Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

TEXAS RESPONSE TO WINTER STORM URI

Plains CO_2 Reduction (PCOR) Partnership Initiative
White Paper

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The EERC contracted with PCOR Partnership partner, Jackson Walker LLP, to develop a case study report documenting the grid failure in Texas during Winter Storm Uri, during the winter of 2021. This case study includes a detailed analysis of the events leading up to the failure of the Electric Reliability Council of Texas (ERCOT) electric grid and current efforts under consideration to ensure grid reliability and dispatchable power are not compromised for other forms of intermittent electricity generation. This study includes high-level potential implications for non-ERCOT regions.

Prepared by:

Jackson Walker LLP

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TEXAS RESPONSE TO WINTER STORM URI

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TEXAS RESPONSE TO WINTER STORM URI

EXECUTIVE SUMMARY

This report details the many causes that led to the systemic failures experienced in the Texas electric grid during the winter storm beginning February 14, 2021 (commonly known as Uri). These historic winter storms caused a massive electricity generation failure throughout a large part of the State of Texas, which led to critical shortages of electricity, food, and water. More than 4.5 million homes and businesses were left without power, most for several consecutive days. Death estimates range from 246 people to as many as 702.

The tragic results of this systemic failure have appropriately caught the attention of every Texas public official. But perhaps the thing that should garner more attention from public officials from across the country is that the Texas grid was just four and a half minutes away in the early morning hours of February 15th from a deadly catastrophe of unprecedented scale, perhaps the worst in U.S. history. This sobering reality of just how dependent our society has become on a reliable and resilient electric grid and how embarrassingly close the Texas grid came to collapsing should serve as a wake-up call to public officials, grid operators, and the public that the stakes are too high to ignore the cautionary tale of this event. That is the reason the authors of this report have worked tirelessly to conduct this forensic analysis so the results and underlying data can be fully understood and reforms implemented to prevent a recurrence of a tragedy of this scale, which was a near-tragedy of epic scale.

The report breaks new ground by challenging the superficial reporting that occurred immediately after the storm (and has persisted ever since) that somehow the failures experienced were caused by a single type of energy system failure, or the result of a "Black Swan Event," or could have been prevented if only the entire Texas grid was more fully interconnected with surrounding states. Each of these popular theories are debunked through extensive presentation and analysis of original data, a compilation of other well-documented studies, and some data assimilation and analysis that helps provide a much more comprehensive view of the situation. In the end, the report documents that, in many ways, the Texas grid failures during Winter Storm Uri were decades in the making, not solely the fault of Texas operators and public officials, and provide a cautionary tale to the rest of the country (and the world).

Key take-aways include:

- The "energy-only" deregulated market within the Electric Reliability Council of Texas (ERCOT) worked well at driving inefficiencies out of the market and keeping prices down when natural gas prices dropped in the late 2000s.

- The lack of valuation of thermal dispatchable capacity within the energy-only electric market, however, did not marry-up well with the overlay of federal production and investment tax credits, as those types of subsidies have a significant distorting impact on price formation, especially in energy-only markets that have no inherent price signal valuing dispatchable capacity versus weather-dependent systems.

- As a result, in just five years between 2015 and 2020, ERCOT netted a loss of more than 6% of total installed thermal capacity, even though electric demand grew by that amount over the same period as the Texas population and economy continue to boom. This growing gap between supply and demand would have expanded even larger if not for the impact of the COVID-19 pandemic, which significantly reduced growth in electricity demand in 2020 and 2021 compared to the 2015-19 trend.

- Another consequence of price suppression and unhealthy economics for thermal generation manifested in the lack of investment in the weather resilience of several power plants, especially in the natural gas-powered fleet. In addition, many gas plants and several coal plants went cold when they were “tripped” offline due to frequency disturbances in the grid during critical periods of time. This created freeze-related restart challenges at plants that might never have been an issue if the plants weren’t forced offline by the instability of the grid.

- Weatherization issues were also experienced in the natural gas supply chain which dramatically increased the scope and duration of power outages. Gas supply issues also contributed to historic price escalation which resulted in billions of dollars being spent on gas supplies during a period of time when such expenditures would normally have been an order of a magnitude (or more) cheaper. This consequence was felt far beyond ERCOT and the Texas State Line. The multi-billion dollar financial exposure of power producers, gas supply utilities, and their customers will take decades to resolve across the country.

- All the issues with natural gas supply and frequency instability should not overshadow the importance of the simultaneous retirement of resilient thermal generation and the rapid growth in the installed capacity of weather-dependent sources in ERCOT. The analysis detailed herein shows that even if weatherization and gas supply issues had not occurred, there still would have been a deficiency of thermal capacity to cover the significant demand for electricity when the wind stopped blowing and the sun disappeared for hours (and even days).

- The best metric to evaluate how much of each part of the power fleet performed when we needed it most is to compare the installed capacity of each type of electricity and the actual generation (or performance) during the key hours when power was needed most and over the course of the entire winter storm event. Both numbers tell a dramatic story. The installed capacity and performance during the full course of the storm and a critical peak hour of demand were as follows:

Installed Capacity	
Wind	28%
Solar	5%
Gas	49%
Coal	12%
Nuclear	4%

February 9-19	
Wind Avg	9%
Solar Avg	1%
Gas Avg	61%
Coal Avg	19%
Nuclear Avg	9%

February 15, 8 PM	
Wind	1%
Solar	0%
Gas	71%
Coal	18%
Nuclear	9%

- So, the data reveals that nuclear and coal combined nearly doubled their role in the grid during the storm and at the most critical hours of need. Even gas, with all the weatherization and supply issues, met and actually exceeded its capacity factor due mainly to the roll of quick-start peaking units.

- On the other hand, weather-dependent resources like wind and solar suffered during the entire storm and especially during critical hours. Despite making up a full third of the installed capacity of the Texas ERCOT grid, wind and solar combined to provide 10 percent of the power that was needed for the duration of the storm and dropped as low as 1% during critical hours of need.

- While wind and solar are not expected by system planners to perform well when the wind is not blowing and the sun is not shining, this report shines a bright light on the fact that we must better plan for that reality and heed the cautionary tale of the Texas grid. The weather does not always cooperate, and that is particularly true during severe winter storms or the hottest summer evenings when the sun stops shining and the wind stops blowing for hours at a time when power demand surges to dangerous peaks.

The report further documents that, if this cautionary tale is not heeded, events like those experienced in Texas in February 2021 could repeat themselves and have dire consequences in cities, states, regions, and nations well beyond the Lone Star State. The forward-looking aspects of the report paint a very stark reality that electric reliability risks are on the rise. This reality is documented with a detailed explanation of the following:

- SPP is quickly (and MISO is close behind) following the ERCOT trend of premature retirements among thermal dispatchable coal and gas units and rapid expansion of weather-dependent wind and solar power, and that trend is expected to continue, if not accelerate.

- Like ERCOT, SPP and MISO show very little planned construction of thermal dispatchable generation and that being planned (which is primarily in MISO) is exclusively natural gas-fired generation, which has resilience, fuel supply, and cost volatility concerns in the wake of the Winter Storm. Recent global events have increased increased forward price projections for natural gas.

- All three markets are in a virtual race for market reforms that secure fuel assurance, better value reliability and resilience, and instill discipline in the siting and interconnection of weather-dependent wind and solar resources.

With the background, context, forensic analysis and projections in mind, the report then turns to the State of Texas's policy response to the storm. That response both affirms the veracity of the forensic analysis provided here and warrants attention by other parts of the country that are trying to prevent recurrence in their own states and regions. The policy response involved both an unprecedented level of legislative activity and continues to this day as extensive regulatory implementation of the reforms is ongoing.

The focal point of the policy response came in the form of the passage and implementation of Senate Bill 3, which is discussed in detail, along with up-to-date regulatory implementation discussion. Equally important and more capable of quick review and comprehension is the July 6, 2021 Directive from Governor Greg Abbott to the PUC Commissioners and ERCOT, instructing the PUC to take certain actions to ensure the reliability of the Texas grid. The Governor's directives and the corresponding PUC and ERCOT reforms are discussed in detail herein, but the four major points are concise and impactful enough to warrant direct quotation in this executive summary:

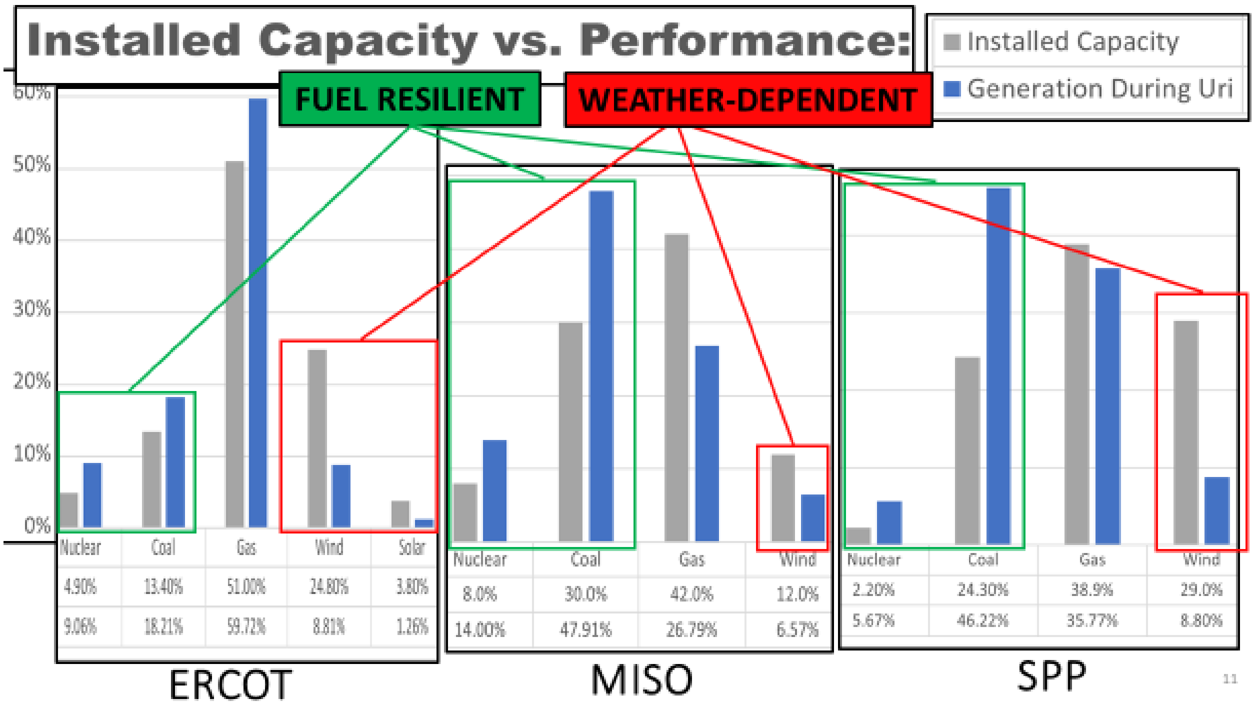
- ***Streamline incentives within the ERCOT market to foster the development and maintenance of adequate and reliable sources of power, like natural gas, coal, and nuclear power.*** *The PUC has the ability to redesign segments of the market to incentivize and maintain the reliable electric generating plants our state needs. Those incentives must be directed toward the types of electric generators we need for reliability purposes. The goal of this strategy is to ensure that Texas has additional and more reliable power generation capacity.*

- ***Allocate reliability costs to generation resources that cannot guarantee their own availability, such as wind or solar power.*** *Electric generators are expected to provide enough power to meet the needs of all Texans. When they fail to do so, those generators should shoulder the costs of that failure. Failing to do so creates an uneven playing field between non-renewable and renewable energy generators and creates uncertainty of available generation in ERCOT. To maintain sufficient power generation—especially during times of high demand—we must ensure that all power generators can provide a minimum amount of power at any given time.*

- ***Instruct ERCOT to establish a maintenance schedule for natural gas, coal, nuclear, and other non-renewable electricity generators to ensure that there is always an adequate supply of power on the grid to maintain reliable electric service for all Texans.*** *Regular maintenance of our natural gas, coal, and nuclear plants must be strategically scheduled to prevent too many generation plants from being offline at the same time. This will help prevent an artificial shortage of power.*

- ***Order ERCOT to accelerate the development of transmission projects that increase connectivity between existing or new dispatchable generation plants and areas of need.*** *Dispatchable generation, such as natural gas, coal, and nuclear power plants, are essential for the reliability and stability of the electric grid because they can be scheduled to provide power to the grid at any time. We must ensure that, at any point in time, ERCOT is utilizing non-renewable electricity in sufficient amounts to maintain reliable power throughout our state.*

While the majority of the discussion in the report is focused on Texas, there are critical insights about the SPP and MISO markets as well. First, the report documents the similarities and differences among the markets during Winter Storm Uri. For example, the metric discussed above for measuring the performance of each aspect of the grid during the days and hours when power is needed the most is set out, side-by-side and tells a compelling story:



As detailed throughout the report, much has been accomplished already by implementing incremental reforms in Texas that will benefit the grid, but when it comes to fundamental, long-lasting market design changes, SPP might outpace ERCOT on some fronts based on recent developments, and only time will tell whether MISO follows suit at the same pace.

The main report to which this case study is attached tackles the critically-important topic of what the grid challenges of Winter Storm Uri tell us about the efficacy and urgency of carbon capture utilization and storage (CCUS). Therefore, the authors of this case study wish to convey some fundamental observations about the topic in hopes of creating a strong logical connection between the extensive analysis contained herein and the larger CCUS question. Put simply, what the cautionary tale of Winter Storm Uri tells us is that losing thermal capacity from our grids and replacing it with weather-dependent wind and solar imposes a significant reliability and resilience penalty on the bulk power system, so we need to find a way to retain those thermal resources and, in fact, build new. Because many of the premature retirements and the shrinking pool of funding for fossil-fuel based thermal generation are tied to a desire by certain power companies, financial institutions, and state governments to "decarbonize" the electric grid in the United States, CCUS becomes central to the discussion. Here is a list of fundamental points offered by the authors of this case study to further the discussion:

- Because carbon captured from a dispatchable fossil fuel plant provides 24-7 low-carbon power, it is a critical reliability component of any decarbonization strategy.

- If we are serious about mitigating anthropogenic CO2 & ensuring market transparency, retirement prudence reviews and resource planning must ensure that ratepayers know the true and total economic, resilience and reliability cost of their low-carbon options so they can make informed decisions about whether existing coal and gas plants should be retired to make way for more wind, solar and batteries.

- Implementing processes and reforms that ensure that this type of review and comparison is conducted is especially urgent given that the premature retirement of every coal or gas plant brings with it a lost opportunity to commercialize CCUS and drive down the cost of the one technology that is widely agreed to be the single most important component of any realistic and cost-effective decarbonization effort.

- For example, according to the IPCC's latest report, carbon capture and sequestration are essential to every decarbonization scenario that does not significantly deprive the developing world of the opportunity to energize and improve lives.

- The time to do the hard work is now so we can leverage the CCUS commercialization opportunities we have with our current fleet. There are many misconceptions of the cost of CCUS in the power sector because the cost estimates are often prepared by entities that lack the development or power marketing experience to know how CCUS projects can be creatively structured to drive down costs and drive up the value of the project to the bulk power system.

- One way to conceptualize how CCUS interacts with power marketing dynamics is to see the carbon capture system as no different than a very large load (customer) in the industrial sector which can be tied to flue gas from more than one power generation unit to expand the flexibility of the plant and the practical and economic feasibility of turning the carbon capture processes up or down depending on market needs and economics.

- In the end, the urgency of integrating CCUS in the U.S. power grid is not because U.S. power sector emissions are a significant player in the global CO2 picture moving forward. In fact, zeroing out the entire fossil fuel fleet from the U.S. grid stands to reduce 2050 global CO2 concentrations by a mere 10.4 ppm (out of 480.3 ppm) or 2.2%. Models associate such a level of reduction to likely impact global temperature by less than 0.053 degrees Celsius. Not exactly moving the needle.

- Instead, a wide-scale deployment of domestic CCUS to accelerate commercialization and drive down costs as a result is the most singularly important step we can do to move the needle where all the growth in CO2 emissions is estimated – globally.

The authors of this report hope the thoughtful forensic analysis contained herein, as well as the compilation of market reforms and principles, will serve as a resource to market operators, public officials, and other stakeholders across the country as we proceed through market reforms designed to shore-up reliability and resilience. The analysis and these reforms need to be taken up and discussed hand-in-hand with the larger report's discussion of CCUS integration in the grid. Our hope is that the timing and quality of this report will be particularly impactful given that we are in the midst of a critical period of time when the lessons learned from this tragedy must be thoughtfully, yet urgently, converted into meaningful and long-lasting reform that can move the needle on reliability domestically and carbon mitigation globally.

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I. INTRODUCTION

For a week in the middle of February 2021, starting on the 10th and 11th and lasting until the 18th and 19th, Texas experienced sub-freezing temperatures and freezing rain and snow during one of the longest, coldest winter storms experienced in the state's history. This winter storm, which was actually the combination of two winter storms – Uri and Viola, will be referred to as Winter Storm Uri as that has become the more popularized reference. The several days of unusually low and, in many areas, record-low temperatures and snowfall caused unprecedented disruption of both electric and water service across Texas and served as a wake-up call to the general public and policymakers about the critical importance of the reliability and resilience of our electric grid in our ever-more-interconnected modern world.

Beginning on Valentine's Day, almost the entire state experienced below-freezing temperatures for more than four days and was blanketed with snow. Winter Storm Uri brought the coldest weather Texans had experienced since the 1980s, and the duration of the storm was unprecedented in the last 100 years. On February 16, 2021, the temperature at the Dallas/Fort Worth International Airport of −2 °F (−19 °C) represented the coldest recorded temperature in North Texas in 72 years. The cold weather and freezing precipitation extended all the way to the southern border with temperatures dropping into the teens with record snowfall, including nearly a foot of snow falling in the border town of Del Rio, Texas as late as February 18.

These historic winter storms caused a massive electricity generation failure throughout a large part of the State of Texas, which led to critical shortages of electricity, food, and water. More than 4.5 million homes and businesses were left without power, most for several consecutive days. According to the Texas Department of State Health Services, at least 246 people were killed as a result of the storm, with some estimates as high as 702. As tragic as the loss of life was and as dramatic the economic impact, a much more significant event was narrowly averted and it is critically important that public officials, grid operators, and the public take to heart the near-catastrophic loss of life that almost occurred. Specifically, if grid frequency had remained at dangerously low levels for just four and a half minutes longer in the early morning hours of February 15th, several experts have testified that it is likely that the entire grid would have shut down and, the state would have been without power for weeks, unleashing a deadly catastrophe of unprecedented scale, perhaps the worst in U.S. history.

The electric grid failures experienced were the result of all types of system failures ranging from weatherization problems impacting natural gas supplies and power plants to a lack of wind and sun to power the state's renewable energy fleet. Few people thought the energy capital of the nation—an oil and gas powerhouse known the world over for driving the shale revolution and having a large, diverse and stand-alone electric grid—would run out of power. The story of how millions of Texans lost power during Winter Storm Uri is a complex one, but the root cause of the failures was many years in the making due to market-distorting subsidies and regulatory policies that caused the Texas electric grid to underinvest in reliable generation and in the reliability and resiliency measures needed to withstand a storm of Uri's caliber. Not surprisingly, as temperatures began to rise and the supply of power and water returned, calls for regulatory reform began to ring out across the State of Texas and immediately became a top priority in the state's legislature.

What follows is an in-depth discussion of what led to the systemic failures experienced during the storm, including many that were decades in the making, as well as the State of Texas's policy response to the storm, which warrants careful study by other parts of the country that are trying to learn from this cautionary tale. After a brief discussion of some key background facts and history about the Texas grid, including the evolution of the state's electric market design, a detailed analysis will be provided about the developments that led to the power outages, including both the events of February 10-19 and the years of erosion of grid reliability that occurred prior to that week. Misconceptions about the events and causes will be addressed, along with a comparative analysis of the Texas experience with other parts of the country that encountered similar weather but did not experience the same magnitude of grid failures.

This case study concludes with a summary of the Texas policy response to the events during Winter Storm Uri. There has been an unprecedented level of legislative activity which, in turn, has put in motion an extensive regulatory overhaul of the Texas electricity market. The focal point of the main body of this report will be the passage and implementation of Senate Bill 3 and a July 6, 2021 Directive from Governor Greg Abbott to the PUC Commissioners, instructing the PUC to take certain actions to ensure the reliability of the Texas grid. To keep the main body of the report concise, we have separated out a comprehensive discussion that captures other policy responses to Winter Storm Uri, which we have included as Appendix A (other legislative enactments) and Appendix B (regulatory implementation of those legislative enactments).

The authors of this case study wish to acknowledge that much of this study was greatly benefited and made more complete due to the significant amount of data accumulation, assimilation, and an analysis conducted by the Public Utility Commission of Texas (the "PUC" or "Commission"), the Electric Reliability Council of Texas ("ERCOT"), the American Society of Civil Engineers, Texas Section ("TASCE"), the Energy Information Agency ("EIA"), and the University of Texas, as well as a wide range of technical and market reform experts who have weighed-in over the past year in legislative hearings, regulatory dockets, and through independent analyses and reports.

We have endeavored to provide robust citation to the original sources of data on which we rely and attribute views of that data to their source as well. Of course, opinions about the events and their causes vary and this study attempts to fairly represent the diversity of that opinion while providing a clear and coherent analysis and convey conclusions we believe are sound and fully supported by the data. Without question, there is wide agreement about many issues, including the need for regulatory reform, given the bipartisan policy response from the Texas Legislature and the ongoing stakeholder process governing the regulatory reform of the Texas electricity market. Still, there will be some who disagree with certain elements of our analysis and key take-aways, but, in the end, we think all will agree that the events of Winter Storm Uri in Texas and the years that led up to that week tell a cautionary tale that should be heeded by other states and regions of our country if they hope to avert similar or even worse catastrophes as that suffered by Texas in February of 2021.

II. BACKGROUND - AN OVERVIEW OF THE TEXAS ELECTRIC GRID, THE CHRONOLOGY OF TEXAS DEREGULATION, AND THE EVOLUTION OF THE ERCOT POWER REGION

At the risk of sounding like the old tourism campaign which boasted that Texas is "like a whole other country," the State of Texas is certainly nation-sized in terms of geographic size, population, GDP, and energy production and consumption. It is not just geographically large (2nd only to Alaska in the U.S.), it is an economic powerhouse (2nd only to California in the U.S. and the 9th largest economy in the world). That economic prowess is the result of a number of factors, including its manufacturing sector (1st or 2nd only to California, depending upon metrics), its population (2nd only to California), and the power generation fleet (1st) that serves both.

Texas generates and consumes more power than the next two states combined (California and Florida)[1] and uses almost as much power for manufacturing as the next four states combined (Louisiana, California, Pennsylvania, and Indiana).[2] Half of the Texas demand for power is from manufacturing, which includes a wide range of industries from computers and beverages, to automobiles and steel, but is most well-known for its nation-leading oil, gas, and chemical sectors. As of January of 2020, Texas accounted for 43% of the nation's crude oil production, 26% of its marketed natural gas production, and 31% of the nation's refining capacity.[3] Texas is the largest chemical producer in the country and leads the nation in manufactured exports.[4]

Due to the size of the state's energy production and consumption, as well as its natural resources and energy policy development, its electric grid has developed in a unique manner that is pertinent to the analysis of the power outages during Winter Storm Uri. What follows is a brief explanation of the history of the Texas grid in order to provide essential context to understand the remainder of this case study. While the vast majority of the discussion will relate to the electrically isolated component of the Texas grid which serves over 90% of the state's demand, the other two grids to which parts of Texas are interconnected will also be briefly discussed.

A. *The Creation of ERCOT*

ERCOT is an independent, not-for-profit organization responsible for overseeing the reliable and safe transmission of electricity over the power grid serving most of Texas. In the late 1800s, utility companies throughout Texas were formed to generate electricity for ice plants and began selling excess electricity to businesses and homes around their facilities. In 1935, the United States Congress passed the Federal Power Act to regulate the interstate activities of electric power producers, prompting the principal Texas electric utilities to isolate themselves from interstate commerce and avoid federal regulation by agreeing that no excess generated power should be

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[1] Electricity Consumption by End-Use Sector, Ranked by State, 2021 Rankings, U.S. Energy Information Administration. Available at: https://www.eia.gov/electricity/data/state/.

[2] *Id.*

[3] Texas State Energy Profile, U.S. Energy Inforamtion Administration, retrieved from: https://www.eia.gov/state/print.php?sid=TX.

[4] Texas Association of Manufacturers, About Us. Available at: https://www.nam.org/state-manufacturing-data/2021-texas-manufacturing-facts/.

transmitted out of the state.[5] Consequently, the existing Texas utilities formed the Texas Interconnected System ("TIS") to protect against the interstate transmission of electricity and to facilitate the transfer of excess generation to the Gulf Coast Region to provide reliable power to the heavy manufacturing industry during World War II.[6]

On Tuesday, November 9, 1965, there was a major disruption in the electric power supply to the Northeast United States resulting in a blackout that left over 30 million people without power for up to 13 hours. As a direct result of the Northeast blackout, the U.S. Congress passed the Electric Power Reliability Act of 1967 to provide increased authority and jurisdiction over the electric power system to the Federal Power Commission ("FPC"), predecessor of the Federal Energy Regulatory Commission ("FERC").[7] The FPC recommended that a council on power coordination be formed comprised of representatives from each regional coordinating organization in the United States to exchange and share information and to review, discuss, and assist in resolving interregional coordination matters.[8] On June 1, 1968, the North American Electric Reliability Council ("NERC") was formed and included 12 regional utility organizations, including TIS.[9] In 1970, TIS formed ERCOT in an effort to comply with NERC's effort to encourage the creation of voluntary regional reliability councils to promote coordinated operations and planning, issue reliability guidelines, and exchange best practices among the councils. TIS transferred all of its operational functions to ERCOT in 1981.[10]

In 1996, ERCOT was designated the independent system operator ("ISO") in Texas to establish an impartial, third-party organization to oversee equal access to the Texas power grid.[11] This change was officially implemented September 11, 1996, when the ERCOT board of directors restructured its organization and initiated operations as a not-for-profit ISO, making ERCOT the first ISO in the country and the only ISO created under state law, not by FERC. ERCOT was charged with maintaining the security of the ERCOT power grid, facilitating market operations, and coordinating transmission planning in the ERCOT power region.[12]

B. Deregulation of the Texas Electric Market

Prior to 1975, municipalities in Texas regulated their electric utility service and rates; however, the electric utilities in Texas had begun to integrate themselves into every aspect of providing electricity to consumers, including the generation, transmission and distribution, and retail sale of electricity along with the associated customer service functions. The vertically-integrated nature of the electric utilities resulted in each utility effectively operating as a monopoly

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[5] Cudahy, R. D. (1995). The Second Battle of the Alamo: The Midnight Connection. *Natural Resources & Environment*, 10(1), 56–87.

[6] History of the Texas Interconnection, Standards to Promote Interoperability: Interconnection Code Compliance & Corrective Actions at 11, ERCOT Market Design and Operations (Oct. 1, 2018).

[7] Nevius, David. *History of the North American Electric Reliability Corporation*, at 4-5 (Jul. 2019) (accessed Dec. 23, 2021) https://www.nerc.com/AboutNERC/Resource%20Documents/NERCHistoryBook.pdf..

[8] *Id*.

[9] *Id*.

[10] The Story of ERCOT: The Grid Operator, Power Market & Prices Under Texas Electric Deregulation, at 20 (Feb. 2011).

[11] 16 Tex. Admin. Code ("TAC") § 25.361(b); *See also*, PURA § 39.151(c).

[12] *Id*.

within its service territory. The vertically-integrated utilities' monopolies within their service territories continued throughout the state until deregulation of the vast majority of the Texas wholesale and retail electric markets in the mid-to-late 1990s.

1. The Public Utility Regulatory Act of 1975

The 64th Texas Legislature, partially in response to the monopolistic nature of the vertically-integrated utilities, enacted the Public Utility Regulatory Act ("PURA") and created the Public Utility Commission of Texas with the authority to regulate the rates and services of electric utilities.[13] The purpose of PURA was to establish a comprehensive public utility regulatory framework to assure just and reasonable rates, operations, and services for both the consumers and the utilities.[14] PURA provided the state with additional regulatory authority over certain aspects of the rates and service of its electric utilities; however, PURA still allowed Texas municipalities to retain original ratemaking authority, with the PUC reviewing those rates on an appellate basis. Ultimately, PURA created a regulatory framework to act as a substitute for competition and served as a check against rate increases by the utilities.

