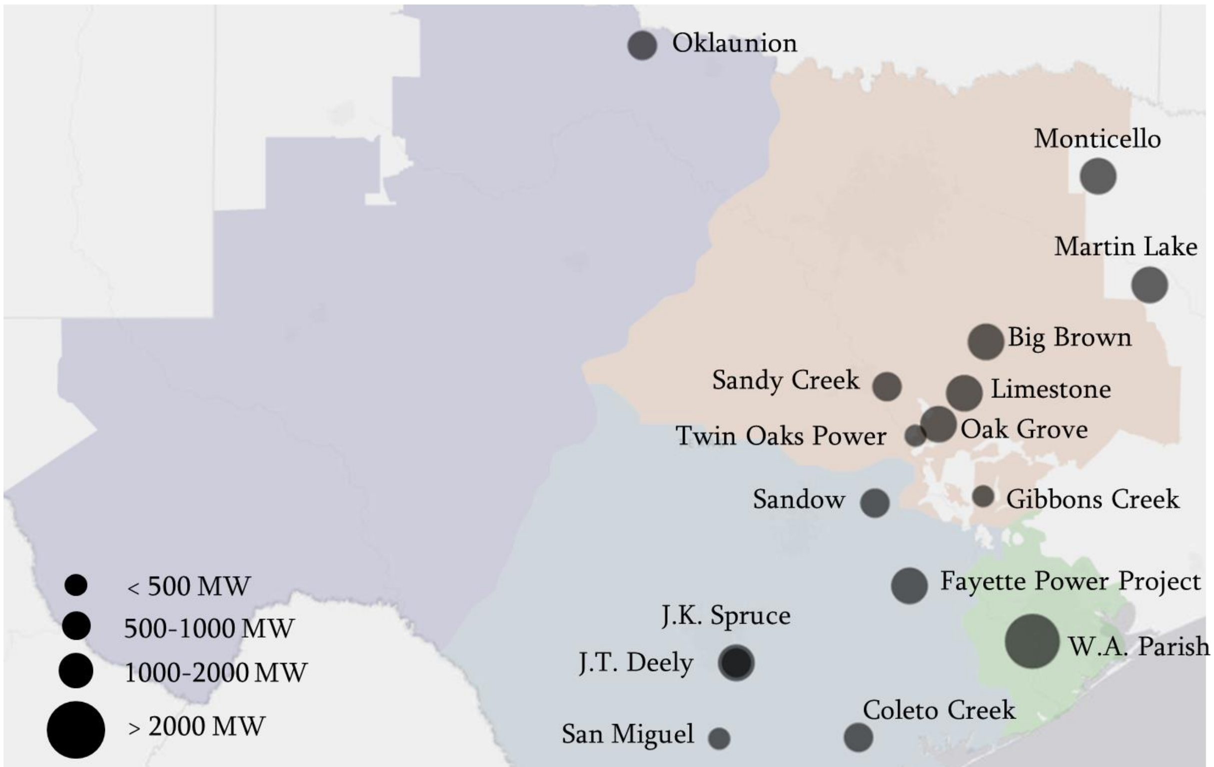
2 *Ibid.*

I. Introduction

Coal is currently a significant part of ERCOT's generation fleet. As of May 2016, ERCOT had 19.2 GW of coal plants, almost 20% of its 90 GW fleet.[3] Figure 1 shows the geographical distribution of the coal power plants that operate within ERCOT. From 2010 to 2015, the coal fleet provided 28%-40% of total electricity generation.[4]

Figure 1
Operational Coal-Fired Power Plants in ERCOT as of May 2016



Source: SNL Financial LC

However, market and regulatory forces are now challenging ERCOT's coal plants. Current natural gas prices are at very low level and are forecasted to remain low for the foreseeable future, which is detrimental to the margins of coal units. Increasing renewable penetration is also crowding out coal as off-peak net load decreases. Furthermore, potential environmental regulations, such as the Regional Haze Rule and the Clean Power Plan, would impose additional challenges to coal units by either requiring installation of environmental control equipment, which requires significant capital expenditure, or requiring coal units purchase allowances or carbon credits to operate, imposing a per MWh cost. These factors could drive ERCOT's coal-

3 ERCOT, Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2017-2026, May 3, 2016

4 ERCOT news release, January 15, 2016, http://www.ercot.com/news/press_releases/show/86617

fired power plants to retire and pose both resource adequacy and local transmission reliability problems.

The purpose of this paper is to evaluate the reliability risks posed by coal retirements and to review options to mitigate these risks. It is important to note that by law ERCOT is prohibited from contracting with any party whose resource will participate in the wholesale market except for short-term mitigation of transmission reliability problems. Therefore, generation solutions are largely unavailable to ERCOT.

We first review the key drivers of potential coal-fired power plants retirement, then evaluate the impacts of the potential retirements on reliability, and finally discuss the options available to mitigate the risks in the short term and long term.

