STATE ENERGY PLAN ADVISORY COMMITTEE

REPORT TO THE 87TH LEGISLATURE
September 1, 2022

STATE ENERGY PLAN ADVISORY COMMITTEE

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The Honorable Greg Abbott, Governor
The Honorable Dan Patrick, Lieutenant Governor
The Honorable Dade Phelan, Speaker of the House of Representatives
Members of the Texas Senate
Members of the Texas House of Representatives

Ladies and Gentlemen:

The State Energy Plan Advisory Committee hereby submits for consideration by the 87th Legislature this report on the comprehensive state energy plan as adopted by the committee by a vote of 7-5 pursuant to Section 33 of Senate Bill 3 (87th R.S).

The committee was directed to evaluate barriers in the electricity and natural gas markets that prevent sound economic decisions; evaluate methods to improve the reliability, stability, and affordability of electric service in this state; evaluate the electricity market structure and pricing mechanisms used in this state, including the ancillary services market and emergency response services; and provide recommendations for improvements to the wholesale electric market. Those recommendations that achieved consensus among the committee members collectively form the comprehensive state energy plan that the committee is charged with producing.

Thank you for the opportunity to serve on this advisory committee and assist the Legislature in evaluating the challenges that face the electric and natural gas industries in Texas.

Respectfully submitted,

Phil Wilson, Chairman

On behalf of the members of the State Energy Plan Advisory Committee:

Mark Ammerman	Jerome "Joey" Hall	Joel Mickey
Bill Barnes	E. Patrick Jenevein III	Julie Caruthers Parsley
Mike Greene	Castlen Moore Kennedy	Kenneth Stevens
Daniel Hall	Wendy King	

EXECUTIVE SUMMARY

The State Energy Plan Advisory Committee issues this report on the comprehensive state energy plan in accordance with Section 33 of Senate Bill 3, 87th Legislature.

The committee is charged with evaluating barriers in the electricity and natural gas markets that prevent sound economic decisions; evaluating methods to improve the reliability, stability, and affordability of electric service in this state; and evaluating the electricity market structure and pricing mechanisms used in this state, including the ancillary services market and emergency response services. As part of this effort, the committee also provides recommendations for removing the barriers it has identified in the electricity and natural gas markets, using the methods prescribed to improve electric service reliability, stability, and affordability. These recommendations collectively form the comprehensive state energy plan.

The committee held two public hearings featuring invited testimony from consumers and consumer advocates, state agencies, the independent system operator, representatives of the electric and natural gas industries, and other experts. Summaries of the testimony presented to the committee are included in appendices B and C.

Dramatic changes in global, national, and local energy and power markets have taken place since the electric industry was restructured with the enactment of Senate Bill 7 by the 76th Legislature in 1999. Despite all the changes that have affected the electric and natural gas markets, commodities pricing, and the fuel mix in Texas, one constant trend has been Texas' growth. According to the U.S. Energy Information Administration, Texas both produces and consumes more electricity than any other state.[1]

The devastation caused by Winter Storm Uri in 2021 illustrated both structural and operational deficiencies in the existing wholesale electric market. In response to hundreds of hours of testimony from industry stakeholders and state agency leadership regarding the Texas power grid's failure to supply enough power to meet demand during Winter Storm Uri, the 87th Legislature enacted Senate Bill 3 as a key step to ensure that the state has a more reliable grid and is better equipped to prevent and respond to energy emergencies.

[1] U.S. Energy Information Administration, "Texas State Energy Profile" (May 19, 2022), *available at* https://www.eia.gov/state/print.php?sid=TX.

The committee appreciates all parties who have provided their insights into the work that has been done to implement Senate Bill 3 and other key reforms at the Public Utility Commission of Texas, the Railroad Commission of Texas, the Texas Division of Emergency Management, the Texas Commission on Environmental Quality, the Texas Energy Reliability Council, and other agencies and across the industry, including the witnesses who presented testimony at the committee hearings. The committee especially wishes to thank the dedicated commissioners and staff of the Public Utility Commission of Texas for their commitment to solving the complex issues around restructuring the competitive wholesale energy market to ensure that all Texans can count on reliable, affordable electricity.

The initiatives that these state agencies and other stakeholders have undertaken to promote the efficient operation of the electric and natural gas markets informs the work of this committee by defining the issues yet to be addressed. The committee has evaluated those agencies' efforts in support of the paramount goals of reliability, stability, and affordability of electric service and presents further recommendations for the Legislature's consideration in advancing the progress that has been made since Senate Bill 3 was enacted.

As detailed in this report, a key problem the committee identified is how Texas can best adapt to the changing electric generation resource mix and support market-based incentives to ensure that the generation resource supply is adequate, resilient, and poised to support the continued economic growth in this state and the Texans who rely on reliable electric power in their homes and businesses.

This report is organized into six sections: (1) an introduction that sets forth the charge of this committee as it relates to the Legislature's overall reform effort and background on each of the areas this committee is tasked with evaluating; (2) a detailed examination of the efforts by the Public Utility Commission of Texas and other state agencies to implement the aspects of Senate Bill 3 that overlap with this committee's charge; (3) an evaluation of the barriers in the electricity and natural gas markets that prevent sound economic decisions; (4) an evaluation of methods the committee has identified to improve the reliability, stability, and affordability of electric service in this state, specifically in the Electric Reliability Council of Texas (ERCOT) region; (5) an evaluation of the electricity market structure and pricing mechanisms; and (6) specific findings and recommendations constituting this committee's comprehensive state energy plan for the Legislature's consideration.

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Section One:
INTRODUCTION

In February 2021, Winter Storm Uri brought record amounts of snow, ice, and sustained freezing temperatures to Texas, leading Governor Abbott to issue a disaster declaration for all 254 counties in the state. A survey by the University of Houston Hobby School of Public Affairs indicated that nearly 70 percent of Texans lost power at some point during February 14-20, 2021.[2] The impacts of the widespread loss of electric power to homes and businesses in Texas were catastrophic. The Texas Department of State Health Services confirmed that 246 deaths were winter storm related.[3] According to initial estimates cited by the Texas Comptroller, the storm contributed to financial and economic losses ranging from $80 billion to $130 billion.[4]

Texas lawmakers were quick to respond to the devastation wrought by Winter Storm Uri. The 87th Legislature, after many days of hearings and hours of testimony, passed landmark legislation that overhauled the structure of the entities that regulate the electric power industry and mandated electricity market reforms to reduce the likelihood and risk of future electric service disruptions to Texas homes and businesses. With the passage of Senate Bill 3, the omnibus electric reform bill, the Legislature ordered an examination and overhaul of all major aspects of the electric market—from natural gas supply chain and all-seasons weatherization activities to consumer communications and oversight of rotating outages (known as manual firm load shed).

As part of Senate Bill 3, the Legislature created the State Energy Plan Advisory Committee. The committee is charged with evaluating barriers in the electricity and natural gas markets that prevent sound economic decisions; evaluating methods to improve the reliability, stability, and affordability of electric service in this state; evaluating the electricity market structure and pricing mechanisms used in this state, including the ancillary services market and emergency response service (ERS); and providing recommendations for removing those barriers using the identified methods to improve reliability, stability, and affordability.

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[2] Chris Stipes, "New Report Details Impact of Winter Storm Uri on Texans" (Mar. 29, 2021), *available at* https://uh.edu/news-events/stories/2021/march-2021/03292021-hobby-winter-storm.php.

[3] Texas Department of State Health Services, "February 2021 Winter Storm-Related Deaths – Texas" (Dec. 31, 2021), *available at* https://dshs.texas.gov/news/updates/SMOC_FebWinterStorm_MortalitySurvReport_12-30-21.doc?terms=February+2021+winter+storm.

[4] Jess Donald, "Winter Storm Uri 2021: The Economic Impact of the Storm" (Oct. 2021), *available at* https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php.

In discharge of this obligation, the committee has examined the work that has been done since the passage of Senate Bill 3 and engaged agency leadership, affected stakeholders, and industry experts to evaluate what remains to be done to improve the lives of all Texans who rely on the critical services provided by these industries.

Implementation Overview

After Winter Storm Uri, the Legislature passed significant reforms to address the Texas power grid's failures, seeking to identify and resolve the underlying deficiencies within the wholesale electric and natural gas markets, and the lack of engagement between those industries, that contributed to the storm's catastrophic effects. The Public Utility Commission of Texas (PUC), which has opened more than two dozen rulemaking projects related to the implementation of Senate Bill 3, has led the way in ensuring that concrete steps are taken to improve the reliability and effectiveness of the electricity market, including electric utility providers' engagement with the natural gas industry. Rules regarding wholesale market pricing, mandatory weatherization, emergency operations, and the prioritization of electric service to critical natural gas facilities have already been implemented. A new program to ensure the availability of generation resources with access to firm fuel is currently being developed. Efforts to examine the benefits posed by demand-side programs, energy efficiency, and distribution-connected resources are being pursued. Although several more important initiatives remain, the PUC has worked diligently to identify and address the root causes of the problems laid bare during Winter Storm Uri.

Fundamental to this work has been the PUC's searching examination of the wholesale electric market design. On this critical front, the PUC has made substantial progress, having held multiple commissioner-led work sessions and public workshops with industry experts and consumer representatives and solicited thousands of pages of stakeholder comments. This work culminated in the development of a comprehensive blueprint for market reform. The PUC's blueprint sets forth solutions that address every facet of the market, from supply adequacy and market-based incentives for new dispatchable generation, to demand-side programs and improvements related to distributed energy resources, to the ancillary services necessary to address specific operational deficiencies and the changing generation resource mix.

The PUC also has directed the staff of the Electric Reliability Council of Texas (ERCOT) to implement the technical aspects of wholesale market reform. ERCOT is a membership-based, nonprofit corporation that serves as the independent system operator of the Texas Interconnection, a power region representing about 90 percent of the state's electric load. In accordance with the Texas Utilities Code, the PUC has certified ERCOT as the "independent organization" charged with managing the electric grid. ERCOT therefore is responsible for ensuring (1) nondiscriminatory access to the grid for all buyers and sellers of power; (2) the reliability and adequacy of the regional electrical network; and (3) accurate accounting for the production and delivery of electricity among generators and wholesale buyers and sellers. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 52,700 miles of transmission lines and more than 1,000 generation units.

Other agencies involved in Senate Bill 3 implementation include the Texas Department of Transportation (TxDOT), the Texas Division of Emergency Management (TDEM) and the Railroad Commission of Texas (RRC). Senate Bill 3 also establishes the Texas Energy Reliability Council (TERC) to "ensure that the energy and electric industries in this state meet high priority human needs and address critical infrastructure concerns" and to "enhance coordination and communication in the energy and electric industries in this state."[5] TERC is composed of leadership of TDEM, the PUC, the RRC, ERCOT, the Texas Commission on Environmental Quality (TCEQ), the Office of Public Utility Counsel (OPUC), the Texas Transportation Commission, and industry and consumer representatives.

Electric and Gas Market Barriers

The first charge of the State Energy Plan Advisory Committee is to evaluate barriers in the electricity and natural gas markets that prevent sound economic decisions. Despite the rise in renewable resources in Texas since the completion of the Competitive Renewable Energy Zone (CREZ) transmission projects, the fuel mix used to generate electricity in Texas is still weighted toward natural gas. In recent years, about half of the energy in ERCOT was supplied by natural gas, followed by wind and coal, with an increasing contribution from solar resources.[6]

Given the dependency of the electric generation fleet on natural gas, natural gas fuel supply availability issues have a direct impact on the production of electric power. The natural gas fuel supply issues experienced during Winter Storm Uri were complex and impactful. These issues included the reduction in natural gas fuel supply caused by weather-related declines in the production of natural gas, natural gas pipeline pressure issues related to the reduction in supply,

[5] Tex. Gov't Code § 418.302.

[6] ERCOT's fuel mix report for 2021 shows that 42 percent of the energy produced was from gas resources, with 24 percent from wind resources, 19 percent from coal resources, 10 percent from nuclear, and 4 percent from solar. The remaining 2 percent from "other" sources includes petroleum coke, distillate fuel oil, and any other or unknown fuel. This category also includes adjustments for Wholesale Storage Load. *See* ERCOT Fuel Mix Report, *available at* https://www.ercot.com/gridinfo/generation.

and natural gas unavailability driven by the terms of electric generating units' natural gas commodity and transportation contracts. Some natural gas producers and pipelines whose operations depend on electric service also reported that they were subject to manual load shed during Winter Storm Uri, thereby rendering them unable to produce and transport fuel to natural gas-powered generation resources. Many natural gas facilities were insufficiently weatherized to operate during the extreme winter weather conditions.

In November 2021, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued a joint report examining the impact the February 2021 storm had on the bulk electric system in Texas and other parts of the southern and central U.S. Their investigation involved staff from all six Regional Entities, including ERCOT; these experts conducted multiple rounds of data analysis and investigations to produce a comprehensive account of the event, including the causes of the Bulk Electric System interruptions.[7]

With regard to the causes of generating unit outages, the FERC/NERC Report determined that freezing issues and fuel issues together caused 75.6 percent of all unplanned outages; reductions in output, known as derates; and failed starts experienced during the entire event.[8] In ERCOT, about 48 percent of the total generating unit outages, derates, and failed starts were due to freezing issues, with the largest sub-cause being icing on wind turbine blades (accounting for 22,231 MW or 32.5 percent of the total MWs of outage or derated capacity in ERCOT).[9] Among its findings related to natural gas issues, the report concluded:

> Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, beginning on approximately February 7, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the South Central U.S. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s and force

[7] FERC, NERC, and Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States at 21-22 (Nov. 2021) ("FERC/NERC Report") (internal citations omitted), *available at* https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and/.

[8] *Id.* at 167.

[9] *Id.* at 167-68.

majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record.[10]

The FERC/NERC Report concluded that natural gas fuel supply issues caused the majority—87 percent—of the outages and derates that occurred due to fuel issues (which accounted for 31.4 percent of all outages and derates during the event).[11]

Further interdependencies between the electric and gas markets exist because natural gas generation is commonly the “marginal” unit dispatched to meet demand; therefore, it generally sets the wholesale market price. As a result, volatility in natural gas prices significantly impacts the prices of wholesale and retail electricity, and this volatility has made it challenging for competitive market participants to hedge their risk and for consumers to plan their energy purchases.

According to data from the ERCOT Independent Market Monitor (IMM), average real-time energy prices increased more than six times in 2021, largely owing to the impacts of Winter Storm Uri and increased average natural gas prices. The IMM’s data illustrate the trends in real-time energy and natural gas prices since 2014[12]:

($/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$40.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$42.78
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$41.57
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$39.98
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$35.51
($/MMBtu)									
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$3.62

[10] *Id.* at 13.

[11] *Id.* at 16, 167.

[12] Potomac Economics, Independent Market Monitor report to the ERCOT Board of Directors (June 21, 2022), https://www.ercot.com/files/docs/2022/06/13/8%20Independent%20Market%20Monitor_IMM_2021%20State%20o%20the%20Market%20Report%20for%20the%20ERCOT%20Electricity%20Markets.pdf.

Electric Service Reliability, Stability, and Affordability

The committee is also charged with evaluating methods to improve the reliability, stability, and affordability of electric service in this state. Examining reliability begins with understanding whether ERCOT has an adequate supply of electric generation to meet demand and maintain capacity reserves to support grid reliability if shortfalls occur. This concept is often referred to as "resource adequacy." Providing sufficient electric power to meet customer demand for electricity is the fundamental purpose of the electric grid. And customer demand in ERCOT—unlike most other parts of the U.S.—has continued to grow. So far in summer 2022, ERCOT has continuously set new peak demand records, including an all-time maximum peak demand record of 80,038 megawatts (MW) on July 20, 2022.[13] ERCOT, and Texas in general, has seen load growth and economic development unlike anywhere else in the country, including installations of new industrial facilities, expansions of liquefied natural gas terminals along the Texas Gulf Coast, increasing construction and electrification of oil and gas production in far West Texas, and the influx of cryptocurrency mining operations.

The PUC and ERCOT employ several measures to evaluate the adequacy of generation supply in the face of variable and growing demand. But, unlike all other electricity systems in North America, the ERCOT region does not have a resource adequacy reliability standard or reserve margin requirement. As the Brattle Group has previously explained in its reserve margin studies performed for the PUC, the reserve margin in ERCOT

> is ultimately determined by suppliers' costs and willingness to invest based on market prices, where prices are determined by market fundamentals and by the administratively-determined operating reserve demand curve (ORDC) during tight market conditions. This approach creates a supply response to changes in energy market prices towards a 'market equilibrium'; low reserve margins cause high energy and ancillary service (A/S) prices and attract investment in new resources, and investment will continue until high reserve margins result in prices too low to support further investment.[14]

[13] ERCOT Monthly Operational Overview for July 2022 at 2 (published Aug. 22, 2022), *available at* https://www.ercot.com/files/docs/2022/08/22/ERCOT-Monthly-Operational-Overview-July-2022.pdf.

[14] The Brattle Group, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region* (Oct. 12, 2018), *available at* https://interchange.puc.texas.gov/Documents/42302_45_996110.pdf.

As has been widely observed, federal tax incentives for investment in renewable generation have been a significant factor leading investors to favor new wind and solar projects, including in the ERCOT region. At the same time, installed generation capacity from dispatchable thermal generation is declining significantly due to unit retirements; ERCOT recently reported that of the 217,824 MW of generation interconnection requests currently being tracked, only about 11,000 MW is for new natural gas projects (representing about five percent of all new generation capacity under study, while over 50 percent is solar).[15]

Given the growth in intermittent renewable resource penetration relative to dispatchable thermal generation, new planning and operational challenges have emerged that add further complexity to the task of assessing system adequacy and reliability. With the influx of intermittent renewable resources, the concept of *peak net load*—demand minus renewable resource output—has become an important determinant of supply shortages. As the IMM has noted,

> The prediction of the future shape of this curve once a large quantity of solar has entered has been referred to as the "duck curve" or, in Texas, the "dead armadillo curve." This curve indicates that conventional [thermal] resources will have to ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. Similarly, shifting weather patterns can cause wind output to fall rapidly and the timing of these decreases can be difficult to predict.[16]

Moreover, renewable resources do not contribute inertia to the grid.[17] The more that power systems rely on wind, solar, and battery storage systems, the greater the risk that a major grid disturbance will cause the grid to cascade into a blackout condition. Further, ERCOT has identified that the growth in intermittent renewable resources may (1) exaggerate the magnitude of the net load ramps that the grid may experience; (2) introduce more uncertainty in intra-hour and hourly net load forecasts; and (3) increase the potential for lower inertia during lighter load periods (typically in the spring and fall, known as the "shoulder months").[18]

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[15] ERCOT Monthly Operational Overview for July 2022 at 4-5 (published Aug. 22, 2022), *available at* https://www.ercot.com/files/docs/2022/08/22/ERCOT-Monthly-Operational-Overview-July-2022.pdf.

[16] Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Markets* at 2 (May 2022) ("2021 SOM Report"), *available at* https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf.

[17] Power system inertia is provided by the "spinning" mass of conventional generators (i.e., the turbines that create electrical energy). As the number of asynchronous resources (like solar, wind, and batteries) increases, inertia declines. Synchronous inertia supports grid operations by supporting the balancing of supply and demand during normal operations and by stabilizing the grid if a disruption occurs (e.g., a unit trip).

[18] ERCOT Staff, "Impact of Growth in Wind and Solar on Net Load" (Oct. 25, 2021), *available at*

Accordingly, traditional measures of both installed generation capacity and reserve margins are becoming less predictive of system performance and supply adequacy. Approaching summer 2019, for example, ERCOT's predicted reserve margin was only 8.6 percent,[19] compared with ERCOT's summer capacity planning reserve margin for 2022 being forecast at 22.8 percent.[20] Yet, just as it did during summer 2019, ERCOT has had to appeal to the public for energy conservation on multiple operating days in 2022.[21]

Ensuring the stability and affordability of electric service are linked concepts that depend on the existence of clear and predictable market rules and policy decisions rooted in sound economic principles. For consumers, electricity prices have been rising, reflecting the ongoing economic downturn and other global events. Nonetheless, retail prices in Texas have continued to be lower than the U.S. average.[22]

As IMM noted in the 2021 ERCOT State of the Market Report, Winter Storm Uri dramatically impacted the stability of the ERCOT electric market and the provision of electric service:

> The sustained shortage pricing led to billions of dollars in excess costs and numerous defaults that ERCOT and that the State of Texas will continue to grapple with for years to come. ERCOT short payments (money owed by entities that was not paid to ERCOT) during Winter Storm Uri exceeded $3 billion. Several retail electric providers were forced to exit the market and one large electric cooperative is seeking bankruptcy protection. The financial stress on the ERCOT market led to significant intervention by the Texas Legislature and the Commission . . . which together authorized and implemented broad securitization and financing measures to stabilize the wholesale market.[23]

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https://www.ercot.com/files/docs/2021/10/25/NetLoad_Ramping_Analysis_v2_WMWG.pptx.

[19] ERCOT, "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region, Summer 2019" (May 8, 2019), *available at* https://www.ercot.com/files/docs/2019/05/08/SARA-FinalSummer2019.pdf.

[20] ERCOT, "Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2022" (May 16, 2022), *available at* https://www.ercot.com/files/docs/2022/05/16/SARA_Summer2022.pdf.

[21] "ERCOT's Use of Energy Conservation" Frequently Asked Questions page, *available at* https://www.ercot.com/files/docs/2021/08/04/Energy_Conservation_7-13-2022.pdf.

[22] U.S. Energy Information Administration, State Electricity Profiles – State of Texas, *available at* https://www.eia.gov/electricity/state/.

[23] 2021 SOM Report at 13.

In the wake of Winter Storm Uri, the ERCOT system operator increasingly has relied on "conservative operations" in managing the grid. This conservative operating posture is characterized by ERCOT's increased procurement of ancillary services (specifically Non-Spinning Reserve Service, or Non-Spin) and its routine, out-of-market commitment of generation resources through reliability unit commitment (RUC). These policy choices come with costs and potential reliability risks. According to IMM, hundreds of millions of dollars in costs due to ERCOT's increased procurement of Non-Spin were incurred in the second half of 2021, and an estimated $210 million to $385 million has been paid year to date in 2022 due to increased Non-Spin procurement and its impact on ancillary service prices.[24] The IMM similarly estimates nearly a half billion dollars in costs associated with ERCOT's use of RUC for excess capacity so far in 2022.[25] Additionally, this use of RUC will increase the risk of generation forced derates due to the increased use of these resources during uneconomic periods.

Market Structure and Pricing Mechanisms

This committee is also directed to evaluate the electricity market structure and pricing mechanisms used in Texas, including the ancillary services market and ERS. ERCOT is considered an "energy-only" market, which pays generators only for the energy they provide to the grid (with very few exceptions). The energy-only wholesale electric market is unique compared with other competitive markets in the U.S. and elsewhere, where generators are paid for having capacity available in their systems.

ERCOT's competitive wholesale market structure relies on market forces to ensure generation sufficiency. For the last decade, federal tax incentives for renewable generation have contributed to significant new wind and solar resources being constructed in ERCOT. According to ERCOT, wind and solar generators accounted for less than one percent of the total generating capacity in 2007,[26] but now account for a combined 38 percent of the total generating capacity.[27] Over the next three years, wind and solar account for about 27,800 MW—or 83 percent—of the roughly 33,500 MW in generation capacity that is proposed to interconnect in the ERCOT region, while

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[24] Potomac Economics, Independent Market Monitor report to the ERCOT Board of Directors (June 21, 2022), https://www.ercot.com/files/docs/2022/06/13/8%20Independent%20Market%20Monitor_IMM_2021%20State%20of%20the%20Market%20Report%20for%20the%20ERCOT%20Electricity%20Markets.pdf.

[25] *Id.*

[26] ERCOT Quick Facts, *available at* https:www.ercot.com/files/docs/2007/06/04/ercot_quick_facts_may_2007.pdf.