Despite the passage of PURA, several factors continued to contribute to the vertically-integrated utilities' monopoly within their service territories. Most notably, the U.S. Congress passed the United States Fuel Use Act in 1978, forcing utilities to use nuclear and coal as fuel for the generation of electricity, rather than natural gas in an effort to address the oil and gas crisis. The required changes to the fuel mix of the vertically-integrated utilities necessitated the development of additional generation capacity in Texas. The subsequent investment by the utilities in new generation infrastructure resulted in the need for rate-recovery from consumers to cover those investments.

2. Deregulation of the Texas Wholesale Electric Market

In 1995, the 74th Texas Legislature concluded that the development of a competitive wholesale electric market that allowed for increased participation by both utilities and certain non-utilities was in the public interest.[15] Consequently, the wholesale electric market was deregulated and any utility that owned or operated transmission facilities was required to provide wholesale transmission service at rates, terms of access, and conditions that were comparable to the rates, terms of access, and conditions of the utility's use of its own system.[16] The PUC was required to ensure that utilities provided nondiscriminatory access to transmission service for qualifying facilities, exempt wholesale generators, power marketers, and public utilities.[17]

Deregulating the wholesale power market and requiring all utilities owning transmission lines to provide open access to their wires to transport wholesale power led to the establishment

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[13] H.B. 819, 64th Texas Legislature, Regular Session, 1975. Note that the Texas PURA was enacted three years prior to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). *See* Public Utility Regulatory Policies Act of 1978 (PURPA) | Department of Energy.
[14] *Id*.
[15] S.B. 373, 74th Texas Legislature, Regular Session, 1995.
[16] *Id*. at Section 2.057.
[17] *Id*.

of the "postage stamp" rate.[18] As was previously discussed, prior to the deregulation of the wholesale market, the Texas utilities voluntarily established TIS and interconnected their transmission systems to enhance reliability and to transfer wholesale power to one another. Participants in the deregulated wholesale market that did not own their own transmission lines would be required to transmit, or "wheel" electricity over the interconnected transmission system. The cost of wheeling power to the utilities that owned the transmission system necessitated a charge to generators for purposes of cost recovery. Competition in the wholesale market required electricity to be transmitted freely across Texas without being subject to individual utility wheeling charges for the use of their transmission system in order to be successful. Wheeling costs that varied by transmission company could hamper the ability of generators to sell power to buyers throughout ERCOT. Therefore, the result of wholesale market deregulation was the establishment of the postage stamp rate, a uniform charge for the wheeling of electricity across the interconnected transmission system regardless of the distance traveled or the utility systems used to transmit that power.[19]

Shortly after the Texas Legislature moved to deregulate the wholesale electric market in Texas, on April 24, 1996, FERC issued Order No. 888, requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file an open-access non-discriminatory transmission tariff that contained minimum terms and conditions of non-discriminatory service.[20] FERC Order No. 888 also permitted public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Section 211, Federal Power Act transmission services.[21] FERC's goal was to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the country's electricity consumers by requiring all public utilities to file tariffs providing nondiscriminatory access to all wholesale users.[22]

3. Deregulation of the Texas Retail Electric Market

In 1999, the 76th Texas Legislature determined that "the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that…electric services and their prices should be determined by customer choices and the normal forces of competition."[23] While transmission and distribution services remained regulated, the Texas Legislature required the vertically-integrated utilities in the ERCOT market to "unbundle" by January 1, 2002, separating their business operations into three distinct entities: power generation companies ("PGCs"), retail electric

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[18] *The History of Electric Deregulation In Texas*, Cities Aggregation Power Project, Inc., (accessed Dec. 29, 2021). http://tcaptx.com/downloads/HISTORY-OF-DEREGULATION.pdf.
[19] *Rulemaking on Term and Conditions for Transmission and Distribution Access, Including Tariffs and Modifications to Existing Transmission Rules*, Order Adopting Amendments to 25.192, 25.193, 25.194, 25.198, and 25.204 as Approved at the December 1, 1999 Open Meeting and Submitted to the Secretary of State at 1, PUC Project No. 21080 (Dec. 9, 1999): "Postage stamp pricing sets a transmission-owning utility's transmission rate based on the ERCOT utilities' combined annual costs of transmission divided by the total demand placed on the combined transmission systems of all transmission-owning utilities within ERCOT."
[20] FERC Order No. 888 https://www.ferc.gov/sites/default/files/2020-05/rm95-8-00v.txt (accessed Dec. 29, 2021).
[21] *Id*.
[22] *Id*.
[23] S.B. 7, 76th Legislature, Regular Session, 1999; See also, PURA § 39.001(a).

providers ("REPs"), and transmission and distribution utilities ("TDUs").[24] The PGCs own and operate the electric power plants and sell power into the deregulated wholesale power market. After January 1, 2002, no PGC, including their affiliates, could own more than 20 percent of the generating capacity in any power region in order to prevent market abuse.[25] REPs purchase wholesale power from the PGCs and re-sell the power to customers and are responsible for all interactions with the customer, including billing the customer for transmission and distribution services and for purchased power costs, REPs were prohibited from owning any generation assets. The regulated TDUs own and operate the interconnected transmission system and distribution systems required to transport power from the PGCs to all customers within a certain geographical area. The vertically-integrated utilities subject to unbundling were authorized to accomplish the required separation either through the creation of separate nonaffiliated companies, separate affiliated companies owned by a common holding company, or through the sale of assets to a third party.[26]

Municipally-owned utilities ("MOUs") and rural electric cooperative utilities were exempt from unbundling, but could choose to opt-in to deregulation. Vertically-integrated utilities operating in areas of the state outside the ERCOT grid were not required to unbundle unless they met certain requirements. The two largest metropolitan areas, Houston-Galveston ("HGA") and Dallas-Fort Worth ("DFW"), are in competition while the other two major metropolitan areas, Austin and San Antonio, are not and continue to have major vertically-integrated MOUs (Austin Energy and City Public Service of San Antonio ("CPS Energy")).

The majority of rural cooperatives have not opted into retail competition but there are exceptions.[27] It is important to note that, because of the interconnected nature of the ERCOT grid, neither MOUs nor cooperatives have the option of "opting out" of wholesale competition – they are subject to ERCOT load shed requirements and market pricing rules which puts them in the unique position of owning and operating generation to meet the needs of their members but having that generation subject to call by the entire grid, which, in emergency conditions, means that the cooperative members may be protected from price blowouts if they own sufficient generation to cover their needs, but they are still subject to load-shed requirements imposed by ERCOT. This was the case during Winter Storm Uri, where some generation and transmission ("G&T") cooperatives were forced to roll their members off the system even though they had sufficient generation to cover their power needs.[28]

a. The Price-to-Beat

As part of the deregulation, the Texas Legislature required utilities to freeze their rates beginning on Sept. 1, 1999.[29] When the deregulated market opened on January 1, 2002, REPs affiliated with the utilities were required to charge a price that was six percent less than the

[24] *Id. See also*, PURA § 39.051(b).
[25] *Id.* See also, PURA §§ 39.154 and 39.158.
[26] *Id. See also*, PURA § 39.051(c).
[27] For example, Nueces Electric Cooperative has opted-into competition, but note that they are still a member of a G&T Cooperative – South Texas Electric Cooperative (STEC).
[28] This was the situation of STEC, as documented during testimony during Texas Legislative Hearings before the House State Affairs and Senate Business Commerce Committees in March and April, 2021.
[29] *Id. See also*, PURA § 39.052 and 16 TAC § 25.41.

regulated rate that existed on Dec. 31, 2001.[30] Until 2005, this "price-to-beat" was the only rate that the REPs were allowed to charge residential and small commercial customers in the vertically-integrated utilities' former service areas, which created a target for competitors to undercut with lower prices. REPs that were affiliated with a former vertically-integrated utility were required to offer the price-to-beat rate until January 1, 2007; however, those REPs could offer plans with alternative prices after January 1, 2005, if they could demonstrate that they had lost more than 40 percent of their customers.[31]

b. The Provider of Last Resort

For the deregulated market to be successful, customers needed to be able to receive power even if some REPs went out of business or if there was a billing dispute with the customer's current REP. To ensure the provision of reliable service, the "provider of last resort" ("POLR") was established as part of the deregulation of the retail market to serve customers whose REP failed to provide service to the customer, failed to meet its obligations to ERCOT and exited the market unexpectedly, or cannot otherwise obtain service from a REP. The PUC is required to designate REPs in areas of the state in which customer choice is in effect to serve as POLRs who are required to offer a standard retail service package for each designated class of customers at a fixed, non-discountable rate approved by the PUC.[32]

c. The System Benefit Fund

The Texas Legislature also established as part of the deregulation of the retail market a user fee on electric service to be deposited in the general revenue-dedicated System Benefit Fund account to support electric rate discounts for low-income customers, finance energy efficiency programs for low-income households, to fund a customer education media campaign relating to retail competition, and to compensate school districts for the loss of any property tax revenue attributable to deregulation.[33] The System Benefit Fund was ultimately defunded when the Texas Legislature ended the 65 cent per megawatt hour charge that supported the program. The remaining balance of the fund was depleted as of August 31, 2016.

4. The Scope of Competition in Electric Markets Report

Prior to January 15 of each odd-numbered year, the PUC is required to report to the Texas Legislature on the scope of competition in Texas' electric markets and the effect of competition and industry restructuring on customers in both competitive and noncompetitive markets.[34] The report is required to include an assessment of the effect of competition on the rates and availability of electric services for residential and small commercial customers, a summary of commission action over the preceding two years that reflects changes in the scope of competition in regulated

[30] *Id*.
[31] The Texas Legislature included one exception to the fixed price-to-beat rate in that REPs were able to increase or decrease the rate no more than twice each year to reflect changes in the price of natural gas prices used as fuel for certain electric generating plants.
[32] S.B. 7, 76th Legislature, Regular Session, 1999; *See also*, PURA § 39.106(a) and 16 TAC § 25.43.
[33] S.B. 7, 76th Legislature, Regular Session, 1999; *See also*, PURA § 39.903.
[34] PURA § 31.003(a).

electric markets, and recommendations to the legislature for legislation that the PUC finds appropriate to promote the public interest in the context of a partially competitive electric market.[35]

C. Present Day ERCOT and the Texas Electric Grid

ERCOT is a 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the PUC and the Texas Legislature.[36] The Technical Advisory Committee ("TAC") makes policy recommendations to the board of directors and has five standing subcommittees, as well as numerous workgroups and task forces.[37] The ERCOT region encompasses approximately 75 percent of the land area in Texas, including the urban load centers of Houston, Dallas, Fort Worth, San Antonio and Austin, as well as most of West Texas, portions of the Panhandle and the Rio Grande Valley.[38] It excludes the El Paso area, Northeast Texas (Longview, Marshall and Texarkana) and Southeast Texas (Beaumont, Port Arthur and The Woodlands).[39] ERCOT's operations activities are headquartered in the Taylor, Texas operations center with an additional back up operations center in Bastrop, Texas.[40]

1. The ERCOT Market Today

ERCOT's primary responsibilities are to maintain system reliability, facilitate the competitive wholesale and retail markets, and to ensure open, non-discriminatory access to transmission for generators.[41] ERCOT manages the flow of electricity to approximately 26 million Texas customers, representing about 90 percent of the state's electric load.[42] ERCOT's responsibility as an ISO requires it to schedule power on the electric grid, connecting more than 46,500 miles of transmission lines with over 710 generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly eight million premises in competitive choice areas.[43] With roughly 1,800 active market participants and approximately 86,000 MW of expected capacity to meet 2021 peak demand, the 2021 generating capacity (and 2020 actual energy use) of ERCOT is comprised of 51 (45.5) percent natural gas, 25 (22.8) percent wind, 13 (17.9) percent coal, 5 (10) percent nuclear, 4 (<2) percent solar, and 2 (<1.5) percent storage/hydro/biomass/direct current tie. See *Figure 1*.[44]

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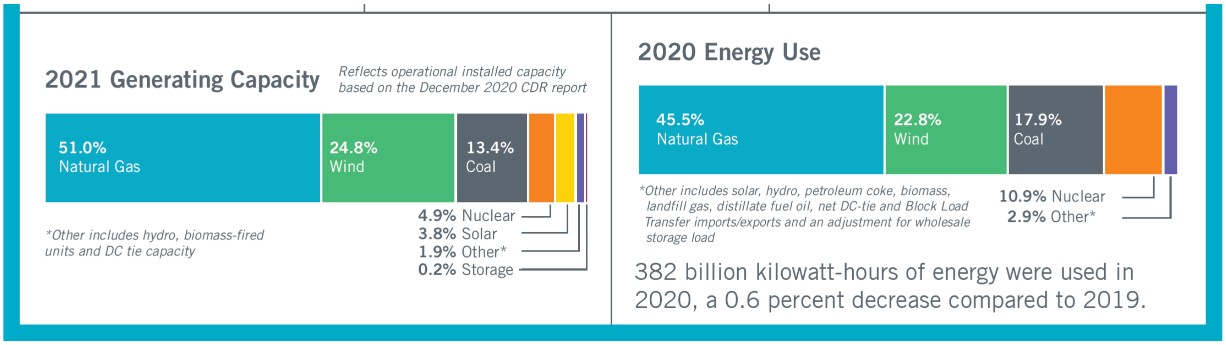
[35] PURA § 31.003(b).
[36] ERCOT Organizational Backgrounder; https://www.ercot.com/news/mediakit/backgrounder and ERCOT Fact Sheet; https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf (accessed February 26 2022).
[37] *Id*.
[38] *Id*.
[39] *Id*.
[40] *Id*.
[41] *Id*.
[42] *Id*.
[43] *Id*. at 2.
[44] *Id*. at 1.

Figure 1: ***ERCOT FACT SHEET, February 2022***[45]



ERCOT is also responsible for controlling the use of the existing high voltage direct current ("HVDC") tie lines connecting the Texas grid to the Eastern Interconnection and Mexico. As was previously discussed, after the passage of the Federal Power Act in 1935, the principal Texas electric utilities elected to isolate themselves from interstate commerce and thereby avoid Federal jurisdiction and regulation.[46] Notwithstanding the "Midnight Connection" incident in 1976, Texas has been successful in avoiding FERC jurisdiction.[47] There are currently five (and the potential for a sixth) HVDC tie lines connecting ERCOT to the Eastern Interconnection and Mexico. The North and East asynchronous HVDC tie lines,[48] which connect ERCOT with the Eastern grid and result in interstate transmission of electricity did not subject ERCOT to Federal jurisdiction because the interconnections were pursuant to FERC waivers of jurisdiction pursuant to Sections 201 through 212 of the Federal Power Act. The waivers provide that interconnections pursuant to those sections will not cause an entity to become a "public utility" under the Federal Power Act if it was not already classified as a public utility. The ERCOT utilities were not already public utilities when they applied for an a FERC interconnection order. There are also three HVDC ties transmitting electric power across the border between Texas and Mexico.[49] However, because power flowing between ERCOT and Mexico is a purely international transfer of power that does not involve U.S. interstate commerce, those HVDC ties do not trigger FERC jurisdiction.

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[45] https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf (accessed February 26 2022).
[46] Cudahy, R. D. (1995). The Second Battle of the Alamo: The Midnight Connection. *Natural Resources & Environment*, 10(1), 56–87.
[47] On May 4, 1976 Central and Southwest Corporation deliberately flipped a switch in Vernon, Texas and sent power from West Texas Utilities to the Oklahoma Public Service Company for several hours presumably placing the entire State of Texas and all its utilities under federal jurisdiction and resulting in significant litigation,
[48] The 220 MW DC North tie connects the American Electric Power ("AEP") ERCOT Oklaunion substation with the AEP Southwestern Power Pool ("SPP") Public Service Company of Oklahoma (PSO) Oklaunion substation. The 600 MW DC East tie connects the Oncor ERCOT Monticello substation and the Southwestern Public Service Company ("SWEPCO") SPP Welsh substation.
[49] The Railroad DC-Tie is a 300 MW HVDC converter located at the Sharyland Utilities' Railroad substation and connects the ERCOT Region with CENACE in Mexico at the Cumbres Frontera substation; The Laredo DC-Tie is a 100 MW Variable Frequency Transformer ("VFT") located at the AEP Laredo VFT station and connects the ERCOT Region with CENACE in Mexico at the Ciudad Industrial substation; The Eagle Pass DC-Tie is a 36 MW HVDC light tie at the AEP Eagle Pass substation and connects with the CENACE in Mexico at the Piedras Negras substation, though it has been unavailable since March 23, 2020, due to a forced outage and the unavailability of necessary replacement parts.

The potential sixth HVDC tie is the Southern Cross Transmission Project, a bi-directional HVDC transmission line that would connect ERCOT to the SERC Reliability Corporation ("SERC"). The 2,000 MW capacity project would allow ERCOT to access power from the southeast transmission system during times of extreme demand in Texas, potentially bringing further stability benefits to ERCOT during scarcity events.[50] The bi-directional capability of the line will also allow ERCOT to export power to southeast markets during times of excess generation and curtailments within ERCOT.[51] A FERC Order to interconnect the Southern Cross Project with ERCOT Transmission Service Providers has already been issued and expressly maintains ERCOT's status as exempt from FERC jurisdiction.[52]

2. PUC Oversight of ERCOT

Pursuant to PURA, ERCOT is subject to oversight by the Public Utility Commission of Texas (PUC) and the Texas Legislature. The PUC is required to certify an independent organization or organizations to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of REP is conveyed in a timely manner to the appropriate individuals; and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the ERCOT power region.[53] Consequently, the PUC designated ERCOT as the ISO for the Texas grid in 1996 and established certain substantive and procedural agency rules to establish the regulatory oversight and control of ERCOT mandated by the Texas Legislature.[54] ERCOT is also statutorily required to contract with an entity selected by the PUC to act as the PUC's wholesale independent market monitor ("IMM") to detect and prevent market manipulation strategies and recommend measures to enhance the efficiency of the wholesale market.[55] ERCOT is required to provide to the PUC selected IMM full access to ERCOT's main operations center and records concerning operations, settlement, and reliability; and all other support and cooperation the PUC determines is necessary for the IMM to perform its functions.[56] The PUC also continues to perform its traditional regulatory function for electric transmission and distribution utilities across the state.

3. Other Wholesale Market Participation in non-ERCOT Regions of Texas

While integrated electric utilities outside of the ERCOT power grid remain fully regulated by the PUC, the PUC is increasingly involved in multi-state efforts to implement wholesale electric competitive market structures and transmission planning in the Southwest Power Pool ("SPP") and Midcontinent Independent System Operator ("MISO") areas. As depicted in *Figure 2* below,

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[50] *Application of the City of Garland to Amend a Certificate of Convenience and Necessity For the Rusk To Panola Double-Circuit 345-kV Transmission Line In Rusk and Panola Counties*, Docket No. 45624, (Feb. 25, 2016); *See also*, Pattern Energy-Southern Cross Transmission Texas, https://patternenergy.com/learn/portfolio/southern-cross-transmission. (accessed Dec. 29, 2021).

[51] *Id*.

[52] 147 FERC ¶61, 113, FERC Docket No. TX11-1-001, Final Order Directing Interconnection and Transmission Service, (May 15, 2014).

[53] PURA § 39.151(c).

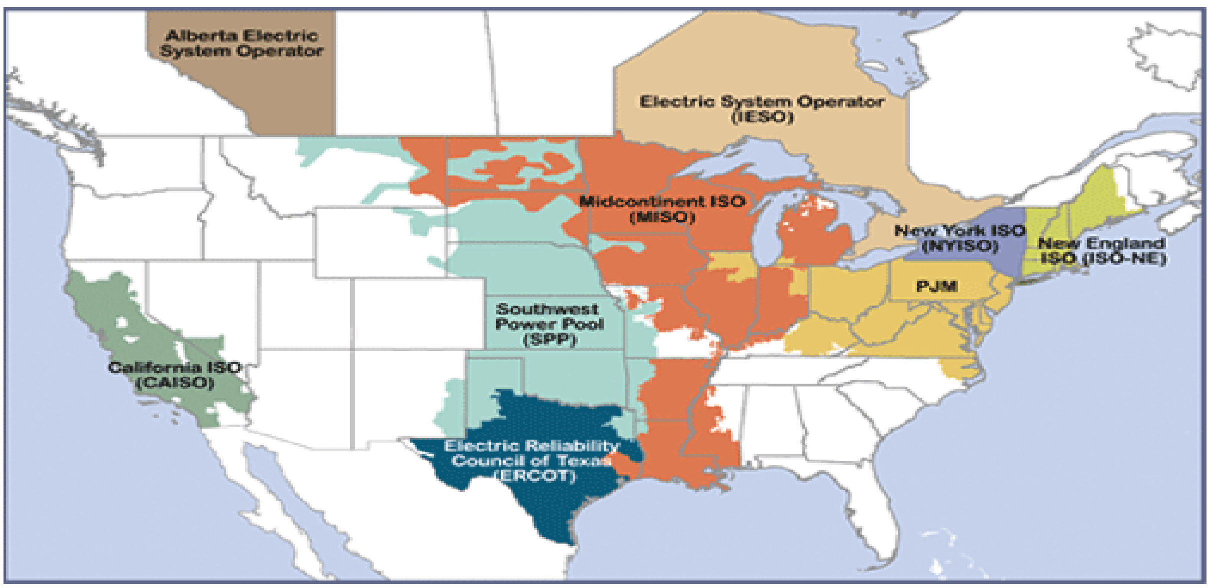
[54] 16 TAC §§ 25.361-25.367 and 16 TAC § 22.251 (16 TAC § 25.361 was previously 16 TAC § 25.197).

[55] PURA § 39.1515(a).

[56] PURA § 39.1515(b).

SPP has 14 member states with 842 generation plants representing approximately 94,648 MW of generation capacity consisting of approximately 38.9 percent natural gas 29 percent wind, 24.3 percent coal, 3.6 percent hydro, 2.2 percent nuclear, 1.7 percent fuel oil, 0.2 percent solar, and 0.1 percent is comprised of other sources.[57] MISO has 15 member states as well as the Canadian Province of Manitoba with 184,287 MW of market capacity consisting of approximately 42 percent natural gas, 29 percent coal, 19 percent renewables,[58] 8 percent nuclear, and 2 percent is comprised of other sources of generation.[59] SPP and MISO faced significant challenges in their southern reaches during Winter Storm Uri and both instituted rolling blackouts. While Texas experienced more extreme conditions, SPP and MISO would have benefited from increased transmission capabilities between each other and neighboring regional transmission organizations throughout their service territories. SPP and MISO would benefit from increasing transmission capabilities between each other and throughout their territories to prepare for the next severe weather event, which includes coordination with ERCOT and providing service to Texas customers.

Figure 2: ***Geographic Extent of Independent System Operators in the U.S. and Canada***[60]



III. EVOLUTION OF RESOURCE MIX IN ERCOT, SPP, & MISO

With the history of ERCOT in hand, we now turn to how the resulting market design, once distorted by a number of factors, ultimately led to tragedy in February 2021. The Texas "energy-only" power market once was lauded all over the world as a model for driving efficiency and

[57] Southwest Power Pool, Overview of the SPP System (nameplate capacity as of Jan. 13, 2021), https://www.spp.org/about-us/fast-facts/ (accessed Dec. 30, 2021).
[58] MISO has roughly 25,974 MW of registered wind capacity and 464 MW of registered solar capacity.
[59] Midcontinent Independent System Operator, corporate information, https://www.misoenergy.org/about/media-center/corporate-fact-sheet/ (accessed Dec. 30, 2021).
[60] From "RTOs and ISOs," Federal Energy Regulatory Commission, n.d. (https://www.ferc.gov/electric/power-sales-and-markets/rtos-and-isos).

lowering power prices. Before the complicated overlay of market-distorting subsidies and systemic neglect set in.

To recap, "energy-only" markets use the purchase of produced energy as the sole means for compensating power plants, unlike in most other electricity markets where power plants are compensated for their capacity to remain in the market and ensure that the system has enough generation to meet peak demand. Most observers agree that this system worked well at driving inefficiencies out of the market and keeping prices down when natural gas prices dropped in the late 2000s, but the lack of valuation of capacity did not marry-up well with the overlay of federal production and investment tax credits as those types of subsidies have a significant distorting impact on price formation in the energy-only market.

What follows is a brief overview of the evolution of the ERCOT generation mix and how some tax credit subsidies, no matter how well intentioned, distort energy-only markets so significantly that they undermine the value of reliability and capacity when those attributes are not otherwise compensated in the marketplace. In the end, the most important cautionary tale of the Winter Storm Uri power outages is how Texas has shown the rest of the country (and the world) just how bad things can get if you do not develop policies to better value reliability and resilience and offset the distorting effects of subsidies. This discussion will conclude with a recap of how the SPP and MISO are following similar trend lines as the ERCOT market and how the cautionary tale of the Texas situation may have occurred just in time to prevent those markets from repeating the same mistakes if preemptive reforms are implemented.

A. Explanation of the ERCOT Generation Mix, including the significant expansion of intermittent resources, from 2001 to 2021.

Given the abundance of natural gas in Texas, the electric generation mix in Texas has long been dominated by gas power plants. As of 2001, at the beginning of full deregulation in Texas, natural gas accounted for more than half of the state's annual electricity generation.[61] Coal, whether mined in state or imported from states such as Wyoming, was a close second at the time, providing about 36% of the state's electricity.[62] There are two nuclear power plants in Texas, which together provided about 10% of the state's electricity mix.[63] Wind and hydropower were nominal contributors to the state's generation mix, a little more than 0.3% each, and solar was virtually nonexistent.[64]

Since that time, a combination of state and federal policies has driven an explosive growth in wind generation in Texas. Most significant among these policies is the federal Production Tax Credit (PTC), which provides the owners of wind generation a tax credit of up to $23/MWh and often forms the foundation of financing agreements that make new wind construction economically feasible. Other forms of federal support, including direct payments to new wind

[61] Net Generation by State by Type of Producer by Energy Source, U.S. Energy Information Administration. Available at: https://www.eia.gov/electricity/data/state/.https://www.eia.gov/electricity/data/state/.
[62] *Id.*
[63] *Id.*
[64] *Id.*

developments, were instituted part of the 2009 federal stimulus package.[65] Even as the 2009 stimulus programs expired, falling costs to build and install wind turbines and the continuation of the PTC have continued the wind boom. By 2020, wind accounted for 20% of electricity generation in Texas[66] and 23% in the ERCOT market.[67]

State policies have also played a significant role in fostering wind development. Most crucial was the creation of the Competitive Renewable Energy Zones (CREZ) in 2005, which authorized the creation of a new network of transmission lines with the primary purpose of facilitating the buildout of new wind and solar generation in West Texas by providing a means for that electricity to reach the major cities in East Texas. That program was estimated to cost $6.9 billion[68] and is entirely paid for by Texas ratepayers through the Transmission Cost of Service (TCOS) fee. The same bill that created the CREZ program, SB 20, also boosted the state's Renewable Portfolio Standard to 10% by 2025. That goal was easily surpassed by 2016 by wind generation alone.[69] In 2001, the legislature also made wind and solar projects eligible for tax value cap/abatement agreements through the Chapter 313 program, which dramatically reduces the largest state tax bill that energy producers pay – local property taxes, which are the primary revenue source of public school funding.

Solar installations remained very limited in Texas until 2017, but installed solar capacity has now reached more than 8 GW and is forecast to reach 24 GW by the end of 2023.[70] Three factors are contributing to the rapid growth of solar in Texas. First, the falling capital costs of solar projects[71] combined with the continuation of the Investment Tax Credit, have made new solar projects competitive in the ERCOT market. Second, the proliferation of wind generation, which tends to produce the least during the middle of the day in the summer, has pushed peak prices to earlier in the day, making it more feasible for solar projects to capture those prices. Finally, the PUC increased the range of conditions during which the Operating Reserve Demand Curve (ORDC)(discussed further below in the market reform discussion) is in effect[72] and, since the sun tends to be shining during hot summer days when the ORDC is most likely to be in effect, solar developers have bet on that change increasing their potential revenues.

Aside from these incentives, the geography of Texas and the design of the ERCOT market also favor wind and solar development. The lack of vertically integrated utilities and long

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65 Federal Energy Subsidies (Dr. Brent Bennett, Life:Powered, 2021). Available at: https://www.texaspolicy.com/wp-content/uploads/2020/04/Bennett-LP-Federal-Energy-Subsidies-2.pdf.

