The Texas Deep Freeze of February 2021: What Happened and Lessons Learned?

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ABSTRACT

Although various factors were blamed for the extended power outage on the ERCOT electricity grid in February 2021, no single problem fully explains the calamity. All forms of generation experienced capacity deratings, but failure to identify and address risks along fuel supply chains was a major contributor. Moreover, most proposed remedies do not fundamentally address what occurred. Some may be driven by opportunistic lobbying. We make several recommendations, some of which are already being implemented.

Keywords: Electricity Markets, Natural Gas, Wind, Market Structure, Reliability, Winterization

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1. INTRODUCTION

Extreme freezing temperatures, snow, and ice from winter storm Uri afflicted Texas February 14-18, 2021. Houston, Dallas, and San Antonio saw record-low temperatures of 13, -2, and 5 °F. The power grid operated by Electric Reliability Council of Texas (ERCOT), which serves most Texas power consumers, came close to catastrophic failure. Millions of ERCOT customers suffered blackouts for multiple days. Although true electricity demand was not measured, forecasted demand matched mid-afternoon 4-hour August peak demands, but for 72 consecutive hours.

Scapegoats for the widespread outages included wind generators, thermal generators, natural gas suppliers, Texas opposition to interconnections, ERCOT management, and ERCOT market rules. We find that each of these contributed, but none was solely responsible. In what follows, we provide context on load and resources in the ERCOT market, summarize the events of February 10-21 (before, during, and immediately after the winter storm), discuss the interdependence of natural gas and electricity systems, address resource adequacy and transmission to neighboring regions, recall lessons from previous winter storms, and provide recommendations.

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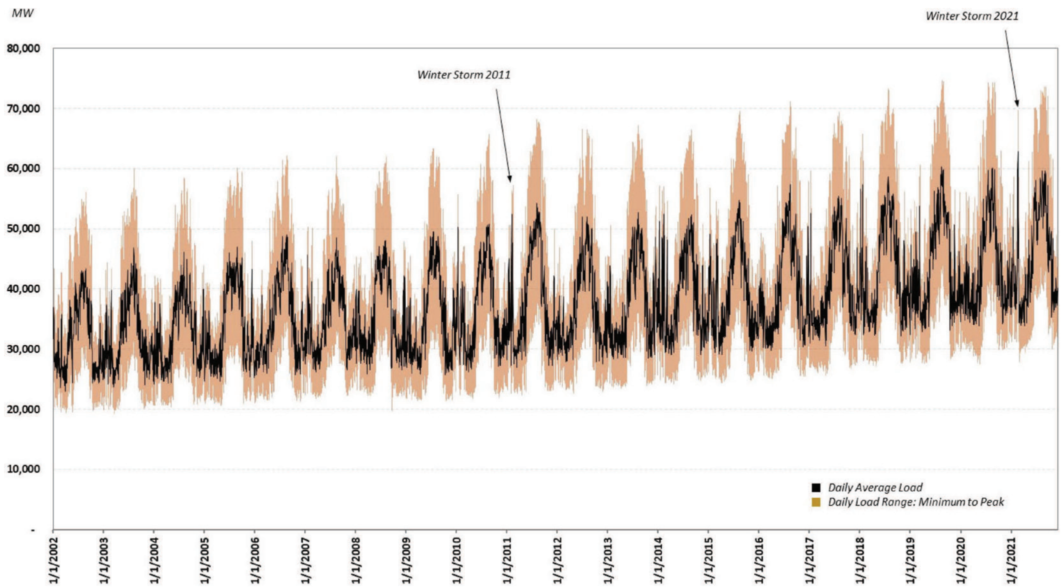
2. BACKGROUND ON ERCOT

2.1 ERCOT Load

Figure 1 shows that daily average electricity load was 42% higher in 2021 than in 2002, at the dawn of the current competitive ERCOT market regime. Strong population growth (36% increase over the same period) and economic growth in Texas drove up electricity demand. Increased demand has, in turn, raised the economic and social costs of outages.