[27] ERCOT Quick Facts, *available at* https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf. *See also* ERCOT Fuel Mix Report, *available at* https://www.ercot.com/files/docs/2022/02/08/IntGenbyFuel2022.xlsx.

gas-fired generating units account for only four percent (and coal units account for zero).[28]

As an energy-only market, ERCOT relies heavily on wholesale pricing to provide key economic signals to guide decisions by market participants. "Scarcity" or "shortage pricing" refers to the price escalation that occurs when supply is not sufficient to satisfy all the system's energy and operating reserve requirements. Scarcity pricing in ERCOT occurs through a market tool called the ORDC, which operates to increase wholesale energy prices as reserve levels drop. As operating reserves decline, the ORDC "adder" drives prices higher to prompt generators and other market participants to produce more electricity in real time. The ORDC was implemented in 2014 and has been subject to successive refinements by the PUC, including as part of the PUC's post-Winter Storm Uri reforms and market design enhancements.

In addition to energy payments, including revenues generated from the ORDC, resources in ERCOT may also qualify to receive payments for providing ancillary services. As noted above, ancillary services are products that ERCOT procures to ensure that there are enough resources and resource flexibility available on the system to meet net load, net load changes, and other uncertainties. Today, ERCOT relies on the following ancillary services:

- Regulation Service – an ancillary service that consists of either Regulation Down Service (Reg-Down) or Regulation Up Service (Reg-Up).
    - Reg-Down and Reg-Up are services that provide capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency.
    - Fast Responding Regulation Service is a subset of Regulation Service that consists of either Fast Responding Regulation Down Service or Fast Responding Regulation Up Service in which the participating Resource provides capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or its detection of a trigger frequency independent of an ERCOT Dispatch Instruction.

- Responsive Reserve Service (RRS) – an ancillary service that provides operating reserves that is intended to:
    - Arrest frequency decay within the first few seconds of a significant frequency

[28] ERCOT Capacity Changes by Fuel Type (May 2022), *available at* https://www.ercot.com/files/docs/2022/06/08/Capacity_Changes_by_Fuel_Type_Charts_May_2022.xlsx. Over the longer-term planning horizon, ERCOT is tracking 1,017 active generation interconnection requests totaling 199,119 MW as of May 31. This includes 106,920 MW of solar, 19,544 MW of wind, 58,249 MW of battery, and 12,888 MW of gas projects.

deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible load;

  - After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal;
  - Provide energy or continued load interruption during the implementation of the Energy Emergency Alert (EEA); and
  - Provide backup regulation.

- Non-Spinning Reserve Service (Non-Spin) – an ancillary service that is provided through use of the part of off-line generation resources that can be synchronized and ramped to a specified output level within 30 minutes (or load resources that can be interrupted within 30 minutes) and that can operate (or load resources that can be interrupted) at a specified output level for at least one hour. Non-spin also may be provided from unloaded on-line capacity that meets the 30-minute response requirements and that is reserved exclusively for use for this service.

Senate Bill 3 also directs this committee to evaluate ERS. ERS is an emergency service that, at the direction of the PUC, ERCOT procures to assist in maintaining or restoring ERCOT System frequency. ERS is not an ancillary service, but is a tool designed to be deployed by ERCOT to help prevent or alleviate an actual or anticipated EEA event. At the time of this report's drafting, the PUC currently is finalizing changes to its substantive rules to increase the budget for ERS and also has taken steps to modify ERS deployment so that ERCOT can dispatch ERS before the declaration of EEA conditions.

Section Two:
IMPLEMENTATION OVERVIEW

Implementation of Senate Bill 3 has proven to be a significant undertaking, requiring the coordinated efforts of several state agencies, industry participants, and consumer organizations. Most regulatory implementation and wholesale market reforms have been directed to the PUC and ERCOT, a nonprofit corporation serving as the independent system operator.

The Texas Legislature created the PUC in 1975 to provide for the comprehensive statewide regulation of electric, telecommunications, and water utility services. In 1999, the Texas electric industry was dramatically reshaped with the passage of Senate Bill 7 (76th Legislature), requiring the unbundling of previously vertically integrated investor-owned utilities and instituting a competitive retail electric market throughout much of ERCOT.

More than 26 million Texas customers, or nearly 90 percent of the state's population, receive electric service from the ERCOT grid. As the independent system operator, ERCOT does not own its own grid infrastructure, but instead relies on power generation and transmission and distribution infrastructure owners and operators to produce and deliver electric energy to consumers. Entities that own power generation facilities in ERCOT include power generation companies (PGCs), municipally owned utilities (MOUs), electric cooperatives, and river authorities. Transmission and distribution service is provided in ERCOT by transmission and distribution utilities (TDUs), MOUs, and electric cooperatives. ERCOT's primary function is to serve as the reliability coordinator and balancing authority that coordinates the production of electric power and the transmission of that electricity across the state.

Senate Bill 3 Implementation: PUC and ERCOT

The PUC has worked diligently in the months following enactment of Senate Bill 3 and other electric industry reforms to meet all statutory deadlines, but its work remains ongoing. To date, the PUC has opened two dozen projects and finalized at least ten amendments to its substantive rules as part of its legislative implementation and electric industry reform efforts since the end of the 87th legislative session. To accomplish the objectives of Senate Bill 3, the PUC also has directed ERCOT to adopt new (or revise existing) market rules, called Protocols, necessary to implement statutory and regulatory directives. In addition, organizational restructuring was required for ERCOT to meet the governance reforms required by Senate Bill 2. A new ERCOT board of directors convened in January 2022 and has been expeditiously processing market policy changes vetted through the ERCOT stakeholder process for PUC review and approval.

Wholesale Electricity Market Reform

On January 13, 2022, the PUC issued an order approving its final blueprint for wholesale market design and directives to ERCOT. The blueprint is a compilation of directives and concepts designed to reform the ERCOT wholesale electricity market, to be implemented in a two-phased approach.

The path to the development of the final blueprint began with a set of directives from the Legislature, largely contained in Senate Bill 3, and a call to action by Governor Abbott. In a letter dated July 6, 2021, Governor Abbott directed the PUC commissioners to take immediate action on a set of directives to increase dispatchable generation and ensure the reliability of the Texas power grid. In response to Governor Abbott’s letter, the Commissioners directed Staff to open a new policy project to evaluate specific market incentives, such as potential changes to the ORDC, ancillary service products, and other reliability services and price incentives, to drive investment in new and existing dispatchable generation. PUC staff opened Project No. 52373 on July 30, 2021.

From that point on, the PUC initiated a comprehensive examination of a broad range of proposed wholesale market design changes, issuing questions for stakeholder comment and holding a series of work sessions with presentations by representatives from ERCOT, IMM, industry consultants, market participants, associations, and consumer advocates.

The PUC has a long track record of successfully developing and refining regulatory policies and market enhancements through a collaborative, consensus-based process involving market participants, agency staff, consumer representatives, and industry experts. The PUC again used this cooperative stakeholder process to develop, refine, and ultimately adopt the final blueprint.

Questions posed to stakeholders addressed wholesale energy pricing, new and revised ancillary service products, demand response, ERS, and other proposals for targeted improvements to reliability and grid resiliency. Over the next several months, the PUC received about 300 distinct sets of written comments totaling thousands of pages, heard testimony from dozens of people, and evaluated scores of detailed proposals for reform.

The final blueprint reflects the totality of these efforts by mandating a range of quantifiable, time-bound reforms over two distinct phases. The PUC’s phase one directives, and its progress in implementing those changes, is summarized below.

- The PUC ordered ERCOT to modify the ORDC to bring generation units online and prompt consumer demand response sooner, resetting the Minimum Contingency Level to 3,000 MW and setting the high system-wide offer cap (HCAP) and value of lost load (VOLL) to $5,000 per MWh.
  - These changes were in effect by the January 1, 2022 deadline established by the PUC.
  - As part of PUC Project No. 53191, the PUC amended its rules to decouple HCAP and VOLL, effective April 29, 2022. A new VOLL will be established "based on quantitative analysis of new revenue to the market that would be directed to reliable generation assets during scarcity events."[29]
- The PUC directed adoption of market mechanisms and technical measures to improve transparency of price signals for load resources; to improve the setting of higher demand reduction performance standards for energy efficiency programs; and to evaluate policy changes for improving customer aggregation participation (i.e., "virtual power plants") as part of an overall focus on improving demand response.
  - Stemming from its work in a project to review distributed energy resources, the PUC has launched a pilot program for the aggregation of distributed energy resources around the state that would include areas open to retail competition as well as areas served by non-opt-in entities.[30] In parallel with the pilot program, the PUC will oversee a task force to work in concert with ERCOT staff and the ERCOT Technical Advisory Committee to identify operational obstacles and make recommendations to the ERCOT board, which must approve and implement any pilot program.
- The PUC directed that ERCOT update its procedures to allow ERS to be deployed sooner in advance of scarcity conditions to help ERCOT avoid issuing conservation appeals and experiencing emergency conditions.
  - Effective December 17, 2021, the PUC approved a revision to the ERCOT Protocols allowing for the deployment of ERS before the declaration of an EEA when Physical Responsive Capability (PRC) falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin.
  - In PUC Project No. 53493, the PUC updated substantive rule 16 Texas Administrative Code (TAC) § 25.507 to reflect the change in the timing of ERS

[29] *Review of Wholesale Electric Market Design*, PUC Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT, Attachment 1 (Jan. 13, 2022).

[30] *Aggregate Distributed Energy Resource (ADER) ERCOT Pilot Project*, PUC Project No. 53911.

deployment before the declaration of an EEA, in order to avoid emergency conditions.

  - As part of Project No. 53493, the PUC also increased the annual budget for ERS to $75 million per year, including a $25 million per year reserve allowance. The revised rule allows ERCOT the flexibility to contract for ERS for up to 24 hours in a contract term. As PUC Chairman Peter Lake noted at the PUC open meeting on July 14, 2022, ERS was deployed the day before and provided an additional 1,000 MW for about 3.5 hours to help balance tight conditions.
- The PUC is overseeing ERCOT's development and implementation of Fast Frequency Response Service (FFR), an ancillary service designed to help stabilize grid frequency.
  - ERCOT's Technology Working Group (TWG) is working with stakeholders on the required market testing, with target go-live in October 2022.
- In an effort to bolster fuel resiliency, the PUC approved a new Firm Fuel Service to be procured for the upcoming 2022-2023 winter season and ultimately expanded in future years.
  - At its May 12, 2022 open meeting, the PUC finalized the design parameters for an initial procurement of 3,000 to 4,000 MW of Firm Fuel Supply Service (FFSS). Resources eligible for the initial procurement will be those with dual fuel capability and onsite fuel storage, or those that own and control transport to a natural gas storage facility. Additional PUC open meeting discussion has touched on whether other eligible resource types, including those with firm fuel supply contracts, may be considered as the program evolves and expands in the future.
  - The PUC approved changes to the ERCOT Protocols in March 2022 to allow for updates to ERCOT's settlement systems related to FFSS implementation.
  - On June 30, 2022, ERCOT issued the Request for Proposals for FFSS for the contract term of November 15, 2022 through March 15, 2023. FFSS competitive offers are due September 1, 2022.
- The PUC directed ERCOT to accelerate its implementation of a new ancillary service product, ERCOT Contingency Reserve Service (ECRS), designed to help maintain grid reliability by managing increasing variability and ramping issues associated with higher renewable resource penetration on the grid in the future.
  - ERCOT's TWG is working with stakeholders on the required market testing, with target go-live in the first half of 2023.
- The PUC directed ERCOT to develop a product to compensate voltage support services that will help maintain grid stability as more inverter-based resources enter the market.
  - ERCOT has filed specification and design requirements with the PUC to prepare

for the development of this new service.

- The PUC also has opened projects to solicit technical feedback and review distributed generation interconnection procedures and examine distribution voltage reduction programs.

The second phase of the PUC's final blueprint addresses the fundamentals of the energy-only wholesale market design that have led to inadequate levels of dispatchable generation in ERCOT—a structural deficiency that was highlighted during Winter Storm Uri and exacerbated the challenges that the electric industry faced during that event.

The chief elements of phase two include the development of a load-side reliability mechanism and creation of a backstop reliability service. The load-side reliability mechanism is intended to ensure the ERCOT fleet includes sufficient dispatchable generation that is able to meet a range of weather and demand scenarios, and to further stimulate investment in dispatchable generation in the ERCOT market. According to the PUC's final order establishing the key principles, the load-side reliability mechanism will be designed to:

- 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);
- Be dynamically sized (e.g., a program based off 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; and
- 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 to a load-side reliability mechanism, the PUC has directed review of a backstop reliability service to 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 ancillary services market. The backstop reliability service is expected to:

- 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 reimbursement 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 truly will 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; and
- Be analyzed in conjunction with other long-term market design enhancements.

The PUC also indicated that it might evaluate various combinations of a load-side reliability mechanism (including Dispatchable Energy Credits) and a backstop reliability service to determine whether a hybrid model is the optimal method to provide long-term, enhanced grid reliability.

Market Design Implementation

Since finalizing the blueprint for wholesale electric market reform, the PUC has been taking additional steps toward implementing both phases.

On May 10, 2022, the PUC executed a contract with an independent consultant to assist in the analysis, development, and implementation of the reforms set forth in the final blueprint. The consultant's contractual obligations include (1) designing a turnkey load-side reliability mechanism that can be fully operational and functioning in the ERCOT power region within one year of PUC adoption; (2) designing a turnkey backstop reliability service that can be fully operational and functioning in the ERCOT power region by summer 2023; (3) analyzing whether a hybrid of backstop reliability service and a load-side reliability mechanism could be created to enhance grid reliability; (4) developing, for each mechanism, a set of business requirements and specifications, policy decisions to be addressed by the PUC, a list of ERCOT Protocols and PUC rules requiring revision, and a cost-benefit analysis addressing expected reliability outcomes, implementation and consumer cost impacts, and potential impacts on future monetary investment in dispatchable generation.

The PUC currently anticipates that over the next several months and leading up to the start of the next legislative session, the consultant will continue to take input from the commissioners on how to iterate different options for these products to create a Texas-specific market design. The PUC will take public comment and ensure that a turnkey solution is presented to the Legislature and the Governor for their consideration before the next legislative session.

Wholesale Energy Pricing

During 2022, the PUC finalized new rules relating to the HCAP and restructuring its substantive rules on the scarcity pricing mechanism and resource adequacy reporting requirements for the ERCOT region. Specifically, new 16 TAC § 25.505 prescribes resource adequacy reporting requirements and requires ERCOT to submit to the PUC a biennial report on the ORDC, new 16 TAC § 25.506 sets forth the requirements for the publication of resource and load information in ERCOT, and new 16 TAC § 25.509 establishes a scarcity pricing mechanism for the ERCOT market.

Under the revised scarcity pricing mechanism, effective January 1, 2022, the PUC set the HCAP to $5,000 per MWh and $5,000 per MW per hour, reduced from $9,000 per MWh and $9,000 per MW per hour. In addition, the PUC removed language from the rule requiring the VOLL to equal the system-wide offer cap, effectively allowing those values to be decoupled in the future. The low system-wide offer cap (LCAP) remains at $2,000 per MWh and $2,000 per MW per hour.

Previously, in Project No. 51871, the PUC modified the value of the LCAP by eliminating a provision that tied the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities are able to recover their actual marginal costs when the LCAP is in effect.

Weatherization

In October 2021, the PUC adopted new 16 TAC § 25.55, relating to weather emergency preparedness measures for generation entities and transmission service providers (TSPs). Known as "phase one weatherization rules," these new requirements mandated that all providers of generation and transmission service submit comprehensive winterization reports to the PUC and ERCOT by December 1, 2021, with attestations by the entity's highest-ranking officer that all winter weather preparations were completed.

The first phase of the PUC's development of robust weather emergency preparedness reliability standards helped to ensure that the electric industry was prepared to provide continuous reliable electric service throughout the 2021-2022 winter weather season. Specifically, the rule required generators to implement all winter weather readiness recommendations identified by industry experts following the 2011 severe winter storm that affected the southwestern U.S., including ERCOT. In addition, generation providers were directed to fix any known, acute issues that arose from winter weather conditions during the immediately preceding 2020-2021 winter weather season, including Winter Storm Uri.

Similarly, the phase one rule required TSPs to implement key recommendations contained in the 2011 "Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1 - 5, 2011," jointly prepared by FERC and NERC, and to fix any known, acute issues that arose during the 2020-2021 winter weather season.

In a parallel rulemaking effort, the PUC also updated its enforcement rules to increase administrative penalties to $1 million per violation per day for violations of rules related to weatherization.

In total, 847 generators were required to submit winter weather readiness reports; nearly all were submitted by the December 1, 2021 deadline.[31] In addition, 54 TSPs were required to submit reports; all but one were submitted by the December 1, 2021 deadline.

As required by the new rule, ERCOT staff performed 324 on-site inspections of generation and transmission facilities located across the entire ERCOT region. Across all sites, ten potential deficiencies were identified at generation sites, and six potential deficiencies were identified at transmission sites. The ten generator deficiencies represent 1.7 percent of the total ERCOT

[31] Nineteen reports by generators were submitted late; three additional reports were submitted by generators that ended seasonal mothball outages early.

generation fleet capacity; most were minor and were remediated. ERCOT reported that some generators and TSPs adopted winter weather preparation measures that went above and beyond the requirements of the PUC's rule.

The PUC is currently finalizing phase two of the weatherization rules. Phase two weather emergency preparedness reliability standards will consist of a more comprehensive, year-round set of weather emergency preparedness reliability standards that will be informed by a robust weather study conducted by ERCOT, in consultation with the Office of the Texas State Climatologist. In addition, the proposed phase two rule will require generators and transmission facilities to be inspected on a periodic basis.

Designation of Critical Natural Gas Customers and Suppliers

In addition to Senate Bill 3, the Legislature enacted House Bill 3648, relating to the provision of natural gas and electric services in this state. This bill amended Chapter 81 of the Texas Natural Resources Code and Chapter 38 of the Texas Utilities Code to require that the RRC and the PUC collaborate to adopt rules to establish a process to designate certain natural gas facilities as critical customers or critical gas suppliers during energy emergencies. Once designated, such entities must provide critical customer and critical gas supply information to ERCOT and the utility that serves the entity's facilities. Such rules must provide for prioritizing the designated facilities and entities for load-shed purposes during an energy emergency and provide discretion to the electric utility, MOU, or electric cooperative providing service to prioritize power delivery and power restoration among the facilities and entities designated as critical on the utility's or cooperative's systems, as circumstances require.

In November 2021, the PUC adopted amendments to 16 TAC § 25.52, relating to Reliability and Continuity of Service, which implemented the twin directives in House Bill 3648 and Senate Bill 3 to increase the coordination between the electric and natural gas industries during energy emergencies. As part of this joint effort, the RRC adopted its new rule 16 TAC § 3.65, relating to Critical Designation of Natural Gas Infrastructure. Together, the PUC and RRC rules require a critical natural gas facility to provide critical customer information to the utility from which the critical natural gas facility receives electric delivery service and require the utility to incorporate this information into its load-shed and power restoration planning.

The same PUC rulemaking also implemented Senate Bill 1876 by adding end-stage renal disease facilities to the list of health facilities prioritized during system restoration following an extended power outage.

Texas Electricity Supply Chain Security and Mapping Committee

As part of Senate Bill 3, the Legislature created the Texas Electricity Supply Chain Security and Mapping Committee (the Mapping Committee). The Mapping Committee is composed of representatives from the PUC, RRC, TDEM and ERCOT. Among other things, the Mapping Committee is charged with mapping the electricity supply chain in Texas and identifying the critical infrastructure sources in the electricity supply chain.

Beginning in August 2021, the Mapping Committee met monthly. The Mapping Committee established various teams composed of staff members from the PUC, RRC and ERCOT to compile the data for the supply chain map. The primary Mapping Committee teams included critical facilities, database, mapping, and weatherization.

On April 29, 2022—more than four months ahead of its statutory deadline—the Mapping Committee adopted the initial electricity supply chain map of critical infrastructure for use during disaster and emergency preparedness and response. To create the map, the various agencies complied an enormous amount of critical information and related data in a geographic information system database, which is readily available to state emergency officials during a disaster or emergency weather event.

The map identifies critical infrastructure facilities that make up the state's electricity supply chain, including electric generation plants and the natural gas facilities that supply fuel to power the plants. State emergency management officials will use the map during weather emergencies and disasters to pinpoint the location of critical electric and natural gas facilities and emergency contact information for those facilities.

The current map has more than 65,000 facilities, including electricity generation plants powered by natural gas, electrical substations, natural gas processing plants, underground gas storage facilities, oil and gas well leases, and saltwater disposal wells, as well as more than 21,000 miles of gas transmission pipelines and about 60,000 miles of power transmission lines.

In addition to infrastructure layers, the electricity supply chain map includes elements such as TDEM regions, and emergency contact information for facilities, as well as visualization of weather watches and warnings as they occur in any part of the state. The map will be updated twice a year or more often if necessary.

Emergency Operations Plans

Senate Bill 3 also directed the PUC to review and analyze the emergency operations plans (EOPs) of electric market participants and to biannually submit a comprehensive report on the electric industry's weather preparedness to the Legislature.

In February 2022, the PUC adopted new 16 TAC § 25.53, Electric Service Emergency Operations Plans, that substantially revised and replaced the PUC's prior rule relating to EOPs. The new rule applies to all electric utilities, TDUs, PGCs, MOUs, electric cooperatives, retail electric providers (REPs), and ERCOT. It requires these entities to develop EOPs that cover a broad range of topics, including manual load shed procedures and communications, extreme weather preparedness, maintenance of critical supplies, staffing, pandemic and epidemic preparedness, and cyber and physical security. Each entity's highest-ranking officer or representative must attest to the plans, and the plans must include information regarding annual training and drills.

On April 15, 2022, all electric utilities, TDUs, PGCs, electric cooperatives, and REPs were required to make their EOP submissions to the PUC and ERCOT. On June 1, 2022, MOUs were required to submit their redacted and unredacted EOP copies and executive summaries.[32] The PUC has received nearly 700 EOP filings to date.

For each subsequent year, beginning in 2023, an entity must make an annual submission to the PUC including any changes to its EOP that materially affect how the entity responds to an emergency, or provide an updated attestation from the entity's highest-ranking representative, official, or officer.

Every entity must conduct or participate in at least one drill each calendar year to test its EOP. Following an annual drill, the entity must assess the effectiveness of its emergency response and revise its EOP as needed.

Power Outage Alert Criteria

Senate Bill 3 amended the Texas Government Code to create a new Power Outage Alert system. Implementation required coordination between TxDOT, TDEM, the Governor's office, and the PUC to develop a new public alert system to be activated when power supply may be inadequate to meet demand.

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[32] Additional time was given for municipally owned utilities to make their submission, as these entities had not previously been subject to a PUC rule relating to their emergency operations plans.

In May 2022, the PUC approved new 16 TAC § 25.57 that implements criteria for the content, activation, and termination of regional and statewide power outage alerts. The rule applies to TSPs in ERCOT and TSPs operating in power regions in Texas other than ERCOT. The rule requires ERCOT to notify the PUC executive director when ERCOT’s forecasts indicate system-wide generation supply is likely to be insufficient to meet demand within the next 48 hours or if ERCOT issues system-wide load shed instructions. ERCOT also must notify the executive director when system-wide load shed instructions have been recalled or when, in ERCOT's judgment, there are material changes in ERCOT’s forecasts.

The executive director is responsible for determining whether to recommend the issuance of a power outage alert and what information should be included in the alert.

The rule requires a TSP operating outside of ERCOT to notify the executive director when it has received system-wide load shed instructions from the applicable reliability coordinator. The TSP must notify the executive director when the applicable reliability coordinator has recalled the system-wide load shed instructions. The TSP’s notice must include a summary of any available information regarding power outages and the expectation for power restoration within its service territory.