66 Net Generation by State by Type of Producer by Energy Source, U.S. Energy Information Administration. Available at: https://www.eia.gov/electricity/data/state/.https://www.eia.gov/electricity/data/state/.

67 ERCOT 2020 State of the Grid Report (Produced Q1 2021). Available at: https://www.ercot.com/files/docs/2021/06/07/ERCOTSOG2020_Final.pdf.

68 PUC Report to the 84th Texas Legislature (2015), page 60. Available at: https://www.puc.texas.gov/industry/electric/reports/scope/2015/2015scope_elec.pdf.

69 Net Generation by State by Type of Producer by Energy Source, U.S. Energy Information Administration. Available at: https://www.eia.gov/electricity/data/state/.https://www.eia.gov/electricity/data/state/.

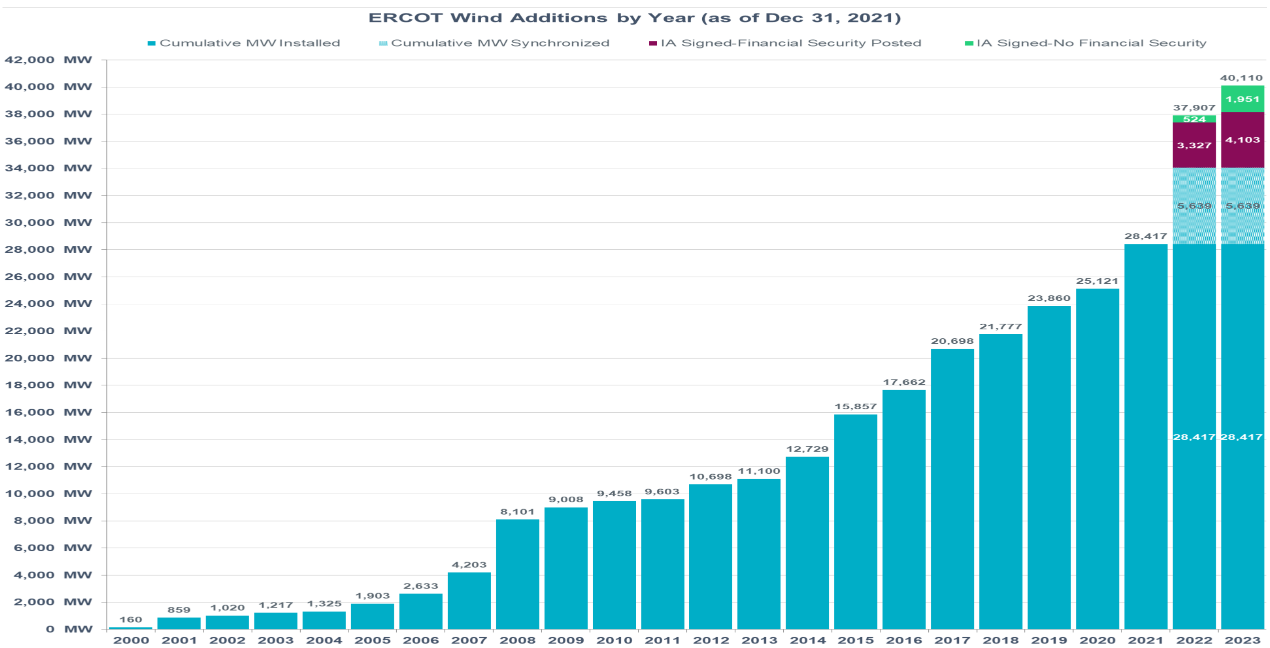
70 ERCOT Capacity Changes by Fuel Type (2021). Available at: https://www.ercot.com/files/docs/2022/01/06/Capacity_Changes_Fuel_Type_Charts_December_2021.xlsx.

71 Lazard's Levelized Cost of Energy (LCOE) – Version 15.0 (October 2021). Available at: https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.

72 Independent Market Monitor (IMM)(Potomac Economics) 2019 State of the Market Report (May 2020). Available at: https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf.

regulatory approval processes, combined with transmission costs that are entirely paid by ratepayers and the availability of cheap land, favors new entrants to the market. Texas also has abundant wind and solar resources and growing demand, which ensures wind and solar developers will be able to produce a lot of electricity and have customers to buy it. Finally, ERCOT's energy-only market design, in which generation resources can bid into the market on an as-available basis with no capacity requirements, is particularly well suited to the business models of wind developers. With zero fuel costs, wind generators can sell electricity at near-zero or even negative prices and still profit from the PTC. The net effect of these favorable forces has been more than $60 billion in wind and solar investments in ERCOT.[73] Wind and solar capacity additions are shown in *Figures 3(a)* and *(b)* below.

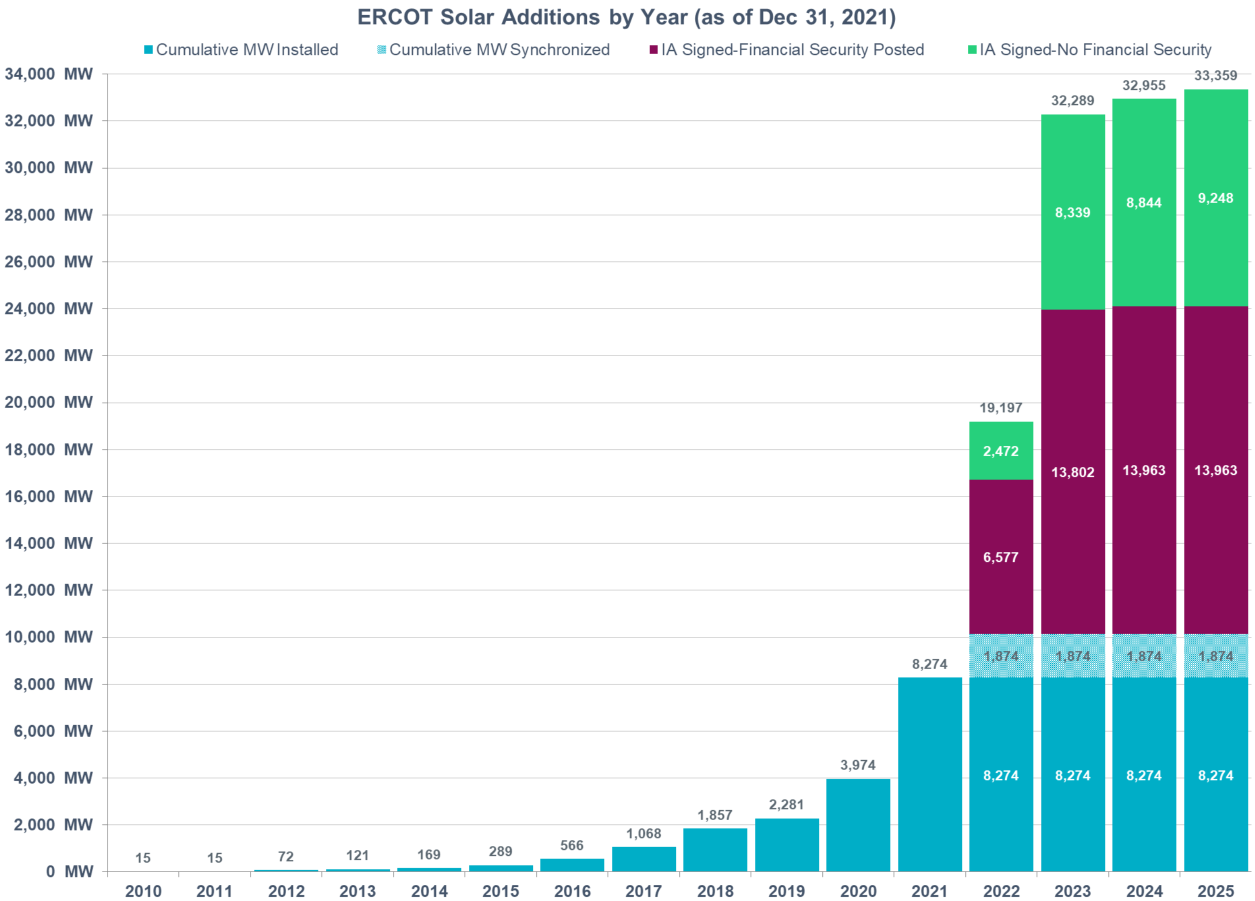
Figure 3(a): ***ERCOT Wind Additions by Year from 2000 to 2023, Actual and Planned***



Notes:
- The data presented here is based upon the latest information provided to ERCOT by resource owners and developers and can change without notice.
- Installed capacities are based on nameplate rating of the commercially operational generation and reflect retirements or rating changes due to facility expansions or repowering as these occur.
- Cumulative MW Installed does not include Private Use Network (PUN) units.
- Note that Installed capacities in ERCOT's Operations reports (such as for example Hourly Wind Output Reports) also include capacities for which Synchronisation to ERCOT grid has been approved (Part 2 Approval of the Commissioning Checklist) but not yet Approved for Commercial Operation.
- Installed capacities include only wind facilities that have registered with ERCOT (Those larger than one megawatt and supply power to the ERCOT system.)
- Distributed Generation Resources (DGRs) are Resources connected to the distribution system that are greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or are greater than one MW and are registered as a Generation Resource to participate in the ERCOT markets.
- This chart reports annual planned units with projected Commercial Operations Dates throughout the calendar year. In contrast, ERCOT's Capacity, Demand and Reserves (CDR) report shows planned capacity projected to be commercially available on or before the start of the Summer and Winter Peak Load seasons.
- Financial security posted for funding interconnection facilities does not include CREZ security deposits, which are refunded to the Interconnecting Entity when an IA is signed.
- Projects that have prior-year Projected CODs that have not been met, and for which ERCOT has not received COD updates, appear as planned projects for the subsequent year.
- Cumulative MW Synchronized pertains to projects that ERCOT has approved to generate energy for the grid but have not passed all qualification testing necessary to be approved for participation in ERCOT market operations.

[73] Advanced Power Alliance Briefing Paper available at: https://poweralliance.org/wp-content/uploads/2021/03/APA-Tax-Incentives-and-Chapter-313-2021_03.pdf.

Figure 3(b): ***ERCOT Solar Additions by Year from 2000 to 2023, Actual and Planned***[74]



Notes:
- The data presented here is based upon the latest information provided to ERCOT by resource owners and developers and can change without notice.
- Installed capacities are based on nameplate rating of the commercially operational generation and reflect retirements or rating changes due to facility expansions or repowering as these occur.
- Cumulative MW Installed does not include Private Use Network (PUN) units.
- Installed capacities include only solar facilities that have registered with ERCOT (Those larger than one megawatt and supply power to the ERCOT system.)
- Distributed Generation Resources (DGRs) are Resources connected to the distribution system that are greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or are greater than one MW and are registered as a Generation Resource to participate in the ERCOT markets.
- This chart reports annual planned units with projected Commercial Operations Dates throughout the calendar year. In contrast, ERCOT's Capacity, Demand and Reserves (CDR) report shows planned capacity projected to be commercially available on or before the start of the Summer and Winter Peak Load seasons.
- Projects that have prior-year Projected CODs that have not been met, and for which ERCOT has not received COD updates, appear as planned projects for the subsequent year.
- Cumulative MW Synchronized pertains to projects that ERCOT has approved to generate energy for the grid but have not passed all qualification testing necessary to be approved for participation in ERCOT market operations.

[74] Wind & Solar Capacity Trend Charts from ERCOT (2022). Available at: https://www.ercot.com/gridinfo/resource.

B. Discussion of premature retirements of existing thermal generation and relative stagnation of new builds.

Power system must be built to handle "peak" conditions – meaning those intervals of time that we need the most power. For Texas, the vast majority of "summer peak" is during the late afternoon and early evening of the hottest parts of the summer. That is good for solar (until the sun begins to set) and bad for wind (given that wind is very often at its lowest production during the hottest periods of the late afternoon).

So, Texas has been "dodging a bullet" – in the form of summer power outages – for years and that is the season that most experts anticipated Texas would have its most severe power outages. What Winter Storm Uri reminded us is that winter peaks, which are often the focus of northern power markets, can be extreme in warmer southern states like Texas as well. During winter peaks, solar rarely performs well and wind often sees dramatic reductions in production, either because the wind is blowing too hard, not at all, or is combined with frozen precipitation that incapacitates the turbine blades.

These weather-dependent energy realities mean that a robust mix of thermal generation from gas, coal, and nuclear power must be maintained in a power system to handle peak conditions when weather-dependent sources perform poorly. What follows is an overview of how the thermal generation mix in Texas actually contracted despite significant population and economic growth during the same period of time that Texas saw the above-described expansion of weather-dependent intermittent renewable resources.

From 2015 to 2020, Texas' population grew by over 1.7 million,[75] the state's gross domestic product expanded by over $200 billion,[76] and electricity demand grew by 5%.[77] Yet, during this period of massive growth, the ERCOT region saw 5.5 GW of coal and 4.8 GW of natural gas retirements, with many of those plants retiring before the end of their remaining useful life.[78] This is an unprecedented loss of thermal generation, even for markets that are not seeing demand growth, let alone a market growing at an extraordinary rate like ERCOT.

So, in just five years, ERCOT netted a loss of more than 4.8 GW of thermal capacity, or about 6% of total installed thermal capacity when its demand grew by almost that same amount. In essence, the gap between the state's electricity demand and its thermal generating capacity has expanded by more than 10%. The gap would have expanded even larger if not for the impact of the COVID-19 pandemic, which significantly reduced the growth in electricity demand in 2020 and 2021 compared to the 2015-2019 trend.

Figure 4(a) below depicts this expansion of intermittent resources and contraction of thermal generation during the above-referenced 5 year period between 2015-2020 while *Figure*

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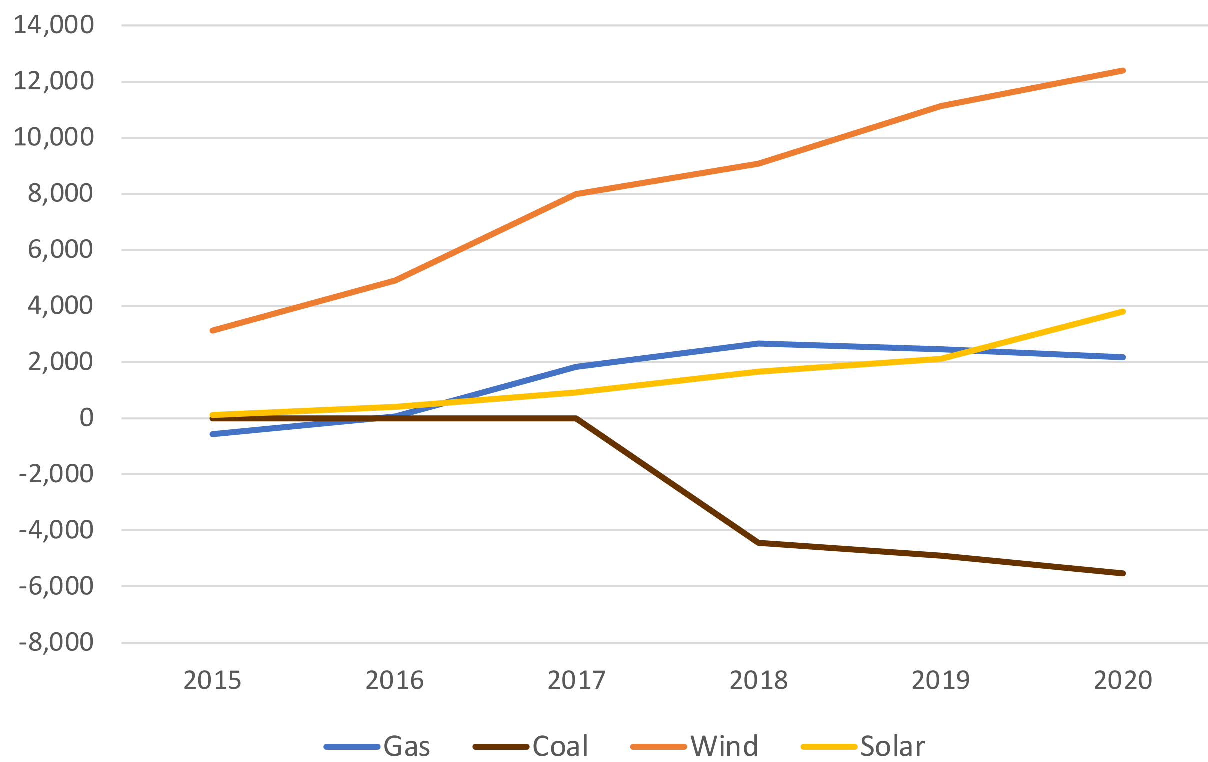
[75] Resident Population of Texas, Federal Reserve Bank. Available at: https://fred.stlouisfed.org/series/TXPOP.
[76] Gross Domestic Product: All Industry Total in Texas. Available at: https://fred.stlouisfed.org/series/TXNGSP.
[77] Net Generation Demand by State. Available at: https://www.eia.gov/electricity/data/state/.
[78] Generator Retirement Summary. Available at: https://www.eia.gov/electricity/data/eia860m/xls/november_generator2021.xlsx.

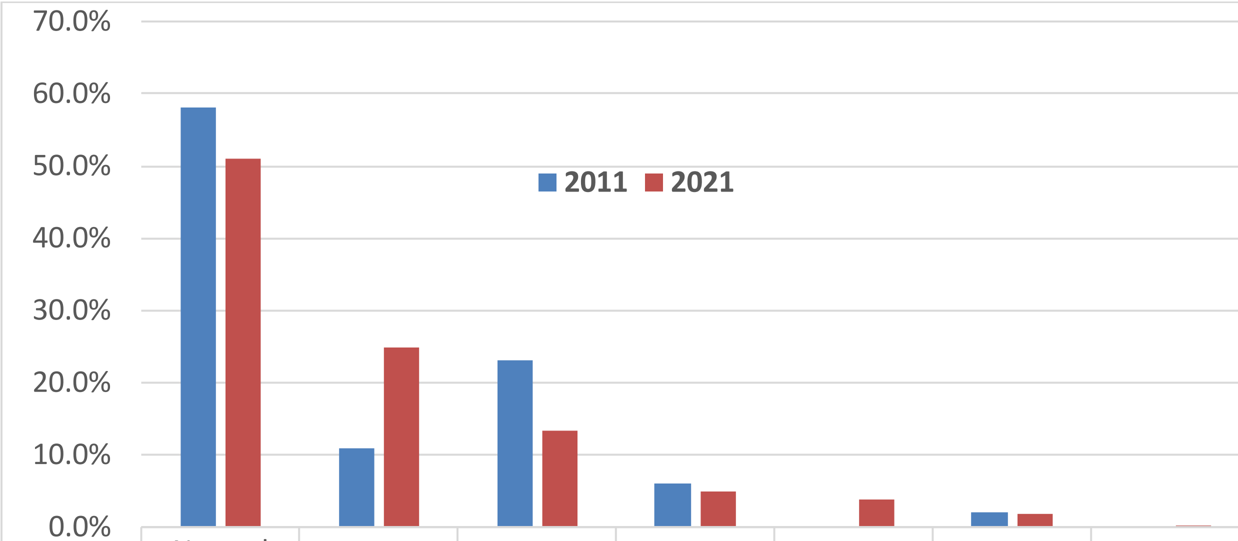
4(b) shows that resulting net installed capacity by resource for a full 10-year period dating back to 2011.

Figure 4(a): ***Changes in annual installed capacity of gas, coal, wind, and solar since 2015***[79]



[79] From "ERCOT Solar Additions by Year," Electric Reliability Council of Texas, December 2021. (https://www.ercot.com/files/docs/2022/01/06/Capacity_Changes_Fuel_Type_Charts_December_2021.xlsx) and "Preliminary Monthly Electric Generator Inventory," U.S. Energy Information Administration, November 2021 (https://www.eia.gov/electricity/data/eia860m/xls/november_generator2021.xlsx).

Figure 4(b): ***Annual installed capacity change of natural gas, wind, and solar since 2015***[80]



	Natural Gas	Wind	Coal	Nuclear	Solar	Other	Storage
2011	58.0%	11.0%	23.0%	6.0%	0.0%	2.0%	0.0%
2021	51.0%	24.8%	13.4%	4.9%	3.8%	1.9%	0.2%

The lack of awareness about this growing gap between electricity demand and thermal generating capacity in ERCOT is compounded by the way in which ERCOT calculates and publishes its reserve margins. ERCOT's Summer 2021 Seasonal Assessment of Resource Adequacy shows 87 GW of available resources to meet 77 GW of projected peak demand[81] However, those numbers are based on the total installed capacity of thermal generation in ERCOT and the *average* output of wind and solar resources during peak demand hours. It is necessary to continue to the next table in the SARA Report, titled "Reserve Capacity Risk Scenarios" to get a more accurate view of the risks to the system.[82] Average outages of thermal power plants in the summer total about 3.6 GW, and wind output can fall 6.6 GW below its average. Therefore, as evidenced by the data in ERCOT's SARA reports, any situation combining normal thermal outages, low wind output, and normal summer peak demand could put the grid at risk of outages.

So, why did thermal generation not expand during this historic period of Texas growth in demand for electricity? That is a part of the story rarely told and a critically important cautionary tale that should be heeded by other markets in our country (and the world) if we hope to avoid a repeat of the Texas disaster. While it is outside the scope of this case study to do an in-depth economic analysis of the interplay between production and investment tax credits and energy markets, one need not be an economics expert to understand why investment in thermal generation in ERCOT was not attractive to capital markets during the past 10 years.

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[80] Data from "Resource Adequacy," Electric Reliability Council of Texas, n.d. (https://www.ercot.com/gridinfo/resource).

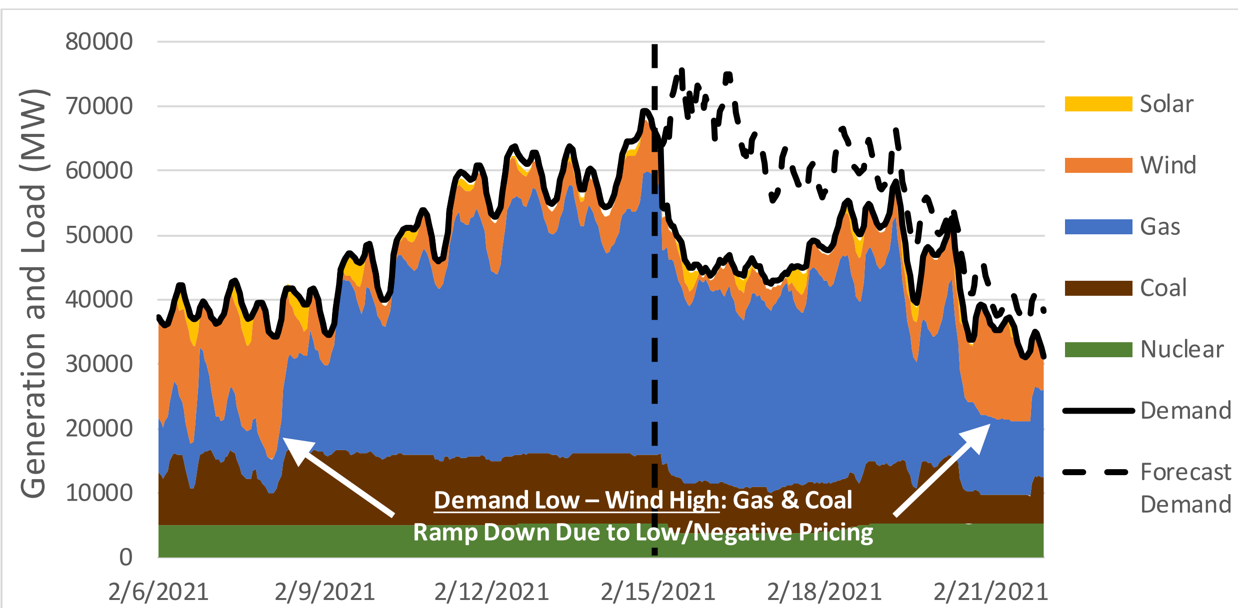
[81] ERCOT Seasonal Assessment of Resource Adequacy (SARA)(Summer 2021). Available at: https://www.ercot.com/files/docs/2021/05/06/SARA-FinalSummer2021.pdf.

[82] *Id*. at page 3.

The data pictured in *Figure 5* below will be explained in much more detail in the subsequent section describing the February 2021 events immediately before, during and following the Texas power outages. The data in that figure (which originates from EIA) also helps explain the underlying market distortion that has prevented the construction of thermal generation in ERCOT. In the figure, brackets framing the days before and after the storm show a phenomenon that has become all-too-common in the ERCOT market. Blowing wind and sunshine drive renewable generation's percentage of overall capacity much higher than any other resource. Then, because electric demand drops due to mild conditions, the role of the wind production tax credit kicks in.

Because the production tax credit is only paid for each megawatt generated and distributed to the grid, there is a perverse incentive for renewable generators to bid their power as low as possible to ensure dispatch, which, during particularly soft demand time periods, can drive the price of electricity negative because the wind generator can still clear some part of the tax credit even if the sales price is below zero. Although the theory of "free electricity" might sound attractive, it does not take an economist to know how damaging it is for thermal generation to have to pay to stay online because of a negative pricing scenario. Yes, you read that correctly – gas, coal and nuclear power plants that want (or need) to stay online, for reasons ranging from contracts to power plant mechanical integrity, while wind is bidding the price below zero, must pay to stay online in the ERCOT market. This is not nearly a one-time situation – it has become far too prevalent during soft demand, high wind days and nights in ERCOT.