A. Key Drivers of Potential Coal Retirement

i. Low Gas Prices

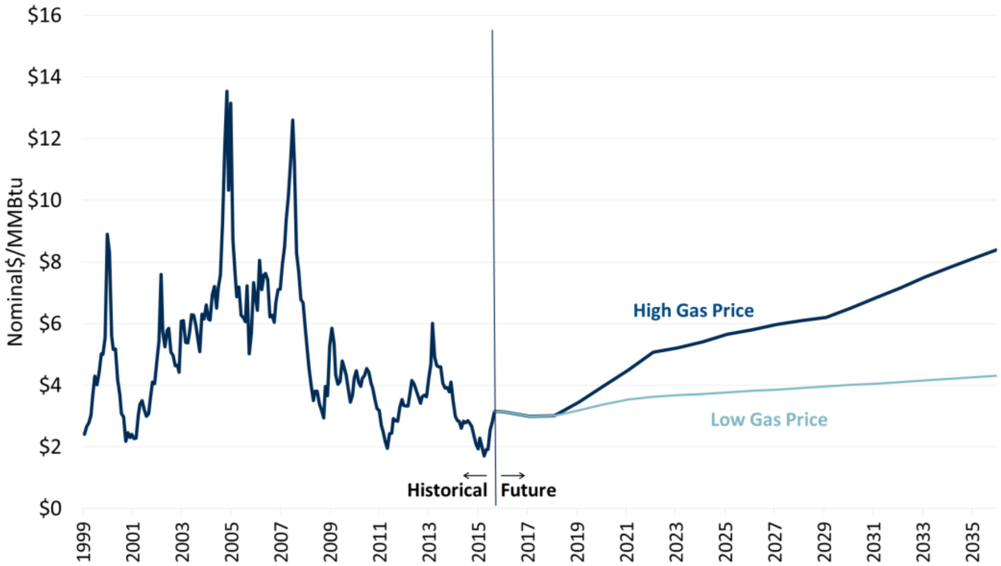
Natural gas prices are important for profit margins of coal units as gas-fired generators are marginal resources in the power market for most of the hours and therefore set prices. Since 2009, Henry Hub gas prices have largely remained below $4/MMbtu, and averaged $2-$3/MMbtu during the last two years. Gas prices are projected to remain low for the foreseeable future. Figure 2 shows the gas price trajectory used in Brattle's prior analysis.

Low natural gas prices have reduced profit margins for coal plants and threaten their economic profitability. According to the ERCOT 2015 State of the Market Report:[5]

"The generation-weighted price of all coal and lignite units in ERCOT during 2015 was $25.94 per MWh…. With a typical heat rate of 10 MMBtu per MWh, the fuel-only operating costs for coal units in 2015 may be inferred to be approximately $30 per MWh…. it appears that coal units were not likely to be profitable in ERCOT during 2015."

[5] Potomac Economics, 2015 State of the Market Report For the ERCOT Wholesale Electricity Markets, June 2016, posted at https://www.potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

Figure 2
Historic and Projected Henry Hub Gas Prices Used in Brattle Prior Analysis



Source: Ira Shavel et al. Exploring Natural Gas and Renewables in ERCOT, Phase IV. May 17, 2016. Posted at http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626.

ii. System Oversupply for the Next Few Years

Based on ERCOT's Capacity, Demand, and Reserve Report (CDR Report),[6] from 2014 to May 2016, 3.1 GW of gas plants and 4.8 GW of wind were added to ERCOT. Looking forward, 7.4 GW of thermal resources have a Signed Generation Interconnection Agreement (SGIA) and have obtained an Air Permit, GHG Permit and Water rights. An additional 11 GW of wind resources and 1.8 GW of solar resources also have a SGIA. Assuming all the resources with a SGIA are all added to the system, the reserve margin for ERCOT in the next few years will be well above the target reserve margin of 13.75%. While it is doubtful that all of these projects will be built, it does indicate that new investment in ERCOT will further increase supply and reduce the margins of existing generators.

As a result of the new wind additions, net load has been decreasing. The ERCOT 2015 State of the Market Report notes that the minimum net load has dropped from approximately 20 GW in 2007 to below 15.4 GW last year, despite strong load growth during these years, while total coal plus nuclear was about 25 GW. This trend is likely to accelerate as more wind is added to the ERCOT system over the next few years and further squeeze coal unit margins.

6 ERCOT, Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2017-2026, May 3, 2016.

iii. Potential Federal Environmental Regulations

Another challenge that coal units face is the potential for new air regulatory requirements. The most significant of the rules are the Regional Haze Rule and the Clean Power Plan (CPP).

Texas submitted its SIP in 2009 to EPA, which was partially disapproved and replaced with a Federal Implementation Plan (FIP) by EPA in January 2016. In July, the Fifth Circuit Court stayed EPA's FIP while the parties negotiated a solution, but a consensus was not reached. The FIP would have required expensive new or upgraded flue gas desulfurization equipment for eight GW of coal capacity in ERCOT; however, EPA has announced that it would remand the rule on November 28, 2016[7]. The future of the Regional Haze Rule in Texas is uncertain at this point.

In August 2015 EPA published the CPP to regulate carbon emissions in the electric sector in each state. The rule allows for several compliance alternatives for each state. States could choose from one of several rate-based standards or mass-based standards. Both rate- and mass-based compliance requires that coal units purchase allowances or carbon credits to operate, imposing a per MWh cost.