When known and as applicable, the power outage alert must provide the following information or instructions on how to obtain the following information:

- Whether system-wide load shed is occurring or expected to occur imminently;
- A statement that an electricity customer may experience a power outage;
- Where an electricity customer can seek assistance while the electricity customer’s power may be out; and
- Any other information deemed relevant and of assistance to electricity customers.

Senate Bill 3 Implementation: RRC

As discussed further above, Senate Bill 3 required the RRC to collaborate with the PUC to adopt rules to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in Texas as critical customers or critical gas suppliers during energy emergencies. In November 2021, both the PUC and the RRC adopted their respective rules. The RRC rule, 16 TAC § 3.65, identifies a general class of natural gas supply chain facilities that are deemed critical during an energy emergency. These facilities include certain wells, processing plants, pipelines, storage facilities and saltwater disposal facilities. The rule allows for some operators to seek an exception from critical designation if they are not prepared to operate during an emergency. This exception process is not available to facilities that are identified on the electricity supply chain map. Operators must file a form with the RRC identifying details about each designated facility and must provide critical customer information to its electric utility provider. The first form submittal deadline was January 15, 2022, and the form must be refiled twice a year on March 1 and September 1.

Senate Bill 3 also requires the RRC to adopt a rule within six months after the Mapping Committee publishes the electricity supply chain map that will require gas supply chain facilities to implement measures to be able to operate during weather emergencies if the gas supply chain facility is designated as critical and is included on the electricity supply chain map. This provision requires the RRC to inspect gas supply chain facilities for compliance with the weatherization standards adopted by the RRC. As noted above, the first map was published in April 2022, and the RRC has initiated rulemaking efforts on this issue.

Similarly, the RRC also is required to adopt rules requiring gas pipeline facility operators to adopt measures to maintain service quality and reliability during extreme weather emergencies if the gas pipeline facility directly serves a natural gas electric generating facility supplying power in ERCOT or in ERCOT and an adjacent power region and is included in the electricity supply chain map. The RRC also is required to inspect gas pipeline facilities for compliance with the standards adopted by the RRC. Draft rules currently are pending for review and comment.

Finally, the RRC is also required under Senate Bill 3 to analyze the emergency preparedness reports created by operators of facilities that produce, treat, process, pressurize, store, or transport natural gas and that are included in the electricity supply chain map. The RRC is required to submit a biennial report to the Legislature based on its analysis. Operators of gas facilities included on the map received letters from the RRC in May 2022 alerting them to the deadline to submit an EOP by August 1, 2022. The RRC held a webinar on June 29 to discuss the required submittal.

Other Legislative Implementation Activities

Beyond the reforms included as part of Senate Bill 3, the Legislature took additional steps to protect electric consumers. House Bill 16, relating to the regulation of certain retail electric products, prohibits an aggregator, broker, or REP from offering a wholesale-indexed product to a residential or small commercial customer. A wholesale-indexed product may be offered to a nonresidential or small commercial customer only if the aggregator, broker, or REP obtains before the customer's enrollment a specific acknowledgment signed by the customer that the customer accepts the potential price risks associated with a wholesale indexed product. The Governor signed this bill on May 26, 2021, and it was effective September 1, 2021. The PUC opened Project No. 51830, Review of Wholesale-Indexed Products for Compliance with Customer Protection Rules for Retail Electric Service, to implement this legislation, and its final rule was issued December 16, 2021.

Section Three:
ELECTRIC AND GAS MARKET BARRIERS

Electric/Gas Coordination

The common refrain from nearly all regulators, investigators, market participants, and industry observers in the aftermath of Winter Storm Uri is that the lack of coordination between the electric and natural gas industries in Texas significantly worsened the impacts of the storm for electric consumers.[33] In many cases, electric service providers had limited awareness of what critical natural gas infrastructure existed within their service areas. Both ERCOT and the electric generators that rely on natural gas to fuel their plants had little to no visibility into the status of the natural gas supply chain, including whether the facilities that serve electric generation were operational or even capable of performing under winter weather conditions. Communication between agency leadership at the PUC and RRC before and during Winter Storm Uri was inconsistent and ad hoc.

The creation of the Texas Electricity Supply Chain Security and Mapping Committee is a meaningful reform to come out of Senate Bill 3. Pursuant to the Legislature's directive, the Mapping Committee was given a deadline of September 1, 2022, to create the initial map of the natural gas supply chain serving electric generation. The PUC already has had occasion in a real-world operational scenario to use an early draft of the map, even before it was finalized, to assist in communication and coordination during severe winter weather in February 2022.

Due to the great efforts by the staffs of the PUC, RRC, TDEM, and ERCOT, the first map was completed and issued in April 2022, several months ahead of the statutory deadline. This milestone initiated the six-month deadline for the RRC to complete its rulemaking process for requiring weatherization of natural gas infrastructure identified on the supply chain map. By accelerating the release of the initial supply chain map, the RRC's winterization rules can now be adopted in time for the 2022-2023 winter season.

To date, the RRC has published draft rules on weatherization for critical natural gas facilities. These rules are expected to be finalized before the end of 2022. As proposed, the rules would

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[33] *See, e.g.*, House Bill 3648 (87th R.S.) Committee Report (finding "better coordination between natural gas and electric providers is essential" to prevent the same problems experienced during Winter Storm Uri in the future); *Critical Natural Gas Facilities and Entities*, PUC Project No. 52345, Order Adopting Amendments to §25.52 as Approved at the November 30, 2021 Work Session ("These amendments also implement new PURA §38.074, added by House Bill (HB) 3648 and SB 3, as part of a joint effort with the Railroad Commission of Texas (RRC) to increase the coordination between the electric and gas industries during energy emergencies."); FERC/NERC Report at 67-68 (discussing lack of coordination between natural gas infrastructure facilities and electric power providers).

require operators by December 1 of each year to weatherize to ensure sustained operations during weather emergencies and to address any problems that may have occurred in the past. The RRC has created a new Critical Infrastructure Division with inspectors in regions across the state who will be conducting inspections once the weatherization rules are adopted. As with electric generation and transmission facilities under the jurisdiction of the PUC's weatherization rule, Senate Bill 3 authorizes fines up to $1 million per violation for operators of critical natural gas facilities who do not comply with these rules.

The RRC took proactive steps this past winter even before its winterization rules were in place. Beginning in October 2021, RRC staff conducted winter weather preparedness site visits at natural gas facilities to observe firsthand the weatherization techniques that are being implemented. Weatherization measures include wind barriers or thermal insulation for equipment. The site visits covered about 22,000 wells and all 37 underground storage facilities in the state.

In addition to creating the Texas Electricity Supply Chain Security and Mapping Committee, the Legislature also mandated PUC and RRC collaboration in determining the rules for designating natural gas infrastructure to be "critical" and therefore prioritized for service by electric utilities during times of manual load shed. Both agencies completed their rulemaking activities in the fall of 2021. The RRC's new rule (16 TAC §3.65) establishes a process for designating certain natural gas entities as critical during an energy emergency. Under the rule, natural gas operators submit designations to their electric service provider for their facilities to be considered critical during energy emergencies on March 1 and September 1 of each year. Similarly, the PUC's updated rule (16 TAC § 25.52) requires each electric utility, TDU, MOU, and electric cooperative that serves a critical natural gas facility to timely process requests for critical designation and incorporate all critical natural gas facilities into the utility's load-shed and restoration planning.

Another significant legislative effort was the creation of the TERC. Under Senate Bill 3, the TERC was established to ensure that the natural gas and electric industries in Texas meet high-priority human needs, address critical infrastructure concerns, and enhance coordination and communication. The membership of TERC represents the broad range of stakeholders whose work is impacted by these important issues. In addition to its state agency leadership, which involves TDEM, RRC, PUC, OPUC, TCEQ, Texas Transportation Commission, and ERCOT, the TERC includes representatives who participate in the natural gas supply chain, all market sectors of the electric industry, and representatives of industrial concerns. By November 1 of this year (and subsequent even-numbered years), the TERC will submit a report to the Legislature on the reliability and stability of the electric supply chain in Texas. This report will include recommendations on methods to strengthen the electricity supply chain in this state and to decrease the frequency of extended power outages caused by a disaster in Texas. For security reasons, the meetings and work of the TERC have not been made public.

The committee members are encouraged by the substantial progress that the PUC and the RRC already have made to address failures during Winter Storm Uri relating to electric-gas coordination issues. Regarding next steps, the committee recommends that the PUC and RRC continue to collaborate and begin to synthesize the substantial information that has been gathered regarding all the critical infrastructure and critical loads operating on the ERCOT system. The committee notes that, in addition to standardizing the criteria for critical natural gas loads, Senate Bill 3 also introduced a critical designation for water supply and water utility-related infrastructure. Ultimately, a more comprehensive effort by the Legislature to develop prioritization standards for electric service, restoration, and customer back-up power requirements for all types of critical electric customers may be needed.

Equally important will be the RRC's completion of its weatherization rules for critical natural gas facilities. The committee is encouraged by the progress that RRC staff, working in coordination with the PUC and ERCOT, have made to complete the first map of natural gas infrastructure critical to the electric supply chain. However, unless and until all the natural gas infrastructure that is critical to supporting electric generation in Texas is identified, mapped, and made subject to mandatory weatherization and inspection requirements, the Legislature's core electric/gas reform will not be realized.

Firm Fuel Supply and Storage

Going beyond improving coordination, the PUC also has taken concrete steps to improve the operational posture of ERCOT during extreme cold weather events with the development of the FFSS. Designed to bolster fuel resiliency, FFSS will be procured beginning this 2022-2023 winter season and expanded in future years. The initial procurement will be 3,000 to 4,000 MW. Resources eligible for the initial procurement will be those with dual fuel capability and onsite fuel storage, or those that own and control transport to an off-site natural gas storage facility. The PUC has discussed that other eligible resource types, including those with firm fuel transport and off-site storage contracts, may be considered as the program evolves in the future.

The PUC, RRC, and other agencies have done considerable work to reduce barriers to efficient and reliable market outcomes. Yet some members of this committee continue to question how Texas can ensure that the supply chain for natural gas-fired generation will perform during the next freeze. The committee heard testimony that Texas natural gas producers are leading the country in production growth due to the robust investment in infrastructure—including more than 400,000 miles of intrastate pipelines. However, the committee believes that more emphasis should be placed on firming Texas' fuel supply for its natural gas-fired generation fleet and supports the PUC's work in expanding the FFSS program.

Much of the testimony the committee heard points to the fact that natural gas storage can play a larger role. As Ms. Beth Garza (R Street Institute) testified, one potential solution would be to create a strategic reserve of natural gas storage dedicated for electricity. The electricity industry could invest in some amount of natural gas storage that could be used and held for extreme winter events. Mr. Ryan White (Kinder Morgan/Texas Intrastate Pipelines) testified that natural gas storage must fill the gap when supply is not available. At the same time, while storage is very important, it does not matter how much gas is in the ground if the gas cannot be extracted, so being able to expand the injection and withdrawal capabilities of gas storage facilities is critical. As Mr. White testified, both prospects are very expensive.

The committee supports the RRC's determination that underground storage facilities cannot be exempt from the weatherization rules and encourages the RRC to maintain this posture for any natural gas storage facilities that serve electric generation. The committee also supports the PUC and RRC looking at market-based programs and policies to further incentivize natural gas storage solutions, including those that focus on optimizing storage injection and withdrawal capabilities.

Section Four:
ELECTRIC SERVICE RELIABILITY, STABILITY, AND AFFORDABILITY

ERCOT's Changing Resource Mix

As described by a number of different witnesses, the increase of intermittent renewable resources in ERCOT has provided the benefit of additional capacity and low-cost energy, while also introducing new operational challenges.

Specifically, as Mr. Sam Newell (The Brattle Group) testified, a fleet with large amounts of wind and solar is more difficult for ERCOT to maintain from an operational reliability standpoint, as demand and supply swing unpredictably. Due to the influx of intermittent renewables, ERCOT now experiences a steeper and less predictable load ramp. As discussed more in the next section on ERCOT's conservative operations, the variable nature of intermittent resources introduces more uncertainty in intra-hour and hourly net load forecasts that ERCOT uses. In addition, with the increase of intermittent renewable resources in West and Far West Texas, ERCOT is increasingly limiting the flows across certain network paths to maintain system stability. This reliability action increases transmission congestion costs. According to the IMM's 2021 State of the Market Report, the congestion rent associated with these stability constraints increased from $190 million in 2020 to $400 million in 2021.[34] Finally, because renewable resources do not contribute inertia to the grid, ERCOT faces a greater risk that a major grid disturbance will cause the grid to cascade into a blackout condition as inverter-based resources proliferate across the system.

In the view of this committee, these issues clearly point to the need for ERCOT to have sufficient dispatchable generation to back up intermittent renewable resources. As Mr. Clif Lange (South Texas Electric Cooperative or STEC) noted, ensuring that adequate generation is available during times of low non-dispatchable output is a key directive from the Legislature and the Governor. Ms. Katie Coleman (Texas Industrial Energy Consumers) agreed that the role of dispatchable generation is transitioning to increasingly serve as a back-up for intermittent generation. Mr. Bob Helton (ENGIE North America) testified that the solar industry is beginning to respond to this signal by developing new solar facilities paired with storage to "firm up" the intermittent solar generation.

While there is general consensus on the need for dispatchable generation and the vital role it plays in serving the net load that goes unserved by renewables, policymakers must decide how much dispatchable generation is needed and how to appropriately incentivize that level of dispatchable

[34] 2021 SOM Report at 2, 62.

capacity. When asked about determining the quantity, Ms. Julia Harvey (Texas Electric Cooperatives) testified that this quantity could be tied to a specific reliability metric, such as an event-based standard or a duration-based standard built or planned around a certain duration of an outage. Other considerations might include the amount of dispatchable generation during the net peak period and how much variable generation needs to be supported by dispatchable generation. Ms. Coleman stated that she opposes adopting a metric to ensure a level of dispatchable generation to meet "absolute" peak demand in ERCOT.

The committee supports the PUC continuing its work with its independent consultant to evaluate these questions and deliver a report on the expected reliability outcomes associated with different levels of dispatchable generation under a range of sensitivities. The committee also encourages the PUC and ERCOT to continue studying operational needs as the new ERCOT contingency reserve ancillary service is developed and becomes operational.

Conservative Operations

One of the most consistently noted issues affecting the reliability, stability, and affordability of electric service is ERCOT's post-Winter Storm Uri "conservative" operating posture. As explained by Ms. Carrie Bivens, the ERCOT IMM, ERCOT changed its operational posture approaching summer 2021 by significantly increasing reserves during all hours of the day. The specific changes Ms. Bivens pointed to include (1) increasing the procurement of Non-Spin; (2) more routine use of RUC, including issuing RUC instructions earlier in the operating day and committing more longer-lead time resources; and (3) adjusting the selection of forecasts to more frequently rely on the highest load forecast and the lowest wind and solar forecasts.

The committee heard extensive testimony about the effects of ERCOT's conservative operations. Ms. Bivens explained how this has caused inefficient pricing, where market prices have become disconnected from ERCOT's underlying operating conditions. These statements were echoed by several other witnesses. For example, Ms. Amanda Frazier (Vistra Corp.) testified that conservative grid operations are placing downward pressure on prices for dispatchable generators, because maintaining 6,500 MW of operating reserves in every hour suppresses prices and reduces the opportunity to have scarcity pricing above a marginal generator's fuel costs. From a reliability standpoint, the increased use of RUC increases the wear and tear on dispatchable units and, in some cases, prevents those units from offering their full cost into the market. Ms. Frazier also described the changes that the PUC has ordered to the deployment of ERS as part of the overall "conservative" approach, and explained that by having the program deployed before emergency conditions, that demand response cuts in front of generators that otherwise would be available to come online. As a result, the opportunity for market prices to reflect the need for more dispatchable generation is reduced. All of these factors point to the same problem: If the energy-only market does not produce sufficient energy revenues for power plants to recover their costs, they will not be economically viable and may be forced to retire, and new generation resources that replace them may not have equivalent dispatch capability.

While Mr. Ögelman, testifying for ERCOT, recognized that these types of out-of-market conservative operations can "undermine" the energy-only market, he and Mr. Woody Rickerson testified that ERCOT nevertheless intends to continue operating in this conservative posture. The committee is persuaded by the overwhelming testimony that if ERCOT's current conservative operating posture persists, then a shift in the market construct is needed to address the misalignment between market outcomes and reliability. While there is a diversity of views on the specific parameters of the solution, there appears to be broad support for some form of a construct to address the uncertainty that ERCOT presently is addressing through costly out-of-market reliability actions.

Proposed Environmental Regulations

The committee heard extensive testimony regarding the new Federal Implementation Plan (FIP) for the 2015 Ozone National Ambient Air Quality Standards (NAAQS) proposed by the U.S. Environmental Protection Agency (EPA).

According to Ms. Tonya Baer (TCEQ), the EPA has issued a proposed FIP to address transported ozone forming emissions. This proposed rule has the potential to impact Texas in several significant ways. First, for the 2023 ozone season, EPA's proposed rule includes an updated and expanded regional allowance trading program, including daily nitrogen oxides (NOx) emission limits for large coal generation units with a capacity of more than 100 MW. Units emitting more than these daily rates would be subject to increased allowance surrender requirements under the plan.

Ms. Baer also stated that, starting in 2023, new lower ozone season NOx emission budgets would be established, which would be adjusted dynamically each ozone season starting in 2025 to reflect changes in generation fleet composition. By 2026, these emission budgets will be about 44 percent lower than actual electric generating unit emissions in 2021. Also, starting in 2026, new NOx emission limits for other industries would apply, and Texas would be one of 23 states subject to these limits. The EPA anticipates that most of the affected units in all industries would have to install new equipment to reduce NOx emissions.

TCEQ worked with the PUC and ERCOT to quantify the potential impact to the existing generation fleet, and they reported in their comments that more than 10,000 MW of generation would be at risk of ceasing operations under the EPA's proposal. According to information ERCOT submitted to the EPA, the reliability risks to the ERCOT grid associated with that level of dispatchable generation retirements would be extremely impactful. ERCOT's immediately evident concerns include:

- The increase in probability that ERCOT will need to direct utilities to shed firm load (i.e., to disconnect customers from the grid) to ensure the reliability of the remaining electric system;
- The reduced availability of outages for the remaining thermal generation fleet (to perform essential maintenance);
- The reduction in system inertia (due to the high degree of inverter-based resources on the system); and
- The impact on transmission flows and associated reliability problems.[35]

ERCOT also would need to evaluate the reliability impacts of reduced output and possible retirements that could occur before 2026 due to daily restrictions that would occur beginning in 2023; the need for additional consumer-funded ancillary services, including a new service to ensure the system operates with adequate inertia; the impact of outages on consumers that will occur while the needed transmission facilities are being constructed, given the five-year lead time of most transmission projects; and a host of other issues.[36]

The committee shares the concerns from TCEQ, PUC, and ERCOT leadership that this cross-state air pollution rule (CSAPR) and the proposed FIP from the EPA present a serious challenge, potentially eclipsing all the other resource adequacy, market design, and reliability challenges that the state is facing today. Should legal challenges to the EPA's proposed actions prove unsuccessful, the committee anticipates that more dramatic changes to the Texas wholesale market structure may be in order. The committee recommends that the PUC and ERCOT continue to analyze the resource adequacy impacts of the EPA proposals, and that the PUC's market design consultant factor these analyses into its final report to the PUC on phase two market design solutions.

[35] Comments of the Electric Reliability Council of Texas, Inc. (June 21, 2022), *available at* https://www.ercot.com/files/docs/2022/06/21/ERCOT%20Comments%20EPA%20Ozone%20Transport%20FIP.pdf

[36] *Id.*

Section Five:
MARKET STRUCTURE AND PRICING MECHANISMS

Comprehensive Reliability-Focused Market Design

In addition to the narrower solutions tailored to specific operational issues discussed in earlier sections of this report, the committee also received extensive feedback on a holistic market design solution for the ERCOT region that centers on reliability. Specifically, the committee heard testimony introducing and debating the merits of the specific proposals that collectively are referred to as the phase two market design proposals—including a load-side reliability mechanism (either a load-serving entity [LSE] obligation or a dispatchable energy credit [DEC] program), a backstop reliability service, and the reliability service proposal from STEC. Outside of the phase two solutions, the IMM introduced a new uncertainty product intended to increase the flexibility of the system. This new product would be a two-hour to four-hour ancillary service to address the uncertainty that ERCOT faces around load forecast or renewable forecast or thermal outages.

Common to all of these proposals is the recognition that the current energy-only market has not resulted in an acceptable level of reliability for Texans.[37] And while each type of solution takes a different approach to managing the uncertainty that ERCOT currently is addressing through its conservative operating posture, the committee believes that all solutions share the goal of managing that uncertainty through a market-based approach.

In addition, there appears to be broad support for the PUC to define a reliability metric for ERCOT. As Ms. Harvey testified, establishing a clear reliability standard or objective for the reforms would help organize and synthesize the efforts that the PUC and ERCOT have been pursuing. Mr. Lange explained that the STEC proposal begins with establishing a defined reserve margin as a benchmark precisely to see whether the reliability objectives are being met, and also to allow an opportunity to set a minimum target to prevent prolonged rotating outages. Ms. Coleman also expressed support for establishing a reliability standard, but emphasized that it should focus on performance in real-time or on a day-ahead basis, as opposed to defining an installed capacity metric.

[37] Note, however, that the committee is not endorsing a view that the failures during Winter Storm Uri were necessarily a failure of the energy-only market.

Finally, the committee also heard overwhelming support for the need for regulatory certainty, as nearly every witness provided testimony supporting this goal. Regulatory certainty is required in order to incentivize not only adequate generation supply, but also industrial investment and economic development.

In light of that, the committee recommends that the PUC expeditiously complete its phase two review and bring forward an analysis of the proposed costs and benefits of the alternatives under consideration. This review also should identify how each proposal addresses the disconnect that exists today with ERCOT's conservative, out-of-market actions. Fundamentally, there should exist the opportunity for market-based, rather than administrative, responses to the identified reliability goal, which will reduce costs for consumers and drive innovation.

Wholesale Market Pricing Mechanisms

Substantial progress has been made toward implementing Senate Bill 3, but the PUC has yet to implement the full scope of the emergency pricing program required under section 39.160 of the Public Utility Regulatory Act.

Under that new section, the PUC must adopt rules establishing an emergency pricing program that takes effect "if the high system-wide offer cap has been in effect for 12 hours in a 24-hour period after initially reaching the high system-wide offer cap."[38] Once triggered, the emergency pricing program will cease pursuant to criteria to be determined by the PUC.[39] The emergency pricing program "may not allow an emergency pricing program cap to exceed any nonemergency high system-wide offer cap."[40] In addition, the PUC must adopt rules establishing an ancillary services cap to be in effect during the period an emergency pricing program is in effect.[41] "The emergency pricing program must allow generators to be reimbursed for reasonable, verifiable operating costs that exceed the emergency cap."[42]

This last provision of Senate Bill 3 is particularly important, as it expresses the Legislature's expectation that when generators are operating to support reliability during an extreme event like Winter Storm Uri, they should not be required to lose money.

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[38] Tex. Util. Code § 39.160.

[39] *Id.*

[40] *Id.*

[41] *Id.*

[42] *Id.*

Despite having updated some of its wholesale pricing rules, the PUC has not yet initiated an effort to implement this aspect of Senate Bill 3, nor does its most recently published rulemaking planner indicate that this rulemaking is imminent.[43] The committee recommends that the PUC open and expeditiously complete a rulemaking project to fulfill the Legislature's directive to establish an emergency pricing program that complies with section 39.160 of the Public Utility Regulatory Act.