Figure 5: ***Demand and Generation by Resource (in MW) from February 6 to February 21, 2021***[83]

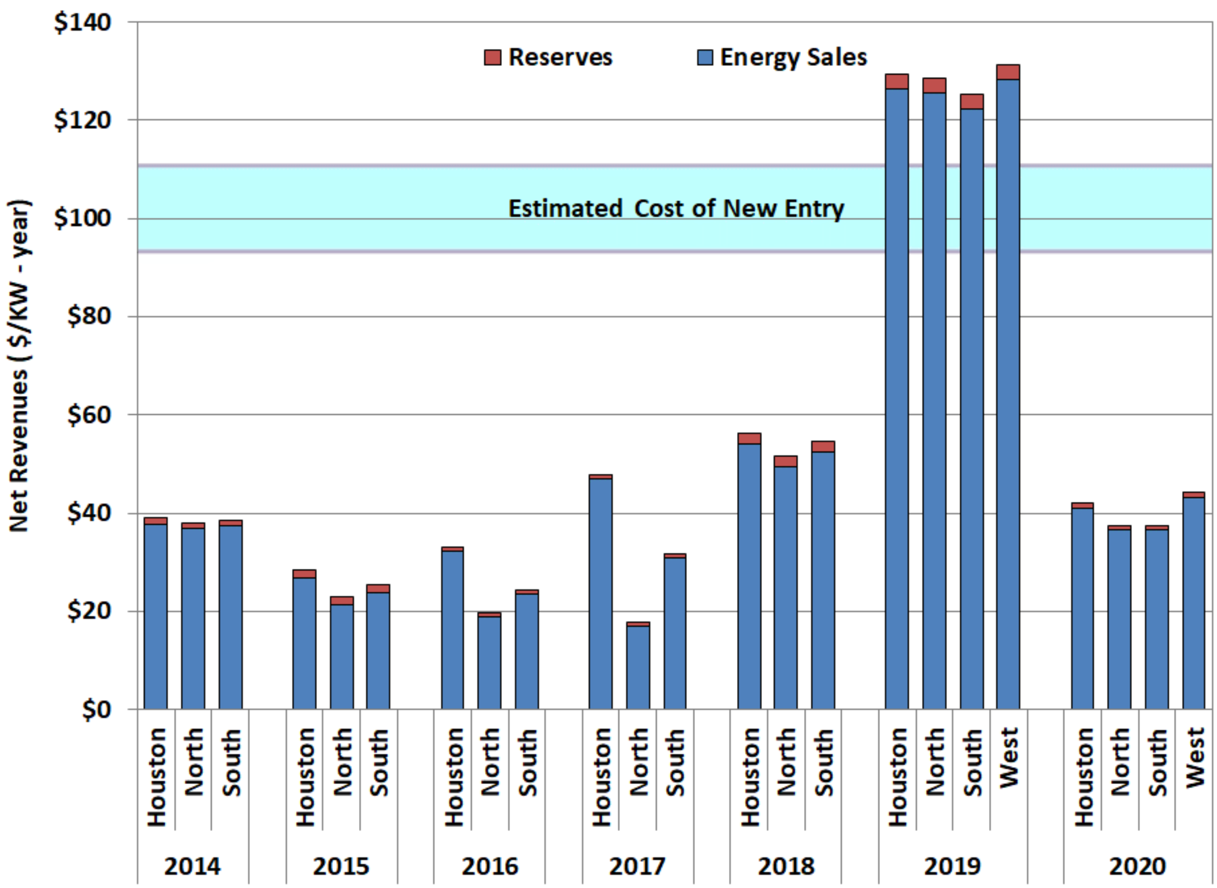


The fact that prices are driven so low (even negative) so often and scarcity pricing happens too infrequently is the central reason why thermal generation has retired early and is not getting

[83] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration; Available at: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

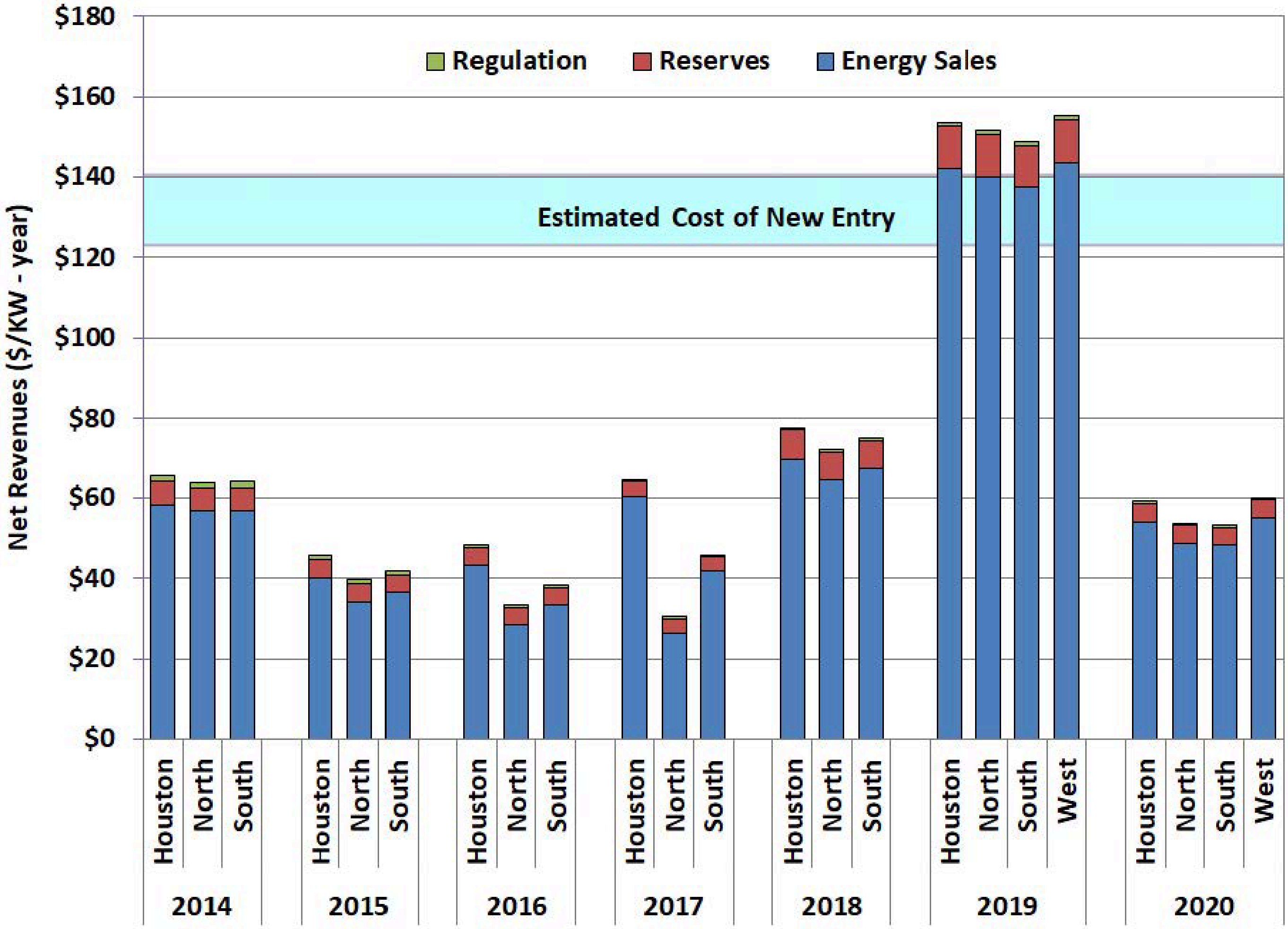
built in the energy-only ERCOT market. The Independent Market Monitor (IMM) for ERCOT has been pointing this "Missing Money" problem out for years, as demonstrated by *Figures 6(a)* and *6(b)* below which depicts how, over a 6 year period starting in 2014, even the most efficient natural gas combustion turbines or combined cycle plants have been "out the money" in ERCOT except for a single year (2019) when summer scarcity pricing escalated temporarily. While this problem led to several PUC and ERCOT discussions about better valuing the capacity, reliability and resilience attributes of thermal generation, those discussions did not result in any reforms to address the "missing money" problem in ERCOT – until Winter Storm Uri, that is.

Figure 6(a): ***Combustion Turbine Net Revenues Relative to Estimated Cost of New Entry***[84]



[84] Independent Market Monitor(IMM)(Potomac Economics) 2020 State of the Market Report (May 2021). Available at: https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf.

Figure 6(b): ***Combined Cycle Net Revenues Relative to Estimated Cost of New Entry***[85]



C. *Discussion of Trends in SPP and MISO showing similar growth in wind and solar, premature retirements of existing thermal generation, and relative stagnation of new thermal generation builds.*

1. *Market Overview of the Southwest Power Pool*

SPP as a regional transmission organization (RTO) ensures the delivery of electricity to its 14 member states. The SPP service territory stretches from North Dakota in the North to Texas in the South, with many of its member states experiencing record-low temperatures and significant operational obstacles during Winter Storm Uri. Due to extreme winter storm conditions which lasted from February 14, 2021, through February 20, 2021, SPP experienced significantly increased electricity and natural gas demand while generators simultaneously experienced fuel supply shortages and forced outages due to cold weather impacts on equipment. Forced

85 Independent Market Monitor(IMM)(Potomac Economics) 2020 State of the Market Report (May 2021). Available at: https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf.

infrastructure outages along with fuel supply and electric generation scarcity resulted in transmission congestion and historically high energy costs in the SPP market. SPP set a new winter peak load of 43,661 MW the morning of February 15, 2021, and, if not for conservation efforts and curtailments, "likely would have reached a wintertime peak of 47,000 MW."[86]

2. Market Overview of the Midcontinent Independent System Operator

MISO is the RTO responsible for ensuring the reliability and resilience of the electric transmission system and facilitating the delivery of electricity to its end-use customers. The MISO transmission system is the largest in North America, serving approximately 42 million people across 15 states and the Canadian province of Manitoba, with roughly 66,000 miles of transmission lines and almost 199,000 MW generation capacity.[87] MISO exercises functional control over the region's transmission and generation resources with the aim of managing them in the most reliable and cost-effective manner possible. The MISO region is predominantly comprised of traditionally structured and state-regulated utilities. During the week of Winter Storm Uri, the MISO region experienced extreme cold temperatures which in turn drove high demand for electricity while simultaneously causing forced generation outages, transmission infrastructure performance issues, and reduced fuel availability. Average energy prices rose 226 percent in February due to the extreme cold weather, with natural gas pricing at 12 times higher than the previous year and transmission outages leading to real-time transmission congestion at record levels.[88]

3. Comparing the Resource Mix Changes in MISO and SPP Compared to ERCOT

The change of the SPP and MISO electricity resource mix away from a thermal dispatchable generation-dominated mix toward deep renewable resources penetration is similar to that of ERCOT in many respects except that the change has not occurred as quickly in those markets. Although the SPP market is trending in the direction of ERCOT more quickly than MISO, the fact that both are following the same trend line cannot be disputed when one evaluates the historic and projected future resource mix of those markets and compares it with the ERCOT experience.

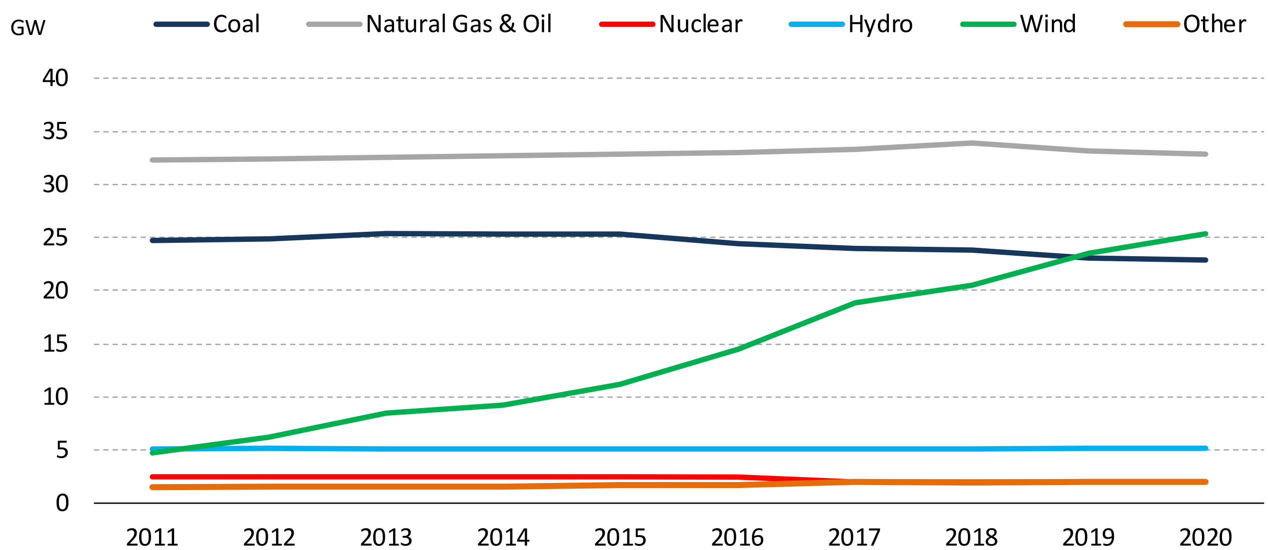
As depicted in *Figures 7(a)* and *7(b)* below, when compared to *Figures 4(a)* and *4(b)* above, the most striking similarities between installed capacity in SPP/MISO and ERCOT are:

- the similar dramatic growth of wind generation (growing from 5 GW to 25 GW in SPP, from roughly 8 GW to 22 GW in MISO between 2011 and 2021, and from 3,000 MW to 12,000 MW in ERCOT since 2015);
- the stagnation of natural gas-fired generation (at roughly 33 GW in SPP, 70 GW in MISO between 2011 and 2021, and from zero to 2,000 MW in ERCOT since 2015); and

[86] *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm* at 40 (Jul. 19, 2021).
[87] *The February Arctic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative*, at 3 ().
[88] *MISO Independent Market Monitor Quarterly Report* at 2 (Apr. 15, 2021).

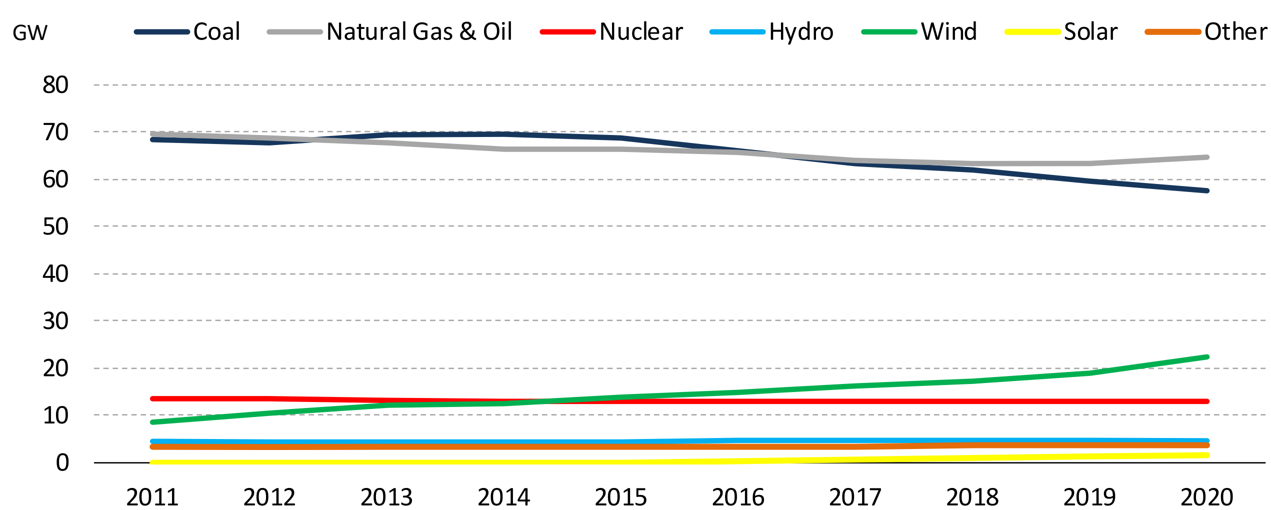
- the significant drop in coal-fired generation due to retirements and the influence of the Production Tax Credit on dispatch characteristics across the markets (dropping from 25 GW to 23 GW in SPP, from roughly 70 GW to 58 GW in MISO between 2011 and 2021, and the loss of 6,000 MW in ERCOT since 2015).

Figure 7(a): ***Evolution of Installed Capacity by Source in the SPP Market.***



Source: EVA analysis of EIA 923 & 860 data

Figure 7(b): ***Evolution of the Installed Capacity by Source in the MISO Market***

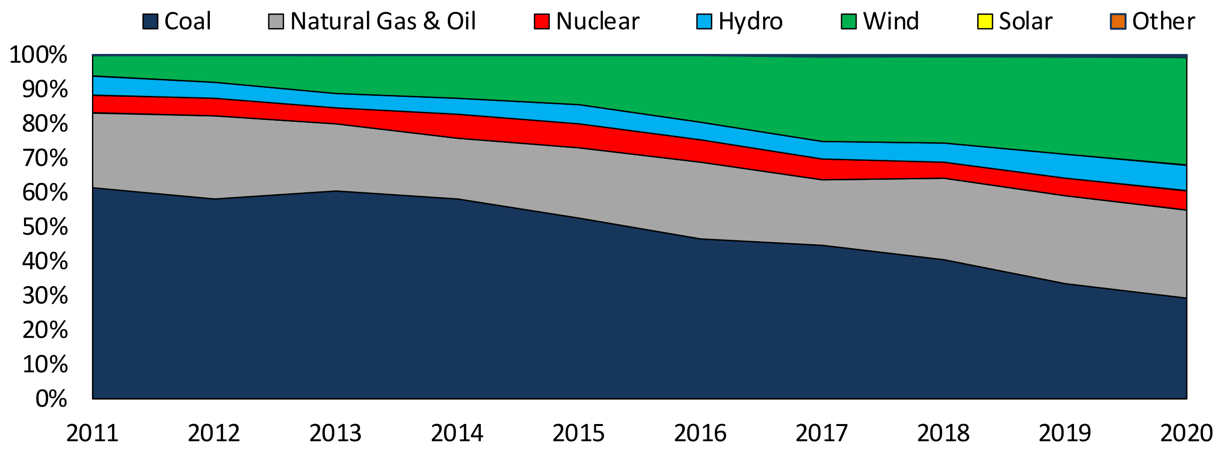


Source: EVA analysis of EIA 923 & 860 data

Note that the shift is quicker in SPP than MISO but the trend is the same. Something to note at this point in the report before our detailed discussion of the events surrounding Winter

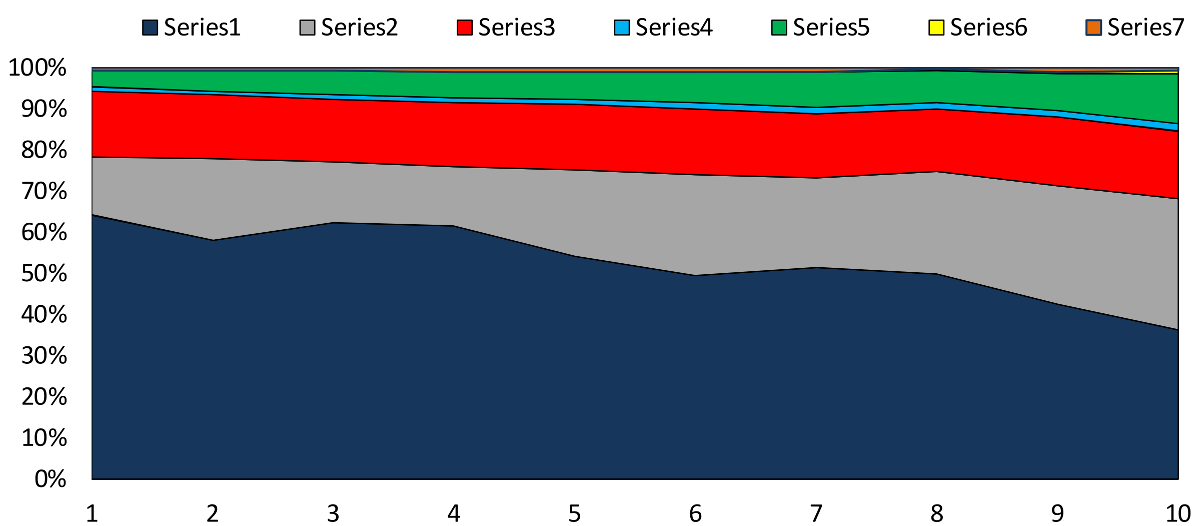
Storm Uri is an important distinction between the state of the resource mix in the SPP and MISO markets compared to ERCOT heading into Winter Storm Uri. As *Figures 7(a)* and *7(b)* make clear, both SPP and MISO still benefit form a large installed capacity of thermal dispatchable generation, especially coal, and *Figures 8(a)* and *8(b)* below show that the actual generation of those resources on an annual basis continues to demonstrate how much of that type of resource is dispatched in those markets.

Figure 8(a): ***Evolution of Electricity Generation by Source in the SPP Market.***



Source: EVA analysis of EIA 923 & 860 data

Figure 8(b): ***Evolution of the Electricity Generation by Source in the MISO Market***



Source: EVA analysis of EIA 923 & 860 data

The fact that SPP and MISO appear to be following the same ERCOT resource mix changes (just on a slower timeline) - makes the cautionary tale of the Texas experience an important one for all the states within those markets if they aspire to prevent the disaster of the Texas experience. This is especially true given that the designs of all three of these organized markets are very similar with the foundation being an "energy-only" framework that does not include a capacity market or any other significant valuation of thermal dispatchable resources other than scarcity pricing. This leaves the markets open to the same distorting effects of federal tax credits which, as discussed at length above, alters the way energy is bid into the market in a way the severely degrades the economics of maintaining the existing thermal dispatchable fleet, let alone building new plants. Again, the only difference is the extent of renewable penetration which governs the extent of the market distortion and economic impact to thermal generators.

What will become clear in subsequent sections discussing the impacts of Winter Storm Uri on SPP and MISO compared to ERCOT is that continued strong presence of thermal dispatchable generation, especially coal-fired generation, in SPP and MISO played a major role in the contrasting experiences of the two markets during Winter Storm Uri. The fact that SPP and MISO are going the way of ERCOT should not be comforting to states within those markets who want to avoid the tragic consequences of the Texas experience, but the good news for those states is that they have not gone as deeply into the abyss as ERCOT and are in a good position to heed the cautionary tale, observe and evaluate the market reforms being implemented in Texas, and deploy similar measures to secure the reliability and resilience of the grid across both markets.

We turn now to the meat of this study – a detailed forensic analysis of the impacts of Winter Storm Uri on Texas, the comparative impacts experienced in SPP and MISO, and what that tells us about how the grid became unreliable and what to do it fix it.

IV. DETAILED ANALYSIS OF THE EVENTS LEADING UP TO AND DURING POWER OUTAGES IN ERCOT

The shift away from dispatchable thermal generators and toward intermittent wind and solar documented above, set the stage for an increasing risk of outages in any situation combining high demand with low wind and solar generation. This increasing risks became better understood when Texas experienced "Level 1 Emergency Energy Alerts (EEA1)" on August 13 and August 15 of 2019,[89] which required conservation measures (but not forced outages) to balance the grid. An emergency would likely have occurred again on August 14, 2020, if not for reduced economic activity due to the COVID-19 shutdowns, which led to 500 MW less peak demand than what was experienced in 2019.[90]

The two EEA1 situations in August 2019 made it clear that low wind output during peak demand periods was creating a resource adequacy problem for the ERCOT region. During that week, the EEAs did not occur on the day of highest demand but on two subsequent days. However, despite the outages that occurred in February 2011, it was not widely expected that Texas would see the first widespread outages due to this problem in the winter. Nevertheless, close scrutiny of the data contained in ERCOT's planning scenarios clearly forewarned that an extreme level of winter demand, comparable to peak summer demand, combined with low wind and solar output,

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[89] ERCOT Calls 2 Energy Emergencies in One Week, 3rd in 5 Years (*Utility Dive*, August 16, 2019)(Available at: https://www.utilitydive.com/news/ercot-calls-2nd-energy-emergency-this-week-3rd-in-5-years/561065/.

[90] Independent Market Monitor(IMM)(Potomac Economics) 2020 State of the Market Report (May 2021). Available at: https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf.

would lead to a situation where the grid was short of firm generating capacity during the cold of the winter.

Winter Storm Uri simply exposed the problems of the ERCOT grid during a different season than most predicted and the resulting strain it placed on the thermal fleet and natural gas supply chain exacerbated the situation dramatically. The focus of media attention during and after Winter Storm Uri was on the numerous operational failures that manifested, from gas shortages to equipment freezing to wind turbine icing. However, as documented below, even if generation outages were minimized and gas supply shored up, the ERCOT region still would have likely experienced outages lasting at least 24 hours.

The loss of dispatchable generation capacity in ERCOT over the past several years made it inevitable that the level of demand experienced during Uri, combined with the low availability of wind and solar resources at the height of the storm, would lead to widespread outages. This is a market design problem resulting from the lack of market incentives to invest in reliable generation and weather resiliency. Seeing that these two categories each deserve close attention, this section summarizes the various causes of generation outages during the storm, and the subsequent sections will examine how the storm exposed the ERCOT grid's shortage of firm generation and what Texas policymakers are doing to reform the Texas power market as a result.

Although Texas has seen the level of widespread cold weather and winter precipitation during Winter Storm Uri in the past, the duration and extent of cold weather, spanning nearly 10 days with several days entirely below freezing, is unprecedented in the past 100 years. The extreme weather led to failures across the entirety of the electricity supply system, from the natural gas supply network to power plants to the transmission and distribution network.

However, even if the weather and operational problems were solved, the ERCOT region still would have likely experienced outages lasting at least 24 hours. Ultimately, the root cause of the outages is the problems with the ERCOT market outlined in the previous section and the lack of market incentives to invest in reliable generation and weather resiliency. This section will summarize the various causes of outages during the storm, and the next section will examine how they are tied back to the root cause of misdirected investment in the ERCOT market.

A. How unique was the weather during February 2021?

The most recent comparison to Winter Storm Uri is the winter storm in February 2011, which saw rolling outages for a few hours across much of the state and significant winter precipitation. However, temperatures during Uri were notably colder than in 2011, and the best comparisons are winter storms in 1983 and in 1989, which saw temperatures fall into the single digits or below zero Fahrenheit across much of the state. Notably, only minor rolling outages were experienced during the December 1989 storm.[91]

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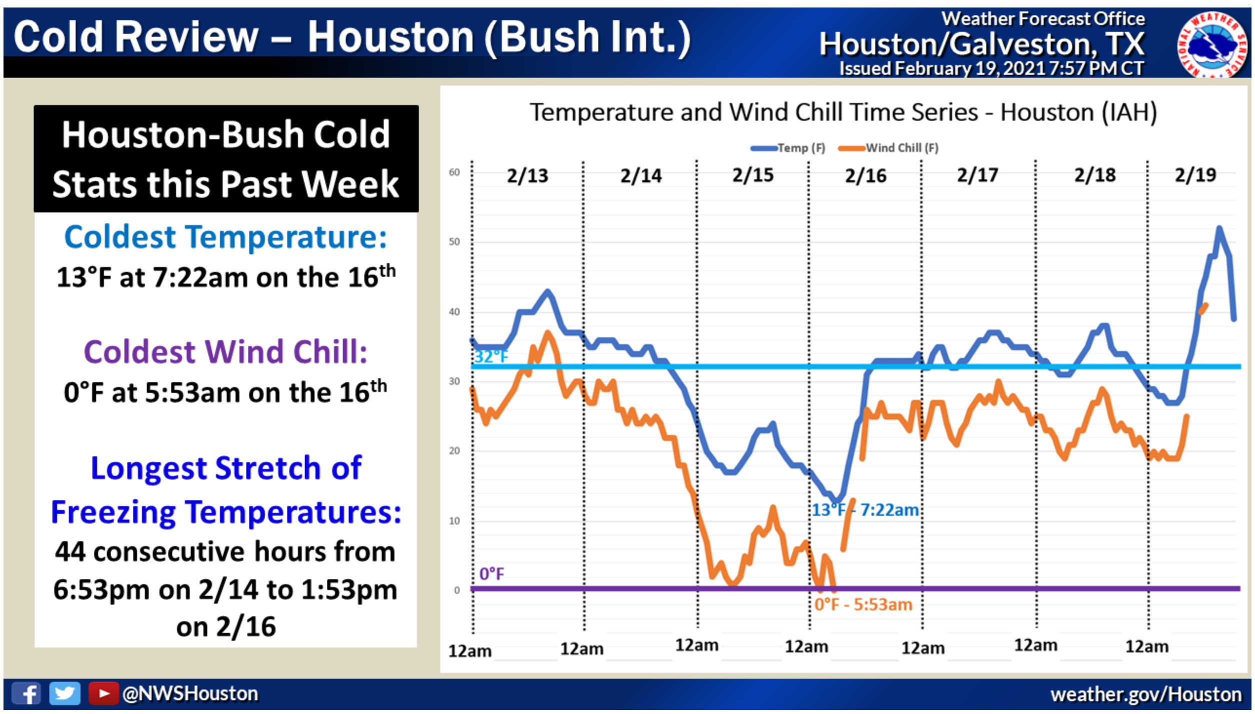
[91] The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, University of Texas Energy Institute (July 2021), page 71. Available at: https://www.puc.texas.gov/agency/resources/reports/UTAustin_(2021)_EventsFebruary2021TexasBlackout_(002)FINAL_07_12_21.pdf.

Table 1: ***Low Temperatures in Dallas, Houston, and San Antonio in 1983, 1989, 2011, and 2021 (°F)***[92]

	December 1983	December 1989	February 2011	February 2021
Dallas	5	-1	13	-2
Houston	11	7	21	13
San Antonio	11	6	16	6

Figure 9 below shows the temperature in the Houston area throughout the week of Winter Storm Uri. High temperatures in Houston in February are usually in the mid-60s Fahrenheit, with lows in the mid-40s, so the deviations from normal are greater than 30°F throughout the entirety of the week, with no recovery until February 19. Normally in Texas, temperatures are well above freezing within a day or two after a winter storm, but this event saw cold weather for several days prior to February 15 and the persistence of below freezing temperatures for four days after that. Therefore, duration is the major differentiator of this event from the similarly cold weather that occurred in the 1980s.