The CPP rule was stayed by the Supreme Court in February 2016 and an oral argument was held on September 27th by the full DC Circuit Court. While the eventual outcome is unknown, coal plant owners are likely to take the potential cost of compliance with some form of a CPP into consideration when deciding whether or not to continue operating a coal plant.

II. Effects of Coal Retirements on ERCOT's Reliability

The factors reviewed in the section above could lead to substantial amount of coal retirements. A recent Brattle analysis showed that up to 12 GW of coal-fired units in ERCOT could retire by 2022 due to persistently low natural gas prices and implementation of the Regional Haze Rule in Texas.[8] The ERCOT 2016 Long-Term System Assessment (LTSA) shows 9.8 GW of coal retiring under the Current Trends scenario by 2022.[9]

There are two broad reliability concerns associated with unit retirements. The first is system resource adequacy. Resource adequacy can be diminished resulting in more frequent scarcity

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7 The US Court of Appeals for the Fifth Circuit, No. 16-60118, Nov 28th, 2016

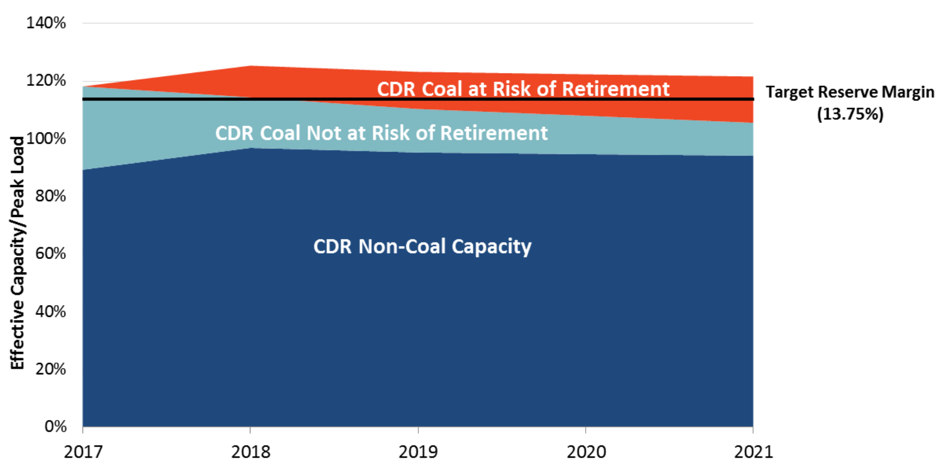
8 Ira Shavel et al. Exploring Natural Gas and Renewables in ERCOT, Phase IV. May 17, 2016. Posted at http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626

9 Doug Murray, 2016 LTSA Update. June 21, 2016. Posted at http://www.ercot.com/content/wcm/key_documents_lists/77730/2016_LTSA_Update_6_21_2016.pptx

events if a large group of units retires quickly and the overall ERCOT reserve margin falls below the targeted level. ERCOT's market is designed to and has to date effectively dealt with resource adequacy needs. Resource adequacy might become a problem for the short term if there is not enough time for market participants to add sufficient new resources.

Figure 3 shows ERCOT's forecasted reserve margin based on existing and planned capacity from ERCOT's most recent CDR, as well as Brattle's projection of coal retirements under a persistently low natural gas price scenario.[10] The figure shows that before 2017, the reserve margin stays above the targeted reserve margin of 13.75% due to the development of new power plants.[11] However, coal retirements could substantially reduce the reserve margin at ERCOT to a level below the targeted reserve margin after 2018.

Figure 3
Potential Effect of Coal Retirements on ERCOT Reserve Margin



Source: Existing and planned capacity are based on ERCOT's May 2016 CDR; coal at risk of retirement is based on Brattle's analysis[12]

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10 ERCOT, Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2017-2026, May 3, 2016, posted at http://www.ercot.com/content/wcm/lists/96607/CapacityDemandandReserveReport_May2016.pdf

11 Per the 2016 CDR report, as of May 3, 2016, 7.4 GW of thermal resources at ERCOT, predominantly gas plants, have executed SGIA (Signed Generation Interconnection Agreement) and obtained air Permit, GHG permit and water rights, along with 11 GW of wind resources and 1.8 GW of solar resources that have also executed SGIA.

12 Ira Shavel et al. Exploring Natural Gas and Renewables in ERCOT, Phase IV. May 17, 2016. Posted at http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626

It is important to note that Figure 3 does not suggest that coal retirements will necessarily cause a significant system resource adequacy problem. However, if multiple retirements were to occur soon and with short notice in a manner unanticipated by market participants, those participants may not be able to add enough supply resources to avoid a short-term resource adequacy issue. Unlike some (but not all) RTOs, little notice is required to deactivate a unit in ERCOT. In ERCOT units wishing to retire are required to provide only 90-days' notice.[13] In comparison, MISO requires 26 weeks of notification,[14] NYISO requires 365 days of notification,[15] and ISO New England requires resources to submit retirement and permanent delist bids approximately one-year prior to the three-year forward capacity auction being held.[16] Similar to ERCOT, PJM and CAISO both require only 90-days' notice.[17,18] However, PJM has a capacity market that requires suppliers to buy out of their capacity commitments if exiting the market with short notice. CAISO also has a resource adequacy program that procures sufficient supply annually at system level to meet the targeted reserve margin and at a local level to ensure local reliability. Thus, the impact of abrupt coal retirement could pose greater challenges for ERCOT than other RTOs to mitigate the risks on resource adequacy.