Ancillary Service Enhancements

Senate Bill 3 added a new charge to the Public Utility Regulatory Act, requiring the PUC to:

(1) 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; and

(2) Evaluate whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation.[44]

Further, the PUC "shall 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."[45]

The committee observes that some of this work has been performed, as it relates to components of the PUC's final blueprint for wholesale market design and directives to ERCOT. The committee recommends that the PUC complete the market design blueprint activities that relate to ancillary service enhancements. Specifically, the committee urges the PUC and ERCOT to prioritize developing voltage support service—a new ancillary service that the PUC already has determined is needed for reliability. The PUC should continue to monitor ERCOT's progress in implementing the new ancillary services that already are in flight, including FFR and ECRS. Finally, the committee recommends that the PUC and ERCOT begin work to expand FFSS eligibility to include resources with firm natural gas transport to off-site natural gas storage, which will increase the number of qualified resources and lower costs for consumers.

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[43] PUC Project No. 52935, CY 2022 Rulemaking Calendar (July 13, 2022).

[44] Tex. Util. Code § 35.004(g).

[45] *Id.* § 35.004(h).

Demand-side Solutions and Distributed Energy Resources

As Ms. Garza testified, ERCOT is facing new challenges where demand, like supply, is becoming more variable as distributed energy resources proliferate. Although ERCOT has made some progress to increase its operational awareness and coordination of demand response and distribution-connected resources, the committee observes that there is still work to be done. Both Mr. Michael McNamara (Lancium) and Mr. James McGinniss (David Energy) testified about the opportunities that their respective companies' business models provide for increasing operational flexibility by offering more tools to ensure reliability. Their testimony illustrated the gap that still exists in syncing up market policies and operating procedures to these new types of technologies. For example, understanding the proportion of the customer base that is price-responsive versus price-agnostic will be increasingly important, especially as it pertains to new types of large loads, such as cryptocurrency mining and data centers. Even on a much smaller scale, understanding the financial incentives for residential and small commercial customers to manage their electricity usage will help drive better policy outcomes.

As Mr. Jason Ryan (CenterPoint Energy) testified, it is also important to keep in mind that utility infrastructure will need to accommodate how customers increasingly want to deploy new capabilities like distributed generation and battery walls. The committee supports further integrating distributed energy resources into the ERCOT market in a manner that maintains the integrity of the transmission and distribution grids and still meets utility service providers' statutory obligation to maintain reliability and cost effectively serve all customers. The committee recommends that the PUC and ERCOT continue to facilitate an open dialogue between all stakeholders that will lead to new solutions that support the needs of this state, as they have been doing with recent initiatives like the ERCOT Large Flexible Load Task Force and the PUC's pilot program for aggregated distributed energy resources.

Section Six:

FINDINGS AND RECOMMENDATIONS

As the Legislature has repeatedly emphasized, maintaining a reliable, affordable supply of electricity for all Texans is essential to our state's continued economic prosperity. The Legislature's passage of Senate Bill 3, the watershed legislation enacted in response to Winter Storm Uri, has dramatically improved the state's ability to prepare for, prevent, and respond to weather emergencies that impact essential services. It also will ensure that Texans are better protected if future energy emergencies occur. The committee members have observed the implementation process in action for over a year and find that the provisions of Senate Bill 3 supply a strong framework for improving grid reliability and market outcomes in ERCOT. It is within that framework that the committee provides the following recommendations that collectively form the comprehensive state energy plan:

Electric and Gas Market Barriers

- The PUC and RRC should continue to work collaboratively to assess the totality of the data that has been gathered regarding all the critical infrastructure and critical loads operating on the ERCOT system and work with the Legislature to facilitate access to the information by the appropriate critical infrastructure electric utility for increased operational and planning effectiveness.
- The RRC should expeditiously continue to finalize its weatherization rules to ensure that all the critical gas infrastructure included on the electricity supply chain map in the state is subject to mandatory weatherization and inspection requirements.
- The PUC and RRC, with oversight by the Legislature, should work to develop a comprehensive set of prioritization standards for the provision of natural gas to electric generation and electric service to critical loads.
- The PUC and RRC should work to minimize the number of unnecessary natural gas production facilities designated as critical and consider re-instating non-critical loads and/or seasonally non-critical loads in the ERCOT Load Resource program.
- The PUC should undertake the planned expansion of its firm fuel supply service to include additional resources with proven firm fuel capabilities.
- The Legislature should study methods to further incentivize natural gas storage solutions.

Electric Service Reliability, Stability, and Affordability

- The key reliability issue facing ERCOT will be to ensure adequate dispatchable generation is available during times of low non-dispatchable output.
- The PUC should define a clear reliability metric or standard for the ERCOT region. The committee believes this is a necessary first step in evaluating the efficacy of the proposals under consideration and "right-sizing" any programs designed to improve reliability in ERCOT.
- To address ERCOT's changing resource mix, the PUC should continue its work with its independent consultant to evaluate expected improvements to system reliability associated with various market design proposals under a range of sensitivities.
- The PUC should evaluate the need to increase transmission pathways for generation availability and create system resiliency by planning for the transmission and distribution grids further into the future. This will ensure that our infrastructure is ready to meet the needs of Texas' economy.
- The PUC and ERCOT should continue studying the system's operational needs as the new ERCOT contingency reserve ancillary service is developed and becomes operational.
- As part of a long-term reliability solution, a shift in the market construct is needed to address the current challenges in maintaining reliability. While there is a diversity of views on the specific parameters of the solution, the committee finds broad support for favoring competitive solutions to manage the uncertainty that ERCOT presently is addressing through out-of-market reliability actions.
- The PUC and ERCOT should analyze the resource adequacy impacts of the proposed EPA regulations, and the PUC's market design consultant should factor these analyses into its review and final recommendations.
- Transmission line planning and construction timelines often serve as a bottleneck; these processes, requirements, and timelines should be re-evaluated.

Market Structure and Pricing Mechanisms

- In order to provide regulatory certainty to the market, the PUC should expeditiously complete its phase two review and bring forward an analysis of the proposed costs and benefits of the proposals under consideration. This review also should identify how each proposal comprehensively addresses the reliability standard and disconnect that exists today with ERCOT's conservative, out-of-market actions.
- The PUC should initiate and timely implement a rulemaking project to fulfill the Legislature's directive to establish an emergency pricing program that complies with

section 39.160 of the Public Utility Regulatory Act.

- The PUC should complete the market design blueprint activities that relate to ancillary service enhancements, including development of voltage support service, implementation of FFR and ECRS, and expansion of FFSS to include resources with firm natural gas transport coupled with off-site storage capabilities for natural gas.
- The PUC and ERCOT should continue studying demand response solutions and work to develop a framework to support integration of distributed energy resources in a manner that maintains the integrity of the transmission and distribution grids and supports utility service providers' statutory obligation to maintain reliability and cost effectively serve all customers.
- Require intermittent generation sources to firm their deliveries with other dispatchable generation technologies.
- The committee does not support a market design that favors new or subsidized generation over existing resources, as doing so could create regulatory inefficiencies and raise capital costs for Texas ratepayers.

Appendix A:
COMMONLY USED ACRONYMS

4CP	4-Coincident Peak
AS	Ancillary Services
CCN	Certificate of Convenience and Necessity
CDR	Capacity, Demand and Reserves Report for the ERCOT Region
CONE	Cost of New Entry
CRR	Congestion Revenue Rights
DAM	Day-Ahead Market
DC Tie	Direct-Current Tie
DEC	Dispatchable Energy Credit
DER	Distributed Energy Resource
DG	Distributed Generation
EEA	Energy Emergency Alert
ELCC	Effective Load Carrying Capability
EMS	Emergency Management System
ERCOT	Electric Reliability Council of Texas
ECRS	ERCOT Contingency Reserve Service
ERS	Emergency Response Service
ESR	Energy Storage Resource
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FFSS	Firm Fuel Supply Service
FIP	Fuel Index Price
IOU	Investor-Owned Utility
GTC	Generic Transmission Constraint
GW	Gigawatt
HCAP	High System-wide Offer Cap
Hz	Hertz
IMM	Independent Market Monitor
IRR	Intermittent Renewable Resource
LCAP	Low System-wide Offer Cap
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
LSE	Load-Serving Entity
MISO	Midcontinent Independent System Operator

MOU	Municipally Owned Utility
MWh	Megawatt-Hour
MW	Megawatt
MMBtu	1 Million British Thermal Units
NERC	North American Electric Reliability Corporation
NOIE	Non Opt-In Entity
Non-Spin	Non-spinning Reserve Service
ORDC	Operating Reserve Demand Curve
OPUC	Office of Public Utility Counsel
PGC	Power Generation Company
POLR	Provider of Last Resort
PRC	Physical Responsive Capability
PUC	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
QSE	Qualified Scheduling Entity
REP	Retail Electric Provider
RDPA	Real-Time Reliability Deployment Price Adder
RRC	Railroad Commission of Texas
RRS	Responsive Reserve Service
RTC	Real-Time Co-optimization
RTP	ERCOT Regional Transmission Plan
RUC	Reliability Unit Commitment
SARA	Seasonal Assessment of Resource Adequacy for the ERCOT Region
SCED	Security-Constrained Economic Dispatch
SPP	Southwest Power Pool
SWOC	System-wide Offer Cap
TAC	ERCOT Technical Advisory Committee
TCEQ	Texas Commission on Environmental Quality
TDEM	Texas Division of Emergency Management
TDU	Transmission and Distribution Utility
TERC	Texas Energy Reliability Council
TWG	ERCOT Technology Working Group
TSP	Transmission Service Provider
VOLL	Value of Lost Load

Appendix B:

MEETING MINUTES

MINUTES OF MEETING
STATE ENERGY PLAN ADVISORY COMMITTEE
Austin, Texas
June 28, 2022

Pursuant to notice posted in accordance with the Texas Open Meetings Act, the State Energy Plan Advisory Committee (Committee) convened in a meeting at 9:01 a.m. Tuesday, June 28, 2022, in the Board Room of the Hancock Building, at the principal office of the Lower Colorado River Authority, 3700 Lake Austin Blvd., Austin, Travis County, Texas.

The following Committee members were present, constituting a quorum:

Phil Wilson, Chair
Mark Ammerman [via videoconference]
Bill Barnes
Mike Greene
Daniel Hall
Jerome "Joey" Hall
E. Patrick Jenevein III
Castlen Moore Kennedy
Wendy King
Joel Mickey
Julie Caruthers Parsley
Kenneth Stevens

Chair Wilson called the meeting to order at 9:01 a.m. After the roll call, Chair Wilson noted a quorum of the Committee was present.

Chair Wilson made welcoming remarks and thanked everyone in attendance for the first hearing of the State Energy Plan Advisory Committee, which was created by S.B. 3 during the 87th Texas Legislature, Regular Session. Chair Wilson noted that pursuant to S.B. 3, the Committee is tasked with preparing a comprehensive state energy plan report with recommendations to the Legislature by Sept. 1, 2022.

Chair Wilson announced the Committee would receive invited testimony from industry experts, gather information and discuss potential policies to help support the Legislature's and Public Utility Commission of Texas' initiatives related to the Texas power market.

The Committee heard invited testimony from seven panels of industry experts as follows:

Panel I: Weather and Summer Operations Outlook
Bob Rose – Chief Meteorologist, LCRA
Woody Rickerson – Vice President of System Planning and Weatherization, Electric Reliability Council of Texas

Panel II: Regulatory Outlook
Thomas Gleeson – Executive Director, Public Utility Commission of Texas
Kenan Ögelman – Vice President of Commercial Operations, ERCOT
Carrie Bivens – ERCOT Independent Market Monitor, Potomac Economics
Tonya Baer – Director of the Office of Air, Texas Commission on Environmental Quality
Erin Chancellor – Director of the Office of Legal Services, Texas Commission on

Environmental Quality
RJ DeSilva – Communications Director, Railroad Commission of Texas
Krista Duke – Director of Government Affairs, Railroad Commission of Texas

Panel III: Solutions at the Intersection of the Electric and Natural Gas Industries
Todd Staples – President, Texas Oil & Gas Association
Ryan White – Commercial Director, Texas Intrastate Pipelines

Chair Wilson recessed the meeting at 11:39 a.m. and reconvened the meeting at 12:12 p.m. Testimony continued as follows:

Panel IV: Solutions for Resource Adequacy and Dispatchable Generation
Samuel Newell – Principal, The Brattle Group
Amanda Frazier – Senior Vice President of Regulatory Policy, Vistra Corp.
Andrew Novotny – Executive Vice President and Chief Operating Officer, Calpine
Clif Lange – Manager of Wholesale Marketing/Qualified Scheduling Entity, South Texas Electric Cooperative
Bob Helton – Vice President of Government and Regulatory Affairs, ENGIE North America

Panel V: Evaluating the Electric Market Structure and Pricing Mechanisms
Beth Garza – Senior Fellow, R Street
Shelly Botkin – Executive Director, Texas Public Power Association
Julia Harvey – Vice President of Government Relations and Regulatory Affairs, Texas Electric Cooperatives
Katie Coleman – Partner, O’Melveny, Texas Industrial Energy Consumers
Cathy Webking – Partner, Spencer Fane, Texas Energy Association for Marketers

Panel VI: Electric Service Reliability: Transmission and Distribution Solutions
Wayman Smith – Director of Transmission Planning in the ERCOT and Southwest Power Pool regions, American Electric Power
Jason Ryan – Executive Vice President of Regulatory Services and Government Affairs, CenterPoint Energy

Panel VII: Demand-Side Solutions
Michael McNamara – CEO, Lancium
James McGinniss – CEO and Co-Founder, David Energy

Chair Wilson made closing remarks and stated that the next meeting of the Committee would be on Aug. 10, 2022.

There being no further business to come before the Committee, Chair Wilson adjourned the meeting at 4:31 p.m.

MINUTES OF MEETING
STATE ENERGY PLAN ADVISORY COMMITTEE
Austin, Texas
Aug. 10, 2022

Pursuant to notice posted in accordance with the Texas Open Meetings Act, the State Energy Plan Advisory Committee (Committee) convened in a meeting at 9 a.m. Wednesday, Aug. 10, 2022, in the Board Room of the Hancock Building, at the principal office of the Lower Colorado River Authority, 3700 Lake Austin Blvd., Austin, Travis County, Texas.

The following Committee members were present, constituting a quorum:

Phil Wilson, Chair
Mark Ammerman
Bill Barnes
Mike Greene
Daniel Hall
Jerome "Joey" Hall
E. Patrick Jenevein III
Castlen Moore Kennedy [via videoconference]
Wendy King
Joel Mickey
Julie Caruthers Parsley
Kenneth Stevens

Chair Wilson called the meeting to order at 9 a.m. After the roll call, Chair Wilson noted a quorum of the Committee was present.

Chair Wilson made opening remarks and welcomed everyone to the second hearing of the State Energy Plan Advisory Committee.

Chair Wilson stated that an initial draft of a comprehensive state energy plan was compiled since the Committee's first hearing and provided a summary of the draft plan. Committee members were provided with the draft and were asked to provide comments and propose substantive changes to the draft policy recommendations.

Chair Wilson outlined the meeting agenda, including the approval of previous meeting minutes, testimony from three industry experts, and the process for the Committee to approve proposed policy recommendations to the comprehensive state energy plan that will be submitted to the Legislature pursuant to Senate Bill 3.

Chair Wilson called for approval of the previous meeting minutes, which were provided to the Committee prior to this meeting. Upon motion duly made and seconded, the Committee voted to approve the minutes of its meeting held June 28, 2022, as presented.

The Committee heard testimony from the following industry experts, who also provided testimony at the Committee's first hearing:

Bob Rose, chief meteorologist, Lower Colorado River Authority

Kenan Ögelman, vice president of Commercial Operations, Electric Reliability Council of Texas

Thomas Gleeson, executive director, Public Utility Commission of Texas

Chair Wilson gave an overview of the draft plan, and the Committee discussed and deliberated each of the draft policy recommendations and the substantive changes proposed by Committee members. The Committee reached consensus to include 20 policy recommendations in the final plan.

The Committee next considered and voted to approve, by a record vote of 7 to 5, the comprehensive state energy plan report with recommendations to the Legislature pursuant to S.B. 3.

Chair Wilson made closing remarks.

There being no further business to come before the Committee, Chair Wilson adjourned the meeting at 11:08 a.m.

Appendix C:

SUMMARY OF TESTIMONY

June 28, 2022, Austin, Texas

Bob Rose – Chief Meteorologist, LCRA

Mr. Rose provided a summer weather outlook for Texas. May 2022 (which averaged 5.5 degrees warmer than normal for the state) was the second-hottest May on record for Texas, while many Texas cities (including Austin, San Antonio, and Abilene) reported May as the hottest May on record. June 2022 is on track to be one of the hottest Junes on record. Mr. Rose addressed the lack of precipitation in Texas over the winter and spring, with about 88 percent of the state experiencing severe to exceptional drought conditions as of June 21, 2022. A weak La Niña remains in place and odds favor it persisting through fall, which will contribute to lower-than-average precipitation for Texas. Mr. Rose stated the average heat dome position over the state will continue to plague Texas with hot, dry conditions through the summer. A forecast model temperature outlook was provided for July through September 2022, including:

- A very hot, extreme summer is predicted.
- Statewide temperatures are forecast to average between 3 and 6 degrees above normal.
- Summer temperatures somewhat similar to 2011 will not be out of the question.
- Closest anomaly years: 2011, 2018, 1996 and 1956.
- Below-normal rainfall forecast for most of the state.

Mr. Rose provided an outlook for hurricane season and indicated Atlantic waters are warmer than normal, signaling a high probability (65 percent above normal) for hurricane activity. The National Hurricane Center is predicting: 14-21 named storms, six-10 hurricanes, and three-six major hurricanes.

Woody Rickerson – Vice President of System Planning and Weatherization, ERCOT

Mr. Rickerson testified on ERCOT weatherization and operations. So far this summer, ERCOT is experiencing very hot temperatures and very high loads. In May, ERCOT set an all-time peak load of 71,688 MW and broke the May record five different times during the month. In June, ERCOT set an all-time peak load record and broke that record eight times. Also, in June, ERCOT established an all-time peak load record, breaking the previous peak from August 2019. ERCOT's tightest day (i.e., the day ERCOT had the least amount of reserves – 3,000 MW) this summer came on a day when more than 3,000 MW of thermal generation had been forced out. That unexpected outage resulted in ERCOT's tightest day, which was less than 3,000 MW of reserves on the system.

Mr. Rickerson defined peak net load, explaining it as the overall load minus what is served by wind and solar. Net load is what dispatchable generation (e.g., nuclear, gas, coal, hydro) must cover. Net load on average for 2022 has been about 53,000 MW on peak. So, assuming an all-time peak load of 77,000 MW, 53,000 MW is the net load average. However, during these hot summer days, ERCOT has seen net load of about 62,000 MW, meaning that about 15,000 MW of load is being covered by wind and solar on most of these peak summer days.

Mr. Rickerson testified that for the remainder of the summer, ERCOT will continue to operate with a very conservative operating posture of bringing reserves online early as it has done for the last couple of years. ERCOT performs a seasonal assessment of resource adequacy (SARA). The SARA report looks at what to expect over the summer and showed the following:

- Peak load of about 78,000 MW.
- High peak load of nearly 80,000 MW.
- Extreme peak load of 81,500 MW.

The reserve margin (the amount of generation above load) for this summer is calculated to be 22.8 percent, which comes out to be about 91,000 MW. Of course, there is more installed capacity than 91,000 MW in ERCOT, but wind and solar are discounted based on an analysis of renewable resources' historical availability. Of the 91,000 MW, about 79 percent is dispatchable generation (coal, gas, nuclear, hydro), 11 percent is wind, and 10 percent is solar. In addition, there are about 2,800 MWh of battery storage on the system.

Thomas Gleeson – Executive Director, Public Utility Commission of Texas

Mr. Gleeson began his remarks by offering additional information on CSAPR. Mr. Gleeson stated that the PUC and ERCOT filed comments in response to the proposed EPA rule on June 21, 2022, and the comments are available on the PUC and ERCOT websites. Mr. Gleeson recommended that the committee members read these comments because the proposed EPA rule is in direct opposition to many of the fundamental tenets that the PUC is trying to accomplish in the ERCOT market redesign.

Mr. Gleeson reported on the PUC's two-phased approach to weatherization for generation resources and transmission substation facilities. Phase one already has been implemented, and it comprises two core elements: (1) generators and TDUs were required to fix any acute failures from Winter Storm Uri; (2) recommendations of FERC in response to the February 2011 severe weather event were codified.

Mr. Gleeson noted that the PUC would like to get phase two adopted in August of this year. Phase two intends to require generators and TDUs to weatherize to a standard looking forward, not backward, and for all new facilities to be built to that capability. The goal is to have the commissioners review and adopt phase two weatherization rules in August, and then ERCOT can begin to inspect facilities based on those new metrics.

Broadly speaking, the PUC has taken a threefold approach to address the reforms mandated by Senate Bill 3, the historic legislation that was passed by the Legislature and signed by the Governor last session. The first reform the PUC enacted was focused on customer protection. This included the PUC's lowering of the HCAP from $9,000 to $5,000 per MWh. Many customers, particularly commercial industrial customers, were charged at that $9,000 per MWh price in their contracts. The PUC also has endeavored to eliminate "Griddy-type" retail electricity plans, which expose residential customers to real-time wholesale market prices.

The second reform effort is to improve grid resilience. In addition to the PUC's two-phased weatherization program, the PUC also undertook an effort to designate critical infrastructure in the state. Mr. Gleeson reported a significant failing during Winter Storm Uri wherein TDUs were shedding load at facilities that were critical to ensuring electricity could be generated. Mr. Gleeson stated that the PUC has seen a significant increase in the number of facilities designated critical because they are an integral part of generating electricity in the state.

Mr. Gleeson reported on the fuel supply mapping efforts. As executive director of the PUC, Mr. Gleeson is the designated chair of the Texas Electricity Supply Chain Security and Mapping Committee. Per Senate Bill 3, the Mapping Committee is required to map the natural gas supply chain serving electric generation no later than September 1 of this year. With the great efforts by the staff of the PUC, RRC, TDEM, and ERCOT, the first iteration of the map was completed in April. One of the most important parts of Senate Bill 3 requires that the RRC then begin its rulemaking process for weatherization of natural gas infrastructure, which must be completed within six months of the issuance of the first map. By accelerating the release of the initial supply chain map, the RRC's winterization rules now must be adopted before this upcoming winter.

The third aspect of reform concerns ERCOT wholesale market redesign. Mr. Gleeson noted that this is similar to the PUC's weatherization approach, as it also is being completed in two phases. The first phase emphasized improving operational reliability. The PUC directed ERCOT to create a firm fuel ancillary service product; reformed ERS; and enhanced the ORDC.

The second phase addresses long-term improvements to incentivize new dispatchable generation in the market. The PUC went through quite an extensive process to take comments on phase two, including multiple public meetings with hours of testimony and thousands of pages of filings in the market redesign docket. Ultimately, that resulted in a blueprint that was adopted by the commissioners in December of last year. The blueprint has two core tenets—a backstop reliability service and a load-side reliability obligation.

Mr. Gleeson discussed that the plan going forward through this year and before the start of the next legislative session is for the PUC's consultant to take input from the commissioners on how to iterate different options for these products to create a Texas-specific market design. The PUC will take public comment and ensure that a turnkey solution is presented to the Legislature and the Governor for their consideration prior to the next legislative session.

In summary, Mr. Gleeson reiterated that since Winter Storm Uri, the PUC and ERCOT's primary focus is reliability, and reliability has to be the core foundation of the phase two market redesign.

In response to questions from committee members, Mr. Gleeson explained that the PUC's stance on the firm fuel product was to quickly implement a new product in time for the upcoming winter and then continue to review and refine it. These further discussions will consider expanded qualifications for the firm fuel product after the initial phase, and the PUC will need to focus on the bridge from having natural gas in storage to ensuring that firm transport contracts are in place to get it where it needs to go.