Figure 9: ***Temperatures at Houston-Bush International Airport from February 13-19, 2021***[93]



The duration of the storm had a significant impact on infrastructure and fuel supply. Natural gas supplies were already stretched thin prior to February 15, leaving no breathing room once temperatures plummeted another 15 to 20 degrees and demand for electricity shot up. The ability of crews to make repairs to power plants, pipelines, transmission lines, etc. was hindered by poor road conditions. Equipment that was frozen took days to thaw out. These weather impacts were

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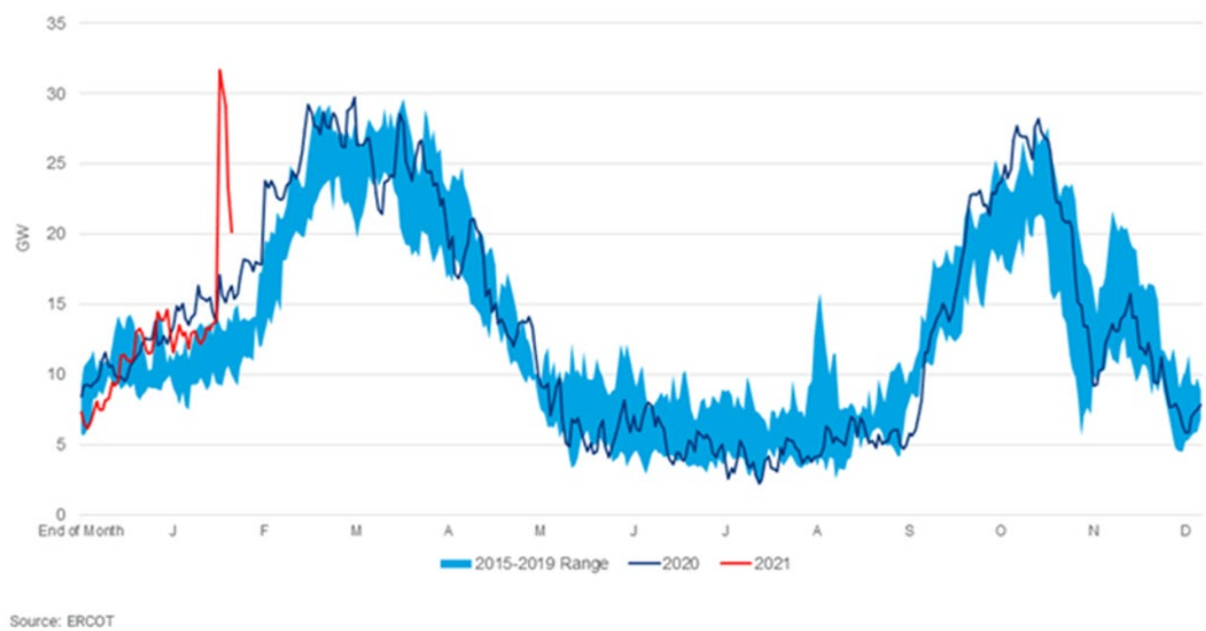
92 Data from "NOWData - NOAA Online Weather Data," National Weather Service, n.d. (https://www.weather.gov/wrh/Climate?wfo).
93 From "Valentine's Week Winter Outbreak 2021: Snow, Ice, & Record Cold," National Weather Service, n.d. (https://www.weather.gov/hgx/2021ValentineStorm).

the primary reason that what might have been one day of electricity outages turned into multiple days for much of the state. However, the problems that were exposed by Uri run much deeper than what can be directly tied to the weather.

B. Preparations made by ERCOT, market participants, and state regulators

While long-range weather forecasters had been forecasting a late winter storm for the central United States for some time, the first clear signs of troublesome weather coming the week of February 15 began to appear as the calendar turned to February. On February 8, ERCOT issued an Operating Condition Notice for an extreme cold weather event,[94] cancelled or delayed transmission outages, and sought to return power plants to service that were undergoing maintenance.[95] In total, about 13 GW of thermal generation was offline prior to February 14, which was in line with the 2015-2020 historical range, as shown in *Figure 10* below.

Figure 10: ***Thermal Generation on Outage in ERCOT, 2015 to 2021***[96]



As the severity of the coming storm became clear over the next few days, ERCOT issued public warnings and news releases calling for preparation and electricity conservation[97]. It also requested and was granted enforcement discretion for power plant emissions,[98] which allowed plants to run at full capacity without any parasitic losses from pollution control equipment, a

[94] Review of February 2021 Extreme Cold Weather Event – ERCOT (February 24, 2021), page 9. Available at: https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf.
[95] *Id* at page 8.
[96] From "Breaking down the Texas winter blackouts: what went wrong?" Wood Mackenzie, 2021 (https://www.woodmac.com/news/editorial/breaking-down-the-texas-winter-blackouts).
[97] ERCOT News Release (February 14, 2021). Available at: https://www.ercot.com/news/release?id=e2b19f22-7283-3fe8-bed2-a4a979dce772.
[98] ERCOT Market Notice (February 14, 2021; 5:58 PM). Available at: https://www.ercot.com/services/comm/mkt_notices/detail?id=4b1be90c-b1be-3c81-8c27-1ce90982caea.

standard practice during any grid emergency. Electric generators and other market participants began sending notices to customers and bringing on extra crews to manage the expected weather problems.[99]

At the same time, the Railroad Commission (RRC) revised its rule regarding natural gas delivery contracts to prioritize delivery first to residential consumers and second to electric power generators,[100] and the PUC coordinated efforts to ensure that staff and resources were prepared for a few days of record winter demand.[101] ERCOT noted during their media availability on February 14[102] that demand could exceed 70 GW during the next two days and that generator outages could be significant, likely leading to prolonged outages. However, the duration and severity of the outages took everyone by surprise.

C. Grid operations and frequency-related issues at the onset of the storm

On the night of February 14, the ERCOT region experienced record winter demand of over 69 GW.[103] However, wind was producing enough electricity at the time that peak net load (demand minus wind and solar production) was below 61 GW, and the thermal fleet was able to meet demand at that time. Although demand began to decrease overnight as people went to bed and residential electricity use dropped, the passing of the storm through Central and East Texas, where a large portion of the state's gas and coal power plants are located, sent temperatures that were already near the freezing mark to well below freezing. Wind production also began to drop off in West Texas and the cold, stable air mass settled in there. These factors led to a precipitous decline in available generation beginning around midnight on February 15.

At 12:15 AM on February 15, operating reserves in ERCOT fell below 2,300 MW, and a level 1 Energy Emergency Alert (EEA1) was called, bringing emergency resources online[104] At 1:07 AM, an EEA2 was declared, and electricity supply to industrial consumers that participate in ERCOT's demand response program was cut. However, power plants continued to go offline in rapid succession as temperatures across most of Texas plummeted into the teens and single digits. At 1:23 AM, an EEA3 was declared, and ERCOT began to order transmission companies to do what is called "firm load shed," that is, to turn off power to customers involuntarily.

As shown in *Figure 11*, within an hour after the EEA3 was first called, an additional 6,078 MW of generation went offline, and 10,500 MW of firm load shed had been ordered. Such a rapid loss of generation during an already declared emergency was unprecedented in ERCOT's history,

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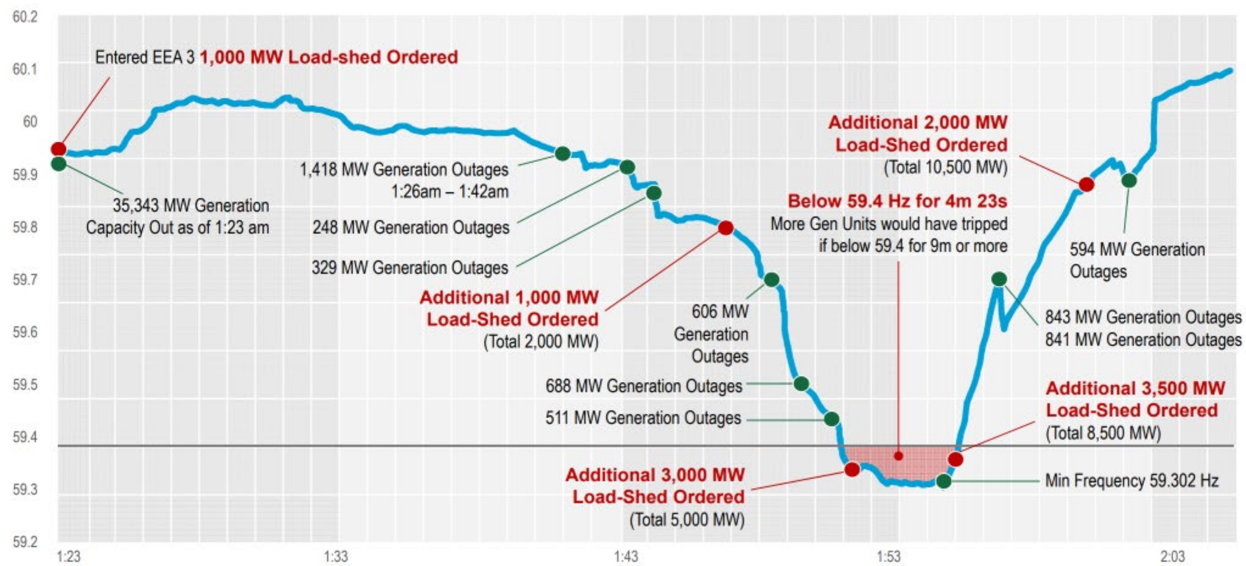
[99] NRG Press Release (February 26, 2021). Available at: https://www.nrg.com/about/newsroom/2021/nrg-ceo-testimony-on-winter-storm-uri.html.
[100] Emergency Order of the Railroad Commission of Texas (February 12, 2021). Available at: https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.
[101] Public Utility Commission of Texas News Release (February 11, 2021). Available at: https://www.puc.texas.gov/agency/resources/pubs/news/2021/PUCTX-REL-ERCOT-COLD21-FIN.pdf
[102] ERCOT Media Call. Recording available at: https://www.dropbox.com/s/yaewlr56grqag37/Winter%20Conditions%20Media%20Call-20210214%202001-1.mp4?dl=0.
[103] Review of February 2021 Extreme Cold Weather Event – ERCOT (February 24, 2021), page 11. https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf.
[104] *Id.*

and the grid frequency dropped perilously low during that time. The grid must be kept very close to 60 Hz because generators, which use rotating masses to create electricity, must be kept in perfect sync with the grid to avoid irreparable damage to their equipment. Beginning at 1:51 AM on February 15, the grid frequency dipped below 59.4 Hz for more than four minutes, and if the frequency had remained that low for more than nine minutes, more generators would have been forced offline. Had that happened, based on testimony of experts during the legislative session, it is likely that the entire grid would have shut down and the state would have been without power for weeks, unleashing a deadly catastrophe of unprecedented scale, perhaps the worst in U.S. History.

Figure 11: ***ERCOT System Frequency, February 15, 1:23 AM to 2:06 AM***[105]



Fortunately, the ERCOT operations team was able to stabiles frequency enough to keep the grid from collapsing, but the unfortunate consequence was shedding about 16% of the demand on the system, necessitating rolling outages throughout the state while most people were asleep. Also, although the frequency was maintained above the level needed to avoid a catastrophe, there were several power plants that reported tripping offline due grid operations beyond their control - low frequency or rapid frequency fluctuations in their part of the grid.[106] Unfortunately, that 10 GW load shedding was just the beginning.

Figure 12 below shows that firm load shed reached 16.5 GW during the morning of February 15 and peaked at 20 GW that night. A combination of additional power plant failures and wind production falling from nearly 10 GW the night of February 14 to less than 1 GW the next evening made the additional load shedding necessary. 20 GW of load shedding was more than 25% of forecast demand across the state at that time, which meant that at least 25% of Texas consumers were without power. The proportion of residential customers affected was much higher because much of the available electricity had to be reserved for critical infrastructure like hospitals,

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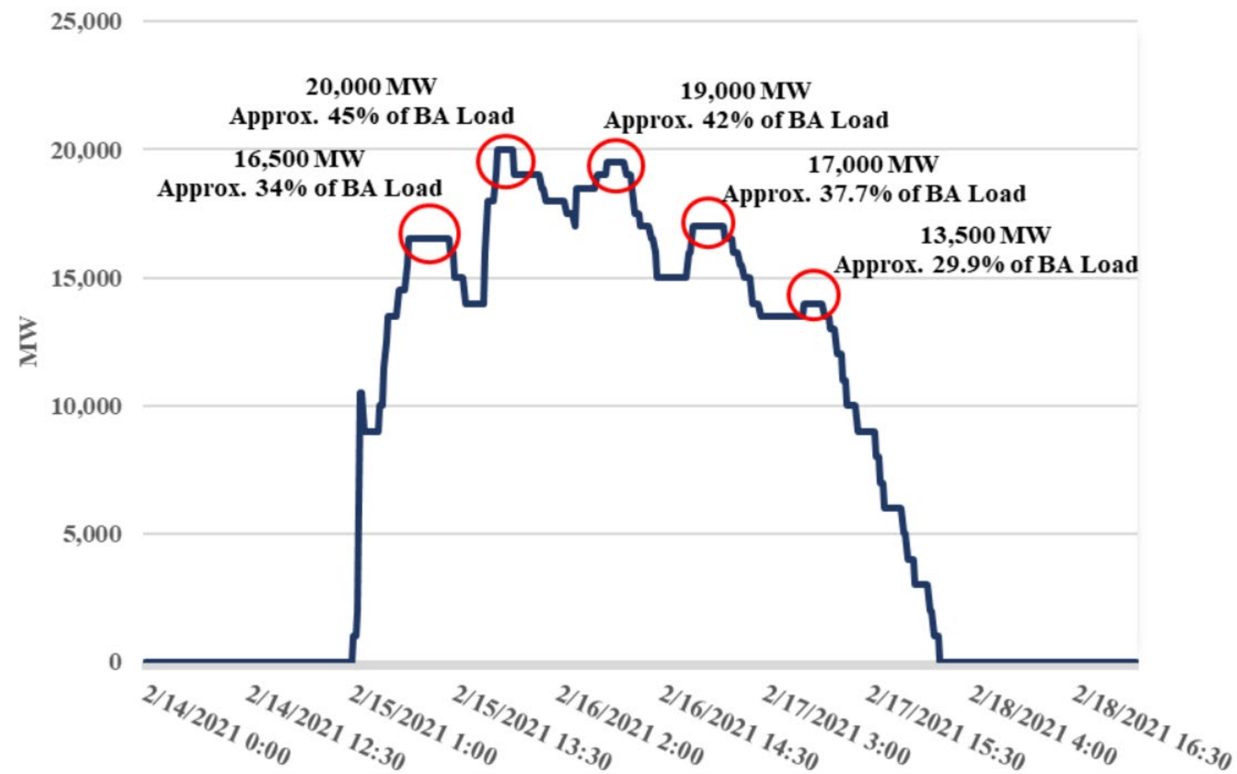
[105] From "Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation," Electric Reliability Council of Texas, 2021. https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf.
[106] *Id* at page 18-19.

and almost all Texas residential and commercial consumers lost power at some point during the day as the outages were rotated.

Figure 12: ***ERCOT EEA 3 Firm Load Shed Ordered (MW)***[107]



Load shedding remained at those high levels all the way through the middle of the day on February 17 before declining and ending on February 18. A primary cause of the outages was a lack of firm capacity to serve the expected demand, and that problem alone would have likely caused more than a day of load shedding, possibly reaching almost 10 GW the evening of February 15. However, the depth and duration of load shedding was made worse by disruptions to gas supplies and to weather-related problems at power plants, which will each be discussed in the next two sections.

D. Disruptions in fuel supplies

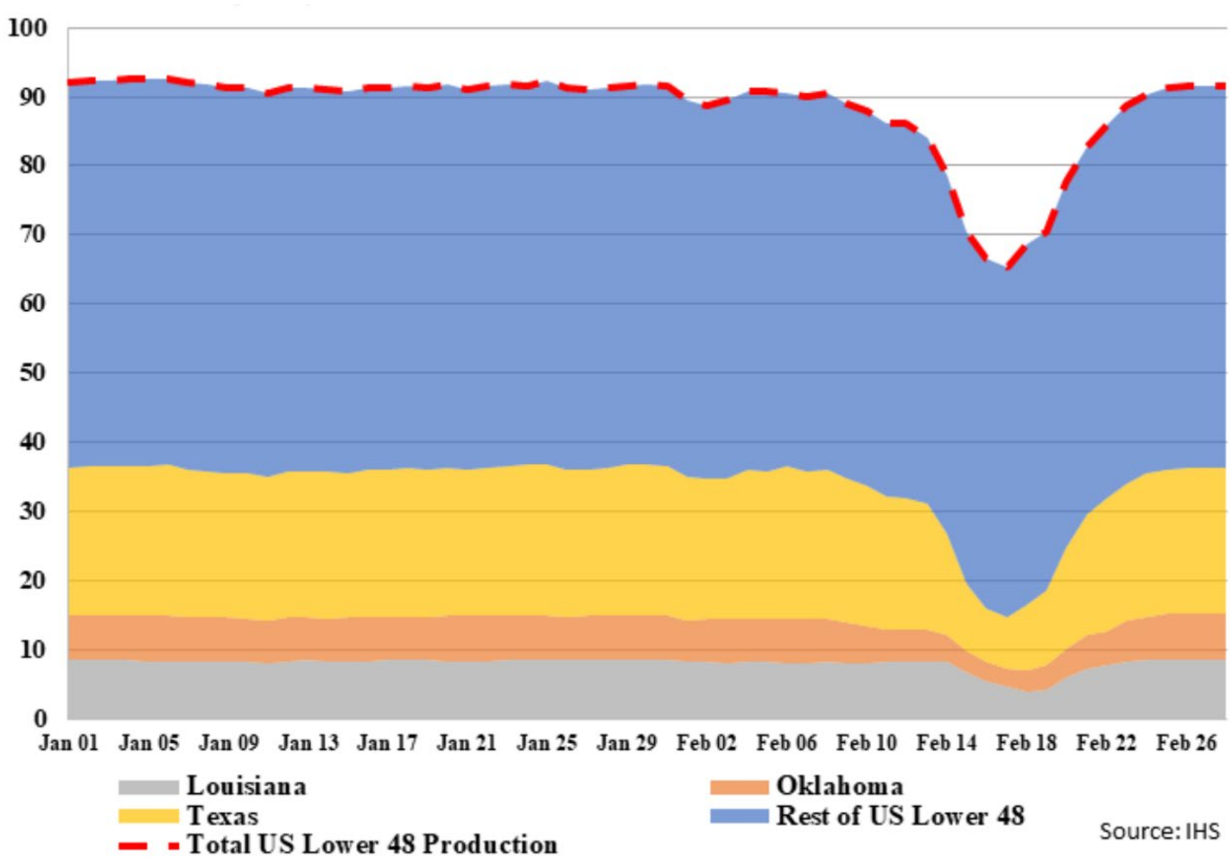
A major cause of the long duration of the outages were disruptions in fuel supplies, which were a factor in some outages going into February 15 but worsened over the next two days and prevented many power plants from coming back online at full capacity. While some coal power plants reported disruptions to fuel supplies, those disruptions were not large in scope, roughly 2 GW, and primarily limited to February 16 and 17.[108] Most of the fuel supply problems during the

[107] From "The February 2021 Cold Weather Outages in Texas and the South Central United States," Federal Energy Regulatory Commission, 2021. Available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.
[108] *Id*. At page 19.

storm—not counting the lack of wind and sun, which will be discussed later—were related to natural gas.

As shown in *Figure 13* below, natural gas production in Texas and Oklahoma declined by about 10% during the week prior to February 14 and then began dropping precipitously on the 14th as the coldest air swept through West Texas, bottoming out at less than half of average daily production on February 17.

Figure 13: ***U.S. Daily Dry Natural Gas Production, January-February 2021 (billion cubic feet per day)***[109]



According to the final autopsy report of the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC),[110] about half the decline in production in the region was due to freezing issues or shut-ins to prevent freezing, and the other half was due to a combination of problems. *Figure 14* below depicts the FERC/NERC analysis of the causes of natural gas production shows that, over the course of the storm, roughly 21.4% of the drop was attributable to a loss of power supply.

[109] The February 2021 cold Weather Outages in Texas and the South Central United States; Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC)(November 16, 2021). Available at: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[110] *Id.* Pages 174 (Figure 96).

Figure 14: ***Natural Gas Production Event Causes, February 8-20, 2021***[111]

Production Event Causes on February 17th (Day of Maximum Production Losses)

		Natural Gas Infrastructure Condition	Facility Event Causes
85.7%	Freezing Temperature and Weather Conditions (44.5% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	18.5%
		Freezing Issues - Midstream	5.3%
		Freezing Issues at Well and Gathering Facilities	10.0%
		Freezing Issues on Roads/Access to Well and Gathering Facilities	10.7%
	Loss of Power Supply (21.6% of production disruptions)	Midstream - Loss of Power Supply	8.8%
		Well/Gathering Facilities- Loss of Power Supply	12.7%
	Multiple Issues (19.6% of production disruptions)	Multiple Issues (combination of two or more of above issues)	19.6%
	Other Issues, Unrelated Issues (14.3% of production distruptions)	Midstream - Line Pressure	5.9%
		Midstream - Other	0.5%
		Well and Gathering Facility Issues - Not Applicable to Event	7.9%
	Total		100.0%

Generation outages or derates due to lack of fuel jumped above 4 GW the morning of February 15 and the number gradually increased until peaking at nearly 7 GW on February 17. The number then declined to less than 3 GW by the end of the week as the weather warmed and natural gas production began returning to normal levels.

E. Weather-related impacts to electric power generators

The weather-related problems with power generators during Uri can largely be traced to the fact that power generators in Texas optimize their operations for the hottest summer days and have little incentive to invest in resiliency against rare winter storms, just as power plants in northern states invest significantly in cold weather resiliency but not for extreme heat. The Texas fleet minimizes outages from June through September, schedules most maintenance outages in the spring and fall, and has a higher level of outages in the winter than in the summer.

Figures 15(a) and *15(b)* below show the amounts and causes of gas and coal generator outages and derates, respectively, from February 14-19. Consistent with historical norms, about 13 GW of gas was offline on February 14, just prior to the onset of the storm. Operators were able to recall all but about 8 GW that was offline for long-term maintenance (gray areas), and there were already about 2 GW of outages reported due to equipment and weather issues. The remaining 3 GW were due to natural gas supply shortages.

[111] *Id*. at page 176 (Figure 97).

Figure 15(a): ***Net Generator Outages or Derates for Natural Gas Generators by Cause***[112]

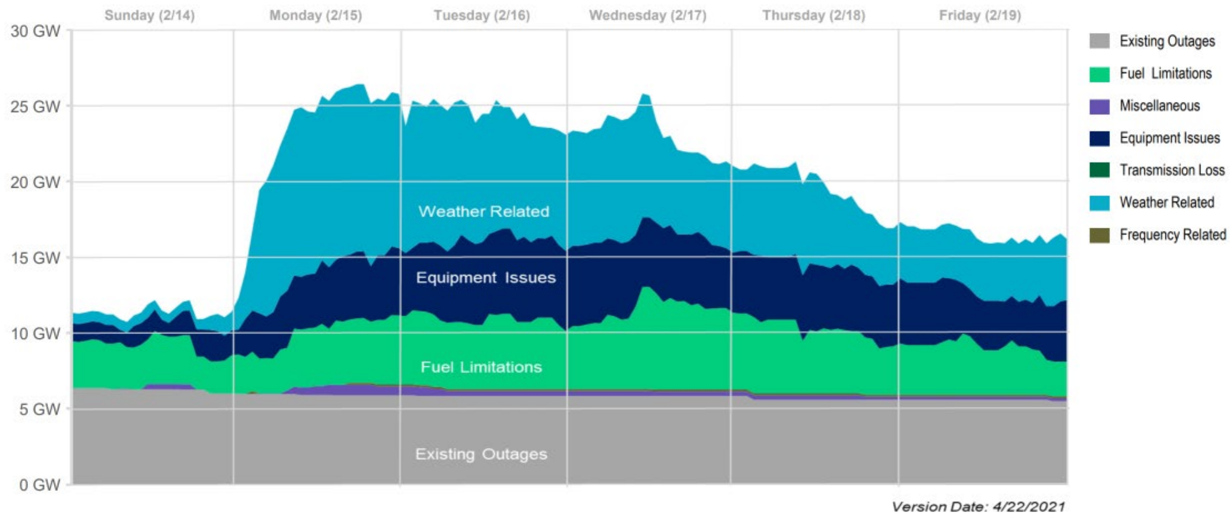
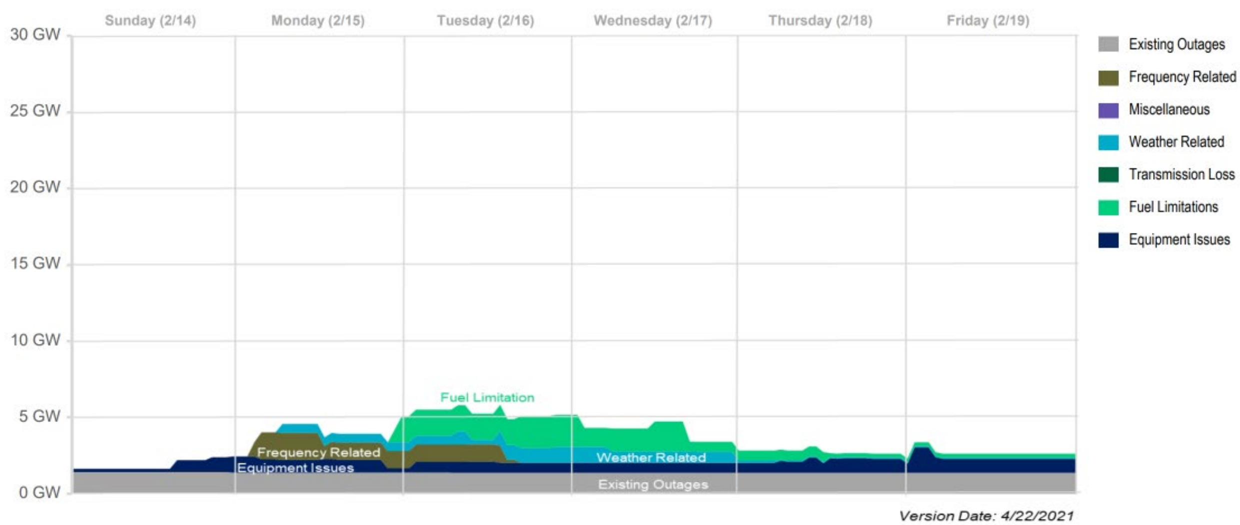


Figure 15(b): ***Net Generator Outages and Derates for Coal Generators by Cause***[113]



As the cold front rolled across the state in the early morning hours of February 15, the amount of gas generation capacity reported offline due to the weather rapidly increased to more than 10 GW, and other equipment problems also increased significantly. One of the two units at the South Texas Project nuclear plant went offline later that morning due to problems with its feedwater pumps.[114] Weather was a less significant problem for coal plants, with frequency-related

[112] From "Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event," Electric Reliability Council of Texas, 2021. Available at: https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

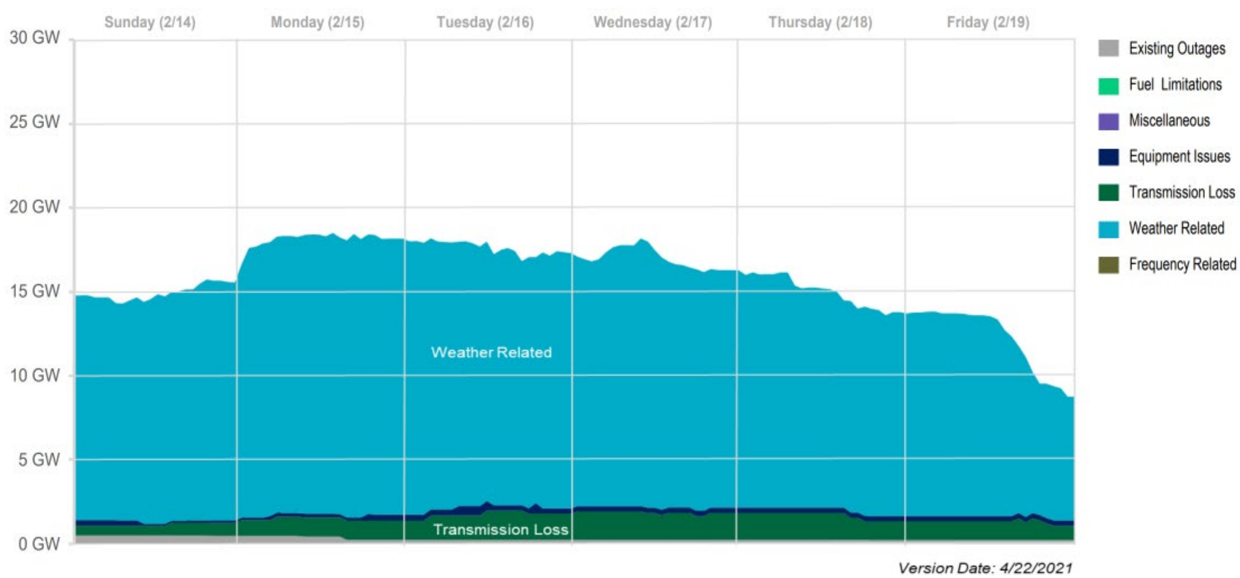
[113] *Id.*

[114] U.S. Nuclear Regulatory Commission (NRC) Event Notification Report (February 16, 2021). Available at: https://www.nrc.gov/reading-rm/doc-collections/event-status/event/2021/20210216en.html.

problems and then fuel supply (potentially due to the weather) causing most of the reported outages and derates. Thermal power plant outages and derates peaked just above 30 GW on February 17. While power plants came back online as the week went on, nearly 20 GW was still offline as of February 19, and demand reduction due to warmer weather was the main reason ERCOT was able to end firm load shedding on February 18.