The second concern is local transmission reliability. In analyzing the potential coal retirements that might occur due to the Regional Haze Rule, ERCOT found significant local reliability impacts[19]. In this case of local problems, the market is unlikely to provide a signal for appropriate local new entry. The ERCOT market has at best limited locational signals for entry. The locational marginal prices (LMPs) may indicate that an existing plant location (or electrically close) would provide better revenue than alternative locations. However, since the Operating Reserve Demand Curves (ORDC), which is meant to provide an energy price signal for resource

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13 ERCOT Nodal Protocols, 3.14.1.1. Posted at http://www.ercot.com/mktrules/nprotocols/

14 MISO Module C, Section 38.2.7, posted at https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=19173

15 NYISO, Technical Bulletin 185, posted at http://www.nyiso.com/public/webdocs/markets_operations/documents/Technical_Bulletins/Technical_Bulletins/Technical_Bulletins/tb_185.pdf

16 http://www.iso-ne.com/static-assets/documents/2016/01/20160128-existing-capacity-qual-process-gen-imports-dr.pdf

17 PJM Manual 14 Section 9.1.1, posted at http://learn.pjm.com/~/media/documents/manuals/m14d.ashx . Resources with forward capacity market commitments must buy out of their commitments

18 CPUC General Order 167, Operating Standards (OS) 22 – 24, posted at http://docs.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/108114.htm

19 ERCOT Regional Planning Group, Transmission Impact of the Regional Haze Environmental Regulation, Oct 15, 2015, posted at http://www.ercot.com/content/wcm/key_documents_lists/76860/Transmission_Impact_of_the_Regional_Haze_Environmental_Regulation__Oct_RPG.pdf

scarcity, is set at the system level instead of local level, it does not provide a locational signal. Similarly, prices for the ancillary services products are also set at the system level and do not vary by location.

In summary, poor or worsening economic prospects combined with looming environmental compliance costs may push many units to retire quickly leaving insufficient time for the market to respond, and market price signals are not likely to attract new resources at the needed locations. The next section will explore what options are available to mitigate these risks.

III. Options to Mitigate Reliability Risks From Coal Retirement

The Texas generation sector was deregulated in 1999 by SB 7 which separated generation and transmission sectors. ERCOT began to operate the wholesale market in 2002, which enabled retail choice. By law, ERCOT cannot plan or contract with wholesale market participants and merchant generation investors must make all of the decisions about when and where to invest in ERCOT. ERCOT's infrastructure role is limited to planning transmission expansion and upgrades. Thus, in ERCOT resource adequacy is ensured through incentivizing merchant generation investment through market prices, while ERCOT is responsible for transmission reliability.

When local reliability needs arise, as they might with coal unit retirements, both transmission and generation are potential solutions. However, ERCOT's primary responsibility is maintaining transmission system reliability. Therefore, ERCOT must take a transmission-based approach except for limited short-term reliability needs (for example RMR and MRA). If a merchant plant is planned for a location that might help address local reliability, ERCOT would take that plant into account in its planning, but ERCOT cannot in any way incent generation beyond what is provided by market prices.

A. Short-term Options

As mentioned above, a generator only needs to notify ERCOT 90 days before it retires, leaving ERCOT with limited time and options. However, there are still some options available to ERCOT to mitigate the risks in the short term

i. Short-Term Operational Options

ERCOT's Reliability Must Run (RMR) policy requires ERCOT to look for short-term alternatives that can avoid the need for an RMR agreement with a generator. ERCOT is required to look the following options:[20]

[20] ERCOT Nodal Protocols 3.14.1, posted at http://www.ercot.com/content/wcm/current_guides/53528/03_070116_Nodal.doc

- Remedial Action Plans (RAPs) and Special Protection Systems (SPSs);
- Load response alternatives; and
- Resource alternatives, including capabilities of distributed generation (DG), load resources.

SPSs are pre-planned automatic actions, and RAPs are operator actions taken when an element is going to be overloaded. Load response and generation resource alternatives are possible if existing demand resources or generators are available.

Three short-term technological solutions are possible for local reliability, which generally fit into RAP category: dynamic power flow, dynamic line ratings, and transmission topology control.

- Dynamic Power Flow: These are new technologies to control the impedance of individual lines. Using these technologies, system operators can adjust the flow through the transmission network.[21]

- Dynamic Line Ratings: Transmission lines are rated for a conservative set of weather conditions (low wind speed, high ambient temperature, and high solar radiation) and physical line conditions. Adjusting ratings for actual ambient and physical conditions of the lines can increase ratings significantly. ONCOR participated in a DOE funded pilot that incorporated sensor data used to adjust line ratings and used the resulting ratings in the ERCOT market engine.[22] ONCOR found 6-14% line rating increases.