Mr. Barnes asked Mr. Gleeson for his perspective on how the reliability goals of the ERCOT market have changed following Winter Storm Uri. Mr. Gleeson replied that there can be a tradeoff between cost and reliability. One of the issues the PUC has discussed with the consultant looking at market design is a cost benefit analysis of what the PUC is doing, because policy makers need to know what it will cost. Mr. Gleeson discussed that post-Winter Storm Uri, the Legislature has indicated that the PUC primarily needs to be focused on ensuring reliability.

In response to a question from Ms. Kennedy, Mr. Gleeson noted that the communication between the oil and gas industry, electric generation, RRC, PUC, and ERCOT have improved greatly. The PUC used the supply chain map in February 2022 to communicate efficiently during a winter weather event. Mr. Gleeson stated it would be an improvement to develop a clearing house at ERCOT to have a comprehensive view of what was going on in both the electric and natural gas industries, and those conversations are ongoing at the TERC.

Kenan Ögelman – Vice President of Commercial Operations, ERCOT

Mr. Ögelman opened his remarks with an explanation of how ERCOT operationalizes directives from the PUC. Many of these initiatives have involved ERCOT taking reliability actions sooner or ahead of an emergency action plan or alert. The PUC also has worked with ERCOT to enhance ancillary services. Mr. Ögelman reported that ERCOT is procuring more ancillary services and changing the characteristics of some ancillary services to accommodate the types of resources that exist on the system. ERCOT is procuring more fast frequency response and is trying to change the procurement characteristics to reflect the ability of batteries and load to participate in those programs. ERCOT also has designed the firm fuel service. The initial tranche for the firm fuel product is 3,000 MW. ERCOT will release the system software for that toward the end of this year and issue the first request for proposals in the next few months.

ERCOT also is in the process of deploying a new 10-minute reserve service called the contingency reserve service. Mr. Ögelman reported that since 2011, the mix of resources is different and that the types of characteristics you might look for from ancillary services are consequently different. An emerging challenge is ERCOT's ability to cover peaks from solar ramping offline as the sun sets. Mr. Ögelman discussed voltage support service and noted that ERCOT has made the least amount of progress on this service. Mr. Ögelman confirmed to the committee that ERCOT plans to engage stakeholders in August to kick off the design of this service.

Mr. Ögelman stated that ERCOT stands ready to implement what the PUC ultimately decides and is working to make sure ERCOT has the bandwidth available to complete the system software design and other enhancements that will be needed to implement the market redesign.

Mr. Hall asked Mr. Ögelman whether incentives are in place for a particular fuel source mix versus continuing to see only new investment from renewable resources. Mr. Ögelman stated that ERCOT's approach is to focus on the features that are needed to serve load reliably, and to define the right characteristics around the ancillary services needed to support a fleet that is increasingly intermittent. Dispatchability, as Mr. Rickerson mentioned, is a very important part of that. Mr. Ögelman stated that one of the key challenges at ERCOT is to define those features that we need and then allow the market to provide those services.

In response to a question from Mr. Hall on the 10-minute contingency reserve service, Mr. Ögelman stated that about four years ago, ERCOT looked at what features were needed in the market to provide reliability. One of the things ERCOT identified was the fact that there were steep increases in load at the same time there were decreases in generation, most notably solar. In

California, this scenario has been described as the duck curve. The basic way to envision it is that load is still rising in the evening as people are returning home and increasing their electricity usage, but solar is dropping, so there is a need for a rapid increase in production of electricity. The contingency reserve service is designed to fill that need by having units capable of responding in 10 minutes or less to meet the additional demand. In a follow-up question by Chairman Wilson about what sorts of technologies would qualify to provide this service, Mr. Ögelman stated that batteries, reciprocating engines, combustion turbines, and load response would fill this need today, but what the technology looks like even a year from now is difficult to predict.

In response to a question from Mr. Barnes regarding goals for market design, Mr. Ögelman acknowledged that conservative operations may undermine the energy-only market. The PUC has begun to explore the answer with its phase two examination of how to ensure proper reserves and attract resources to the ERCOT footprint. Those are the items under consideration with the LSE obligation and the DEC. There is also the backstop reliability service and the STEC proposal, which looks like a formal capacity market with some more straightforward price transparency and trading of capacity. If you assume conservative operations to complete the circle, you do have to go back and challenge yourself as to whether the energy-only market can meet its intended goals with that underlying assumption.

In response to a question from Ms. Kennedy, Mr. Ögelman reported that ERCOT is in the process of creating a gas desk, but the data flow is not entirely in their hands. Currently, ERCOT does not have the authority to get information on the gas infrastructure, and that is an ongoing process between the PUC and the RRC. The purpose of an ERCOT gas desk would be to analyze conditions and have an understanding of those markets.

Carrie Bivens – ERCOT Independent Market Monitor, Potomac Economics

Ms. Bivens introduced Potomac Economics as the IMM for the ERCOT region. Ms. Bivens opened her remarks by stating that the ERCOT market is experiencing major changes and evolving needs. This is driven by two primary factors: the changing generation mix and the conservative operating posture that ERCOT has adopted since July 2021. The latter can cause inefficient pricing, where pricing becomes disconnected from the underlying operating conditions. The IMM has several recommendations to accommodate these changes and to ensure that the energy only market can be successful.

First, Ms. Bivens testified that real-time co-optimization of ancillary services and energy should be implemented as soon as possible. Second, she advocated introducing an uncertainty product as an ancillary service to increase the flexibility of the system instead of trying to adapt our current ancillary services to requirements for which they are not well suited. Third, she emphasized the need to address cost allocation issues, particularly transmission cost allocation. Finally, she stated that if the current conservative operating posture persists, then a shift in the market construct is needed to address the misalignment between market outcomes and reliability.

Ms. Bivens discussed the IMM's concerns regarding the phase two blueprint approved by the PUC, beginning with the LSE obligation proposals. The IMM has expressed concerns about market power and about the deliverability of the contracted-for capacity, because it would not be centrally cleared. The value of central procurement is that it makes the buying and selling optimal and would result in efficient pricing. This does not mean that there cannot be an LSE obligation where much of the activity occurs bilaterally, but at the end there is a residual centrally cleared auction with a slope demand curve and a participation requirement for large suppliers that have available capacity. This approach could mitigate some of the market power concerns.

There are several different versions of the LSE obligation proposal. One is what has been called the DEC proposal. The best means to achieve market objectives is to produce price signals that will reflect the overall supply and demand for dispatchable generation in ERCOT. The DEC proposal will very specifically distort those price signals. There is no reason to exclude existing resources from any sort of capacity product that they could provide. The results of the DEC proposal will be the retirement of existing generation.

An even more straightforward approach would be to accredit dispatchable capacity to satisfy some kind of LSE obligation in a way that reflects their relative advantage in maintaining the reliability of the ERCOT system. For example, DECs do not reflect the fact that dispatchable resources with energy limitations provide less reliability than conventional dispatchable generation.

Ms. Bivens also commented on the proposal from STEC, which she described as excluding wind, solar, and energy storage resources from a centrally procured capacity market. Ms. Bivens noted that while the IMM understands that as more of these resources enter the system, their marginal value decreases, in her view it still is preferable to include and appropriately accredit them.

Last, Ms. Bivens discussed a backstop reserve service as a direct way to retain existing resources, but a costly means to improving reliability.

In response to a question from Mr. Greene, Ms. Bivens expanded on the current method of transmission cost allocation, the 4 coincident peak (4CP) method. She explained that when industrial consumers can avoid generating electricity during the four 15-minute intervals (which occur during June, July, August and September) in a single year, they pay zero transmission charges. She explained why this is problematic from a cost-shifting standpoint because it shifts costs on to residential and small commercial entities. Also, from a market efficiency standpoint, it also incentivizes demand response that is not necessarily related to prices. The IMM supports transmission cost allocation based on cost causation. Transmission planning is done for every hour of the year because transmission is not built for four 15-minute intervals of the year.

Mr. Barnes asked whether Ms. Bivens is aware of any “true energy-only markets” currently in existence that rely only on the spot price of electricity. Acknowledging that she is not, Ms. Bivens explained that under a true energy-only market, there would be no payment for the opportunity cost of reserving capacity in order to meet some reliability need, such as loss of a large unit. Regardless, those reliability needs have to be met, and they have to be paid for.

Mr. Barnes asked Ms. Bivens to elaborate on the IMM’s recommendation to develop an uncertainty product. Ms. Bivens discussed that the uncertainty product would be a two-to-four-hour ancillary service to address the capacity uncertainty that ERCOT faces with regards to load forecast or renewable forecast or thermal outages. Ms. Bivens explained that right now ERCOT is using the RUC tool to bring on excess generation, and this is an out of market action that interferes with price formation in real time. Other markets, including the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO), are considering similar products.

Mr. Barnes asked Ms. Bivens to expand on the IMM’s second recommendation to consider adopting a form of capacity procurement that augments the economic signals provided by the energy-only market to ensure adequacy of ERCOT’s resources over the long-term. Ms. Bivens stated she was referring to things like the DEC program, targeting particular resources or even the firm fuel service. Mr. Barnes asked Ms. Bevins to discuss her concerns that the DEC proposal could accelerate retirement of resources that are not receiving those payments and actually exacerbate a reliability concern. Ms. Bivens stated that the DEC proposal will accelerate retirements of existing resources because it is a subsidy for new generation. Their marginal costs are going to be lower, so those resources would offer lower into the market, and their clearing prices would be lower. Resources that are on the margin today would effectively have the decision about whether to retire made for them.

In response to a question from Mr. Mickey, Ms. Bivens responded that Winter Storm Uri was not an energy-only market failure, and a capacity market in any form would not have prevented the issues that we saw. Those are more weatherization issues and other issues that have been addressed through legislation.

Chairman Wilson asked Ms. Bivens to explain what the technology or the product looks like for this new 10-minute uncertainty ancillary services product. Ms. Bivens stated that we need to define the reliability service that ERCOT needs and let the investment come to solve those needs. It will be better to develop a market-based service to do what the RUCs are doing.

Tonya Baer – Director of the Office of Air, Texas Commission on Environmental Quality

Ms. Baer testified regarding legal and technical aspects of the U.S. EPA's new FIP for the 2015 NAAQS.

The EPA has issued a proposed FIP to address transported ozone forming emissions. This proposed rule has the potential to impact Texas in several significant ways. First, for the 2023 ozone season, EPA's proposed rule includes an updated and expanded regional allowance trading program, including daily NOx emission limits for large coal generation units with a capacity of more than 100 MW. Units emitting more than these daily rates would be subject to increased allowance surrender requirements under the plan.

Ms. Baer also stated that, starting in 2023, new lower ozone season NOx emission budgets would be established, which would be dynamically adjusted each ozone season starting in 2025 to reflect changes in generation fleet composition. By 2026, these emission budgets will be about 44 percent lower than actual electric generating unit emissions in 2021. Also, starting in 2026, new NOx emission limits for other industries would apply, and Texas would be one of 23 states subject to these limits. The EPA anticipates that most of the affected units in all industries would have to install new equipment to reduce NOx emissions.

Ms. Baer reported that TCEQ believes that the EPA's estimated reduction potential is inaccurate. The EPA relies on incorrect data with regard to sources that they claim are subject to the rule. Also, Texas already has equivalent or stronger rules on the books. Finally, some of the companies that EPA points to as needing to have controls already have these controls in place.

TCEQ provided comments on the proposal that point to several technical issues with the manner in which the EPA conducted its analysis. The EPA's analysis incorrectly focuses on whether the state has the potential to reduce the emissions not whether the emission reductions are actually needed. This inappropriate merging of the ability to reduce emissions with the need to reduce emissions may result in the proposed rule requiring controls in states that do not contribute significantly to nonattainment. The EPA failed to verify that the steep emission reductions required in their proposal are not more than is needed to meet the requirements of the statute. In other words, the EPA fails to prove that this is not overcontrol. The consequences of this may be severe.

Electric generating units are not selling allowances given the uncertainty regarding EPA's proposal. This has created a shortage that has significantly driven up the cost of NOx allowances. Ms. Baer reported that TCEQ also has concerns that the EPA has designed the proposal to require electric generating units to consider generation shifting as a normal and practical procedure for meeting the requirements of this rule without any regard to reliability or pricing on the electric grid.

The EPA's proposal also significantly underestimates costs in several ways. Specifically, the EPA's emission control device cost calculations do not account for site specific information and plant layouts that may make retrofit difficult and more costly. In summary, the EPA's proposed regulations have broad implications without any clear, proven or justified environmental benefit.

In response to a question from Ms. Kennedy, Ms. Bear addressed how the proposed EPA regulations could impact current installed generation capacity in the state. TCEQ worked with the PUC and ERCOT to quantify the potential impact to the existing generation fleet, and they reported in their comments that more than 10,000 MW of generation would be at risk of ceasing operations under the proposal.

Erin Chancellor – Director of the Office of Legal Services, Texas Commission on Environmental Quality

Ms. Chancellor discussed legal aspects of the EPA's proposed FIP as well as EPA's disapproval of Texas' proposed State Implementation Plan (SIP). In comments submitted to EPA on the proposed FIP, TCEQ pointed out multiple legal errors and technical concerns. TCEQ respectfully requested that EPA withdraw the proposed FIP, and, alternatively, that EPA address and remedy those technical and legal errors.

Ms. Chancellor said that EPA's proposed FIP is arbitrary and capricious as well as inconsistent with statutory authority. The proposed FIP infringes on separation of powers and has the potential to impact the ability of states like Texas to maintain electricity generation sufficient to meet demand. Ms. Chancellor stated that EPA is attempting to shift generation resources intentionally and illegally, and that the proposal has the potential to jeopardize the reliability of the grid, the state's economy, and the health and welfare of the public.

TCEQ requested that EPA approve Texas' SIP revision for the 2015 8-Hour NAAQs pertaining to a Clean Air Act Section 110 requirement to address interstate transport. TCEQ submitted that SIP revision on August 17, 2018. EPA proposed to disapprove that SIP 42 months later, on February 22, 2002. TCEQ fully addressed Clean Air Act requirements in its SIP submittal and, as such, TCEQ opposes any disapproval of the SIP and the subsequent inclusion of Texas in the proposed transport FIP.

Ms. Chancellor reported that EPA prematurely prepared the proposed FIP before finalizing action on Texas' SIP revision to address the interstate transport requirements. Under Clean Air Act Section 110(c)(1), EPA shall promulgate a FIP at any time within two years after disapproval of a SIP. States have an opportunity to correct deficiencies in a proposed SIP, and the administrator then approves the plan or plan revisions before the administrator promulgates a FIP. Final disapproval of the SIP triggers EPA's authority to issue the FIP, not simply proposing a disapproval. EPA has only proposed disapproval of the Texas SIP submittal, and it has signaled its intent to include Texas in the FIP once that disapproval is final. Texas has not had the opportunity to challenge EPA's disapproval of that SIP, nor has the state had the opportunity to correct its SIP submittal. This approach is inconsistent with congressional intent and ultimately serves to alter Congress' SIP and FIP schedule.

Ms. Chancellor stated that EPA did not provide sufficient time for regulatory agencies and operators to provide analysis concerning the scope and impact that EPA's proposed FIP will have on the ability of states to maintain electricity generation sufficient to meet demand.

Ms. Chancellor reviewed for the committee some related litigation history regarding Texas' 2008 Eight-Hour Ozone NAAQs transport SIP.

At the conclusion of Ms. Chancellor's remarks, Chairman Wilson commented that this CSAPR and the proposed FIP from EPA have become a headwind along with all the other resource adequacy, market design and reliability challenges that the state is facing today. This rule is being driven by two air monitors in Wisconsin, who are essentially saying that there are challenges created by electrical generation units in Texas that relate to emissions in Wisconsin. Much of this will be litigated going forward. The Texas Attorney General along with state agencies and ERCOT have submitted filings and reports. Chairman Wilson said that the committee should bear in mind the increased complexity of these environmental rules that may be existential to thermal generation.

RJ DeSilva – Communications Director, Railroad Commission of Texas

Mr. DeSilva offered an overview of the RRC's rulemaking implementation, site visits, cross-industry collaboration and communication activities, all of which are intended to fortify the state's natural gas supply chain. Mr. DeSilva began with a discussion of RRC implementation of the Critical Designation of Natural Gas Infrastructure rule. The new rule (16 TAC §3.65), which became effective in December 2021, establishes the process for designating certain natural gas entities as critical during an energy emergency as specified by Senate Bill 3 and House Bill 3648. Under the rule, natural gas operators submit designations as critical during energy emergencies on March 1 and September 1 of each year.

Mr. DeSilva reported that Senate Bill 3 mandates that RRC weatherization rules for critical natural gas facilities be adopted by September 2022. However, RRC took proactive steps this past winter, beginning in October 2021, by conducting winter weather preparedness site visits at natural gas facilities to observe firsthand the weatherization techniques that were implemented even before the RRC rule was adopted. Weatherization measures included wind barriers or thermal insulation for equipment. The site visits encompassed about 22,000 wells and all 37 underground storage facilities in the state.

Mr. DeSilva reported that the RRC has adopted draft rules on weatherization for facilities with the critical designation. The plan is to publish these for comment and have these rules adopted by the end of the summer. As drafted, the rules would require operators by December 1 of each year to weatherize to ensure sustained operations during weather emergencies and to address any problems that may have occurred in the past. RRC has created a new Critical Infrastructure Division with inspectors in regions across the state who will be conducting inspections once the weatherization rules are adopted. Mr. DeSilva noted that Senate Bill 3 authorizes fines up to $1 million per violation for operators who do not comply with these rules.

Mr. Mickey asked if implementation of weatherization rules and inspections means that we can expect the gas supply is not going to have limitations during the next freeze. Mr. DeSilva replied that the weatherization activities observed by RRC during site visits and the performance of the supply system during the freezes that happened this past winter indicate that Senate Bill 3 and the other legislation are going to help moving forward.

As a follow up, Mr. DeSilva said that he believes Texas is going to have sufficient natural gas supply for additional dispatchable generation capacity that the state needs.

In response to a question from Ms. King about the role of processed gas storage, Mr. DeSilva responded that underground storage facilities are not exempt from the weatherization rules. Certain producing facilities with lower thresholds of production would be exempt, but not the underground storage facilities.

Krista Duke – Director of Government Affairs, Railroad Commission of Texas

Ms. Duke discussed the RRC's collaboration on the Texas Electricity Supply Chain Security and Mapping Committee. As directed by Senate Bill 3, RRC staff is working in conjunction with the PUC to map the interconnected supply network between natural gas and electric generation. The goal is to know with precision which gas pipelines are feeding which generation facilities. This effort also is extremely important to the RRC's weatherization rule, because RRC needs to know which operators are on the map in order to ensure proper weatherization activities are occurring ahead of winter.

Ms. Duke reported that the supply chain map already has proven to be a beneficial tool. During an ice event this past winter, emergency operations staff were able to use a draft version of the map at the State Operations Center (SOC). A generator had communicated to ERCOT and PUC that their gas had been shut off. RRC staff at the SOC were able to quickly determine which pipeline fed that particular generation unit and contact the pipeline to discuss remediation. This issue was resolved in a manner of minutes, whereas previously it may have taken hours.

Ms. Duke noted that RRC also collaborates with energy industry leaders through the TERC, which came out of Senate Bill 3 as well. TERC is meeting regularly to provide recommendations to the Texas Legislature and to promote continued communication and collaboration between agencies and the energy industry. Ms. Duke provided the committee with a chart that shows the amount of processed gas available on a daily basis to feed generation. Peak demand is 15 billion cubic feet and, as the chart indicates, there are sufficient supplies in pipelines, underground storage and daily production.

Nim Kidd – Chief, Texas Division of Emergency Management

Chief Kidd was unable to attend the June 28 hearing. He provided the committee a written summary of the activities of the TERC.

TERC was established by the 87th Texas Legislature to (1) ensure that the energy and electric industries in this state meet high priority human needs and address critical infrastructure concerns, and (2) enhance coordination and communication in the energy and electric industries in this state. Following are general duties of the council:

- The council shall foster communication and planning to ensure preparedness for making available and delivering energy and electricity in this state to ensure that high-priority human needs are met, and critical infrastructure needs are addressed.
- The council shall foster communication and coordination between the energy and electric industries in this state.

TERC conducted 12 meetings between September 2021 and June 2022, including full council meetings, a two-day symposium and an after-action review for the January 2022 winter weather event.

TERC initially formed temporary work groups to establish a charter and bylaws. In addition, there are standing TERC committees for communications, supply chain and recommendations. TERC committees meet separately, outside of full TERC meetings, and the chair and vice chairs of each committee have equal representation from the oil & gas and electric industries.

TERC has taken the following actions to operationalize TERC recommendations and best practices:

1. Facilitated meetings between agency partners to address roles, responsibilities and expectations for SOC representatives and agency participation during events.
2. Invited TERC council members to participate in briefings from state agencies, National Weather Service/TDEM weather updates and operational updates from each TDEM region each morning during a disaster.
3. Compiled a comprehensive online winter weather resource page for a one-stop shop for all Texans.
4. Instituted industry-wide coordination calls daily during potential severe weather and throughout weather events for resource requests. These Energy Industry Coordination Calls (EIC) consist of the key staff from PUC, RRC, TCEQ, ERCOT, and TxDOT, as well as members of all sectors of the energy industry, including gas producers, electric

generators, and industrial users. Average attendance during events is 150-200 callers. The EICs allow state agencies to provide industry with pertinent information from TDEM's meteorologist and agency partners, and for industry participants to make resource requests.

Todd Staples – President, Texas Oil & Gas Association

Mr. Staples testified that creating a state energy plan that allows and preserves sound economic conditions for decision-making is of the utmost importance. He believes keeping the market structure where the risks are absorbed by the participants and the consumers benefit is very important in all the decisions that are made. The oil and gas industry, according to Mr. Staples, is engaged in this process for two very important reasons:

1. Texas – if it were a country – would be the third-largest natural gas-producing country in the world. Production of natural gas continues to increase very significantly to meet not only the state's demands, but also demands throughout North America and increasingly globally as well.
2. Oil and gas companies are some of the biggest consumers of electricity in Texas and want to make certain that a good sound system is maintained.

Mr. Staples pointed out two important considerations of what the oil and gas industry would hope would be included in a state energy plan and report to the Legislature. For phase one, Mr. Staples outlined the overall business climate (taxes, permitting, infrastructure, education, environment, market). For phase two, he outlined what constitutes a solid plan for the electricity sector.

<u>Evaluate barriers to electricity and natural gas markets that prevent sound economic decisions</u> – In looking at these barriers, Texas natural gas producers are leading the country in production growth because there is robust investment in infrastructure in both interstate and intrastate pipelines and the host of infrastructure that goes from production to transmission to refining and then ultimately to ports. Changes can be made that would create barriers that would prevent the sound economic decisions from occurring. Both industrial users and electric companies have some of the lowest cost for natural gas in the country thanks to more than 400,000 miles of intrastate pipelines, thousands of receipt points, and dozens of physical trading points within Texas to receive that product. Mr. Staples stated that the competitive nature provides options to market participants and creates opportunities for them to be certain that they can plan and establish redundancies, and that results in an optimum system that results in benefits to consumers.

<u>Evaluate methods to improve the reliability, stability and affordability of electric service in the state</u> – Mr. Staples testified that the Legislature did make meaningful changes that have

fundamentally made Texas much more reliable and more prepared today. The designation of critical load was key. Before Winter Storm Uri, oil and gas producers in the field were discouraged from registering their assets. Today those producers are required to do so. It will also be important to know how much natural gas is needed for the electric generation system and whether the generating units have the firm contracts to supply the amount of gas necessary during peak periods.

Regarding affordability, Mr. Staples suggested that if in fact a small number of generators own as much as 80 percent of the retail electric market, that should be explored to determine if a broader discussion around deregulation is needed and whether the goals of deregulation were met if the markets have reaggregated. Mr. Staples emphasized a desire for a healthy robust electrical generation market in Texas and a desire for the entities on which oil and gas companies rely for product that runs the systems to be very reliable, very efficient and be financially stable.