FIGURE 1

ERCOT daily average, minimum and peak loads (Jan 1, 2002–Nov 30, 2021)



Source: Figure data are derived from ERCOT hourly loads (https://www.ercot.com/gridinfo/load/load_hist).

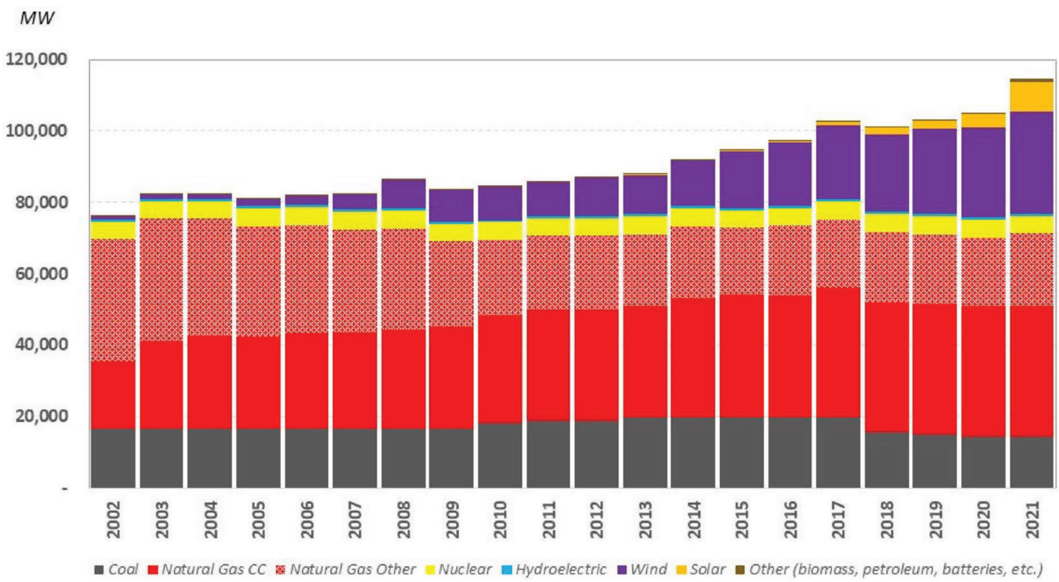
Figure 1 also highlights the day just prior to the power outages caused by Uri, along with a less severe winter storm in 2011. February 14, 2021, recorded the highest *daily average* load seen in ERCOT to that time, although the peak loads experienced during Uri, while high, did not reach the levels typical of summer. Summer demand peaks are expected in Texas, but they typically last 3-4 hours on any given day. The then-record high average daily loads during Uri reflect the persistent high loads for an extended period that ultimately challenged the grid and required more sustained crisis management.

2.2 ERCOT Resources

Figure 2 shows that, from 2002–2021, nameplate generation capacity increased by 50%, from 76 GWs to 114GWs. By comparison, the annual average hourly load increased by 41.5%, from 31.95 GWs to 45.2 GWs. The mix of generating technologies also increased, with nuclear and hydroelectric generation capacity remaining unchanged, coal generation capacity declining, and wind and utility-scale solar increasing. Natural gas combined cycle generation capacity also expanded, but it was almost fully offset by reduction of natural gas generation capacity that is *not* combined cycle (gas turbine, internal combustion, and steam turbine). As a result, ERCOT capacity growth over the last 20 years is almost entirely accounted for by the 36

GW increase in wind and solar generation. The lower load factor of wind and solar generators also explains why total capacity has increased more than load.

FIGURE 2
ERCOT resources, nameplate (2002–2021)



Source: Compiled from ERCOT Resource Adequacy reports (https://www.ercot.com/gridinfo/resource).