- Transmission Topology Control[23]: Under certain circumstances, operators switch lines that might otherwise overload out of the system. This is done on an ad hoc basis. Transmission Topology Control formalizes these ad hoc procedures and makes them an integral part of market operations. In effect, the market operator dispatches generation and transmission. This can be very effective way to mitigate local reliability impact due to generation unit retirements.

These three technologies have a basic advantage over generation or demand-side solutions in that they address the transmission problem directly and often more effectively than generation or load resources can. This is because generation and load reductions reduce the flow on affected transmission lines, but by only a fraction of MW of the generation or load reduction. This is

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21 http://www.smartwires.com/

22 https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf

23 http://newgridinc.com/wp-content/uploads/2015/08/PRuiz-TCA-FERC-Tech-Conference-2015-FINAL.pdf

often called the "shift factor." Direct control of the transmission system is generally more effective.

ii. Reliability-Must-Run Contracting

Reliability Must-Run (RMR) Service contracts are a short-term, backstop measure through which ERCOT can directly contract with a generator to prevent it from retiring or entering into long-term mothball status, if doing so would be "necessary to provide voltage support, stability or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist".[24] Whenever a generator provides a 90 day notice of its intent to cease operations for a period of greater than 180 days, including seasonal mothballing, ERCOT evaluates if an RMR contract is needed. If an RMR contract is necessary to avoid system reliability problems, ERCOT can contract with the generator to provide payments to cover going-forward costs. ERCOT cannot compel a generator to enter into an RMR agreement. Once in place, ERCOT also can exit an RMR agreement with 90 days' notice to the RMR unit owner.

Since the implementation of the nodal market, ERCOT has rarely entered into RMR contracts. ERCOT's June 2016 RMR agreement with the Greens Bayou Unit 5 plant was the first since 2011.[25] ERCOT staff has stated that market based solutions are preferred to RMR, but that RMR contracts may be increasingly necessary going forward.[26]

After a 90 day notification ERCOT must make an initial determination of need for the unit within 24 days. ERCOT must make a final determination of need 60 days after receiving the notification. As part of the evaluation process, ERCOT must consider potential lower-cost alternatives to an RMR agreement. If a cost-effective alternative is identified, ERCOT must develop a timeline to study and/or implement it.

RMR contracts cover major going-forward fixed and variable costs, but not all costs. Excluded costs include depreciation, return on equity, debt and interest, and taxes. The resource owner provides good faith estimates of covered costs to ERCOT, who reviews and approves the budget.

In general, RMR contracts are limited to a length of one year. However, ERCOT may execute RMR contracts of length greater than one year if the generator owner must make a major capital

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24 ERCOT Nodal Protocols 3.14.1, posted at http://www.ercot.com/content/wcm/current_guides/53528/03_070116_Nodal.doc

25 SNL Financial LC. ERCOT board approves reliability must-run agreement for NRG plant, June 15, 2016.

26 *Ibid.* "ERCOT Vice Chair Judy Walsh said she did not have an issue with the Greens Bayou plant, but that "the whole idea of RMR" should be examined, with the goal of moving toward more market based solutions. "In the future you could see more and more of these [RMR agreements] as the mix changes," she said, adding that market based solutions might be a better way to deal with the underlying issue."

expense to comply with environmental regulations, or if ERCOT deems that an RMR contract is appropriate to continue operations for more than12 months.

Although RMR contracts are designed to address local reliability issues, ERCOT has used them in 2011, with the approval from the PUC, to manage the system outage issue due to record-breaking temperature and severe drought.[27]

iii. Must-Run Alternatives (MRA) Contracting

Within 90 days' after the execution of an RMR Agreement, ERCOT is required to explore if there are lower-cost alternatives available to provide solutions to address the reliability concerns that would otherwise be solved by the RMR units. Based on the ERCOT protocol, the annual savings from the proposed MRA resources need to be at least $1 million more than the projected net annualized costs for the RMR agreement and the resource satisfies objective financial criteria to demonstrate that the seller is reasonably able to fulfill its performance obligations as determined by ERCOT.

ERCOT is required to provide the information that allows a potential alternative resource to evaluate its capability to replace an RMR unit in a more cost effective way. This includes at a minimum the technical requirement and/or operational characteristics required to eliminate the need for the RMR Unit. The MRA alternatives ERCOT can look to include short-term transmission solutions, local demand response, distributed generation, and short-term contracts with new grid connected generation. Once MRA resources are identified, ERCOT can start to implement the alternative and consider exiting the RMR agreement[28].

iv. Federal Authority

If ERCOT and state authorities could not reach an agreement with a generation owner to retain a unit in service that was needed for reliability, the U.S. Department of Energy has authority under Section 202(c) of the Federal Power Act to direct the operation of electric generation plants in order to maintain the reliability of the bulk power system in 2005. DOE used its authority to prevent the Potomac River Power Plant from shutting when its owner, Mirant, wanted to close the facility.