<u>Evaluate the electric market structure and price mechanisms</u> - Mr. Staples testified that the oil and gas industry believes that ancillary services and the firm fuel supply agreements are very important to having a reliably managed grid. For firm fuel, offsite storage is very important, and firm contracts for natural gas supply, both for the storage and transmission, need to be examined.

Mr. Staples stated that the oil and gas industry has concerns with conversations that are occurring around a potential capacity market because at some point the design loses its market focus, and that may cause us to revisit the whole premise of deregulation. Mr. Staples emphasized the need to identify the market structure that rewards both reliable and low-cost suppliers in a balanced manner.

Ryan White – Kinder Morgan/Texas Intrastate Pipelines

Mr. White testified about Kinder Morgan's assets in Texas; its experience during Winter Storm Uri including preparations; and matters of importance to improve the overall reliability of the natural gas system. Kinder Morgan is focused on how to ensure natural gas deliverability for power generation and human-needs customers across Texas.

During Winter Storm Uri, Kinder Morgan stayed at the maximum withdrawal of about 3 billion cubic feet for five consecutive days due to winterization efforts that Kinder Morgan made on its pipelines and storage facilities. Power generators and local distribution customers (LDCs) who held capacity on the Kinder Morgan intrastate system were able to receive 100 percent of their firm contracted storage during Winter Storm Uri. Following Winter Storm Uri, Kinder Morgan is actively working to expand its natural gas storage capabilities, but also is looking to expand its withdrawal capabilities by an additional 650,000 cubic feet per day of withdrawal, giving a total withdrawal capacity about 3.6 billion cubic feet per day.

Following a significant freeze event in 2018, Kinder Morgan took steps to winterize its key facilities, including some of the pipeline locations, meter stations and compressor stations. Not only did Kinder Morgan take steps to improve engineering controls, but it also worked diligently to improve administrative controls. Communication was key in the preparations. Key compressor stations and meter facilities were staffed going into Winter Storm Uri. In addition to posting information on an electronic bulletin board, Kinder Morgan communicated with its individual customers leading up to, during and following the storm as customers started seeing a lot of the markets ramp back up.

During Winter Storm Uri, Kinder Morgan's storage capabilities were critical to the Texas human-needs markets. Proper winterization or preparation ensured reliable service during and following Winter Storm Uri. Following the storm, Kinder Morgan has seen an increase in storage capacity contracted from power generators and LDCs.

Mr. White emphasized solutions that are in progress (e.g., winterization, emergency planning, efforts to learn from previous experiences, regulatory and industrial coordination, improved coordination/communication across the industry).

Regarding gas storage and firm transportation capacity investments, Mr. White testified natural gas storage must fill the gap when supply is not available. He believes power generation and LDCs need to have more storage capacity, emphasizing again that storage was critical during Winter Storm Uri. Power generators need a mechanism for recovering their storage costs. Pipeline companies need the ability to construct pipeline infrastructure to meet the incremental natural gas demand in growing markets, infrastructure required to not only deliver the natural gas on a day-to-day basis, but also to move natural gas from storage locations to key markets during the loss of supply.

Mr. White was asked by committee members if Texas needs more natural gas storage capability. He replied that while storage is very important, it doesn't matter how much gas is in the ground if the gas cannot be extracted, so being able to expand the withdrawal capabilities of gas storage facilities and the injection capabilities (both of which are very expensive) is critical. Following up, Mr. White reiterated the importance of having in place the required infrastructure to ensure natural gas can be transported to key market areas (e.g., Dallas, San Antonio, and Houston).

Committee members asked Mr. White how many of the issues observed during Winter Storm Uri were related to the geographic location of storage relative to natural gas demand and how much of the problem was related to the concept of firm contracts versus non-firm contracts. Mr. White replied that from a geographic standpoint, there is a need to improve existing infrastructure or construct new infrastructure to be able to get natural gas from storage back to key markets. He pointed out that most all storage facilities are limited by the location of natural formations—old oil and gas reservoirs that have depleted. Therefore, pipeline infrastructure is needed to get that natural gas back to those key market areas. Regarding firm contracts for natural gas, Mr. White testified that if a customer had firm transportation contracts in place during Winter Storm Uri, there was no curtailment in that transportation capacity. Also, the ability to move interruptible natural gas via transportation was present as well during the winter storm, but the supply was simply not available for transport.

Samuel Newell – Principal, The Brattle Group

Mr. Newell stated the key problem is resource adequacy, availability, and always having enough supply available to meet demand even in extreme conditions. There are three solutions, based on experience addressing these questions for ERCOT and the PUC from 2011 through last fall, and through Brattle's experience analyzing and designing markets to address similar challenges in other jurisdictions. The first solution is to keep the energy-only market that has no reliability requirement, but allow prices to get high when there are tight conditions. This will attract investment and recognize which types of capacity are valuable but may not deliver acceptable reliability. The second option is to pay for backstop reliability services, which are strategic reserves of existing and new capacity with special side-payments, but keep those megawatts out of the energy market so they do not displace in-market investment.

Mr. Newell explained that option three is to impose a resource adequacy requirement on loads that requires loads to pay for enough reliable supply to essentially always be able to meet demand. All other jurisdictions in North America and most of the world have such a requirement. There are many valuable lessons about how to administer such a program in a competitive market environment. Option three would help, but it is not a perfect solution because administratively accredited capability is no guarantee of performance, even if incentives are in place. "In work that we did for the PUC, last fall we estimated that it would cost an additional $1.5 billion or so per year in the long run," Mr. Newell said. "And probably $7.5 billion paid for this capability, this capacity market, but with energy prices probably $6 billion lower because you don't have scarcity as often."

Mr. Newell stated that even if one of the three options are implemented, additional improvements are needed to make the system more resilient. Lowering demand in extreme weather conditions through energy efficiency in new and existing buildings is important. There is a big opportunity for improvement because Texas has enjoyed low-cost energy and has not had to prioritize this in the past. Also, Mr. Newell supports enabling better-targeted manual load shed capabilities so customers on feeders without critical loads are better protected. In general, more targeted ways are needed to either get backup generation to secure those critical loads or to curtail customers, whether using smart meters and other technologies.

Mr. Newell identified an additional challenge ERCOT faces in maintaining operational reliability as demand and supply swing unpredictably, especially in a fleet with large amounts of wind and solar. The concern becomes the efficiency of maintaining reliability, which depends on the fleet's flexibility characteristics and how the fleet and market are operated. The key is to align the ancillary services and energy market to provide the operators all the tools they need *in-market* to operate the system. The recent prevalence of RUC suggests a lack of alignment. Additionally, the implementation of Real-Time Co-optimization will allow for more efficient operations of the fleet and provide a platform for other reforms.

In response to Mr. Jenevein's question on quantifying the value of reliability to Texas, Mr. Newell stated that before designing a mechanism to achieve something, we need to understand what is it that we want to achieve and how it relates to the value. Other jurisdictions that have a resource adequacy requirement have not really asked that question. The energy-only market privatizes the value of energy. The issue is quantifying the damage done by losing power. The industry is getting an inconsistent message by setting the cap at $5,000 per MWh but indicating that we cannot have a shortage. In response to Ms. Kennedy's question on a reliability standard, Mr. Newell stated that other jurisdictions are starting to rethink the question of what is the right metric.

In response to Mr. Barnes' question regarding Mr. Newell's report titled "ERCOT Investment Incentives and Resource Adequacy" dated June 1, 2012, Mr. Newell indicated that the high-level observations from the report remain valid. Responding to Mr. Barnes' question on the cost of capacity markets, Mr. Newell stated that the cost of a new capacity market is not additive to the existing market because the current costs include the risk of shortage pricing in the energy-only market. Moving to a capacity market that supports a much higher reserve margin reduces the energy costs from scarcity risk. "To get more reliability will cost a little bit more, but not nearly as much as you might think," Mr. Newell testified. In response to Mr. Barnes' question on the efficiency of additional operational reserve demand curve shifts, Mr. Newell responded, "I don't know if we'll be able to go far enough with these approaches to satisfactorily avoid shortages."

In response to Chairman Wilson's question on proposals that can be implemented today that will incentivize new generation, address the new risk profile of thermal generation, and address the perverse incentives created from the Production Tax Credits and Investment Tax Credits, Mr. Newell emphasized the intermittency of wind and solar and how prices get high in the hours where the intermittent resources are not producing. Mr. Newell explained, "So even an energy-only market is self-healing. The question is, is it at a high enough degree of reliability for us to be satisfied?" The goal is to recognize the value to provide at all the times when it is needed most.

Amanda Frazier – Senior Vice President of Regulatory Policy, Vistra Corp.

Ms. Frazier opened her remarks with an update on the PUC's status in implementing market design reforms and ERCOT's conservative operations. In order to determine whether the changes the PUC has implemented are working and whether more are needed, Ms. Frazier advised that first a goal must be defined. The Legislature has been clear that they want to see increased reliability through investment in new dispatchable generation through market solutions. The PUC's phase one changes are likely not enough to achieve that goal. Conservative operations of the grid have or will put downward pressure on prices for dispatchable generators. Keeping 6,500 MW of operating reserves in every hour suppresses prices and reduces the opportunity to have any scarcity pricing above a marginal generator's fuel costs. Achieving additional reserves through RUC is inefficient and creates additional wear and tear on units that will make them less reliable in the future. ERCOT's rules do not always fully compensate those units for RUC and in some cases do not allow them to offer their full cost in the market. Changing the deployment of the ERS demand response program to be deployed in pre-emergency conditions will allow demand response to cut in front of generators that otherwise are available to come online. That reduces the opportunity for pricing to reflect the need for more dispatchable generation. Resources need to get paid through the energy revenues. And if the revenues collected through the energy market do not cover those costs, power plants will not remain economically viable.

In some cases, the phase one changes are not even sufficient to cover the ongoing maintenance and operating costs of existing dispatchable generation, especially with the additional weatherization requirements. Ms. Frazier testified that Vistra's focus for phase two market design proposals is to work toward mutually beneficial solutions and approach problems with an open mind. Vistra does not have any current plans to build a gas generator, and it has in its existing fleet gas plants that are not recovering their costs and are therefore at risk of retirement.

"Subsidies when reflected in market behavior distort market outcomes and suppress the price for existing generators, which can push some of them to shut down prematurely," Ms. Frazier explained. Subsidizing resources through government intervention exacerbates the impact, causing a lower price, discouraging investment in existing and new generation, and increasing the likelihood that marginal plants will retire.

Ms. Frazier testified that the PUC must focus on market design solutions that define a clear reliability metric and provide stable sources of revenue to dispatchable resources that will allow the market to achieve that metric. Competition has served ERCOT well. It has lowered costs and risks to consumers. Vistra is confident that phase two market design changes can be devised in a way that will promote new investment in a market-friendly manner without compromising the economic viability of the existing fleet.

In response to Chairman Wilson's question on proposals that can be implemented today that will incentivize new generation, address the new risk profile of thermal generation, and address the perverse incentives created from the Production Tax Credits and Investment Tax Credits, Ms. Frazier confirmed that Vistra retired a significant amount of resources due to these factors. Vistra also has additional units that are at similar risk of retirement. Some of that is based on economic pressures, while some plants are at risk due to the EPA's proposed rules. PJM has added 22,000 MW of gas generation, primarily combined-cycle gas turbines. ERCOT had added only about 2,600 MW. Ms. Frazier stated the primary reason is that PJM has a market design that specifically incentivizes thermal generation to be built through their capacity market. She stated, "The concern that we have with the energy market is that it provides incentives to develop what we have developed, which is solar primarily." There needs to be a mechanism that targets specifically what is needed—"something that says we need *x* amount of dispatchable to meet the reliability metric that's based on the value that the state wants."

Andrew Novotny – Executive Vice President and Chief Operating Officer, Calpine

Mr. Novotny highlighted the importance of setting a reliability target and assessing where the market is relative to that target to help determine future dispatchable generation needs. Mr. Novotny also discussed the difficulty of determining the loss of load expectation in today's environment and determining whether the recent addition of generation capacity has been sufficient.

Mr. Novotny echoed Mr. Newell's concerns regarding the diminishing effectiveness of new solar that is added. Additionally, there are some serious environmental regulations coming from the coal fleet that puts them at risk of retirement. Some of the new load growth in Texas comes with price response, which can be good for reliability because when prices get high, some of that load starts to shed. However, it also makes it more complicated to identify how much of the load ERCOT can curtail.

Mr. Novotny explained that once a reliability target is set there are two pathways to proceed. One pathway is some form of resource adequacy load-serving obligation that may include: a bilateral resource obligation on the part of LSEs, a traditional capacity market like PJM, a nontraditional residual capacity market, or a DEC proposal. The second pathway addresses different constructs to the energy-only market. This will require new reserve products and require continued shifts to the operating reserve demand curve. Ultimately, either path chosen can get ERCOT to a reliable grid.

Mr. Novotny stated that, with any path that is chosen, it is important to provide regulatory certainty. ERCOT's conservative operations are up for debate with many questioning whether the approach is too expensive. Mr. Novotny discussed the difficulty in committing to build a new combined-cycle generation facility without knowing what the rules will be when that facility comes online. "The problem is that the revenue curve of the forward market declines each year, and part of the reason for that is people don't know whether some of these policies will stay in place," he stated. Mr. Novotny discussed the importance of not developing a policy that will discriminate in favor of new generation at the expense of the existing fleet. Policies favoring new generation have been tried in other markets like California with mixed results.

In response to a question from Mr. Jenevein regarding pricing the value of reliability, Mr. Novotny stated when the price cap originally was set there were a series of studies that attempted to quantify the VOLL, and those studies determined $9,000 per MWh at the time was the correct value. "With the events of Uri, the value of lost load is a complex equation because there is a big difference between load going out for two hours on a July day with a small amount of rolling blackouts and 90 hours in a row on a cold winter day. And certainly, during Uri that value was much, much higher than $9,000 a megawatt hour," he said. The best solution on the load side is more demand response.

In response to Chairman Wilson's question on proposals that can be implemented today that will incentivize new generation, address the new risk profile of thermal generation, address the perverse incentives created from the Production Tax Credits and Investment Tax Credits, Mr. Novotny stated that the risk of retirements is really the biggest reliability risk that ERCOT is facing in the next five years. Looking forward, there needs to be more regulatory certainty. “A regulatory construct that doesn’t do harm to these existing assets while at the same time, whether it’s through a capacity or a reliability obligation or simply from continuing to make the energy market more conservative by shifting the operating reserve demand curve,” Mr. Novotny said. “Any one of those things, I think, will work.”

In response to Mr. Jenevein’s question on regulatory certainty, Mr. Novotny testified that ERCOT needs a nondiscriminatory market construct that has enough additional operating reserves “as padding for reliability.” Calpine’s studies showed that an additional thousand megawatts would take ERCOT from a one-in-three-year loss of load expectation to possibly a one-in-10. That study will need to be redone to integrate the impacts of other reserve products. The additional padding through the operating reserve demand curve shift is to make the market prices align with the expected grid risk determined by ERCOT.

In response to Chairman Wilson’s question on technology deliverability, Mr. Novotny emphasized the importance of having everything accredited and determining the effective load carrying capacity of a resource, which will allow policies to be technology-neutral.

Clif Lange – Manager of Wholesale Marketing/Qualified Scheduling Entity, South Texas Electric Cooperative

Mr. Lange presented STEC’s reliability service product to the committee, highlighting how it meets the four essential elements that the Legislature and the Governor directed the PUC to focus on. First, they are to ensure appropriate reliability during extreme weather. Second, adequate generation needs to be available during times of low non-dispatchable generation. The third key item is nondiscriminatory cost allocation. Mr. Lange said that, in this case, nondiscriminatory doesn’t mean that it can’t apply differently to different technologies, but more so that it needs to be nondiscriminatory amongst those to whom it applies. Finally, this needs to be done through a transparent, liquid, market-based framework.

Mr. Lange testified that there are six elements to STEC’s proposal. The first element is a reliability standard. Under the proposal, it is imperative that a defined reserve margin is established. This provides a benchmark to see whether the reliability objectives are being met, but also allows an opportunity to set a minimum target to prevent prolonged rotating outages. STEC supports a one-in-10 loss of load expectation. There are opportunities there to look at other metrics, but the end goal is really to ensure some degree of assured reliability. The second key element is the target procurement volume. There needs to be enough of this product to meet peak net load plus that reserve margin that is set in the first key element. The current capacity demand and reserve inputs are not conservative enough. The third key element is participation criteria. Senate Bill 3 was very explicit in terms of what a reliability service or an ancillary service needed to have to incentivize participation by dispatchable resources. The current battery portfolio in ERCOT does not meet the criteria and will require longer duration to be able to meet that continuous operating requirement.

Mr. Lange stated that the fourth key element is the procurement methodology. This should allow resources that have not yet been constructed to be able to participate within the confines of a capacity market, with clearly defined inputs determined by the PUC, to make sure that reliability targets are being met. The fifth key element is cost allocation. The three allocation buckets include contributions from metered load, non-dispatchable generation (based on the level of uncertainty that exists between what they can produce and what is expected), and generators who were receiving a benefit from this reliability service but did not deliver. Mr. Lange said that the last key element is performance and penalties. There needs to be assurances that resources can provide this service and meet the high availability targets that are assigned to them.

In response to Mr. Greene's questions regarding potential issues with the STEC proposal, Mr. Lange stated, "from the renewable side, there is obviously a lack of interest in it because, first of all, under our proposal they would not be able to participate in receiving the revenue benefit from it, but second of all, they would also be allocated a portion of the costs for the particular product." From the load perspective, they would like to see the full impacts of the phase one changes and are concerned with the cost increases.

In response to Mr. Mickey's question about the cost estimates, Mr. Lange stated that STEC intentionally did not determine cost estimates, and the approach they took was to assess how reliability can be increased in ERCOT. This approach works to address items from Senate Bill 3 and by the Governor through his directives to the PUC. Cost estimates for the proposal are going to be driven by the details of the final design parameters.

In response to Chairman Wilson's question on proposals that can be implemented today that will incentivize new generation, address the new risk profile of thermal generation, and address the perverse incentives created from the Production Tax Credits and Investment Tax Credits, Mr. Lange stated that the current market in Texas does not value reliability—it values cheap power. The forward energy curves are high through about the first year, but they quickly drop off, and the reason is because there is not enough market certainty. There needs to be enough incentive to not only invest in dispatchable generation, but also to encourage loads that potentially are buying renewables to help pay for reliability.

Bob Helton – Vice President of Government and Regulatory Affairs, ENGIE North America

Mr. Helton highlighted the inadequacies of capacity markets to meet expectations for reliability and getting the right amount of resources online. Some markets started with a load-serving obligation that had to more toward a centralized capacity market. There are many examples at FERC where centralized capacity markets are continuously making changes and tweaks to their market design, which is costly. On the renewable side, solar is responding to the changes in the market by developing new solar facilities with storage to firm up their generation. Even as a standalone, solar provides needed capacity and a benefit into the system.

Mr. Helton expressed his concerns that we continue to look backward at solutions for a future problem. Before pursuing a capacity market, we should look at the value of wind and solar, especially when these assets add storage that will provide more reliability. Regardless of the decision, the market design needs to be technology-neutral.

In response to Mr. Hall's question, Mr. Helton referred to the STEC proposal as an example of a proposal that is not technology-neutral. Any technology that can provide capacity to the system should be able to participate in that type of product. Even standalone renewables just need to be accredited appropriately.

In response to Mr. Barnes' comments on changes to the energy-only market, Mr. Helton agreed that both the energy-only market and capacity markets need constant tweaking. However, his concern is that if another mechanism is implemented, it may increase the amount of review and frequency of changes required. Responding to Mr. Barnes' follow-up question on the need for additional dispatchable capacity, Mr. Helton agreed that reliability needs to be the top consideration. "But what I'm advocating is there is a lot of other avenues of looking forward for future products and things that we haven't even looked at that I think we could look at before we went down some of these roads," Mr. Helton said.

In response to Chairman Wilson's question on proposals that can be implemented today that will incentivize new generation, address the new risk profile of thermal generation, and address the perverse incentives created from the Production Tax Credits and Investment Tax Credits, Mr. Helton pointed to the number of batteries in the interconnection queue and their ability to help with reliability and dispatchability. On renewables, Mr. Helton said, "what you find is all of the companies that are moving into Texas are our customers. They're the ones that are coming to us and saying, we want renewable energy because we want to get our sustainability rules and our goals in place as we move forward. And they're actually requiring that for their upstream and downstream partners that they have. So that's kind of the way we're built, through demand."

Beth Garza – Senior Fellow, R Street Institute

Ms. Garza opened her testimony discussing Winter Storm Uri and noting that it was not a market failure. One of the issues that the storm highlighted is the disconnect between electricity and gas. One potential solution would be a strategic reserve of natural gas storage for electricity. The electricity industry could invest in some amount of natural gas storage that could be used and held for extreme winter events. Ms. Garza also expressed her disappointment in ERCOT's reaction and lack of recognition that winter emergencies are worse, different, and higher risk than summer emergencies. She acknowledged that it makes sense to implement RUC for winter but not for summer, as ERCOT has been doing throughout 2022.

On market design, Ms. Garza stated that ERCOT is challenged with a world where the supply is more variable and the demand is going to become more variable as customers have the ability to use distributed energy resources. These factors render the goal of providing reliability a harder problem to solve going forward—but this is a universal problem that all markets across the world are facing. Generators make money when there is scarcity and on a capacity basis. To the extent the market doesn't provide an expectation of those returns, then there will not be additional investment.

Ms. Garza believes it is possible to have a reliable system with wind, solar and batteries, although it may not be the most effective. An energy-only market would not work in that system because the generation fleet is zero variable cost, zero energy cost and there would have to have a capacity construct to make up that difference in capacity needs. One possible solution would be to buy different types of ancillary services, which are just short-term capacity commitments. The concern is current ancillary services are a day-ahead capacity commitment, and to incentivize new generation, there needs to be some kind of capacity construct not like the current eastern markets. That type of capacity market does not work in ERCOT where every decision is decentralized. "An energy-only market design can work, it just may not be able to work and provide the level of reliability that seems to be being imposed upon us," Ms. Garza said. "And so to make that transition, I think we're going to need some sort of capacity construct."

In response to Mr. Mickey's question on the LSE obligation, Ms. Beth compared the concept with RECs. Generators would be certified or be accredited for so many of these types of credits to exist, and there would need to be a process to ensure that there are enough of those credits in circulation.

In response to Mr. Barnes' questions regarding the demand-side component of the LSE obligation, Ms. Garza explained that we tend to think of demand response or demand curtailment as replacement or substitute for supply, but another way to think about it is demand expressing their willingness to pay. This is consistent with our world now where all these decisions are decentralized. "As part of an LSE reliability obligation, then, maybe I don't have to procure any additional supply because I've taken care of it on the demand side," she said.

In response to Chairman Wilson's question on defining the problem to be solved, Ms. Garza stated that the concern is that as the amount of dispatchable generation declines, the risks of having days where solar and wind are insufficient to meet customer requirements for electricity increase.

In response to Mr. Barnes' comments comparing ERCOT to other markets, Ms. Garza discussed examples of the markets in the eastern U.S. and how their capacity markets are evolving away from paying for units "just to exist." She continued to reference the ERCOT market as the other extreme, and projected that the trend will be for both extremes to meet in the middle somewhere.

Shelly Botkin – Executive Director, Texas Public Power Association

Ms. Botkin testified that the Texas Public Power Association (TPPA) is committed to working toward system reliability and good market outcomes for all participants and that their members always have thought in terms of being part of the broader Texas grid. This includes understanding that since Winter Storm Uri, there are going to be costs for Texans associated with increased reliability.