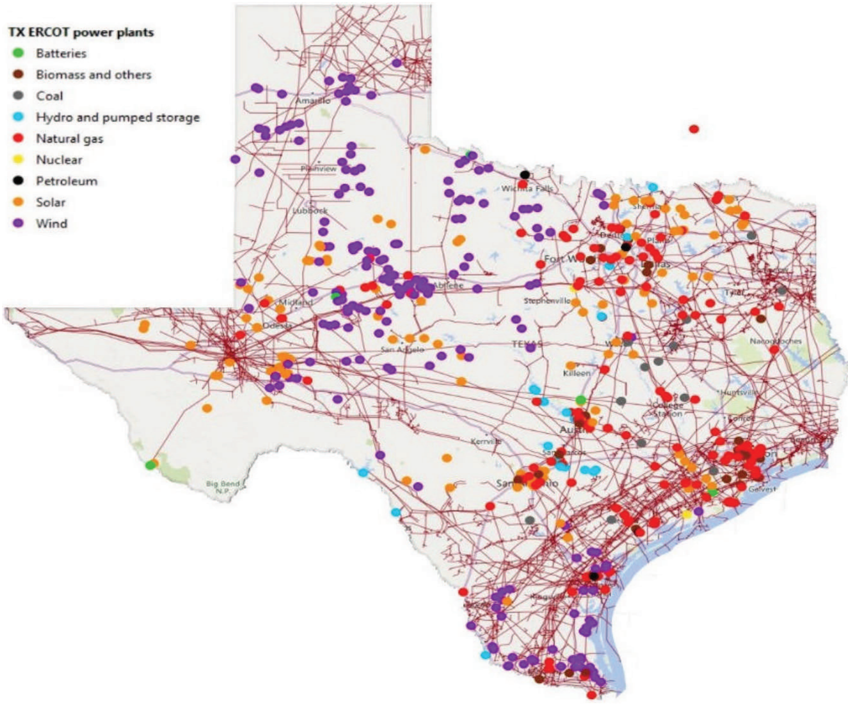
Table 1 summarizes ERCOT resources in December 2020, including switchable and DC interconnect capacity with neighboring regions. While natural gas was 47% of nameplate capacity, it was 61% and 64% of "rated" capacity in summer and winter, respectively (seasonal rating is discussed in Section 3.3).

TABLE 1
ERCOT resources as of December 2020

Resource Type	Nameplate Capacity (MW)	Summer Rated Capacity (MW)	Winter Rated Capacity (MW)
Natural Gas (combined cycle)	28,705	28,705	28,705
Natural Gas (all other)	18,009	18,009	18,009
Nuclear	4,973	4,973	4,973
Coal	14,408	14,408	14,408
Hydro	556	478	434
Wind	31,290	8,504	7,750
Solar	7,637	6,110	535
Other (biomass, petroleum, batteries etc.)	954	677	668
Sub-Total	*104,804*	*81,863*	*75,481*
DC interconnects	1,220	850	838
Switchable Natural Gas (combined cycle)	2,949	2,949	2,949
Switchable Natural Gas (all Other)	1,110	1,110	1,110
Total	**111,810**	**86,722**	**80,377**

Source: ERCOT Capacity, Demand and Reserves Report December 2020 (https://www.ercot.com/gridinfo/resource/2020). Totals include resources with an executed interconnect agreement. Switchable capacity are units available to ERCOT that can interconnect with other regions and thus supplement interconnects as a means of trading electricity with neighboring ISO regions. The rated capacities for thermal plants do not account for maintenance outages, which are highest in the spring, then fall, then winter and lowest in summer.

FIGURE 3
Map of ERCOT electricity generation resources and natural gas pipelines



Source: GIS mapping done by authors using power plant data from Form EIA860 (see https://www.eia.gov/electricity/data/eia860/) and gas pipeline networks (red lines) from Petroleum Economist (see https://gulfpub-gisstg.esriemcs.com/ewa_assets_premium/).