As shown in *Figure 16* below, Wind generation also suffered extensively from the weather, both because the frontal boundaries significantly reduce wind currents and from ice that coated wind turbine blades that rendered them inoperable. About half of the installed wind capacity in ERCOT was offline for the entire duration of the storm,[115] and most of that capacity was offline prior to February 14 due to freezing precipitation that had already occurred in West and North Texas, where most of the state's wind capacity is located. Some transmission-related constraints and outages were reported, particularly in South Texas where fewer generators were offline due to blade icing, but those losses were limited to about 2 GW. Some weather-related outages of solar generators were also recorded, but those losses were limited to a few hundred MW.[116]

Figure 16: ***Net Generator Outages/Derates for Wind Generators by Cause Based on Installed Capacity***



[115] Update to April 6 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event (April 27, 2021). Available at: https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.
[116] *Id.* at page 23.

The largest problem for wind and solar generators was the lack of wind and solar resources available throughout the storm. Solar generators do not expect to produce much electricity during such storms, especially during the winter peak demand hours around 8-9 AM and 8-9 PM, but ERCOT anticipated average wind production of 7 GW during the peak demand hours.[117] However, wind generation dipped below 1 GW during the forecast peak demand hours around 8 PM on February 15 and around 8 AM on February 17 and averaged only 4.3 GW across all hours from February 15-19.[118]

Having more wind turbines online would have helped significantly on February 14 and on the morning of the 15th as the primary cold front was passing through the state, adding more than 10 GW of generation at the time rotating outages began, according to the backcasts provided by ERCOT[119] However, during the rest of the storm, eliminating all the wind outages and derates would have only added at most 7 GW of generation on the night of February 18 and only a few GW during most of the remainder of the week—nowhere near enough to prevent widespread blackouts.

This problem highlights the fact that, while weather and fuel supply problems added to the depth and duration of the outages that Texans experienced, resource adequacy was a fundamental cause of the outages. In fact, as discussed in more detail below, even if the weather and fuel supply problems had been eliminated, it is likely that the ERCOT region would have experienced up to 24 hours of outages with as much as 10 GW of load shed the night of February 15. While resource adequacy received relatively little discussion in the media and in many of the autopsies of the event, it did not escape the attention of Texas legislators (see sections 14 and 18 of SB 3, discussed below) and the PUC, which has begun a detailed examination of market reforms to address resource adequacy. Therefore, this issue deserves a more detailed discussion.

FOCAL POINT: The Shortage of Firm Generation During Winter Storm Uri

One reason that winter outages are difficult to forecast is that unlike in the Texas summer, when it is consistently hot and record temperatures fall within a narrow range, winter low temperatures in Texas very dramatically. Therefore, winter peak demand is also highly variable. ERCOT's Winter 2020/2021 SARA report shows a 43% reserve margin for average peak demand of 57,699 MW and available generating capacity of 82,513 MW.[120] Normally, reserve margins over 15% are more than adequate, but a deeper look into the side cases provided by ERCOT (see *Table 2* below) shows why these numbers do not represent the true risks to the system.

While the 57,699 MW forecast represents a median scenario for peak winter demand, ERCOT also includes an upper 10th percentile scenario (labeled High Demand Adjustment in

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117 ERCOT Seasonal Assessment of Resource Adequacy (SARA)(Winter 2020/2021). Available at: https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.
118 EIA Hourly Grid Monitor. Available at: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO.
119 ERCOT Seasonal Assessment of Resource Adequacy (SARA)(Winter 2020/2021) at page 21. Available at: https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.
120 *Id* at page 2.

Table 2) that is 9,509 MW higher, or 67,208 MW, just shy of the 69,222 MW record reached on February 14. Add to that higher demand scenario the normal amount of long-term maintenance and forced outages for thermal power plants (third column in the table), and the projected reserve margin shrinks to 5,892 MW, or about 10%. Prior to the outages, ERCOT's forecast peak demand for the week was 76,819 MW[121] which means that even with average thermal outages during Uri, the grid may have been short nearly 4,000 MW.

Table 2: ***Range of Potential Risks from ERCOT Winter 2020/2021 SARA***[122]

Winter Resources Available	82,513	82,513	82,513	82,513	82,513
Estimated Winter Peak Demand	57,699	57,699	57,699	57,699	57,699
- High Demand Adjustment	9,509	9,509	9,509	9,509	9,509
- Typical Maintenance Outages, Thermal	0	4,074	4,074	4,074	4,074
- Typical Forced Outages, Thermal	0	0	5,339	5,339	5,339
- Low Wind Output Adjustment	0	0	0	5,279	5,279
- 95th Percentile Forced Outages, Thermal	0	0	0	0	4,540
Total Uses of Reserve Capacity	9,509	13,583	18,922	24,201	28,741
Reserve Margin, MW	15,305	11,231	5,892	613	-3,927
Reserve Margin, %	26.5%	19.5%	10.2%	1.1%	-6.8%

However, the problem runs much deeper than that because the hours of lowest wind output during Uri were correlated with some of the times of highest demand. Wind generation fell as low as 649 MW at 8 PM on February 15 and again dipped below 1 GW at 8 AM on the morning of the 17th. [123] At no time during the 8 AM or 8 PM peak demand hours from the 15th to the 18th did wind generation reach the 7,070 MW average level given by the SARA report.

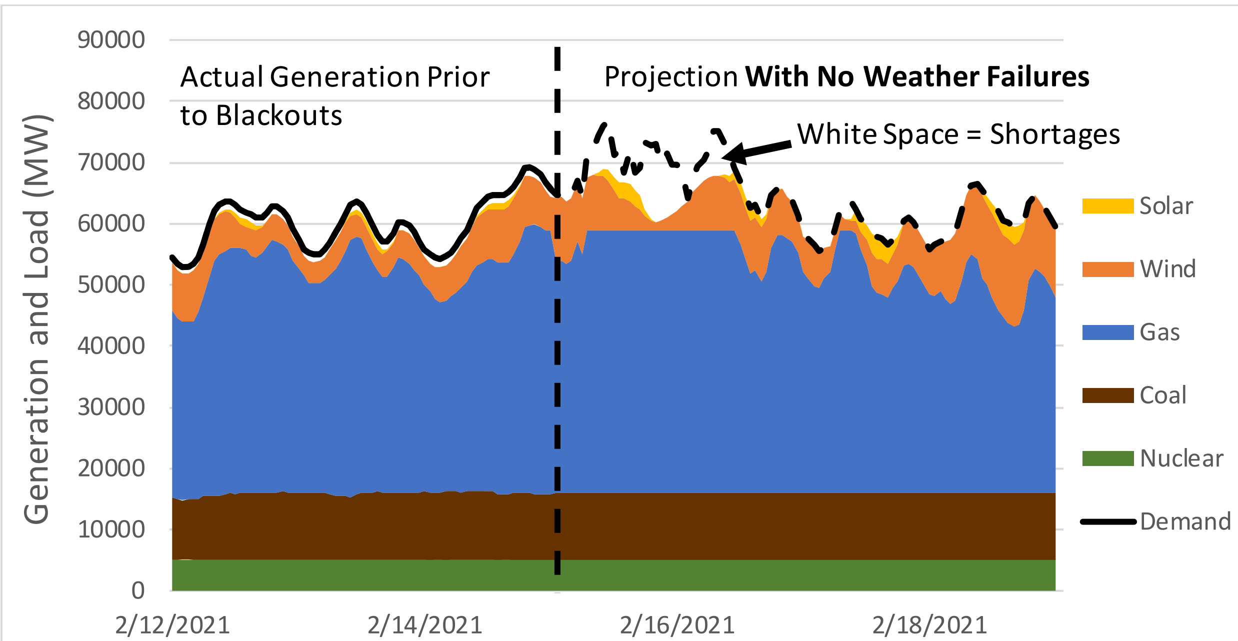
Even adding back the lost wind output due to weather-related failures,[124] generation would have only been around 3 GW on the night of February 15. This scenario is roughly equivalent to the scenario given in the fourth column in *Table 2,* but with 6 GW more demand, leaving the ERCOT grid still well short of having adequate generation resources. Again, this is a scenario where thermal outages are less than 10 GW, which is fewer outages than what was experienced the week prior to Uri and better than the operational performance of the thermal fleet during weather events that were far less severe than Uri.

In other words, outages were inevitable to some degree during Uri, even if the weather failures and gas supply problems that began on February 14 and lasted throughout the week were

121 *Id* at page 21.
122 From "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).
123 EIA Hourly Grid Monitor. Available at: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO
124 From "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).

not present. A simple way to show this gap between supply and demand is to project through the week of the storm using the demand forecasts from before the outages started, assuming the same level of thermal fleet outages as existed on February 14 (i.e., minimal weather-related failures), and doubling the amount of wind generation that was actually realized. *Figure 17* shows that even under this idealized scenario, the ERCOT grid would still have experienced outages lasting roughly 24 hours from February 15-16.

Figure 17: ***Actual Demand and Generation by Resource Type (in MW) Prior to February 15, 2021, and Forecast Demand and Generation from February 15 Onward, Assuming No Weather-Related Problems for Thermal Generators and Twice the Actual Wind Generation That Was Realized***[125]



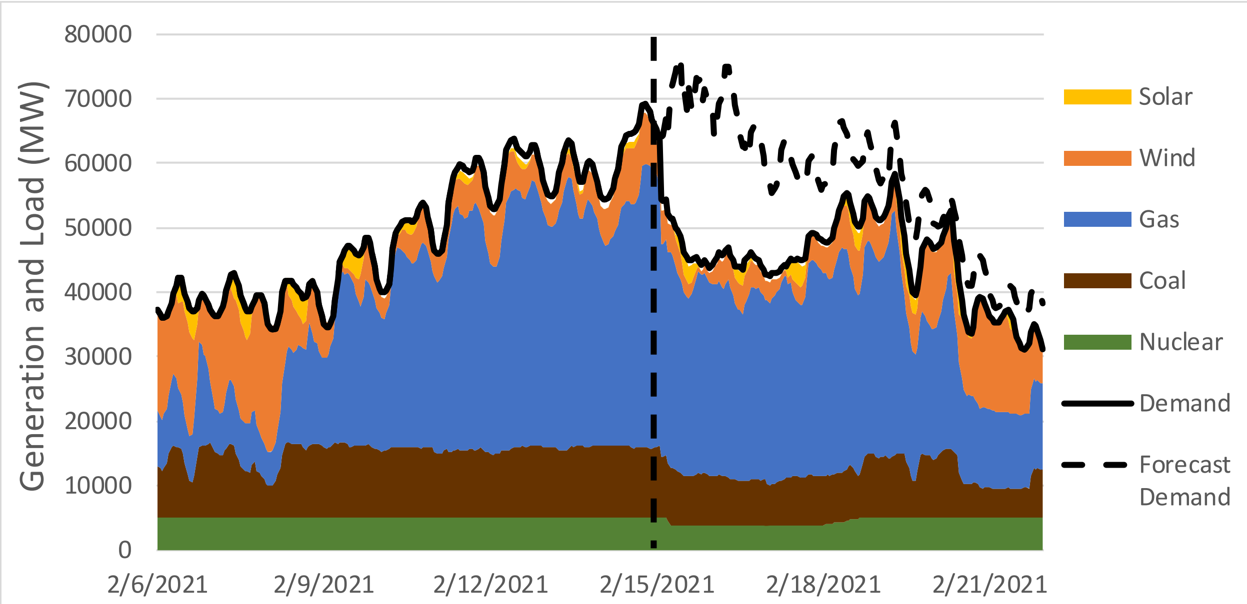
From a policy and market design standpoint, it is unreasonable to design the ERCOT grid to handle an event as rare and severe as Uri with no outages whatsoever. However, looking beyond the obvious weather resiliency problems exposed by the storm, the resource adequacy problems that first became apparent in 2019 are clearly growing worse. If Texas continues to rely on new wind and solar generation to meet its growing electricity demand, while at the same time shrinking its base of reliable gas and coal generation, outages will be more common in the future under far less severe weather conditions than the state experienced during Uri.

Taking a broader look at the generation resource mix both before and after Uri demonstrates the depth of the intermittency problem that Texas is facing. As shown in *Figure 18*, prior to the initial onset of cold weather on February 10, wind at times exceeded half of the generation mix in ERCOT, and gas and coal plants were ramping down to accommodate the influx

[125] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

of excess wind generation. Real-time prices in the wholesale market were near zero the morning of February 8 and generally near or below $20/MWh until February 9.[126]

Figure 18: ***Demand and Generation by Resource (in MW) from February 6 to February 21, 2021***[127]



Wind production then dropped after the first cold front moved through the state, coinciding with the drop in temperatures as a cold high-pressure system set in. It is common for high-pressure systems during the summer and the winter to reduce wind speeds, because those air masses are more stable, and to create extreme high or low temperatures, because low winds lead to less mixing in the atmosphere. Therefore, low wind generation is frequently correlated with high electricity demand, exacerbating the degree to which gas and coal plants need to ramp up or down compared to a system where demand is the only variable factor.

This effect was evident during Uri, as wind generation did not exceed 10 GW, or about a third of total installed wind capacity in the ERCOT region, until temperatures began warming again on February 19, at which time wind generation returned to pre-storm levels.[128] The variability of wind resources was reflected in real-time market prices. Even prior to the onset of outages, the combination of high demand and low wind production drove average real-time prices above $1000/MWh for most of February 13 and 14, before being fixed at the market wide cap of $9000/MWh from February 15-19 [129] Real-time prices then went briefly negative on February 19

[126] From "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).
[127] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).
[128] *Id.*
[129] From "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).

as demand dropped and wind production recovered, and negative prices were present multiple times over the course of the next week.

The average capacity factor of wind generation from February 9-19 was only 15%, and solar was only 11%.[130] Over that period, wind and solar provided 10% of the electricity generated in the ERCOT region, even though they made up 33% of installed capacity in the region at the time (see *Table 3*). At the nadir of combined wind and solar production on the night of February 15, those resources produced less than 2% of the total generation in the region. Coal, gas, and nuclear, on the other hand, provided 90% of the state's electricity throughout the storm, and despite the raft of outages, the thermal fleet exceeded its average February capacity factor from February 9-19.

Table 3: ***Installed Capacity of Generation Resources in the ERCOT Region as a Percentage of the Grid-Wide Total, Proportion of Total Electricity Generation from February 9, 2021 to February 19, 2021, and Proportion of Total Electricity Generation at 8 PM on February 15.***[131]

Installed Capacity	
Wind	28%
Solar	5%
Gas	49%
Coal	12%
Nuclear	4%

February 9-19	
Wind Avg	9%
Solar Avg	1%
Gas Avg	61%
Coal Avg	19%
Nuclear Avg	9%

February 15, 8 PM	
Wind	1%
Solar	0%
Gas	71%
Coal	18%
Nuclear	9%

As noted above, the reduced performance of wind and solar during Winter Storm Uri is primarily a resource adequacy problem that is a result of typical winter weather patterns that combine extreme low temperatures with low wind and solar output. Comparisons of how many wind and solar generators were offline versus thermal generators during Uri miss the point. The policy implication of this data is that the ERCOT market design needs to ensure that adequate resources are available when high demand correlates with low wind and solar output, which can not only happen during summer afternoons but also during winter storms.

Unfortunately, ERCOT's December 2021 Capacity, Demand, and Reserves (CDR) Report[132] is not projecting significant growth of thermal, dispatchable resources to meet increasing winter demand, leading to a greater likelihood of shortages when temperatures are not as cold as they were during Uri. Applying the upper 10th percentile adjustment factor to the peak demand forecasts in the CDR report, which was still several GW short of the forecast demand during Uri,

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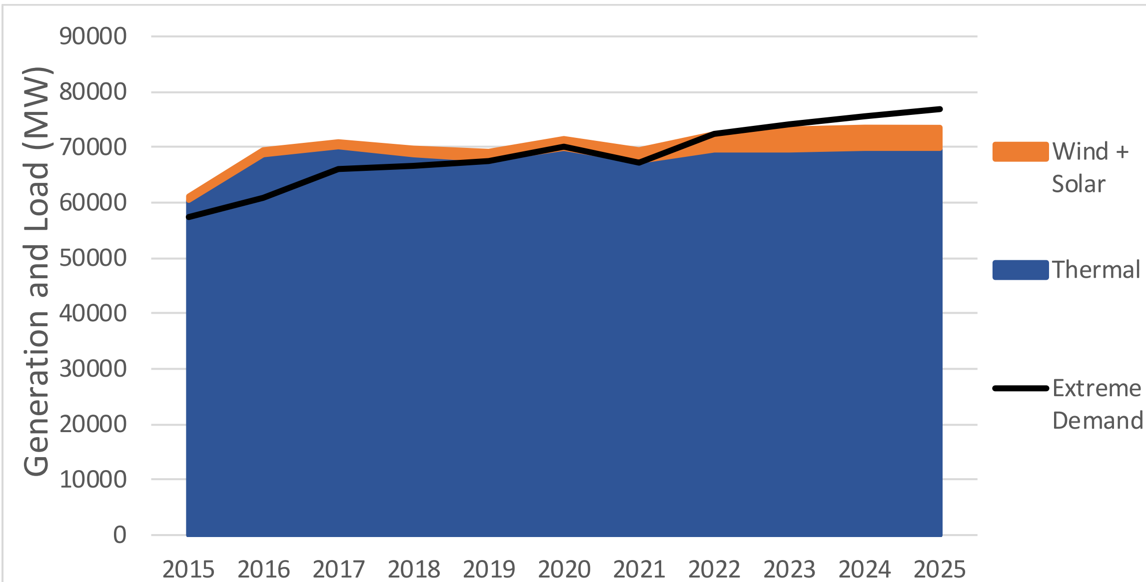
[130] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

[131] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO); "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).

[132] "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021," Electric Reliability Council of Texas, 2020 at page 28. (https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf).

Figure 19 shows that a combination of high demand, normal thermal outages, and low wind and solar output will result in shortages as soon as 2024. The actions of the Texas Legislature and the Public Utility Commission of Texas to address both the problems that were specific to Winter Storm Uri and the broader resource adequacy problem facing the ERCOT region will be summarized in the next two sections.

Figure 19: ***Projected Winter Demand & Generation for the ERCOT Region Assuming High 10th Percentile Peak Demand, Low 5th Percentile Wind & Solar Output, and Average Thermal Power Plant Outages***[133]



The policy implication of all of the data analyzed above is that the ERCOT market design needs to be reformed significantly. The resource adequacy problems that first became apparent in 2019 are clearly growing worse. Texas' growing reliance on weather-dependent resources to meet its growing electricity demand, while at the same time shrinking its base coal and gas generation, is going to make outages more common in the future in the absence of significant market reform.

V. COMMON MISCONCEPTIONS OF ERCOT POWER OUTAGES

As is often the case when there is a massive system failure with tragic consequences, the power ourates in Texas led to several playing the "blame game" before a full assessment of the facts on the ground could be completed. One narrative that was launched was that the sole reason for the capacity shortage was the extreme nature of this weather event and that even climate change is playing a role. While these cold temperatures were extreme and certainly unusual, they were not unprecedented and the most assuredly weren't the sole cause of the blackouts — just the straw that broke the camel's back.

[133] From *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO);

A second press-distributed narrative narrowly focused on "frozen gauges" at nuclear plants and even "frozen coal piles." As discussed at length above, while there were weatherization issues at one of the nuclear plants and some coal supply disruption occurred due to insufficient onsite fuel storage and protection, those challenges would very likely not have occurred in a colder climate with operators more accustomed to cold weather fuel handling (see discussion in the next Section regarding SPP coal fleet performance). Other stories and reports focused almost exclusively on the role that natural gas infrastructure and the performance of gas-fired power plants played in the power outages. As discussed above, gas disruptions and gas-fired power plant forced outages were a major part of the story, but as data set out above demonstrates, there would have been significant outages even with minimal disruption in gas-fired generation because the market's heavy penetration of weather-dependent renewables and lack of sufficient thermal capacity reserve. It is also important to remember that the vast majority of issues with gas supply and generation disruption during the storm came down to a lack of investment to safeguard equipment against cold weather.

Ultimately, the problem with the event-specific blame game framed in terms of "what broke during the storm" is that it obscures the long-term policy decisions that made the system failures inevitable. To use a modern colloquialism (and pardon the terrible pun), it is "gas-lighting" and detracts from the in-depth, multi-decade forensic analysis that a failure of this magnitude warrants. The compelling evidence set above makes it clear that, as a result of failed policies from both sides of the political "aisle," Texas never had enough reliable capacity to make it through this event without blackouts. As documented above, even if every thermal power plant, wind turbine, and solar panel had been operating at the same level of reliability that they do during the peak summer days, the evidence shows that the combination of high demand, low wind speeds, and no sun during the cold mornings and nights meant that there would still have been several hours the night of Monday, February 15, when wide-scale power outages were inevitable.

There are several studies that present sufficient data to allow an informed reader to cut through the spin and separate truth from the many misconceptions reported in the media and advocacy papers, but none get straight to the point like the comprehensive study conducted by the American Society of Civil Engineers, Texas Section ("TASCE").[134] Although the TASCE study provides an exhaustive analysis supported by voluminous data, their Executive Summary gets straight to the point in way that provides true clarity to this situation:

> *ASCE Texas Section identified two primary and related problems:*
>
> > *1) a failure to support reliable dispatchable power generation, and*
> >
> > *2) the negative impact from sources of intermittent electric power generation.*
>
> *This assessment concludes that*
>
> > *1) revenue insufficiency from ERCOT's energy-only market model, influenced by federal and state subsidization of intermittent resources, fails to adequately pay for reliable dispatchable generation and*
> >
> > *2) that these market model deficiencies are the leading contributor to making the ERCOT system less reliable.*

[134] Reliability and Resilience in the Balance Texas Section of the American Society of Civil Engineers (Executive Summary released 21 January 2022; Full Report released 16 February 2022). Available at: www.TexASCE.org/beyond-storms.

Stepping back from a hyper-focus on the Texas situation and looking broadly at typical winter weather performance of power generation resources across North America, the informed reader can discern that thermal power plants using gas, coal, and nuclear fuel operate in much colder weather than Winter Storm Uri all over the world. With coal and nuclear, no energy expert would contend that the sources of those fuels are the cause of failure in extreme cold. In fact, they are widely recognized as the most weather-resilient fuels because of the ability to store large quantities of fuel on-site, insulated from supply chain, transportation, and pipeline disruptions. This point is verified by the experience of other organized markets during the same winter storm.

VI. COMPARISON OF ERCOT, SPP, & MISO EXPERIENCES DURING URI

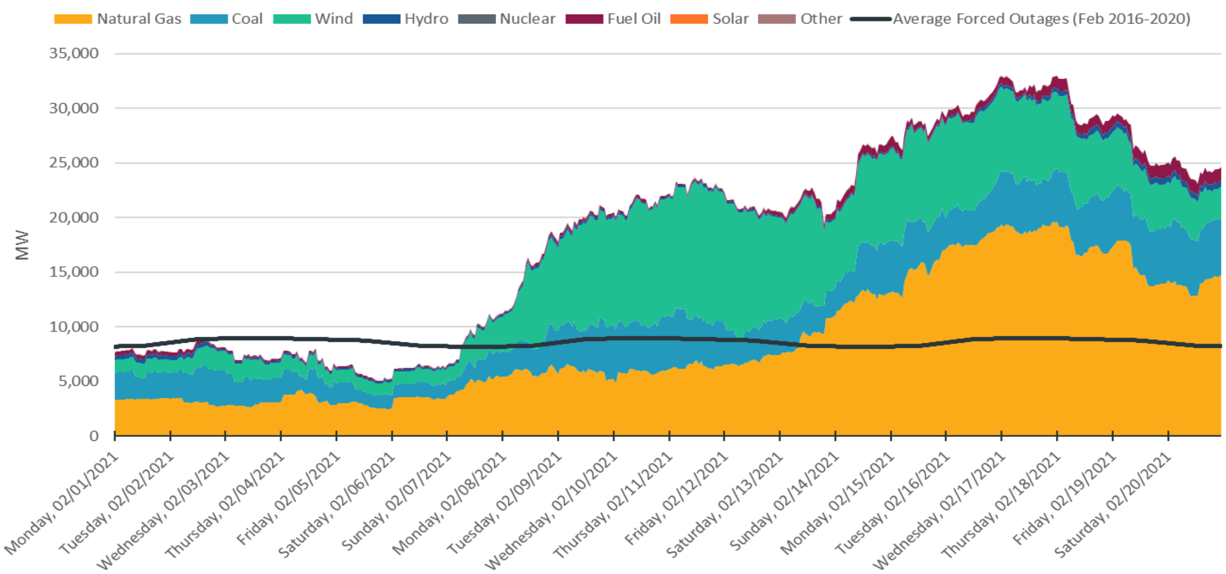
This section contains a comparison of the experience during Winter Storm Uri in the SPP and MISO markets with that of ERCOT. While the level of forensic analysis of SPP and MISO is not as comprehensive as the exhaustive analysis set out above, a summary is provided of some key studies already conducted and the different experiences in those markets is adequately addressed to draw some topline conclusions about why those experiences differed and what that tells us about the preferred model of regulation and market design.

A. Southwest Power Pool

Based on a five-year historical average, the SPP market typically has about 55,000 MW of available generation capacity in February.[135] However, that capacity dipped to roughly 35,000 MW during the week of Winter Storm Uri. Furthermore, soaring natural gas prices resulted in record-high energy offers in the SPP market, setting a record SPP market price of $4,274.96/MWh in the day-ahead market on February 15, 2021, when the average price of energy in the 2020 SPP day-ahead market was $17.69/MWh.[136] Natural gas generation experienced an average of nearly 18,000 MW of forced outages on February 16, 2021, 75 percent of which were due to a lack of fuel supply.[137] Generation outages as reported to SPP by fuel type are illustrated in the table below:

[135] *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm* at 40 (Jul. 19, 2021).
[136] *Id*. at 8
[137] *Id*. at 41.

Figure 20: ***SPP Generation Resource Performance and Demand During Winter Storm Uri*** [138]



The loss of approximately 20,000 MW in available capacity during the week of February 14, 2021, was primarily attributable to "higher than usual fuel-supply deficiencies, wind turbine freezing, and other challenges associated with operating equipment in extremely cold conditions such as frozen cooling towers, intakes, fuel lines, transmitters."[139] In addition, transmission congestion and reduced power generation in neighboring RTOs resulted in up to 2,500 MW of potentially importable power being unavailable on February 15 and 16, 2021.[140] Ultimately, generation outages, fuel-supply shortages, and record demand during the winter storm resulted in SPP directing its transmission operators to curtail electricity through firm load-shed instructions to transmission operators twice during Winter Storm Uri. The first instance was to reduce regional energy demand by about 1.5 percent for approximately 50 minutes on February 15, 2021, and then to reduce demand on the transmission system again by roughly 6.5 percent for just over three hours on February 16, 2021.[141] On those two days, generators reported that roughly 50 percent of the forced outages experienced were due to fuel supply-related issues.[142] This was the first time in its 80-year existence that SPP has resorted to region-wide curtailments.