B. Long-term Options

In the long term, additional generation capacity or upgrade transmission lines can be brought online to address reliability concerns. As already noted, ERCOT cannot evaluate or plan

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27 ERCOT, http://www.ercot.com/news/releases/show/424

28 For more details about the protocols of RMR and MRA, please refer to ERCOT current nodal protocol, Section 3.14.1, posted at http://www.ercot.com/content/wcm/current_guides/53528/03_070116_Nodal.doc

generation as part of transmission solutions. However, properly located new or expanded merchant generation can mitigate reliability difficulties and are discussed below.

i. New Generation Supply Options

1. *Gas Power Plants*

Gas power plants are an option to replace retiring coal capacity. A significant amount of new gas plants are currently under development. As of May 2016, more than 6 GW of gas plants are expected to come online by 2020 with a SGIA, Air Permit, GHG Permit and Water Rights.[29]

Coal plant capacity can either be replaced by building a greenfield gas plant at a new site or brownfield development at the same site. However, brownfield sites may require significant remediation, which could make them unsuitable for redevelopment as gas plants.

The construction time for new gas plants in ERCOT since 2000 has ranged from 1 – 3 years.[30] Combustion turbines have taken up to 14 months to build; combined cycle plants have taken up to 33 months.[31] When brownfield sites have been redeveloped, construction times appear to be been slightly faster to develop than greenfield sites.

2. *Utility-Scale Solar*

Relative to much of the United States, Texas has very high quality solar resources, as shown in Figure 4. In comparison to conventional fossil power plants, solar power plants can be built relatively more quickly. Since 2010, the construction time for solar additions, either new facilities or expansions to existing facilities, has generally been less than a year.[32]

Solar deployment is expected to grow in the coming years due to declining cost, federal tax incentives and the high quality of solar resources in ERCOT. Prior Brattle and ERCOT analyses have found that up to 13 GW of new solar capacity may be added by 2022.[33] Much like wind,

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29 ERCOT, Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2017-2026, May 3, 2016, posted at http://www.ercot.com/content/wcm/lists/96607/CapacityDemandandReserveReport_May2016.pdf

30 Brattle analysis based on new construction data from Velocity Suite, ABB Inc.

31 *Ibid.*

32 *Ibid.*

33 Ira Shavel et al. Exploring Natural Gas and Renewables in ERCOT, Phase IV. May 17, 2016, posted at http://www.brattle.com/system/publications/pdfs/000/005/292/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT__Part_IV_-_The_Future_of_Clean_Energy_in_ERCOT.pdf?1464026626 and Doug Murray, 2016 LTSA Update, June 21, 2016, posted at

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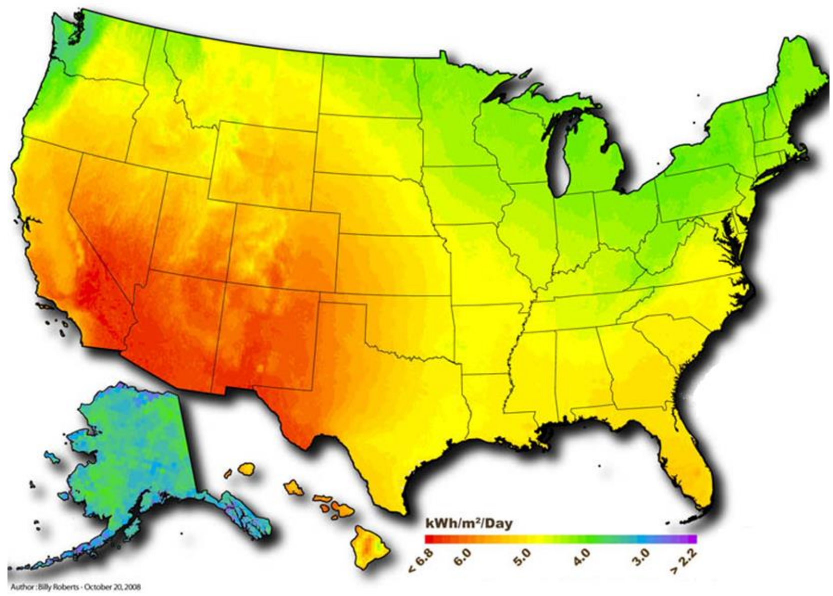
the highest quality solar resources in ERCOT are in western Texas. Using solar data from locations throughout Texas, we find that the capacity factor of East Texas solar is on average 20% lower than that of West Texas solar.[34] This is consistent with the current trend that all of the planned solar projects in ERCOT are in the western area.

Figure 5
US Solar Potential



Sources and Notes:

National Renewable Energy Laboratory (NREL). Annual average solar resource data are shown for tilt = latitude collector. The data for Hawaii and 48 contiguous U.S. states are a 10 km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998 – 2005.