Figure 3 maps power plants serving ERCOT in December 2020, along with natural gas pipelines in Texas. Most wind power is in Northwest Texas, while most natural gas generation is in the area between Dallas, Houston, and San Antonio. As detailed below, generator location affected the timing of the storm impacts, while the configuration of natural gas pipelines affected the impact of reduced natural gas deliveries to generators.

3. EVOLUTION OF THE WINTER STORM AND ITS CONSEQUENCES FOR ERCOT

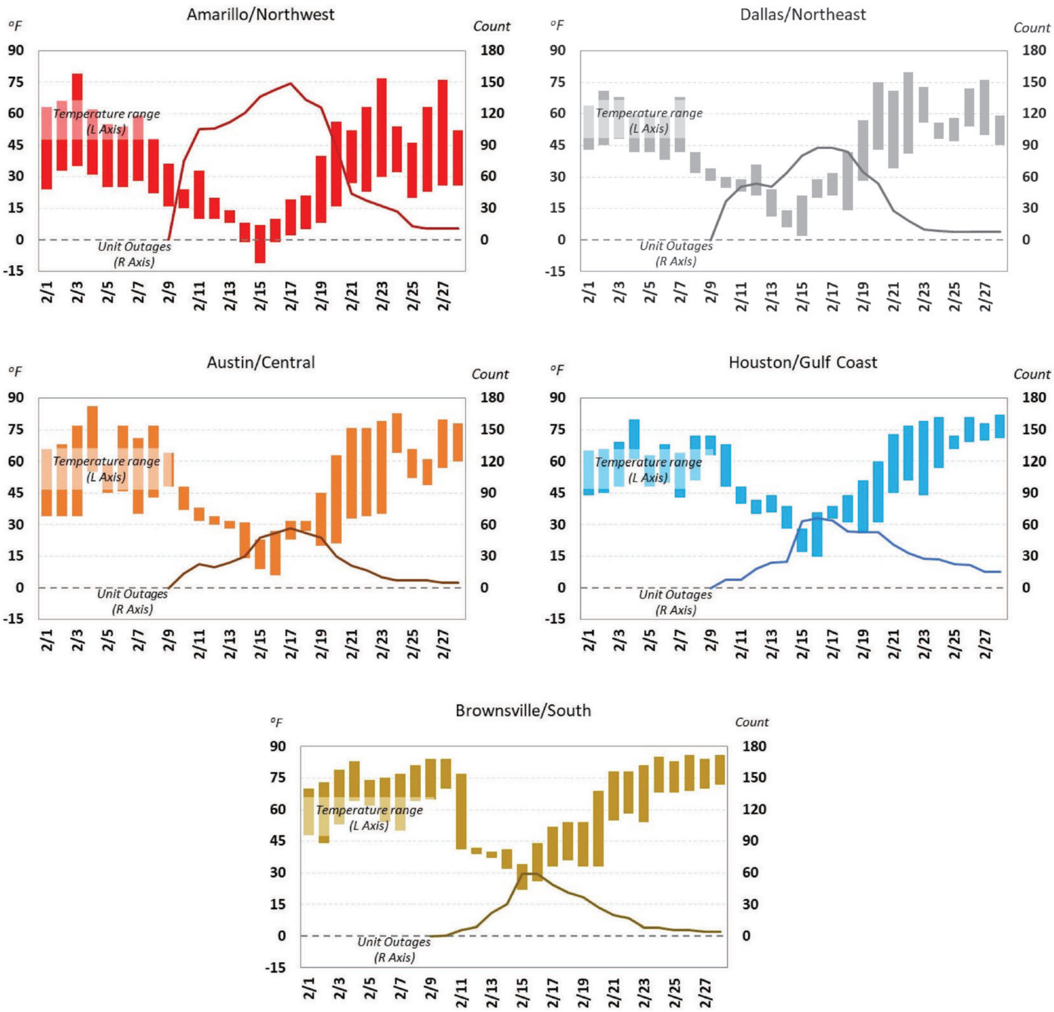
3.1 Temperature changes

Very low temperatures prevailed February 7-18, reaching extremes very rarely seen February 13-15. Within-state variation also was significant, with Brownsville and Amarillo, for example, experiencing 22°F and -11°F, respectively, on the coldest day of the week – February 14. Generally, temperatures were warmer moving south and towards the coast. Low temperature extremes in North and West Texas, from Amarillo to Dallas, were more than 20 °F below extremes from Houston to Brownsville, while temperatures in central Texas (Austin) were about midway between these.

Figure 4 graphs February 2021 daily temperature ranges in five key cities along with maximum daily ERCOT unit outages for regions surrounding those cities (Appendix Figure A1 shows how regions were mapped to cities). Exposure of generation resources to more extreme cold temperatures, and therefore the number and duration of unit outages, generally increased with distance from the Texas coast toward the Northwest (see Appendix Table 1 and Figure A2 for detail on regional outages).