Ms. Botkin emphasized the variability and diversity of TPPA membership participation throughout both the generation and transmission parts of the Texas grid. She said, "this perspective makes our members very focused on reliability, stability and affordability and committed to the long-term health and stability of the grid. We've been, like everyone else, having some concerns about the conservative operations of the grid, and we hope to work with ERCOT and other stakeholders to find the right balance in that conversative posture."

Ms. Botkin discussed efforts to improve the resource adequacy reports that many policymakers rely on in order to better understand how resources are likely to behave under certain circumstances. Although the reports do not fix resource adequacy, they communicate grid conditions, and that helps drive toward a solution. "Evaluating phase two proposals, TPPA has consistently taken the position that the Commission should … consider a robust analysis of the proposals on the table, with transparency, methodology, weighing costs and benefits and the opportunity for comment by stakeholders and the public, and a recognition that in addition to the changes listed in phase one that these phase two changes will have a cost," Ms. Botkin said. "We just want to say we're looking for fair market outcomes to support grid reliability." Additionally, these initiatives are truly meant to be about diversity of the resources, not pro one way or the other way and balancing customer price impacts with the cost of new incentives.

Julia Harvey – Vice President of Government Relations and Regulatory Affairs, Texas Electric Cooperatives

Ms. Harvey stated although there are concerns about increasing costs, the market needs to be sustainable and delivering the reliability that consumers expect, striking a balance between the interests of costs and reliability. The PUC has made real strides toward supporting reliability in ERCOT over the last year, but there are trade-offs, and the market redesign effort is still a work in progress. Some of the changes make sense in the short-term, but they will not necessarily support long-term stability. One of the directives of the committee is to remove barriers in the electric market, and some of the short-term changes have created barriers. For example, the conservative operational posture was implemented to avoid scarcity in ERCOT; however, it seems that a policy choice has been made to move away from the energy-only model that is premised on scarcity, and that has created some uncertainty because it is unclear whether the conservative operational posture is temporary or not.

Ms. Harvey referenced earlier testimony about how conservative operations can have a negative physical impact on the fleet with RUC instructions, how they are imposing a cost that may not be justified in all hours of the day, and how they distort market outcomes because those actions are at odds with the current market design based on scarcity.

Discussing phase two market design changes, Ms. Harvey testified that establishing a clear reliability standard or objective for the reforms would help organize and synthesize efforts. "There are a lot of levers being pulled right now," Ms. Harvey said. "It's kind of unclear how they all interact or how it all fits in a holistic solution." The goal to avoid another reliability event and incent additional dispatchable capacity is generally understood, but the goal needs to be better articulated or quantified so that long-term reforms can then be designed around the goal.

Regarding specific long-term proposals, Ms. Harvey pointed to the importance of seeing the impacts from the independent analysis the PUC is conducting. The study needs to show the cost impact to consumers and the benefits in terms of improvements to system reliability. Regarding the LSE proposal, more details on the mechanics are needed. “If we do adopt kind of a more capacity market style construct, I believe we can consider reevaluating and possibly removing some of the scarcity pricing mechanisms that are currently in our market design because they won’t be needed anymore, because the revenue would be derived from the capacity market instead of the energy market,” Ms. Harvey said. Once phase two is adopted, the expectation would be that those elements of the market could be reevaluated, and that would support the goal of affordability.

In response to Chairman Wilson’s question on long-term dispatchability risk, Ms. Harvey discussed the transition with the grid moving from a summer peaking system to kind of a net peaking system where the most stress occurs during those intervals of low renewable production. Ms. Harvey agreed with Ms. Garza that there is a dispatchable generation problem. Additionally, this problem is compounded by other factors, like potential EPA actions. On the question of the quantity of dispatchable generation that is needed, Ms. Harvey suggested additional possibilities including an event-based standard, or a duration-based standard where we build or plan around a certain duration of an outage. Other considerations include the amount of dispatchable generation during the net peak period and how much variable generation needs to be supported by dispatchable generation.

Katie Coleman – Texas Industrial Energy Consumers

Ms. Coleman stated the importance of a market design that preserves the flexibility to participate in the market in different ways, so that individuals can tailor their participation, costs, and risks to their business needs. “As compared with other jurisdictions, ERCOT’s deregulated market has provided maximum flexibility for large users, and it has been a major economic development driver for my members,” Ms. Coleman said. “Our number one objective though, I want to be very clear, is reliability. We have to have reliability to operate our plants and to compete in global markets. Our objective is making sure that we’re getting a fair benefit for the bargain, that we’re actually getting measurable improvements and reliability for those additional dollars that we’re being asked to spend.”

Ms. Coleman discussed her perspective on fundamental principles of the deregulated model in ERCOT. The primary driver of deregulation was that investment risks would be borne by the competitive market, competitive investors, and competitive market participants. In a regulated model, the consumers get the power plants and all the energy they produce at cost. Therefore, one concern regarding the market design discussions is the extent to which that risk is being shifted back to customers. There is a point where that balance can be upset so significantly that a regulated design might be a better outcome for customers.

Another fundamental feature of the competitive market is that generators are paid for performance, for providing energy, or providing certain reliability services—not just for owning a power plant. Ms. Coleman stated that, in her view, a lot of the proposals are some version of a centralized forward capacity market, which she believes will be detrimental to reliability.

Ms. Coleman stated that capacity markets solve the wrong problem. Any reliability issue in ERCOT has been driven by some operational problem, and those problems have increased as our load and resource mix are becoming more variable. Performance in real-time or on a day-ahead basis is a key metric for reliability standards. Installed capacity, on the other hand, is less useful because it does not capture how units are going to operate on a day-to-day basis. The role of dispatchable generation is transitioning to a role of backing up intermittent generation; therefore, dispatchable generation resources should not expect to make all their revenues in the energy market. Instead, those resources will need to be paid for providing backup or standby service. Ms. Coleman stated, "There is nothing the state can do that can really stop the train of ESG investment and the cost advantages that renewables have. And when we think about what is the best way to incentivize performance and provide those investment signals and compensate dispatchable generation for that backup capability, we really believe that it's through ancillary services and other reliability services" that are procured closer to real time.

Ms. Coleman agreed with the importance of regulatory certainty for generation investment, as well as for industrial investment and economic development. Once a framework is established, there needs to be a signal to the investment community that the framework will not continuously be changed. Additionally, the speed of implementation from some of the market design features will be important. "Something like a forward capacity market, whether it's a full centralized forward capacity market or a bilateral obligation, it's very bureaucratic by nature," Ms. Coleman said. "Even by conservative estimates it's going to take at least a couple years to design, at least a couple years before you can pull the trigger on that and do an initial procurement. Even being generous you're looking at five years from now before that's going to have any real impact." The focus should be what are things that can be done today that will have meaningful impacts.

In response to comments from Mr. Jenevein, Ms. Coleman discussed competitive resources in the energy market. She highlighted the additional procurements in the market to cover certain risks like losing the largest unit on the system, wind performing below expectations, or demand coming in higher than expected. "The difference between what we do today and some of the proposals that are under consideration is that those are procured on a day-ahead basis to meet expected real-time volatility, a real-time contingency risk rather than paying plants two, three years in the future for just owning capacity. But I believe that you can get to the same level of investment incentive if you're paying for that insurance policy every single day."

In response to Ms. Parsley's comments on transmission cost allocation and the incentives to avoid those costs, Ms. Coleman stated that the entire industrial sector is not capable of demand or response or 4CP avoidance. In fact, many large industrials pay a significant amount of transmission costs.

In response to Mr. Greene's question on the backup reliability service, Ms. Coleman stated that there always have been methods for paying for dispatchable resources on a day-to-day basis. That is different from a forward procurement of installed capacity. The value of day-ahead or seasonal procurements would move up as the energy prices get lower from the intermittent penetration. She emphasized the need to determine what the market's actual operational variability is, which will vary by season and change over time. Ms. Coleman pointed out that the PUC also is considering a new service called ERCOT contingency reserve service, one of the goals of which is to back up the seasonal variability.

In response to Chairman Wilson's question on long-term dispatchability risk, Ms. Coleman stated that she is not sure there is a dispatchability problem today, but one may be on the horizon. ERCOT already has been taking steps to try to head that off by buying more ancillary services even before Winter Storm Uri. "I do not think that the metric should be ensuring we have enough dispatchable generation to meet absolute peak demand in ERCOT," Ms. Coleman said. This would be very expensive, and the market would be better off going back to an integrated resource planning model of the 1970s. The appropriate objective is to determine the variability and net peak load, and move away from an installed capacity metric toward a real-time volatility metric.

Responding to Chairman Wilson's question on a product that fixes the dispatchable challenge, Ms. Coleman stated that replacing ERCOT's continued conservative operations with a longer term ECRS procurement would be a solution. Ms. Coleman also supports implementing a product like the IMM's uncertainty product, which is a two- or four-hour ancillary service that is designed protect against variability.

In response to Mr. Hall's questions on a reliability metric, Ms. Coleman stated the need to be mindful of cost and flexibility. The biggest benefit of the current market design is that members can hedge risk in the way that best suits their needs.

In response to Mr. Barnes' comments on flexibility, performance, competition, and reliability, Ms. Coleman stated disagreement with the characterization that this is balancing an overall design of purely energy purchases in real-time and long-term installed capacity purchases. "Customers are paying a lot for ancillary services right now," Ms. Coleman said. "Where I get concerned is when you shift away the operational capacity procurements and more toward [where] people are getting paid just for owning power plants independent of real-time performance or any services that are being provided."

Catherine Webking – Texas Energy Association for Marketers

Ms. Webking began her testimony by providing a summary of the REP's role in the market and how wholesale market pricing might affect the retail market and the end-use customer's experience. The REP takes all of the market complexity and price signals, absorbs the market risk, prices that risk and gives it to a residential customer on a fixed price basis.

Ms. Webking discussed competitive forces being the primary driver for prices and services, both in the production and sale of electricity. These are the fundamental tenets of our electric market that provide tremendous benefits to the economy for Texas. Consumers can determine some of their power supply cost because they can participate in the competitive market in whatever form they choose. REPs purchase most of their power on a bilateral basis through a variety of different potential sellers of wholesale power.

Ms. Webking underscored that there were no actions of the retail market that affected the outcome in Winter Storm Uri. Her REP members' aim is to ensure that, whatever wholesale market decisions are made, they are ultimately competitively neutral to the REPs so that this pricing construct can continue, customers can continue to have options and providers can continue to drive innovation. Ms. Webking said this will continue if a market design is first reliable, but also transparent. The market needs liquidity and must be constructed in a way that load can respond to price signals. At times, there may be a regulatory need for an additional reliability safety net, like the firm fuel service and a reliability backstop mechanism of some sort, or the uncertainty product that the IMM has discussed. The Texas market is distinguished by its competitive retail market, which does not exist at this level in any other place in the country.

The impacts to the retail market are potentially severe depending on how these different models are constructed. Ms. Webking stated her concerns about locking in changes that will not allow the same sort of nimbleness that exists in today's market, which allows new technology to come in and adjust quickly.

In response to Mr. Mickey's question on the LSE obligation, Ms. Webking expressed concerns that it would significantly dampen competition in the retail market. Citing the example of the LSE obligation in California, she stated that many independent REPs lost the ability to compete because a new customer would have to find a supplier with sufficient capacity credits available to be able to even offer a contract.

In response to Mr. Barnes' comments on market design, Ms. Webking stated that Texas has a competitive retail electric market that looks different than it does in any other state and that it has been a big success. She agreed with Mr. Barnes' comments that resources can deliver the reliability services for which they are paid. "I think that we can construct a service that does provide that pricing signal," she said. "It doesn't pay it three years ahead of time, but it does provide certainty to those resources that they will get paid for delivering that service when it's delivered."

Wayman Smith – Director of Transmission Planning in the ERCOT and Southwest Power Pool regions, American Electric Power

Mr. Smith outlined improvements to the transmission planning process needed to stay current with today's market. Mr. Smith said the pace of the evolution in the industry is as rapid as he has ever seen with advancements such as intermittent resources, decarbonization, electric vehicles, and distributed energy resources. As a result, Mr. Smith believes it is vitally important that the transmission planning process needs a forward-focused approach to ensure the grid is robust, reliable, resilient, and flexible.

Mr. Smith laid out three ideas to modify and enhance the transmission planning process and criteria. First, ERCOT needs to implement "N-1-1" planning criteria for all seasons (i.e., the simultaneous loss of two transmission elements) to further increase redundancy on the system, which would improve reliability and reduce transmission congestion. Additionally, Mr. Smith pointed out ERCOT's mandatory summer outage restrictions in place from May 15 through September 15 limit the ability to further develop transmission infrastructure construction for a large portion of the year. He stated that these outage restrictions illustrate that the current system likely does not have enough redundancy or capacity built into it.

Second, Mr. Smith testified that it is necessary to have the ability to proactively develop and expand capacity in the transmission system, particularly in key strategic areas in Texas with extensive interest in load-side development. Utilities cannot receive a project endorsement from ERCOT until a signed load interconnection agreement is executed. Mr. Smith said such loads typically want to be connected to the system in two years (or less), but the current process often takes five to seven years from ERCOT endorsement to energization.

AEP and other Texas TSPs often are in competition with other states to interconnect loads and support economic development. If capacity is not available and transmission bulk system upgrades are not yet available, the five- to seven-year timeframe hinders the ability to attract these loads. Mr. Smith advocated for the implementation of transmission planning criteria based on the number of load requests and the magnitude of load in strategic areas to proactively build capacity into the system that could accommodate new loads on a faster timeline.

Finally, Mr. Smith stated that the current transmission planning horizon of six years needs to be extended. Mr. Smith believes this process is constantly focused on a "just in time" transmission and, unfortunately, many times we are "not in time." In some cases, transmission work is performed as energized construction because it was not planned sooner. In such instances, Mr. Smith stated that if projects were planned three to four years earlier, transmission outages could be secured, thus allowing projects to be completed in a safer and more cost-effective way.

Jason Ryan – Executive Vice President of Regulatory Services and Government Affairs, CenterPoint Energy

Mr. Ryan shared a similar point of view on Texas' need for robust transmission system planning, coupled with several strategic initiatives to meet the ever-increasing need for power. Mr. Ryan touched on the topics of utility load management, revising energy efficiency programs and modernizing the electric distribution system as part of an "all of the above" approach.

To avoid turning off power during peaks times, Mr. Ryan pointed to proactive load management programs where utilities pay larger customers to be off-line. Mr. Ryan offered that "energy efficiency and load management can play a big part into whether or not you need to build more transmission or how much more transmission you need to build." Mr. Ryan also pointed out that Texas' energy efficiency programs are almost 20 years old, and perhaps are not being used in the most effective way. Mr. Ryan emphasized the need to make homes and businesses more energy efficient in addition to the need for examining existing energy efficiency programs to ensure the right types of programs are in place.

On the topic of the electric distribution system, Mr. Ryan recapped how system operations have changed with technological advances and emphasized the importance of distribution system operators staying abreast of these advancements. The distribution system of the future will look different from the distribution of today and the distribution system of the past. Installations of battery walls or other kind of distributed generation that put power back on the distribution system are increasing. It is important to understand how customers want to use these capabilities so that new infrastructure can accommodate it. In addition to ensuring the distribution system adapts to expanding customer needs, Mr. Ryan discussed the importance of storm hardening the distribution system similarly to how the transmission system is built.

Mr. Ryan discussed having the ability to now install emergency generation at substations that can be activated during long-term outages when the bulk power system is not providing power. While noting it is an important short-term fix, the laws addressing these assets and their affordability should be further examined. Mr. Ryan explained that utilities cannot own such assets and instead must lease them under the law passed during the 87th legislative session. Mr. Ryan suggested that enough safeguards exist in the law for utilities to own such assets, which would result in a less expensive tool for customers.

In response to committee members' question about the growing number of identified critical customers placing limitations on the ability to shed load, Mr. Ryan said his company is working to develop technology that would allow critical customers to maintain their power while having the ability to turn off power to non-critical customers sharing that same circuit. Mr. Ryan presented the example of a hospital on the same circuit as a neighborhood, and that the homes could be rolled off while the hospital maintains power. Mr. Ryan said this technology would allow utilities to better rotate outages instead of simply turning off the power.

Michael McNamara – CEO, Lancium

Mr. McNamara delivered a presentation on the benefits Lancium can provide on the demand side to the ERCOT grid as the first company with "load-only" controllable load in the world. Lancium creates technologies and builds infrastructure to enable more clean energy production while balancing and stabilizing the grid. Lancium is working to provide demand-side management on a large scale, which Mr. McNamara believes would be cost-effective to ratepayers while providing the PUC and ERCOT control of large amounts of load.

Controllable loads must respond to basepoints from ERCOT while having primary frequency response. Mr. McNamara asserted that frequency response is a way for loads to provide grid inertia. Lancium technology communicates with the grid in real time, has the ability to ramp power consumption up or down in less than five seconds, and can be adjusted based on supply and demand, market prices, and agreements with ERCOT.

Mr. McNamara highlighted Lancium's future 1,000-acre campus in Abilene, Texas, with a planned capacity of 1,200 MW, making it the world's single largest load at a single location. Mr. McNamara described controllable loads as a potential "silver bullet solution."

James McGinniss – CEO and Co-Founder, David Energy

Mr. McGinniss introduced David Energy as a REP and a Qualified Scheduling Entity in ERCOT that has developed software to integrate customers' distributed energy resources, particularly small commercial and residential customers, by connecting them to energy markets.

Mr. McGinniss advocated that distributed energy resources are the best tool Texas could use to build a more resilient grid and cautioned that an LSE reliability obligation would be detrimental to further developing DERs. He described the LSE obligation as "a capacity market without the market," and referenced California's lack of reliability and the northeastern markets' overpriced capacity. Mr. McGinniss urged the committee to maintain an energy-only market structure while allowing the PUC to continue with projects such as the DER aggregation pilot.

"Our grids are highly centralized, composed of large, mostly thermal generation plants connected by extensive transmission and distribution networks to customers, a hub and spoke model. So, you can buy all the dispatchable capacity you want, but you will still see outages from wires or Uri-like events. That is why the only true solution to grid failure is a highly decentralized grid with a lot of customer-sited DERs," Mr. McGinniss stated. Mr. McGinniss further stated that a distributed grid would reduce customer prices by eliminating transmission and distribution costs, while increasing flexibility for grid operators by offering more tools to ensure reliability.

Appendix D:

SUMMARY OF TESTIMONY

August 10, 2022, Austin, Texas

Bob Rose – Chief Meteorologist, LCRA

Mr. Rose presented to the committee weather data for summer 2022, including the upcoming hurricane season. He also provided an outlook into the fall and winter weather forecast.

Kenan Ögelman – Vice President of Commercial Operations, ERCOT

Mr. Ögelman discussed ERCOT's summer 2022 operations and performance, highlighting the peak demand records that had been set, generation resource issues, ERCOT's operating posture, and related data.

Thomas Gleeson – Executive Director, Public Utility Commission of Texas

Mr. Gleeson updated the committee on the activities of the PUC since the June 28, 2022 hearing.

Appendix E:
CONCURRING AND DISSENTING OPINIONS

To: Phil Wilson: Chairman, State Energy Plan Advisory Committee;

From: Mark Ammerman, Committee Member

Date: August 22, 2022

Subject: *The inclusion of "Additional recommendations, comments or clarifications to be included in the non-consensus addendum of the Report"*

Mr. Chairman, in accordance with Senate Bill 3 the State Energy Plan Advisory Committee was formed with a diverse group of experts from within the Power, Oil and Gas producer, Financial and Renewable Power industries. While there were several subtopics to our mandate the overarching task was stated in section 33 (b), **"The advisory committee shall prepare a comprehensive state energy plan"**. The purpose of this plan is to inform members of the Texas legislature of our opinions regarding the strength and reliability of Texas' energy grid, it's pricing mechanisms and the veracity of those mechanisms to incentivize the reliable production and delivery of power under extreme weather events.

The formation of such a knowledgeable group to work as a committee, each supported by their own both deep and experienced resources within their respective industries, and empowered by the office of the Governor, Lieutenant Governor and Texas legislature holds significant promise for the greater public and the business community of the state. My purpose for not consenting to the "Report", as it has so been renamed, is driven by what constitutes the Committee's work product: Our Committee has indeed produced a Report rather than a Plan, as mandated, and the quality and results of that Report do not address the key mandates of SB3.

Accordingly, in my opinion we have failed to: 1) evaluate barriers in the electricity and natural gas markets that prevent sound economic decisions; 2) evaluate methods to improve the reliability, stability, and affordability of electric service in the state; 3) provide recommendations for removing the barriers described by 1) and 2) above; and 4) evaluate the electricity market structure and pricing mechanisms used in the State, including the ancillary services market in emergency response services. Lastly, the requirement of the Senate bill to perform the above analysis and recommendations by September 1, 2022, became impossible when this Committee only met for the first time in July.

<u>My Key Observations</u>:

As a Committee, the time invested by this group and the testimony that has been presented us has brought a number of issues to the forefront and for the benefit of the readers of the report and my comments I offer several items as key observations from someone who is outside of the power industry looking in:

"**If the goal of management is to do things right, leadership is doing the right things"**. Texas is the envy of the United States due to its ability to deploy up to 1/3 of its total electricity capacity with renewables, no other state can match this penetration. In fact, the availability of this amount of renewables has made Texas attractive to many outside companies which otherwise would have to purchase credits to meet their mandated obligations for renewals consumption. Leadership as well evidenced in this outcome. It is the complexity of the management of our grid and its pricing mechanisms in the face of changing barriers that has provided me concerns. An example is the very language of the emergency order provided by ERCOT after the beginning of winter storm Uri:

*Presented from (**SECOND ORDER DIRECTING ERCOT TO TAKE ACTION AND GRANTING EXCEPTION TO COMMISSION RULES; February 2021)***

I. Energy Prices Lower than System-Wide Offer Cap During Load-Shed Event

ERCOT has informed the Commission that energy prices across the system are clearing at less than $9,000, which is the current system-wide offer cap pursuant to 16 TAC § 25.505(g)(6)(B). At various times today, energy prices across the system have been as low as approximately $1,200. The Commission believes this outcome is inconsistent with the fundamental design of the ERCOT market. Energy prices should reflect scarcity of the supply. If customer load is being shed, scarcity is at its maximum, and the market price for the energy needed to serve that load should also be at its highest.

In the words of the management theoretician Dr. Peter Drucker, "*you have to be extremely careful of your incentive compensation system because it always works*". Quite obviously our incentive compensation system was tested and found to incentivize bad behavior, in example:

1. Blackouts were occurring when marginal electricity prices during the emergency were $1200 Mwh although a permitted cap of $9000 Mwh was available to incentivize more power to be brought on. Typically, financial incentives will work every time, we need to better understand why they failed in this instance and address for changes.

2. Outages were not evenly spread across counties or utilities. Tarrant, Dallas and Collin counties in the Dallas-Fort Worth region; Harris, Brazoria, Fort Bend, Montgomery, Wharton, and Galveston counties in the Houston Galveston region, and Hidalgo County in the Rio Grande Valley, experienced the highest number of hours of customer outages across the state. This is a glaring *management issue* that needs to be further studied and addressed.

3. Systemic inequities, disproportionate impacts, and lack of resources for those most vulnerable were demonstrated. In 27 of the 32 counties with the longest outages per person, over 10% of residents live in poverty, including over 30% of residents of Zapata County. Additionally, many other counties most affected are in rural areas where residents would be less able to depend on resources in nearby communities.

4. Water impacts. Power outages reviewed above need also to reflect that 14.9 million Texans were impacted by resulting water outages and related unsafe drinking water that lasted into the following month. The cascading failures from the natural gas and renewables sector to the power delivery sector to the water sector underscore the interdependence of our state's infrastructure.

My observations of issues outside the scope of the Committee's mandate:

During the course of the public testimony presented to the Committee it became aware that we are encountering barriers or perverse incentives in other areas that should be addressed:

1. Wind: Since 2020, hour wind generation capacity has risen from 20 to 30 Gwh but the average run rate of that installed capacity has been as low as 5 and as high as 10 Gwh or

in other words averaging less than a third of installed capacity. There has been no discussion regarding this inefficiency.