After the storm, on March 2, 2021, the SPP Board of Directors and Members Committee ("SPP Board") directed a comprehensive review of SPP and stakeholder responses to the Winter Storm Uri. The goal of this comprehensive review was to identify how the organization can learn, adapt, and be better prepared for future extreme weather threats to grid reliability and resilience. This comprehensive review was designed to analyze five general areas: operations, including operational reliability and transmission planning; finance, including settlement and credit-related issues; communications, including protocols and coordination governmental and public

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[138] *Id*. at 42: Figure 20: Forced generation outages as submitted in CROW (Control Room Operations Window) by Fuel Type.
[139] *Id*.
[140] *Id*. at 40.
[141] *Id*. at 28-29.
[142] *Id*. at 8.

communications; resource adequacy, including an evaluation of cost allocation; and overall market performance, including actual gas settlement pricing and market behaviors. Five teams and a steering committee were formed to address the five areas of analysis discussed above.

The action items recommended by the working groups resulting from the comprehensive review were organized into one of three tiers. Tier 1 recommendations include those actions that must be taken as soon as possible because they are necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks. Tier 1 recommendations were designed to address the immediate identified causes of system-related issues during Winter Storm Uri and to mitigate the impact of future extreme weather events on SPP's system performance.[143] There were a total of 26 Tier 1 initiatives identified relating primarily to resource planning and availability and fuel assurance:

- develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region;
- evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events;
- perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix; and
- improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives that ensure sufficient resources will be available during normal and extreme conditions.[144]

The SPP Improved Resource Availability Task Force ("IRATF") has primary responsibility for addressing and implementing the Tier 1 recommendations. IRATF began its work immediately upon SPP Board approval and as of the most recent SPP Winter Weather Event Initiative Update, two have been completed,[145] 17 initiatives are under way, and seven have not been started.[146]

Tier 2 recommendations included those actions that, while necessary to reduce the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events, were slightly less imperative as they did not address direct causes of system-related issues during Winter Storm Uri causes of the 2021 winter event, are high-priority initiatives expected to significantly improve SPP's response to extreme system events in the future. Tier 3 recommendations included those actions, policies or assessments that would improve SPP's

[143] *Id.* at 10.
[144] SPP *2021 Winter Weather Event Initiative Update* at 5 (Jan. 13, 2022).
[145] SIR214 FA2.4: Inform gas pipeline operators they are susceptible to power outages caused by other events not controlled by the TOPs & encouraged to be prepared for such losses of service; and SIR230 RPA2.10: Create a complete listing of all utility scale resources within the SPP BA showing utility scale resources not participating in the market for usage in energy emergencies.
[146] 2021 Winter Weather Event Initiative Update at 11.

response, communications and public perception during extreme system events, but were not considered to be urgently needed. A total of 92 Tier 2 and 3 initiatives were identified by SPP, eight of which have been completed,[147] 13 are in progress, and 71 have yet to be initiated.[148]

The SPP communications department launched the Regional SC -Winter Storm Event Survey for stakeholders input on March 30, 2021, and closed the survey April 9, 2021.[149] SPP Staff distributed survey invitations to the 10 members of the Regional State Committee ("RSC"), the 11 members of the Cost Allocation Working Group ("CAWG"), and extended an invitation to complete the survey to the Texas Office of Public Utility Counsel (OPUC). The RSC commissioners, OPUC, and nine members of the CAWG completed the survey. On a scale of zero to four, with zero being "highly ineffective" and four being "highly effective," survey respondents gave an average rating of 2.95 when rating SPP's overall effectiveness during the winter storm event.

Although IRATF has primary responsibility for addressing and implementing the Tier 1 recommendations, SPP also has multiple stakeholder advisory groups, comprised of representatives from SPP member companies and at times contract signatories, many of which address the market reforms identified in the SPP comprehensive review:

- <u>Future Grid Strategy Advisory Group</u>: oversees periodic assessments of the future state of the SPP grid, identifies gaps between those future state projections and current trajectories, and increases organizational awareness of value-added opportunities to shape the future grid;
- <u>Model Development Advisory Group ("MDAG")</u>: coordinates, develops and maintains transmission system planning models in accordance with SPP planning criteria, regional standards and procedures. The MDAG also supports development of interconnection-wide models.
- <u>Reliability Compliance Advisory Group</u>: provides guidance on reliability compliance matters related to federal requirements, NERC Reliability Standards, or SPP governing documents.
- <u>Seams Advisory Group</u>: provides direction, guidance and advice regarding SPP's seams agreements, joint operating agreements, or arrangements with neighboring transmission providers, transmission owners or customers.

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[147] SIR245 WWE OTCP1.1. Post cascading analysis results (with respect to flowgates) to R-Comm or GlobalScape.; SIR302 WWE CR1. The CPWG will analyze the virtual reference prices expected for 1Q'22 to determine if they will adversely impact virtual activity in 1Q'22; SIR307 WWE COMM3. Corporate Governance Committee to consider the formation of a stakeholder group whose scope would include discussion of matters related to emergency communications. SIR313 WWE MMU R5. Stakeholders should approve the MMU State of the Market recommendations related to outages. The Generator Outage Task Force has approved this and is awaiting ORWG action; SIR358 WWE CCR 1. Develop a plan to ensure stakeholders have a dependable way to receive real-time alerts and contextual information about events' root cause and impacts; SIR359 WWE CCR 2. Drill emergency communications procedures; SIR360 WWE CCR 3. Develop a plan to ensure non-operations staff have the opportunity to participate in … drills of emergency scenarios. SIR361 WWE CCR 4. Develop a plan to co-manage with stakeholders an accurate contact list of member representatives, regulators, elected officials, and other stakeholders.

[148] *A <u>Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm</u>* at 40 (Jul. 19, 2021).

[149] *Id*. at 99.

- Interregional Planning Stakeholder Advisory Committee ("IPSAC"): facilitates stakeholder review and provide stakeholders the opportunity to advise the Joint Planning Committee ("JPC") on matters related to the development of the Coordinated System Plan. SPP's stakeholder representation on ISPAC comes from the Seams Steering Committee as well as SPP Transmission Owners are connected with the SPP neighbor.
- Security Advisory Group: advances the physical and cyber security of the electricity infrastructure within the SPP footprint. This group provides a forum for discussing physical and cyber security issues and sharing best practices; and

  System Protection and Control Advisory Group: provides technical guidance and expertise to SPP stakeholder groups, primarily the Transmission Working Group and Operating Reliability Working Group, regarding protection and control systems.[150]

Finally, SPP also created the Stakeholder Prioritization Task Force ("SPTF") to provide a mechanism by which stakeholders can provide input into the prioritization of projects and enhancement and revision requests. SPP staff post a quarterly report of all enhancement requests, revision requests, and projects, including priority ranking and cost estimates, for stakeholder review and comment.[151] Staff then holds a meeting where interested parties can provide feedback regarding items on which comments were submitted. SPP submits a quarterly report summarizing the meeting's discussion and any resulting updates made based on the input received.[152]

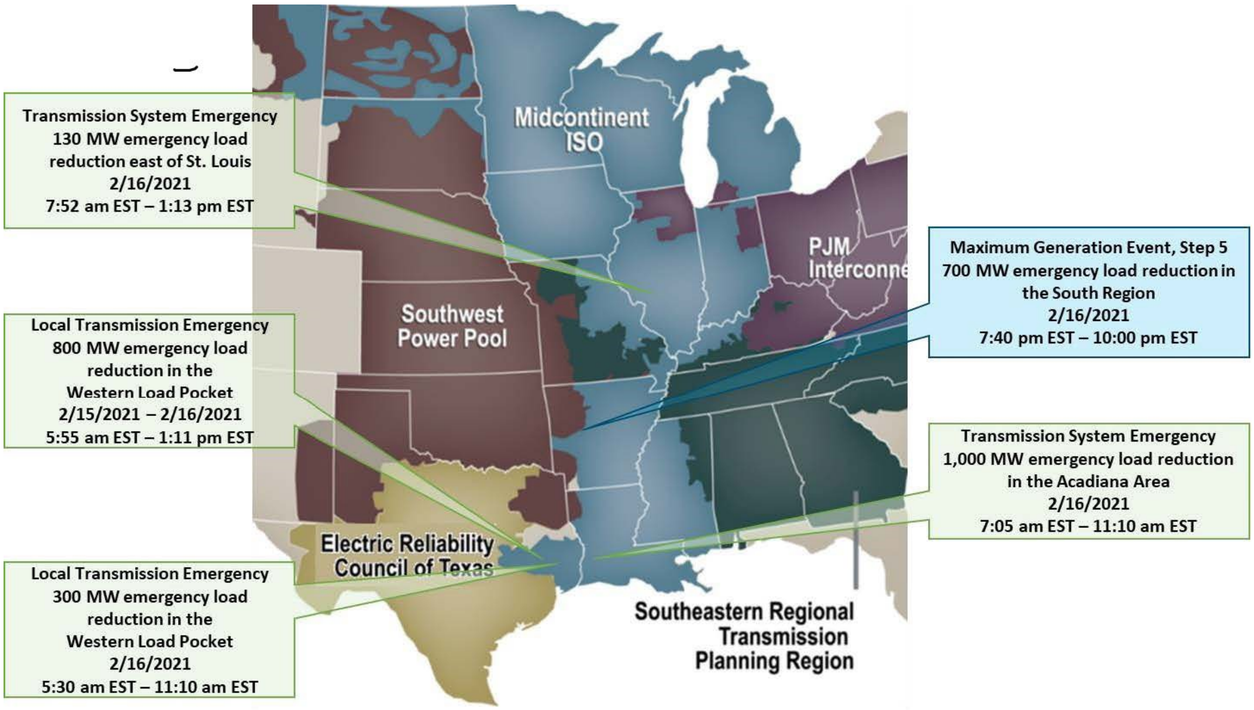
B. The Midcontinent Independent System Operator (MISO) Market

Extreme cold weather throughout MISO the week of February 14, 2021, led to unusually large generation outages and derates of 30 percent and 40 percent in the Midwest and South Regions of MISO, respectively.[153] MISO's peak demand was 98,962 MW at 8 PM on February 15, 2021 while net generation was 92,678 MW.[154] Approximately half of the generation outages and derates were due to forced outages and fuel supply shortages, both of which were substantially caused by cold weather.[155] Natural gas supply interruptions from February 12 through 16, 2021, resulted in natural gas prices soaring to as high as $700 per MMBTU and resulted in natural gas supply-related outages of approximately 12,000 MW.[156] On February 15, 2021, east-to-west import power flows approached 13,000 MW to help mitigate generation shortfalls and meet winter peak energy demands in MISO and SPP. However, as a result of generation and transmission outages, MISO was forced to resort to firm load shed events as a means of reducing demand on the transmission system. MISO declared several transmission emergencies from February 15 to February 16 to manage the large imports of power to help mitigate energy emergencies caused by generation shortfalls and to meet winter peak demand.[157] As can be seen in *Figure 21* below, in

[150] Southwest Power Pool Stakeholder Groups (accessed February 28, 2022).
[151] *Southwest Power Pool Stakeholder Prioritization Process* (accessed February 28, 2022).
[152] *Id.*
[153] *MISO Independent Market Monitor Quarterly Report* at 4 (Apr. 15, 2021).
[154] *United States Energy Information Agency Hourly Electric Grid Monitor*, (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48).
[155] *Id.* at 4.
[156] *Id.* at 5.
[157] 2021 FERC Cold Weather Grid Operations-Preliminary Findings and Recommendations Presentation at 10 (Sep. 23, 2021).

total almost 3,000 MW of firm load shed at different times and locations on the MISO grid to was required maintain bulk-power system reliability.

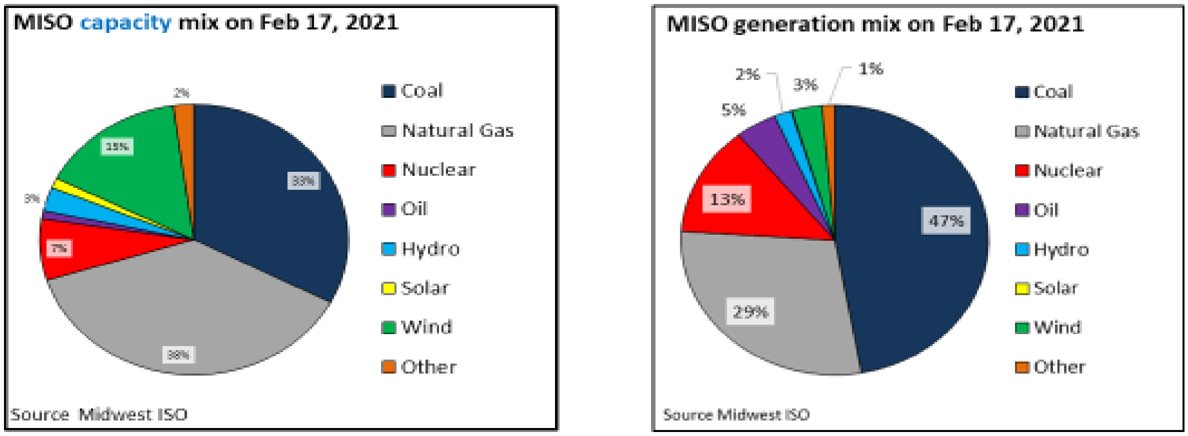
Figure 21: ***Firm Load Shed Events in MISO During Winter Storm Uri***[158]



Extreme winter weather conditions continued into February 17, 2021 and resulted in almost 40 percent of the installed generation resources in MISO being unavailable. *Figure 22* below illustrates the MISO generation fuel mix capacity versus actual generation on February 17, 2021.

158 The February Arctic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative, at 19.

Figure 22: ***Installed Capacity Versus Generation in MISO on February 17, 2021***



As is shown above, baseload power generation represented 79 percent of the installed capacity in MISO but produced 94 percent of electricity. Ultimately, MISO identified five key takeaways, 20 specific lessons learned, and over 35 actions to take, often in conjunction with member utilities, regulators or other partners, in response to the impact of Winter Storm Uri on its transmission system. The five key takeaways are:

- Generation performance: extreme weather events cause even significant negative impacts on generation performance due to unexpected weather-related generator outages or fuel delivery challenges. Winterization to protect generation and fuel supplies from extreme weather can mitigate this risk but MISO and its members must assess and establish certain criteria. Finally, seasonal specific load reduction protocols, as the needs and constraints are different between winter and summer and any emergency load reduction events create significant hardship in affected areas, must be developed and implemented;
- Resource adequacy planning: MISO experiences tight supply and demand conditions with increasing frequency across all seasons. A seasonal rather than annual resource adequacy review process along with fuel availability must be considered in reliability planning;
- Transmission planning: is vital to moving electricity from where it is generated to where it is needed most. The MISO region had adequate generation during the Winter Storm Uri, but transmission constraints, overloaded lines, and transfer limits interfered with power being transmitted to areas of the MISO region in need. In addition to new transmission capacity, improved interregional coordination and interconnection will bring significant benefits to facilitate reliability and efficiency;
- Operations: Given the rapid shift in resource portfolios, more detailed and complete data to support event and post-event analyses, planning, and modeling is required to support real-time operation decisions and withstand extreme weather-related events. Operational tools such as parallel flow visualization, automation and advanced analytics techniques, and effective modeling and managing of the Regional Dispatch Transfer Limits will be required; and

- Reliability: The role of regulatory bodies, members, market participants, and end-use customers need to be reviewed and adjusted to ensure that we collectively ensure continued reliability. Reliability is the outcome of many years of forward-looking planning and decision-making.[159]

MISO has a multitude of committees and working groups to facilitate stakeholder engagement in fostering market reforms, particularly after Winter Storm Uri. A non-exhaustive list of committees and working groups whose membership is comprised of stakeholders and are designed to facilitate the stakeholder input process:

- Distributed Energy Resources Task Force: serves as a focused forum for stakeholders and MISO to address many cross-functional issues associated with distributed energy resource issues; engage appropriate parties, including regulators, distribution utilities, and other subject matter experts in developing the coordination framework required by FERC Order 2222;[160] identify potential risks and opportunities stemming from the integration and participation of DERs in the MISO markets, including study of the various services DERs can offer; and recommend approaches and/or solutions to address these risks and opportunities;
- Entergy Regional State Committee: comprised of retail regulatory commissioners from agencies in Arkansas, Louisiana, Mississippi, Texas, and the Council of the City of New Orleans, it provides collective state regulatory agency input on the operations of and upgrades to the Entergy Transmission System, including issues relating to the MISO Independent Coordinator of Transmission;
- Interconnection Process Working Group: provide stakeholders a forum to develop revised generator interconnection queue process procedures with the goal of reducing study time and increasing certainty. It is intended that the work product of this Working Group will be included in Tariff filings to FERC and modifications to the Generator Interconnection Business Practice Manual;
- Loss of Load Expectation Working Group: reviews and provides recommendations to MISO on the methodology and input assumptions to be used in performing the Loss of Load Expectation analysis that calculates the Planning Reserve Margin requirements for each Load Serving Entity within MISO;
- Market Subcommittee: provides input and policy guidance on all market activities including but not limited to transmission, energy, capacity, and credit and ancillary services. The Market Subcommittee reviews and considers the elements of existing and future market designs and implementation and conducts ongoing evaluations of market mechanisms and suggests refinements as necessary;
- Planning Advisory Committee: provides advice to the MISO Planning Staff on policy matters related to the process, adequacy, integrity and fairness of the MISO wide transmission expansion plan;
- Planning Subcommittee: advises, guides, and provides recommendations to MISO staff with the goal to enable better execution of its planning responsibilities, in an efficient

[159] *Id.* at 7.

[160] FERC Order 2222 directs the ISO/RTO's to edit MISO's tariff to remove barriers to participation for DER aggregations in the ancillary services, energy, and capacity markets.

and timely manner, as set forth in the MISO Tariff, Transmission Owner Agreement, FERC Order 2000 and other applicable documents;

- Resource Adequacy Subcommittee: provide input and policy guidance to MISO management on all market and operational activities and processes that facilitate adequate planning resources within MISO for the long-term planning horizon and coordinate its efforts with other MISO stakeholder groups;
- Seams Management Working Group: considers issues and topics related to seams coordination with other market or non-market entities and other RTOs as necessary to optimize the efficiencies and communication across the seam; and
- System Restoration and Reliability Training Working Group: provides a forum to discuss system operator training, resiliency, emergency preparedness, and power system restoration, and advises MISO and its stakeholders on reliability risks and mitigation of risks.[161]

Finally, MISO has recognized that the lessons learned from Winter Storm Uri will require actions from stakeholders and MISO has stated that it is committed to working collaboratively with its members, regulators, and other stakeholders to address key takeaways in workshops and working groups meetings established by MISO for that purpose.[162]

C. Comparing the Experiences of SPP and MISO with that of ERCOT

So why did SPP and MISO fare so much better than ERCOT during the storm? At the most basic level, it is fair to say that the storm did not expose more northern states in SPP and MISO with weather conditions at as great a variance with normal February conditions as the shock it gave Texas. Somewhat related to that fact is the reality that both power plant operators and the plants themselves in SPP and MISO are more accustomed to and designed more for extreme cold than the Texas fleet which, until now, was optimized for extreme summer heat when winterization can actually be detrimental. But, as the detailed analysis of ERCOT above should make clear, climate and winterization only explains problems that contributed to the outages during the storm – it does not explain how the ERCOT grid became so thin on dispatchable reserves that it nearly collapsed when faced with those problems.

In order to conduct an appropriate comparative analysis of the experiences of all three markets during Winter Storm Uri, it is important to assess the resource mix performance during an identical time period across the entire storm *Figures 23 (a), (b),* and *(c)* below depict the performance during the storm of the different sources of electricity relative to their installed capacity.

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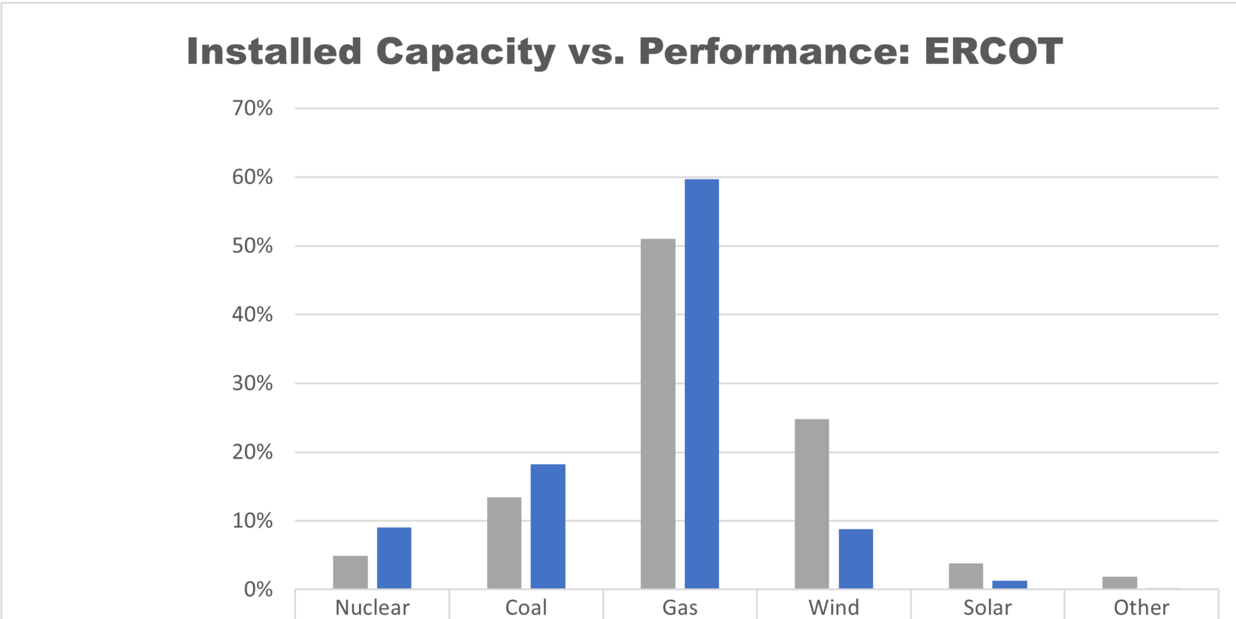
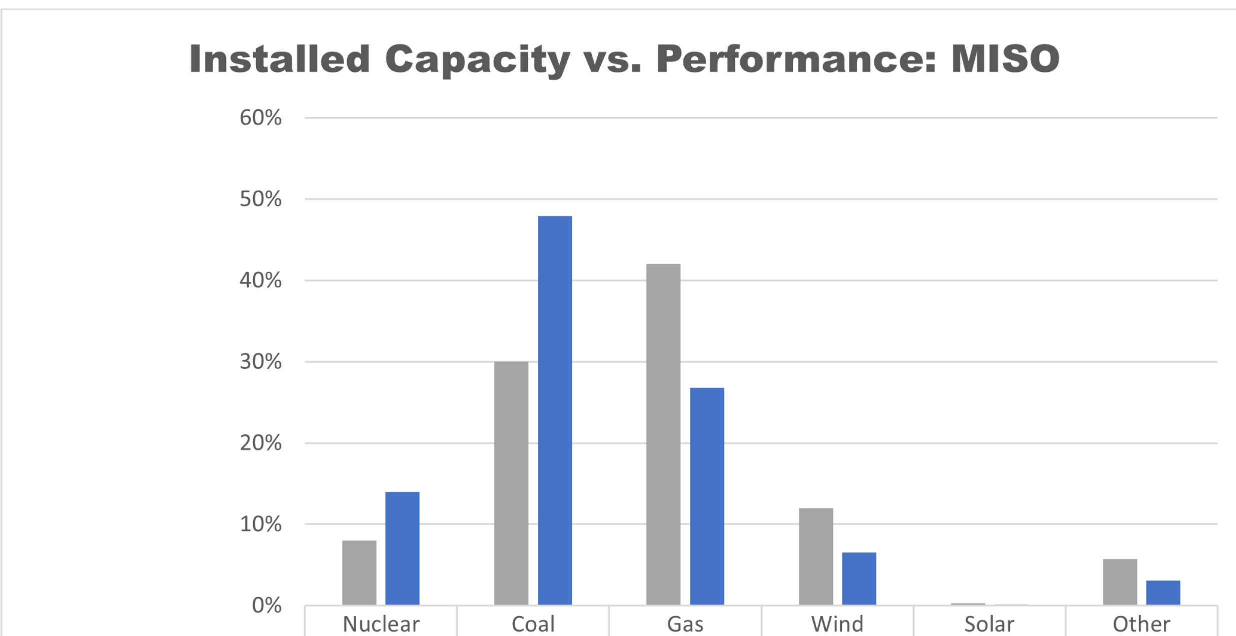
161 Midcontinent Independent System Operator Stakeholder Entities & Workshops (accessed Febraury 28, 2021).
162 *The February Arctic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative*, at 23.

Figure 23(a): ***ERCOT Resource Performance Relative to Installed Capacity During Winter Storm Uri***



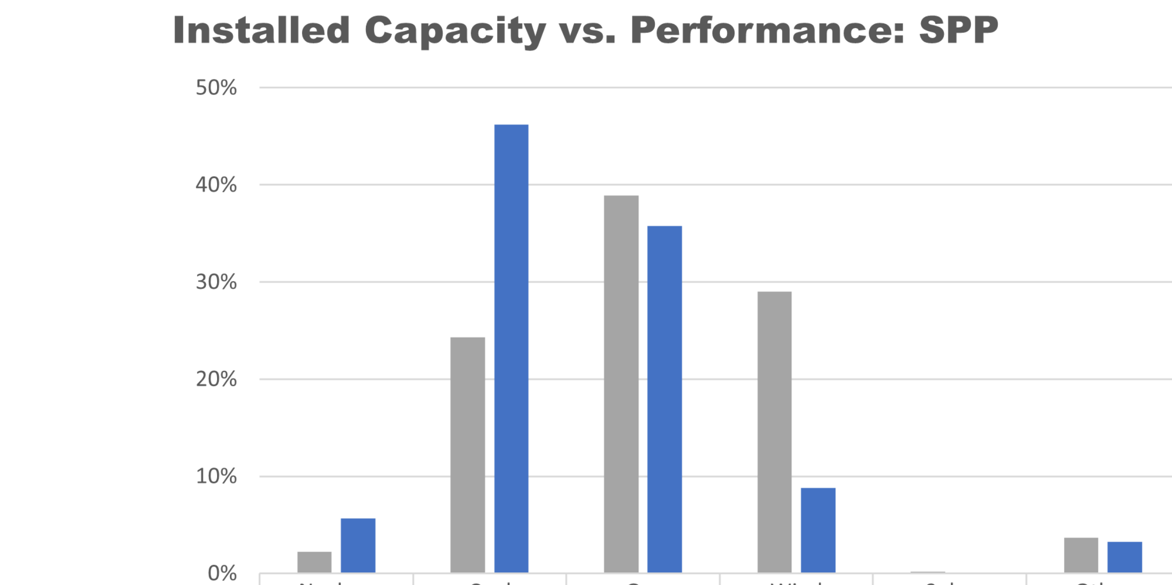
	Nuclear	Coal	Gas	Wind	Solar	Other
Installed Capacity	4.90%	13.40%	51.00%	24.80%	3.80%	1.90%
Generation During Uri	9.06%	18.21%	59.72%	8.81%	1.26%	0.23%

Figure 23(b): ***MISO Resource Performance Relative to Installed Capacity During Winter Storm Uri***



	Nuclear	Coal	Gas	Wind	Solar	Other
Installed Capacity	8.0%	30.0%	42.0%	12.0%	0.25%	5.75%
Generation During Uri	14.00%	47.91%	26.79%	6.57%	0.11%	3.04%

Figure 23(c): ***SPP Resource Performance Relative to Installed Capacity During Winter Storm Uri***



	Nuclear	Coal	Gas	Wind	Solar	Other
Installed Capacity	2.20%	24.30%	38.9%	29.0%	0.20%	3.70%
Generation During Uri	5.67%	46.22%	35.77%	8.80%	0.08%	3.25%

These figures paint a very clear picture of how important coal-fired generation was to the SPP grid during Winter Storm Uri when renewable resources dropped off significantly and supply disruptions prevented natural gas generation from playing as big a role as it could have. The size and ability of the coal fleet in SPP and MISO to cover the needs of the grid when renewables and gas-fired generation underperformed protected SPP and MISO members states from experiencing anything close to the power disruptions seen by ERCOT.

No public official summed up the important role of coal-fired generation during Winter Storm Uri more clearly than Oklahoma Governor, Kevin Stitt, when he stated the following during a special-called press conference during the storm:

> Renewable sources like wind and solar dropped to almost zero production. Natural gas wells froze, and compressor stations went offline. That left utility companies really scrambling to buy extra energy on the spot market at skyrocketing prices. [...] Wind is normally about 40 percent, and it dropped to 10 percent. Coal in Oklahoma is normally 10 percent, and it went to 40 percent. I've talked to several other Governors that coal was really bailing us out in the production.[163]

No matter what opinion on may have about the relative merits of different sources of electricity, for the Governor of an oil and gas State that has no in-state thermal coal mining to make this type of statement, coupled with the data in the figures above, is a clear indication of the importance of coal-fired generation to grid reliability and resilience during winter storms.