FIGURE 4

Daily temperature ranges and maximum unit outages across Texas, Feb 2021



Note: Regional temperature data shown are for Amarillo Airport, Dallas FAA Airport, Austin Bergstrom International Airport, Houston William P. Hobby Airport, and Brownsville/South Padre Island International Airport, and are obtained using the Local Climatological Data tool at NOAA's National Center for Environmental Information (see https://www.ncdc.noaa.gov/cdo-web/datatools/lcd). Maximum unit outages per day are compiled from hourly outage data in ERCOT's Unit Outage Data reported on March 12, 2021. Additional detail, including the regional definitions, is provided in the Appendix. Additional outage information is detailed in Figure 6 by MW for all of ERCOT.

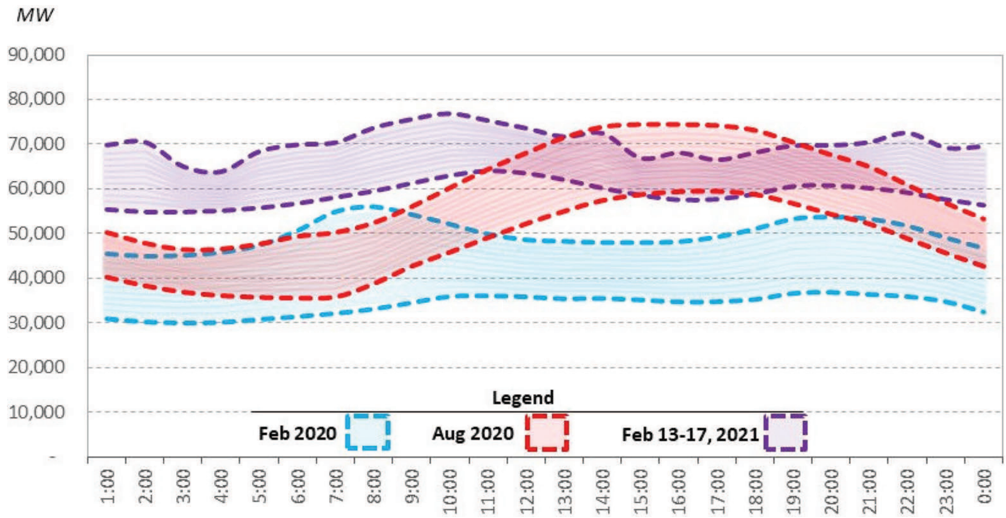
3.2 Demand increases

Cold temperature extremes also increased demand. Figure 5 graphs ranges of demand by hour within a day in three time periods. The first period covers February 13-17, 2021.[1] For comparison, the range of loads by hour within a day are also graphed for all of February 2020

1. Since widespread outages reduced actual loads during February 15-17, day-ahead load forecasts are used.

(representative of historical ERCOT February loads) and all of August 2020 (representing the prior summer peak).