2. Solar: Since 2020, we've gone from 4 to 8 GWH of installed capacity but yet average utilization is about 1 Gwh or averaging 17%.

3. Batteries: there are plans over the next three years to increase the solar and wind capability of the state by almost a third of our existing total capacity of power (30 Gwh). The disconnect is there is very little planned dispatch power to be added. Accordingly, we are increasing the percentage of our power that is intermittent, unreliable, and will subject us to outages driven by the fickleness of weather. There was no testimony provided on the availability of long-term power storage which will allow us to benefit and store the power of our renewables at the time that they are actually generating it.

Encouragements:

1. In testimony received, we understand that we now have Railroad Commission and Public Utility Commission individuals sitting side-by-side to identify problems real-time when there's an interruption in natural gas supply that may take down a generator. In the winter of 2021 this "war room" was activated several times and had proven results in reducing pipeline outages to minutes instead of hours/days as previously.

2. The Railroad Commission indicates that it has completed a state-wide and top-down review from the wellhead through the delivery network. Winterization efforts have been completed on the vast majority (85%+) of the producers and the transportation system.

3. Technological solutions which have the ability to adjust power demand or only now being recognized for their potential advantages. Numerous companies have demonstrated their efforts to help better control or lessen power demand at the residential level through in home-based smart technology and also methods to insulate or substitute power consuming appliances with high efficiency replacements. In example, www.Incentifind.com catalogues online all available state, federal and local rebates and incentives a builder, remodeler or homeowner could benefit from. Per their CEO, upwards of $80B of incentives are available nationally and as dispersed will put downward pressure on demand or at least reduce needed power production growth.

4. Favourable opportunities:

A) The public wants reliability and fervently does not want the power to go out again in the winter or during a peak day in the summer. **This demand for reliability is an opportunity and should be considered for our political leadership's focal point and key message**.

B) Texas has an excessive amount of generation capacity in wind that is not being stored and the opportunity is before us to become a leader in developing storage/battery technology. Having no less than Elon Musk in our state, obviously one of the world leaders in this field, should be harnessed to help us become a leader in storage technology in whatever forms that may take.

C) Our abundance of natural gas locally, the ability to add to our nuclear profile and, we don't need significant changes to the eminent domain laws because the right-of-ways for transmission capacity are generally in place. We also have abundant feed stock to support wind and solar expansion and with the state's high credit profile we have a strong financing market.

Conclusions: I encourage our political leadership to consider carrying out the planned effort of SB3 to thoughtfully study the incentives and the barriers within Texas' power system to bring it up as a matter of discussion more thoroughly within the public realm. The report they will be presented representing the work of this committee is inadequate. There are several things that are unstudied but obvious to those on the committee. We have the opportunity to capture the imagination of a generation of young people who are being encouraged to leave fossil fuels behind at all costs without being aware of the nature of the unreliability of renewables given present storage technology. Texas' leadership in technology, and fuels which both drive the mind and power our state should be harnessed along with the imagination of our younger generations to solve the storage issues and correct the unreliability that we presently experience with our reliance on renewables. It is my sincere wish that the mandate of this committee be extended to further study the key points of the senate bill and then a presentation be made to the Legislature, in due course.

<u>Addendum Recommendations from Daniel Hall</u>

Electric and Gas Market Barriers

- The PUC and RRC, with oversight by the Legislature, should work to develop a comprehensive set of prioritization standards for the provision of natural gas to electric generation and electric service to critical loads.

- **Addendum:**
  - As part of the review of prioritization standards for the provision of electric service to critical loads, consideration should be given to the responsibility of the critical load customer to make necessary arrangements for an alternative source of electric power should a localized outage or major weather/system impact event occur. In accordance with PUC Substantive Rule 25.497, customers designated as critical load are not guaranteed an uninterrupted supply of electricity. Customer-driven arrangements for back-up power should be considered for loads that are highly critical.

Electric Service Reliability, Stability, and Affordability

- Transmission line planning and construction timelines often serve as a bottleneck; these processes, requirements, and timelines should be re-evaluated.

- **Addendum:**
  - The following change and clarification is proposed to the recommendation in relation to construction timelines vs transmission planning and approval process timelines.

  - Transmission line planning and ~~construction~~ *approval process* timelines often serve as a bottleneck; these processes, requirements, and timelines should be re-evaluated.

  - In evaluation of transmission line planning and construction to increase transmission pathways for generation availability and creating system resiliency, additional consideration should be given to optimizing transmission planning criteria and approval process timelines which would provide for more timely execution of transmission related projects to serve the increasing electric demand in the state.

To: Phil Wilson, Chairman, State Energy Plan Advisory Committee
From: Joel Mickey, Member, State Energy Plan Advisory Committee
RE: Non- consensus addendum comments

I voted "aye" on the overall report as presented to this Committee because this Committee has a statutory duty to provide this report to the Texas Legislature by September 1, 2022. Subsequently, I have decided to dissent on two last minute additions that were submitted in the Market Structure and Pricing Mechanisms section. These additions, in my opinion, have not been adequately vetted and could cause significant reliability problems within the Electric Reliability Council of Texas (ERCOT) grid. I strongly support the competitive market structure in ERCOT and the competition among generators and retail electric providers that provide the best solutions for Texas consumers and Texas businesses. I believe these additional recommendations undermine the benefits of competition that ensure reliable, clean, affordable electric service that Texans deserve and expect from ERCOT.

1: "Require intermittent generation sources to firm their deliveries with other dispatchable generation technologies"

The recommendation that intermittent generation must firm its energy delivery to the ERCOT grid with a competitors generation output is discriminatory and ignores the fundamental purpose of ERCOT as an Independent System Operator (ISO). The main purpose of an ISO is the ability to take the energy offered from many diverse resources and deploy those resources for the benefit of customers on the electric grid. No generation resource is 100% predictable, and all generation resources shut down for predicted and unpredicted, or planned and unplanned, amounts of time. ERCOT balances these shortcomings among all resources with other generation. That is the paramount function of ERCOT.

As an example, when one of our Texas nuclear units tripped unexpectedly in June, ERCOT used the other generation resources it had available to fill the gap caused by the loss of that resource for approximately two weeks. These events and ERCOT's seamless response happens all the time. The fact that ERCOT has additional resources to utilize is a testament to the value of an integrated grid with resources of all types available to it. Ask yourself, what if the Texas legislature determined that our nuclear resources should pay for all the energy provided by those competing generation resources for the weeks that ERCOT had to procure power because nuclear was not as available as expected for routine maintenance? That could be a bankrupting event. That does not benefit Texas or Texans.

My second concern is the discriminatory application of this recommendation which can be expected to result in thousands of Megawatts of existing renewable generation resources shutting down if forced to purchase large amounts of power from their competitors In addition, this recommendation will discourage new renewable generation from being added to the ERCOT grid. Both results will reduce reliability in ERCOT and increase the likelihood of emergency conditions or rotating outages.

Solar generation has and continues to play a key role in ensuring that ERCOT has enough energy on the grid to serve Texans during the hot summer days. ERCOT's market signals are already incentivizing most new solar development to include storage. With the continued growth of demand in Texas, more renewable generation will help guarantee that ERCOT can serve both existing and new customers as Texas continues to grow. There is very little thermal generation that is planned to be built in the near future in ERCOT, and discouraging new solar generation will be a consequential disservice to Texas and its electric customers.

This discriminatory recommendation will also hamstring ERCOT's ability to operate the grid in the most efficient, reliable manner for Texans. If this recommendation is applied more broadly, the electric industry as a whole - and Texans and Texas businesses - will lose. The key aspect of our current energy-only market structure is to allow real-time energy prices to encourage generation resources and storage to come online when they are needed.

2: "The committee does not support a market design that favors new or subsidized generation over existing resources, as doing so could create regulatory inefficiencies and raise capital costs for Texas ratepayers."

First of all, The ERCOT market does not favor new vs existing resources. All resources get paid the same price for energy produced as set by ERCOT's Nodal day-ahead and real-time pricing. It is a simple fact that new gas-fired generation resources are more efficient than older gas-fired units in converting natural gas into electricity.

Questions to ask:

- Should ERCOT artificially increase the cost of the new units so that they have no economic benefit over the older generation? (There is discussion about state and federal support for new nuclear generation technology to be developed that, if deployed in Texas, could provide additional reliable baseload capacity.)

- Should Texas reject or penalize certain new technologies to protect the older generation resources that have not yet been retired? (The Texas Legislature and the PUC have made it clear that they want to encourage the development of new dispatchable generation and storage in the ERCOT region. If the state wants to achieve that goal, then new resources will be needed. Indeed, targeted state incentives can be used to encourage the development of this new dispatchable generation while minimizing market disruption.)

In sum, if the policy of the Committee is to discourage ERCOT from favoring any subsidized generation resources, then it would be important that the state of Texas account for and eliminate the benefits of all direct and indirect state and federal tax breaks, tax incentives, and any other subsidies for all existing nuclear, coal, gas, and hydro generation resources to ensure that all generation resources are held to the same standard. Here again, the impact of such a policy, if applied fully and on a non-discriminatory basis, could have significant impacts on all generation resources and, in the end, undermine ERCOT's ability to operate the grid reliably if not applied thoughtfully.

Non-consensus addendum of Kenneth Stevens

Texas has a two-part problem to address:
1. Prevent retirement of current dispatchable generation facilities in the near term.
2. Provide incentive that guarantees new dispatchable generation is built sooner, rather than later.

What we do know:

Ancillary service procurement of megawatts has been increased by over 40% since this point in 2021. Since ERCOT is islanded, ancillaries are crucial to regulating the energy volatility within the system to maintain reliability. As a result, ERCOT now contracts about 10% of total system dispatchable capacity within the system on any given day. As intermittent generators become more dominant as a resource more ancillaries will need to be procured to cope with extreme swings in their output. Under our current market design, these services are procured on a day ahead basis. conditioned on procurement methodology that is adopted by ERCOT on an annual basis. No matter what the PUCT adopts as a market design modification, more ancillary services will still need to be procured at ever greater levels to cope with intermittent energy from renewables.

Ancillary services are clearly allowed under PURA to be procured, and costs passed through to all retail consumers of electricity as a non-bypassable charge.

Some megawatts procured under ancillary services withheld from the market and excluded from reserves computed in real time price formation for electricity. This is the case for "non-spin" megawatts which has a minimum of 1400 MW of 10- and 30-minute rampable generation resources withheld from the market. The result is that the market sees the system is in scarcity more often when in fact it is not, artificially raising real-time prices. Incidentally, this replicates the same effect that the backstop reliability service would have on real time prices.

What is the effect:

Generators are now profitable and economically able to operate, given higher prices for power and the ability to bed into a larger pool of ancillary services on a day ahead basis.

What we could do:

Forward price signal-
Instead of procuring ancillary services on a day ahead basis, which does not provide a forward price signal for generators, these could be procured on a monthly and day ahead basis. ERCOT would forward procure a target range of megawatts for each service based on an adopted methodology the month prior to every operating day. If ERCOT believes it needs more ancillary service in the days approaching real time, it can then purchase more the day prior. What this method would lose in cost deficiency for the market would gain in providing forward price certainty for both generators and loads who would be able to lock those resources and costs in incrementally, while still being able to respond in real time. Similar to LSERO this would provide forward price signals for generators where they would be able to lock in a contracted price for their power from month to month.

Backstop Reliability Service (BRS)-
A backstop reliability service could still be implemented to supplant or complement the

capabilities already contracted for within the Non-Spin Reliability Service, but in the instance of BRS, it would encompass less efficient, older units that may otherwise retire. It would have the same effect on real time prices as the current non-spin megawatts since they would be withheld from real time reserved for the purposes of price formation and used only for "black swan" events.

Guarantees for New Generation-
Establish a system for certain qualifying generators to create Dispatchable Energy Credits (DEC), which would be bought, sold, or traded in a similar fashion to the Renewable Energy Credits (REC) now. DEC's would still be needed based on a target reliability standard the PUCT should adopt. If our projected demand is greater than our ability to supply it with dispatchable energy there should be extra value associated with DEC qualifying generation. DEC's could be associated with any megawatt produced by any dispatchable generation resource built after a certain time period. (this would allow the market to determine the type of dispatchable generation we need).

Desired outcome:

Existing generators stabilize in the near term, able to harvest more certain returns on forward ancillary service contracts and more robust real time prices. Over time these existing resources would be slowly replaced by DEC qualifying generation, and the transition would be managed by the rate of newly built generation entering the market with the value of incentives tied to the need to meet demand growth.

ADDITIONAL NOTES

Over the next several years Texas will experience significant growth in load as well as a changing generation Resource profile. It will take all the relevant state agencies and advisory resources from the private sector to tackle the challenges. More work from a group such as SEPAC or a similar group should be done with the SEPAC mission in mind to

(1) evaluate barriers in the electricity and natural gas markets that prevent sound economic decisions;
(2) evaluate methods to improve the reliability, stability, and affordability of electric service in this state;
(3) provide recommendations for removing the barriers described by Subdivision (1) of this subsection and using the methods described by Subdivision (2) of this subsection; and
(4) evaluate the electricity market structure and pricing mechanisms used in this state, including the ancillary services market and emergency response services.

I would recommend to the Legislature that the continuation of the State Energy Plan Advisory Committee (SEPAC) be adopted.

State Energy Plan Advisory Committee Report
Comments from Castlen Kennedy
For the non-consensus addendum
Revised 08.22.2022

I did not have an opportunity to review the full report before its final submission. I therefore voted against the report on Wednesday, August 10 during our second committee hearing.

I am including below a summary of the comments I initially provided on the draft report I reviewed in July. I am hoping some of these were addressed in LCRA staff revisions and am respectfully asking they be included in the appendix.

Sincerely,
Castlen Kennedy

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In general, I am concerned that some of the language in the report perpetuates the overestimation of the role natural gas outages/fuel issues played in the grid's failures during Uri. I respectfully ask that this report not further contribute to this confusion and instead accurately represent the scope the fuel issue played in the broader problem (Note specifically the inaccurate reference and interpretation of the FERC/NERC study data.)

Comments by section/page:

- Executive Summary
  - Page 4: "This report details the initiatives that these state agencies and other stakeholders have undertaken…" – I am not sure this is accurate, nor is it part of what has been asked of us. Recommend striking that sentence.
- Implementation Overview
  - Page 7: "The Public Utility Commission of Texas (PUC), which has opened more than two dozen rulemaking projects related to the implementation of Senate Bill 3, has led the way in ensuring that concrete steps are taken to improve the reliability and effectiveness of the electricity market and its engagement with the natural gas industry." Suggest striking "and its engagement with the natural gas industry." That engagement is a component of addressing the bigger problem – the primary focus is to improve reliability of the and effectiveness of the electricity market.
- Electric and Gas Market Barriers
  - Page 8 and 9: These paragraphs do not seem to address the issue of market barriers.
  - Page 8 and 9: There is little discussion here regarding the causes of the issues at the generating units themselves. From the perspective of a nat gas producer; our biggest challenge was losing power to our facilities, which drove our supply issues.
  - Page 9: The FERC study section misrepresents the data about nat gas' role in the issues.
    - "The FERC/NERC Report concluded that natural gas fuel supply issues caused the majority—87 percent—of the outages and derates that occurred due to fuel issues.8 Natural gas fuel issues were found to be the second-largest cause of generating unit outages overall."
    - The FERC/NERC report is more nuanced: "Natural gas fuel supply issues caused the majority, 87%, **of the 31.4 percent of outages and derates due to fuel**

issues, and **caused 27.3 percent of all outages**, derates and failures to start during the Event." Upon further examination of this data point, **the Natural Gas Supply Association discovered power losses and contracting issues were included in the 27.3% number and when removed, production declines were responsible for, at most, 15.4% of the total outages**. The FERC/NERC report states that of the unplanned outages and derates of gas generating units, 44.2% were caused by freezing issues and 21% by mechanical/electrical issues (page 175). In other words, **2/3rds of the outages and derates were caused by problems at the plants themselves**, not that they could all have been avoided, but they are contained to their operations and not a result of natural gas supply issues.

        - **<u>ERCOT data suggests only 12% were attributable to fuel limitations</u>**.
    - Page 9 and 10: "As a result, volatility in natural gas prices significantly impacts the prices of wholesale and retail electricity, and this volatility has made it challenging for competitive market participants to hedge their risk and for consumers to plan their energy purchases." It should be noted in this section that volatility is a choice generators make when they opt not to secure firm gas product or storage.
    - To the question of actual market barriers in the nat gas markets: as a producer, we have identified several specific issues:
        - There is a lack of market transparency. Specifically, on intra-state pipelines there is no public pipeline gas flow by meter or pipeline interconnect information, no details on the shipper (who owns FT capacity and term), or information on public transport rate matrix;
        - There are no standard multiple nomination cycles;
        - Some pipeline's marketing affiliates control pipeline's commercial and operational decisions regarding daily/monthly open capacity for 3rd party shippers
        - Indexes can be set on nominal traded volume which affects physical and financial deals. For example, during Winter Storm Uri, HSC posted $400 which was established from 5 deals totaling 50,000 MMBtu. $400 was then assigned to all physical and financial deals priced off the GD HSC index.
        - Lack of storage capacity in Permian Basin. Storage capacity gives market participants the ability to access gas from storage during times of supply-demand shortfall, or the ability to inject gas into storage during times of supply-demand surplus
- Electric Service Reliability, Stability, and Affordability
    - Page 11: "As has been widely observed, federal tax incentives for investment in renewable generation have been a significant factor leading investors to favor new wind and solar projects, including in the ERCOT region. Given the growth in intermittent renewable resource penetration relative to dispatchable thermal generation, new planning and operational challenges have emerged that add further complexity to the task of assessing system adequacy and reliability." It seems like we should elaborate here on the issue of the subsidy encourages investment in the renewable generation but the investments do not cover the full cost of having the unreliables on the grid – which is the need to have reliable back up.
- Market Structure and Pricing Mechanisms

    - Page 14: in this paragraph about changes in gen capacity from different sources over time, it would be worth also highlighting the amount of coal-fired gen that has been lost over the same time period, "ERCOT's competitive wholesale market structure relies on market forces to ensure generation sufficiency. For the last decade, federal tax incentives for renewable generation have contributed to significant new wind and solar resources being constructed in ERCOT. According to ERCOT, wind and solar generators accounted for less than one percent of the total generating capacity in 2007, but now account for a combined 38 percent of the total generating capacity.23 Over the next three years, wind and solar account for about 27,800 MW—or 83 percent—of the roughly 33,500 MW in generation capacity that is proposed to interconnect in the ERCOT region, while gas-fired generating units account for only four percent (and coal units account for zero)."
- Implementation sections – I am not sure why these are needed in the report. Seems outside of scope of what we need to summarize for the lege.
- Senate Bill 3 Implementation: PUC and ERCOT
    - In general, this section is very complimentary of the PUC. Seems outside the scope of what we should be commenting on – just stick to the facts. It should mirror the next section on the RRC that is void of commentary on how the RRC has conducted their rulemakings.
    - Page 22: The discussion of weatherization lacks context on how significant this problem of insufficient weatherization at generators was in the storm. Recommend elaborating here or in early sections where appropriate.
- Senate Bill 3 Implementation: RRC
    - Page 27: the rule does not allow "opt out"; an entity must request and be approved for an exception.
    - Page 28: First paragraph: initial rule has been published, final rule expected by fall.
- Section 3: Electric and Gas Market Barriers
    - Page 29: Strike first paragraph, very one-sided. First sentence is conjecture, and I do not agree with it. This makes it sound like all the problems were nat gas producers not communicating with generators. There were numerous details not available to the nat gas producer community – like the amt needed by generators. Again generator outages far exceeded outages related to fuel supply.
    - Page 31: strike back half of this sentence, "The committee is encouraged by the substantial progress that the PUC and the RRC already have made to address failures during Winter Storm Uri **<u>that were created or exacerbated by electric-gas miscoordination and related issues</u>**."
    - Page 31: in this sentence, "Ultimately, a more comprehensive effort by the Legislature to develop prioritization standards for electric service, restoration, and potentially also customer back-up power requirements may be needed." This seems to be more a job for the respective agencies than the lege.
    - Page 31: the work described in this paragraph is happening, don't think this is needed. "Equally important will be the RRC's completion of its weatherization rules for critical natural gas facilities. The committee is encouraged by the progress that RRC staff, working in coordination with the PUC and ERCOT, have made to complete the first map of natural gas infrastructure critical to the electric supply chain. However, unless and until all the critical gas infrastructure in Texas is subject to mandatory weatherization and inspection requirements, the Legislature's core electric/gas reform will not be realized."

  - Page 31: disagree with this sentence, please strike. "Yet this committee continues to have questions about how Texas can ensure that the natural gas supply chain will not have limitations during the next freeze." Next two sentences are not in conflict, unclear on the point being made here.
  - Page 32: in the discussion about underground storage, I would emphasize "market-based" programs/policies/solutions.
  - Page 32: ERCOT Gas Desk – this concept is ill-defined and since we do not have a clear view of what it would do or even that it is definitely needed, and then acknowledge TERC will look into it further, I don't think it adds value here. Recommend striking the whole section.
- Findings and Recommendations
  - Page 42: Electric and Gas Market Barriers
    - second bullet about RRC is already happening. Strike.;
    - fourth bullet; "to include resources with **firm natural gas supply, transport, and storage**." Not just a transport issue.
  - Page 42: Electric Service Reliability, Stability and Affordability
    - Add a bullet similar to the nat gas bullet above, "The Legislature should study market-based solutions to incentivize the development of additional and nonintermittent/reliable power generation."

MEMORANDUM

To: Phil Wilson, Committee Chair

From: Wendy King, Committee Member

Date: August 22, 2022

Subject: Addendum To Draft State Energy Plan Advisory Committee Report

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This is my addendum to the Draft State Energy Plan Advisory Committee Report that I understand will be included with the Final State Energy Plan Advisory Committee Report. I have not seen the final report at the time of this writing, so these comments are directed toward the draft report.

The section of the draft report titled "Electric and Gas Market Barriers" presents a limited view of the barriers preventing sound economic decisions. We heard extensive testimony from the witnesses regarding the different challenges that face the power generation industry. Key among the Market Redesign objectives was improving operational reliability and incentivizing new dispatchable generation. We heard many concerns that the growth of non-dispatchable power was undermining the economic viability of dispatchable power generation. Additionally, there were other barriers to improving reliability including federal emissions regulations, subsidies and inefficient pricing mechanisms. Despite this myriad of important barriers affecting economic decisions, the draft report focusses on the issue of natural gas fuel supply during Winter Storm Uri. While historic weather events like Winter Storm Uri were within the scope of consideration, other barriers caused by other common weather events that cause peak demand should be considered as well. As an example, Texas routinely experiences high demand for electricity during the summer season, yet the draft report focusses instead on this historic winter event.

In addition to the singular focus on Winter Storm Uri, the draft report further focusses solely on natural gas fuel issues. There were other far more significant failures during Winter Storm Uri. ERCOT identified "Fuel Limitations" as the fourth leading cause (12%) of outages and derates during Winter Storm Uri. "Weather Related" at 53%, "Existing Outages" at 15% and "Equipment Issues" at 14% contributed more significantly to the outages during Winter Storm Uri. Additionally, the draft report does not appreciate the complexity and extent of the supply chain responsible for delivering natural gas fuel especially for wellhead gas. Power failures within the supply chain had a profound effect causing equipment to freeze once the flow of production was halted. Much work has been done and is ongoing to address power delivery to the natural gas supply chain. A more reliably energized grid, properly managed load shed and increased utilization by power generators of firm fuel supply services such as natural gas in storage coupled with firm transport from storage to the generator will help to assure the natural gas supply chain performs as expected.

As the grid continues to include more renewable energy, demand side management and increased storage with reliable dispatchable energy will play key roles.