This raises the question of how much solar power from the western area can be brought to market by the current CREZ transmission system before its output gets curtailed due to transmission constraint and solar in East Texas becomes more appealing. While many factors affect where merchant developers decide to develop a solar plant, such as the locational prices it

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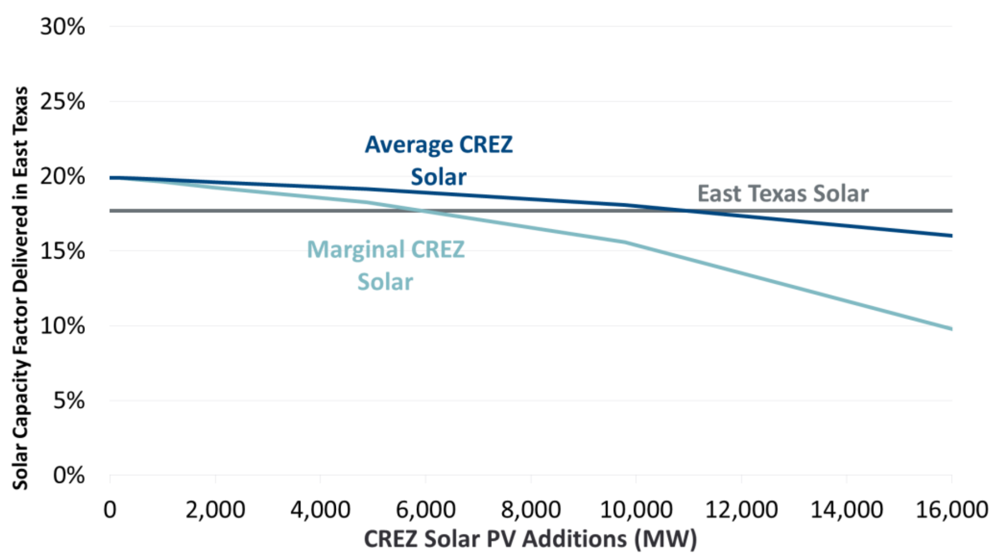
http://www.ercot.com/content/wcm/key_documents_lists/77730/2016_LTSA_Update_6_21_2016.pptx
7,200 MW added in "Texas Recession" scenario; 11,900 MW added in "Environmental Mandate" scenario.

34 We use NREL's System Advisory Model to convert solar irradiance data in 2005-2014 from NREL PVWatts to solar output based on solar unit characteristics in Brattle's 2015 report for First Solar: "Comparative Generation Costs of Utility-scale and Residential-Scale PV in Xcel Energy Colorado's Service Territory." Then we average hourly PV outputs for Odessa, Ft. Stockton, El Paso, and Las Cruces (New Mexico) to represent the solar profile in West Texas, and average hourly PV output in San Antonio, Austin, Ft. Worth, and Houston to represent the solar profile in East Texas. .

receives and land cost, we provide a preliminary analysis to estimate the potential solar capacity which the CREZ line could accommodate based on comparing the average capacity factors in these two regions after considering western solar curtailments due to CREZ's transfer limit.

The CREZ system is nearly fully subscribed with operating and planned wind farms, but it can also be utilized to carry solar power. Texas' wind resources produce the most energy at night so solar resources can generally use the line during the day. Using 2012 historical hourly western wind generation pattern from ERCOT and the 10 year hourly average solar generation pattern from NREL, we find that about 11 GW of solar can be developed in western Texas and carried east on the CREZ system before the average capacity factor for solar units in western Texas becomes lower than eastern Texas, as shown in Figure 6. It is interesting to note that after 6 GW have been added, marginal curtailments for solar in West Texas due to existing wind power and the CREZ line limit make building solar in eastern Texas more attractive. However, since the system is indifferent in dispatching solar with different in-service dates, merchant developers would still prefer the higher average capacity factors in West Texas until over 11 GW of solar were built. If more than 11 GW of solar were to be built, additional transmission capability would be needed to make it more cost-effective to move the power to East Texas than to develop solar locally in East Texas, assuming the costs of developing solar are similar in both West and East Texas.

Figure 6
Solar Capacity Factor as Delivered in East Texas



Sources and Notes: We use 2012 West Texas Wind profiles and an assumed wind curtailment of 2% to derive a transfer limit of the CREZ system given that it is designed to transfer power from 18.5 GW of wind in the west.[35] We also assume the generation from wind farms is always dispatched before solar due to the federal PTC. Capacity factor is reported as per kW-AC.

3. Wind

Texas has particularly rich wind resources. Developers in ERCOT have added 16 GW of wind as of the end of 2015[36], ranked as the No. 1 state for the installed capacity in the nation. However, wind has limited ability to offset retirement of baseload coal facilities and thus to be used as an option to address reliability concern. First, wind has limited capacity value since it does not coincide well with peak load. Second, wind facilities at ERCOT may also have limited ability to meet local reliability concerns, due to the geographic limitations of where wind can be built.

4. Storage

Energy storage is an emerging option for mitigating reliability risks due to coal retirement. Storage may have certain advantages. Because storage does not emit pollutants at the site it may be easier to permit, and the modular nature of storage may make it faster to construct.[37] Storage's modular nature makes it movable to other sites as needed. Storage can be located electrically close to the constrained transmission element, making it a potentially a very effective solution.

However, the primary disadvantage of storage is that it is energy limited and becomes more costly with more hours of energy storage. This limits storage's ability to supply power during long-duration events as compared to conventional supply.

Under Texas law, storage that is deployed to address a transmission reliability problem cannot participate in the wholesale markets. Ways to separate the transmission function from the potential wholesale market operations have been proposed. This would improve the overall economics of storage.[38]

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36 Potomac Economics, 2015 State of the Market Report For the ERCOT Wholesale Electricity Markets, June 2016, posted at https://www.potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf, Page XV.