FIGURE 5
Minimum to Maximum Hourly Loads across Three Periods



Source: ERCOT Native Loads (https://www.ercot.com/gridinfo/load/load_hist) and Feb 15-17 load forecasts from (https://www.ercot.com/news/february2021).

Figure 5 shows that electricity demand during Uri was within the range of daytime summer demands in August 2020. However, while peak summer demands typically last a few hours, high demands during Uri persisted for multiple consecutive days, far exceeding historically typical February 2020 demands. ERCOT demand management programs are designed to handle much shorter duration summer demand peaks. Uri posed a unique challenge.

3.3 Supply disruptions

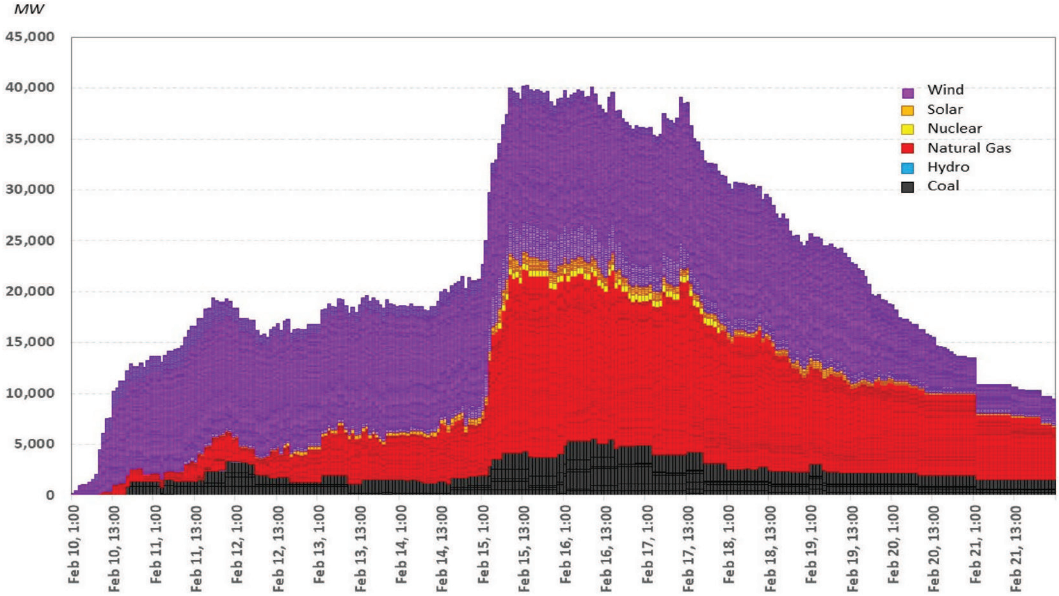
From February 10-21, 263 power plants within ERCOT experienced at least partial outages, while 95 plants, accounting for 14.6 GW, experienced a 100% outage. Peak capacity *un*availability exceeded 40 GW on February 15-16 (Figure 6).[2]

Every source of power generation experienced outages, although some sources that are small fractions of total ERCOT capacity – such as hydro and batteries – had a minor impact on the system-wide failure. Natural gas and wind each accounted for about 41% of peak unavailable capacity, while coal, solar and nuclear accounted for 14%, 3% and 2%, respectively. The reported cause for outage varies by plant. Excluding pre-existing outages, ERCOT listed "weather-related" (53%), "equipment issues"[3] (14%) and "fuel supply deficiency" (12%) as the top three causes of capacity outage, or derate.