[163] https://www.youtube.com/watch?v=mCJD5AyDMOs.

Some have contended that the difference lies in how power plants are regulated and interact with the markets in SPP and MISO relative to ERCOT. All three markets have very similar market designs wherein only produced energy, not capacity, generates revenue, but they vary dramatically in other ways. One prominent difference between SPP states and ERCOT is the fact that the investor-owned utilities that own generation in all the other SPP states are regulated by state public utility/service commissions and integrated resource plans (IRPs) provide a valuable system-planning tool in those states in contrast to the controversial market-wide resource adequacy assessments conducted by ERCOT in the absence of any regulated generators in that market.

It is beyond the scope of this analysis to assess the merits (and demerits) of deregulation and what role it played in the Texas power outages, but suffice it to say the absence of formal system planning and the lack of a guaranteed rate of return for thermal generation could be seen as drivers. Nevertheless, the system planning track record of investor-owned generators is far from perfect, especially given the current trend of premature retirements of baseload generation in favor of "relying upon the markets" in which they are located to make up for the loss in reliable capacity and/or the buildout of weather-dependent resources without firming up those resources with an adequate supply of thermal dispatchable generation and energy storage.

Moreover, as will be discussed in detail below, the "missing money" problem in ERCOT need not be solved by rate-of-return regulatory structures. Instead, the adversity of the recent Texas tragedy spawns an opportunity for Texas to develop an innovative set of market-friendly reforms that better value capacity, reliability and resilience without necessarily reverting to the incumbent utility monopolies and rate-of-return regulated markets of the past.

The sections that follow and related appendices spell out how Texas policymakers appear to have learned from the lessons of Winter Storm Uri and have started down the path of a Texas-style solution that embraces markets, but not so much as to sacrifice reliability and resilience. If successful, the Texas reforms could provide a model for other markets in the U.S. and across the globe as grids attempt to integrate weather-dependent renewables without sacrificing the reliability and resilience of the electric grid. A failure to learn from this tragic cautionary tale demands a clear-eyed forensic analysis of what broke in order to know how to fix it. Hopefully, the extensive discussion above has armed the reader with the former.

VII. POLICY RESPONSE FROM TEXAS LEADERSHIP

On February 16, 2021, Governor Greg Abbott declared that ERCOT reform was an emergency priority for the state legislature, and that there would be an investigation of the power outage to determine long-term solutions. In March 2021, the Texas State Legislature introduced a package of bills that would put measures in place to prevent a future power outage in extreme temperatures.

The Texas Legislature concluded its 87th Regular Session on May 31, 2021. From the storm in February to the end of May, the legislature conducted hundreds of hours of hearings and considered a myriad of bills relating to the storm, and finally passed a wide range of measures that squarely deal with storm-related issues such as market rules and price formation, generation weatherization, ERCOT and PUC reform, debt securitization, and the appropriate role and accountability of renewable resources in securing reliability of the grid. The legislation that was passed and signed by the governor will affect all segments of the Texas energy economy and prompt significant change in the years ahead.

Most of the new laws are targeted at the PUC, the Office of Public Utility Counsel ("OPUC"), ERCOT, the RRC, the Texas Commission on Environmental Quality ("TCEQ"), and the Texas Division of Emergency Management ("TDEM"), but several reach (and create) other agencies and groups as well. What follows is a brief overview of the major areas of reform followed by a deeper dive into the most significant electricity market reform aspects of the legislation. To keep the main body of this study more concise, we have separated-out the more detailed analysis of other storm-related reforms into **Appendix** with the detailed discussion of the regulatory implementation of that wide range of reforms discussed in **Appendix B.**

A. Overview of Texas Legislative Response

A remarkable aspect of Winter Storm Uri was that it occurred roughly 3 weeks before the bill filing deadline for the 87th regular session of the Texas Legislature. As a result, several dozen bills were filed related to the storm or to electric grid reforms in general. The analysis below and contained in the Appendix A will only cover bills that passed and were signed into law and will focus on the most consequential market reforms.

Figure 24 below (which is also included with hyperlinks at the beginning of **Appendix A**) provides a visualization of the totality of the reforms organized by subject matter. *Table 4* below provides a rundown of the legislation by category, bill/section reference, and includes a short description of each for quick reference.

As reflected in *Figure 24* and *Table 4* below, the legislative changes passed in response to the storm fall into four categories: (1) Coordination: reform of state agency leadership structures and emergency management practices, (2) Consumer protection: how end-use consumers will be protected in the future from both price and reliability impacts, (3) Securitization: how debts from the storm will be managed, and (4) Weather Resiliency/Market Reform: how energy infrastructure weatherization is addressed and how the ERCOT power market will be reformed.

Figure 24: ***Visualization of Texas Legislative Response to Winter Storm Uri***

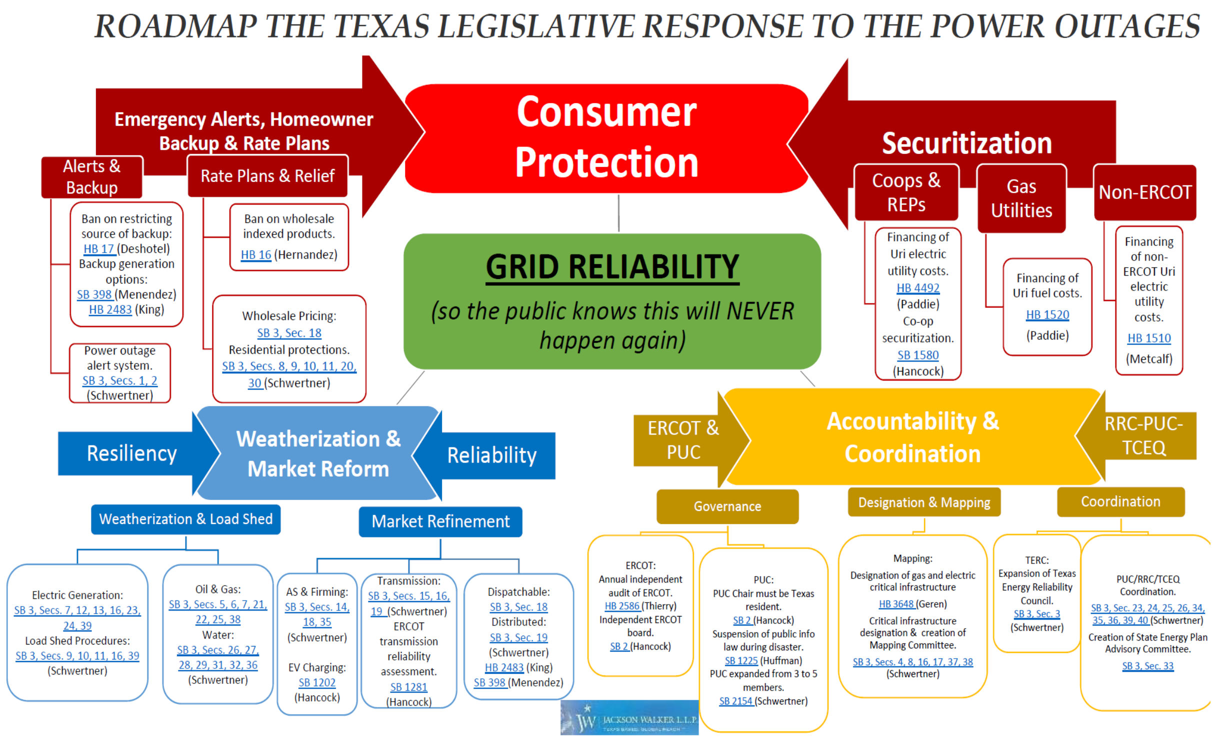


Table 4: ***Legislation Passed by the 87th Texas Legislature to Address the Problems Exposed by Winter Storm Uri***

Category	Legislation	Description
Coordination: Agency Leadership	SB 2	Reform of ERCOT leadership structure
	SB 3 Secs. 34, 35	Annual review the statutes, rules, protocols, and bylaws for PUC and ERCOT leadership
	SB 2154	Reform of PUC leadership structure
Coordination: Emergency Management	SB 3 Secs. 4, 17, 37	Designation of critical natural gas facilities and creation of the Texas Electricity Supply Chain Security and Mapping Committee
	SB 3 Sec. 24	Requires the PUC to submit biannual emergency preparedness reports
	SB 3 Sec. 25	Requires the RRC to submit biannual emergency preparedness reports for critical natural gas infrastructure
	SB 3 Secs. 26, 36	Requires water utilities to ensure minimum pressure levels during power outages
	SB 3 Sec. 33	Establishes the State Energy Plan Advisory Committee
	SB 3 Sec. 3	Establishes the Texas Energy Reliability Council
Consumer Protection	SB 3 Secs. 1, 2	Mandates the creation of a statewide power outage alert system

	SB 3 Sec. 18	Mandates the creation of a new wholesale market emergency pricing program
	HB 16	Prohibits wholesale-indexed electric plans for residential or small commercial customers
	SB 3 Secs. 8, 9, 10, 11	Reform of load shedding procedures for critical residential and industrial consumers
	SB 3 Sec. 16	Designation of critical natural gas facilities and new procedures for load shedding
Securitization	HB 4492	Securitization of debts for retail electric providers and financing of uplift charges
	SB 1580	Securitization of debts for electric cooperatives
	HB 1520	Securitization of weatherization costs for non-ERCOT electric utilities
	HB 1510	Securitization of debts for gas utilities
Weatherization	SB 3 Secs. 5, 6, 21, 22, 38	Weatherization of natural gas facilities
	SB 3 Secs. 7, 13, 16, 39	Weatherization of electrical generation
	SB 3 Secs. 28, 29, 31, 32	Weatherization of certain water utility systems
Market Reform	SB 3 Sec. 18	Wholesale market reform, reliability standards, and weather resiliency requirements
	SB 3 Sec. 14, 35	Ancillary services market reform
	SB 1281	Transmission planning and approval reform

Of the passed bills that in some way touched the energy and electric industries in the wake of Winter Storm Uri, there were two that provided the most significant power market governance and reform directives—Senate Bill 2 by Chairman Kelly Hancock (R-Euless) and Senate Bill 3 by Chairman Charles Schwertner (R-Georgetown.).

Senate Bill 2 (SB 2) addresses the governance of the PUC, OPUC, and ERCOT. Among other provisions, the bill requires the commissioner designated as the presiding officer of the PUC and the chief executive of OPUC to be Texas residents and requires that any rules adopted by, or enforcement actions taken by, ERCOT receive approval from the PUC before taking effect.

Senate Bill 3 (SB 3) was a hefty omnibus bill drafted and enacted solely in response to Winter Storm Uri. It is a massive overhaul that amends the Government Code, Natural Resources Code, Utilities Code, and Water Code to set out provisions relating to preparing for, preventing, and responding to weather emergencies and power outages. SB 3 requires the state of Texas to implement measures to weatherize power plants and natural gas supply (Sections 13 and 16), addresses the cost allocation of reliability impacts of renewables (Section 14), and attempts to preserve reliable generation and grid resilience (Section 18).

Senate Bill 2 and Senate Bill 3 were both passed during the regular session of the 87th Texas Legislature and signed into law by Governor Greg Abbott on June 8, 2021. They both became effective immediately. At the press conference immediately after signing the two bills, Governor Abbott declared that "everything that needed to be done was done to fix the power grid in Texas." He later issued a directive to the PUC and ERCOT stating how and why market reform legislation should be implemented and expanded, as discussed further below.

B. Market Reform: SB 3 and Governor Abbott's Letter to the PUC

Senate Bill 3 implements several market reforms after the 2021 winter storms caused widespread power outages. Importantly, Section 18 of SB 3 requires the PUC to ensure several things of ERCOT, including that ERCOT must: (i) establish requirements to meet the reliability needs of the power region; (ii) periodically, but at least annually, determine the quantity and characteristics of ancillary or reliability services necessary to ensure appropriate reliability during extreme heat and extreme cold weather conditions and times of low non-dispatchable power production in the power region; (iii) procure ancillary or reliability services on a competitive basis to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region; (iv) develop appropriate qualification and performance requirements for providing such ancillary or reliability services including appropriate penalties for failure to provide the services; and (v) size the services procured to prevent prolonged rotating outages due to net load variability in high demand and low supply scenarios.

In addition, SB 3 requires the PUC is to review the type, volume, and cost of ancillary services to determine whether those services will continue to meet the needs of the electricity market in the ERCOT power region. It also requires the PUC to evaluate whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation. Finally, the PUC must require ERCOT to modify the design, procurement, and cost allocation of ancillary services for the region in a manner consistent with cost-causation principles and on a nondiscriminatory basis. See **Appendix A** for a more detailed overview of SB 3's requirements.

After SB 3's adoption, on July 6, 2021, Governor Abbott sent a letter to the Commissioners of the PUC stating that laws passed in the 2021 legislative session "significantly reform[ed] Texas' energy and electric power market," but that "more can be done to increase power generation capacity and to ensure the reliability of the Texas grid." To achieve those goals, Governor Abbott directed the PUC to immediately take the following actions:

- **Streamline incentives within the ERCOT market to foster the development and maintenance of adequate and reliable sources of power, like natural gas, coal, and nuclear power.** The PUC has the ability to redesign segments of the market to incentivize and maintain the reliable electric generating plants our state needs. Those incentives must be directed toward the types of electric generators we need for reliability purposes. The goal of this strategy is to ensure that Texas has additional and more reliable power generation capacity.

- **Allocate reliability costs to generation resources that cannot guarantee their own availability, such as wind or solar power.** Electric generators are expected to provide enough power to meet the needs of all Texans. When they fail to do so, those generators should shoulder the costs of that failure. Failing to do so creates an uneven playing field between non-renewable and renewable energy generators and creates uncertainty of available generation in ERCOT. To maintain sufficient power generation—especially during times of high demand—we must ensure that all power generators can provide a minimum amount of power at any given time.

- **Instruct ERCOT to establish a maintenance schedule for natural gas, coal, nuclear, and other non-renewable electricity generators to ensure that there is always an adequate supply of power on the grid to maintain reliable electric service for all Texans.** Regular maintenance of our natural gas, coal, and nuclear plants must be strategically scheduled to prevent too many generation plants from being offline at the same time. This will help prevent an artificial shortage of power.

- **Order ERCOT to accelerate the development of transmission projects that increase connectivity between existing or new dispatchable generation plants and areas of need.** Dispatchable generation, such as natural gas, coal, and nuclear power plants, are essential for the reliability and stability of the electric grid because they can be scheduled to provide power to the grid at any time. We must ensure that, at any point in time, ERCOT is utilizing non-renewable electricity in sufficient amounts to maintain reliable power throughout our state.

The PUC's efforts to implement SB 3 and the directives found in the Governor's letter are ongoing, as discussed below and in more detail in **Appendix B**.

C. Market Reform: PUC Implementation

The PUC opened Docket No. 52373, Review of Wholesale Electric Market Design, on July 30, 2021, in order to implement the requirements of SB 3 and the Governor's letter, and in recognition of the problems discussed above with Texas' "energy-only" power market and the lack of incentives for adequate dispatchable generation. Since that date, the PUC has held many public work sessions to address the functions and deficiencies of the ERCOT wholesale market and has received thousands of pages of comments from stakeholders, experts, and the public with the goal of identifying solutions that would enhance grid reliability.

On October 20, 2021, Chairman Lake issued a "strawman" market redesign proposal in a memorandum addressing key concepts that are believed should be the foundation of the ERCOT market redesign process, as a starting point for further discussion. Perhaps the most important proposed change in Chairman Lake's proposal is the potential adoption of a Load-Serving Entity ("LSE") reliability obligation, which is similar to a capacity obligation. Under the proposed LSE Obligation, ERCOT would calculate whether there are sufficient generation resources to meet projected demand. If there is a deficit, the PUC would initiate a process under which each LSE would be required to demonstrate that it has contracted for sufficient generation to meet their projected non-interruptible load during peak hours. If an LSE cannot meet this standard, ERCOT would charge a penalty that would be used to acquire generation to cover this amount.

On December 1, 2021, after extensive discussions and feedback on his initial proposals, Chairman Lake issued an updated proposal in a new memorandum for discussion at the PUC's December 2 work session. The proposal included pairing the LSE Obligation with a Backstop Reserve Mechanism previously proposed by Commissioner Lori Cobos discussed further below.

At the PUC's December 2, 2021 Work Session, after much debate, the PUC agreed to further consider and evaluate a load-side obligation that includes resources and with components from Commissioner McAdams' Dispatchable Energy Credits ("DECs") proposal. The Commissioners agreed on the following key principles for the Load-side Obligation and Reliability Backstop service:

Load Side Obligation:

- Size to cover seasonal net peak load;
- Needs to address market power concerns;
- Technology agnostic approach;
- Ensure that mechanism sends appropriate forward price signals to existing dispatchable generation and attracts investment of new dispatchable generation;
- Establish performance standards and non-compliance penalties for both load and generation tied to the Cost of New Entry; and
- Incorporate components of Commissioner McAdams' DEC proposal, including that different DEC values would be established for different levels of resource performance.

Reliability Backstop:

- Implement Reliability Backstop as soon as possible;
- Leverage use of existing framework (like Black Start) to accelerate implementation;
- Ensure that reserves are withheld from the market until the Minimum Contingency Level ("MCL") is reached;
- Size to cover seasonal net peak load; and
- Establish performance standards and non-compliance penalties.

On December 6, PUC Staff issued a memorandum setting out the second draft "strawman" of what will eventually be the blueprint for ERCOT market redesign. This "strawman" included proposed Phase I and Phase II market design concepts and principles, including concepts consistent with discussions at the December 2 Work Session.

1. Phase I – Enhancements to the Current Market Design

The updated "strawman" proposed reforms to address: (1) improving price signals and operational reliability, and (2) enhancing Ancillary Services ("AS").

The following reforms to improve price signals and operational reliability were addressed:

- Modify the ORDC to reward reliable generation assets that are able to be dispatched as the reserve margin in ERCOT decreases. The enhanced ORDC will bring generation units online and prompt consumer demand response earlier to help enhance regular market operations and avoid conservation appeals. Immediate- and longer-term solutions were identified.

- Adopt changes that allow for more targeted demand response to increase utilization of load resources for grid reliability.
- Reform the Emergency Response Service ("ERS"). ERS is an operational reliability tool that should be deployed earlier to allow participating large commercial and industrial consumers, DG facilities, and aggregated customers to curtail their electricity consumption to reduce demand on the grid to help avoid conservation appeals and emergency conditions.

The following reforms to enhance Ancillary Services were addressed:

- ERCOT is currently developing a new grid frequency AS product – Fast Frequency Response Service ("FFRS") – to help stabilize grid frequency in the future.
- Expansion of ERCOT's existing Non-Spinning Reserve Service (Non-Spin) to allow loads to participate in the service to provide additional versatility for addressing forecast error or ramping issues in the future.
- The PUC should direct ERCOT to develop a discrete firm fuel-based reliability service that would provide additional grid reliability and resiliency during extreme cold weather and compensate generation resources that meet a higher resiliency standard.
- The ERCOT market will develop a product to compensate valuable voltage support services that will help maintain grid stability as more inverter-based resources enter the market.
- ERCOT is currently developing the ERCOT Contingency Reserve Service ("ECRS") to serve as an additional operational reliability tool to help maintain grid reliability by managing increasing variability and ramping issues associated with higher renewable generation penetration on the grid in the future.
- The PUC will open rulemaking proceedings and other projects to request technical feedback and provide rate recovery of reasonable and necessary distribution voltage reduction costs and review DG interconnection procedures.

2. Phase II –Market Design Proposals

The PUC has agreed in principle to develop a load-side reliability mechanism and a backstop reliability service. The goal of the load-side reliability mechanism is to ensure the supply of dispatchable generation is sufficient to meet system demand in ERCOT. The PUC's development of a load-side reliability mechanism will take into consideration the following proposals and how they can be implemented adhering to the principles that a load-based reliability mechanism should:

- Offer economic rewards and provide robust penalties or alternative compliance payments based on a resource' s ability to meet established standards (including penalty at cost of new entry for both non-compliance of load and non-performance of generation).
- Build on ERCOT's existing Renewable Energy Credit ("REC") trading program framework or other existing framework to the extent practicable.

- Be self-correcting (in a properly functioning market, higher energy prices will incentivize new supply and over time that additional supply will drive energy prices back down to market equilibrium).
- Have clear performance standards (incentivize higher performance).
- Sizing of the program must be dynamic (e.g., peak net load).
- Provide a forward price signal to encourage investment in dispatchable generation resources.
- Value or qualify resources based on capability.
- Establish standards that can be regularly tested or certified upon the start of commercial operation.
- Be proportional to the system need, with dynamic pricing and sizing to ensure reliability needs are met without over-purchasing reserves.
- Be compatible with ERCOT's robust competitive retail electricity market that provides choice for consumers.
- Ensure market power concerns are mitigated, especially regarding electric generation companies that also serve retail customers, so that competition and innovation will continue to thrive in the ERCOT market.

In addition, the PUC has agreed to develop a backstop reliability service that will serve as a new dynamic and flexible reliability tool to prospectively target and meet specific reliability needs that will not be met by ERCOT's real-time and AS market. The backstop reliability service will be used to procure accredited new and existing dispatchable resources to serve as an insurance policy to help prevent emergency conditions in ERCOT.

The backstop reliability service should:

- Be sized on a dynamic, flexible basis to meet a specific reliability need (i.e., seasonal net load variability, low-probability/high-impact scenarios).
- Include new and existing accredited dispatchable generation resources that are seasonally tested and able to meet specific minimum and maximum start-time and duration requirements.
- Include robust non-performance penalties and clawback of payment for noncompliance.
- Deploy generation resources in a manner that does not negatively impact real-time energy prices (i.e., the deployed generation resources will truly serve as a backstop).
- Provide a forward price signal through an annual procurement on a seasonal basis to encourage investment in dispatchable generation resources.
- Include cost allocation to load based on a load ratio share basis that is measured on a coincident net-peak interval basis.
- Be developed through a framework that would allow maximum expedited implementation by ERCOT.
- Be analyzed in conjunction with other long-term market design enhancements.

The PUC may also evaluate various combinations of the Backstop Reliability Service, the DEC proposals, and the LSE Obligation proposals to determine whether the models' features can complement each other to provide long-term enhanced grid reliability.

D. Outstanding Questions Concerning LSE Obligation Program

On February 15, 2022, ERCOT made a filing in the docket noting several outstanding issues concerning the PUC's LSE Obligation Program, many of which were raised by interested persons filing comments. In raising the questions, ERCOT assumed the LSE Obligation program would have the following elements: (1) a defined reliability standard for the ERCOT system, (2) the actions required by the LSEs necessary to meet that reliability standard, (3) accreditation of grid resources to determine their eligibility for participation in the program, (4) performance monitoring and penalties for LSEs not meeting the requirements of the program, and (5) performance monitoring and penalties for participating grid resources.

In its filing ERCOT identified several issues and raised many questions concerning needed specifications and decision points for the design of the LSE reliability mechanisms. As an example, the memo raised the following questions, among others:

What is the reliability level or objective that the program is intended to achieve?
What metrics will be used to assess the reliability of the ERCOT system?
How will grid resource performance be assessed?
How should dollars collected by ERCOT be allocated?

As described above, the ERCOT market reform process will take time and discussions of the most significant reforms are still ongoing. No doubt, some of the most important decisions lay ahead as the PUC endeavors to address a number of outstanding questions relating to ERCOT market reform generally and the LSE Obligation in particular. Among the several issues with the Phase II proposals that were noted in public comments filed in the docket, was the absence of any explicit allocation of the additional costs likely to be incurred in implementing these reforms. Of particular note is the absence of any explicit allocation on a cost-causation basis to intermittent generation as contemplated by SB 3 and expressly directed by the Governor's July 6 letter. Discussions continue to evolve around how cost-allocation of the new reforms (or combinations/hybrids of those reforms) might occur to satisfy the requirements of SB 3, the Governor's Directive, including the concept of intermittent renewables being allocated some portion of those costs unless they "firm" or back-up the intermittence of their generation.

These concerns have led to significant legislative and stakeholder discussion of an alternative proposal developed and offered by the South Texas Electric Cooperative (STEC). STEC has proposed a "Reliability Service" that they contend (and many stakeholders agree) is more market-based and targeted to dispatchable generators with performance-based incentives. Because it includes specific provisions for cost-allocation based on cost-causation principles, it directly aligns with Sections 14 and 18 of Senate Bill 3, as well as the Governor's July 6, 2021 Directive. This Reliability Service would be an expansion of the existing set of ERCOT ancillary services and, as such, involves the auctioning of capacity. It appears to propose a framework that is more transparent, efficient and targeted than other existing capacity-related programs across the country such as load-side obligations in CAISO, MISO and SPP or multi-year centralized forward capacity markets utilized in PJM and NYISO.

E. Relationship & Applicability of Texas policy reforms to SPP and MISO

As noted above, both SPP and MISO conducted studies of their experiences during Winter Storm Uri and that has triggered a wide range of stakeholder discussions that will likely lead to reforms in both markets. Even a tertiary review of those studies and the ongoing discussions shows that significant market reforms could be on the horizon. As noted above, the fact that MISO, SPP, and ERCOT have similar "energy-only" fundamentals, means that the market reforms implemented in ERCOT could serve as models for the other markets moving forward and vice-versa. In fact, although much has been accomplished implementing the market reforms in Texas described above, when it comes to fundamental, long-lasting market design changes, SPP might outpace ERCOT on some fronts based on recent developments in the Regional State Committee (RSC) and especially the activities of the Improved Resource Availability Taskforce (IRAT) relating to fuel assurance, reliability and resilience.

Given the expected dramatic growth of intermittent resources in all three markets, there will no doubt be great interest in how Texas tackles the above-referenced problem of cost-allocation in light of the Governor's July 6 directive. Different ideas about how to tackle the cost-allocation problem will be debated for months, if not years, but the above-referenced study by the American Society of Civil Engineering, Texas Section, squarely took up this specific issue in their comprehensive analysis and they provided some thoughtful observations about how market reforms could potentially address the issue that are worthy of consideration:

> *Incremental intermittent generation is reaching the tipping in its share of the energy market and should bear the cost of negative reliability impacts on the system through a reliability standard that requires funding reliability payments to dispatchable generation within the system or provide complementary reliability capability with similar duration tenor.*[164]
> . . .
> *Any energy transition must have at its foundation an expectation and requirement of even higher levels of reliability and resilience, especially given the current environment of increased electrification and infrastructure interdependence. Transition can never be used as an excuse for reduced reliability and resilience.*[165]
> . . .
> *Furthermore, with high fixed and low operating costs, subsidized non-dispatchable generation diminishes margins in an energy only market for the dispatchable generators. In a perverse outcome that negatively impacts reliability and resilience, non-dispatchable generation negatively impacts the economics of dispatchable generation critical for a reliable and resilient system.*[166]
> . . .

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[164] Reliability and Resilience in the Balance Texas Section of the American Society of Civil Engineers (Executive Summary released 21 January 2022; Full Report released 16 February 2022), page 12. Available at: www.TexASCE.org/beyond-storms.
[165] *Id.* at page 21.
[166] *Id.* at page 36.

ASCE Texas Section recommends a market mechanism that rewards reliability, whether the unit is dispatched or not, balanced with reasonable electricity prices for consumers to replace the current flawed energy-only market, with subsidized intermittent generators, that solely depends on scarcity pricing to provide revenue sufficiency for reliability investments. This can be done with a hybrid reliability prioritized approach that enhances the existing energy-only market.[167]

XII. CONCLUSION

What occurred in our fuel supply and electric grid in Texas and beyond during the second week of February 2021 was tragic, because the events led to significant loss of life and treasure and were only minutes away from having catastrophic consequences. The fact that the event was not more catastrophic should be soberly recognized as good fortune that we may not be blessed with in the future. The forensic analysis contained herein of the time leading up to, including and immediately following Winter Storm Uri can serve as a resource to market operators, public officials, and other stakeholders across the country as we proceed through market reforms designed to shore-up reliability and resilience across the nation.

[167] *Id*. at page 46.