37 As one example of the potential for storage to be built quickly, the AES Corporation recently announced a project to build 37.5 MW /150 MWh of storage capacity for San Diego Gas & Electric within six months. See http://www.utilitydive.com/news/blackouts-looming-california-speeds-battery-deployment-after-aliso-canyon/424241/

38 Judy Chang, et al. The Value of Distributed Electricity Storage in Texas. November 2014, posted at http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf

ii. Demand-Side Resources

Demand-side resources, including demand response (DR), Energy Efficiency (EE), and distributed resources, may also address resource adequacy. While ERCOT may be able to deploy these resources during emergency conditions to maintain grid reliability, these resource contracts were not put in place to resolve local grid reliability issues. Deploying these resources at times when there is no grid emergency would require market protocol changes. Our previous analysis indicated that 3 GW of new EE programs and around 2-4 GW of new DR programs by 2030 are identified as economically achievable.[39]

There are several different types of DR programs at ERCOT. First, Transmission and Distribution Service Provider (TDSP) Load Management Programs provide payments to end-use customers for reducing peak load during specified peak load hours. In 2015, there were about 180 MWs participating[40] in this program. Second, customers providing Emergency Response Service (ERS) agree to reduce load on 10-minute or 30-minute notice. In 2015, ERS includes between 275 MW and 600 MW of the non-weather-sensitive programs and less than 22 MW of weather-sensitive program. Third, Load Resources can provide ancillary services, including about 1400 MW of Responsive Reserve Service (RRS) and participate the real time energy market. Lastly, there are some price responsive DR programs in which customers reduce their load in response to energy prices or transmission charges. Load Resources and ERS are directly administrated and dispatched by ERCOT while TDSP require coordination between ERCOT and utilities. ERCOT can effectively use these DR programs to help address reliability issues because they are controlled by ERCOT directly or in close coordination with TDSPs and reliably reduce load when called. In contrast, price responsive DR products are less valuable for reliability as they depend on customers responding to high prices.

Texas law requires that all utilities meet energy efficiency goals. The target is currently set at 30 percent of annual peak demand growth and transitioning to a 0.4 percent reduction in total peak demand. The targets have been consistently exceeded since 2003.[41] Two types of energy efficiency programs are offered in Texas, one is Standard Offer Program, where utilities offer incentives to customers based on energy efficiency performance, and the other is Market Transformation Program, which is an effort to remove barriers and increase adoption of targeted energy efficiency technologies, services, and practices. With the state legislations and federal codes and standards, energy efficiency is expected to continue increasing and provide some benefits for reducing the generation resources. Compared to DR, energy reduction from energy

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[39] Ira Shavel, et al. Exploring Natural Gas and Renewables in ERCOT, Part III: The Role of Demand Response, Energy Efficiency, and Combined Heat & Power, May 29, 2014, posted at http://www.brattle.com/system/publications/pdfs/000/005/013/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT_Part_III_Shavel_Weiss_Fox-Pennerf.pdf?1401907416

[40] ERCOT, 2015 Annual Report of Demand Response In the ERCOT Region, May 2016

[41] http://www.texasefficiency.com/index.php/publications/reports

efficiency is more enduring once an energy saving measure is taken, such as installing a more efficient HVAC, whereas DR is more effective at reducing load in certain hours.

Distributed generation includes solar and behind the meter gas generation. Since Texas does not have a state-wide net metering, roof-top solar penetration has been limited in Texas. This might change in the future if the cost of solar continues to decline. For example, SolarCity has entered Dallas-Fort Worth area in 2015 and is expanding to the Houston area recently.[42] Similar to utility-scale solar, roof-top solar has the value for peak reduction as it coincides with the peak load.

iii. Transmission Upgrades

Ultimately at least some transmission upgrades and new transmission will almost certainly be needed to address reliability shortfalls due to retiring coal units. In that case, TSPs (Transmission Service Providers) can propose transmission projects to the Regional Planning Group (RPG) for review, which is led and facilitated by ERCOT.[43,44] In addition, each year ERCOT conducts Regional Transmission Planning (RTP) in coordination with the RPG and the TSPs to identify transmission needs of ERCOT system over next six years. Projects identified in RTP are to meet the ERCOT/NERC reliability requirements (reliability projects) and to reduce system congestion (economic projects) that meets the ERCOT economic criteria. The system upgrades identified by RTP need to be further reviewed by the appropriate TSPs to determine the need for an earlier in-service year. Roughly speaking, a rebuild project takes 2-3 years to complete after review and studies are complete; new construction takes 4-5 years due to more time required for routing analysis and PUC approval.

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42 http://www.utilitydive.com/news/in-texas-1-company-is-making-rooftop-solar-work-without-net-metering/423192/

43 The RPG is comprised of representatives of the TSPs and other market participants such as representatives of generators, marketers, consumer groups, environmental groups, landowners, governmental officials, PUCT Staff and other entities

44 ERCOT categorizes all transmission projects into four tiers. Depending on the cost and impacts on reliability, some projects may not need review of RPG and ERCOT while other projects need. For details, please see the link here: http://www.ercot.com/content/committees/other/rpg/keydocs/2014/ERCOT_Regional_Planning_Group_Charter___ERCOT_Board_Approved.doc

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