2. Adding capacity that was offline for scheduled maintenance would bring total unavailable capacity to 52 GW.
3. The partial outage at the South Texas nuclear power plant, for example, was caused by low steam generator levels from the loss of two feedwater pumps https://www.nrc.gov/reading-rm/doc-collections/event-status/event/2021/20210216en.html

FIGURE 6

Nameplate capacity unavailable to ERCOT by facility and energy source, hourly, Feb 10-21

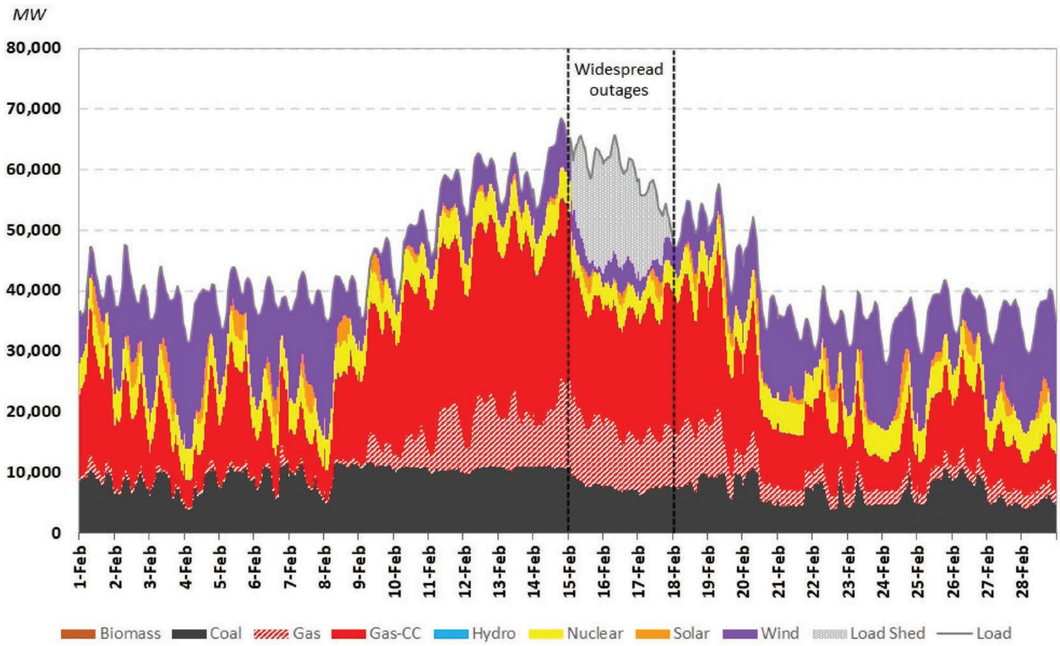


Note, the data depicted do *not* include planned and existing outages.
Source: ERCOT (see https://www.ercot.com/files/docs/2021/03/12/Unit_Outage_Data_20210312.xlsx.)
Available at February 2021 Extreme Weather Event website (see https://www.ercot.com/news/february2021).

The unavailable *nameplate* capacity graphed in Figure 6 does not adjust for seasonal ratings. It captures absent generation capacity, not reductions below expected seasonal availability. As Table 1 suggests, wind and solar are always rated below their nameplate capacities. According to the December 16, 2020 ERCOT Capacity, Demand and Reserves (CDR) report, solar is rated at 80% of nameplate capacity during the summer, but 7% during the winter. Wind is rated at 29%, 61% and 19% in the Texas panhandle, the coast, and other locations, respectively, during the summer, and 32%, 43% and 19%, respectively, during the winter. Seasonal ratings are based on location-specific solar irradiance and wind velocities by season. Using seasonal ratings as a performance benchmark does not recognize that underperformance was due to freeze-related issues rather than typical weather issues. The plants could not have delivered power even if solar irradiance and wind velocities were at seasonal highs. Furthermore, wind and solar resources often deliver above their seasonal ratings, and nameplate capacity is used to calculate their average load factors. Finally, seasonal ratings allowing for unavailability due to planned maintenance are not used for thermal plants.

Figure 7 depicts hourly generation by resource for February 2021 along with forecast load during the period of widespread outages. Natural gas capacity suffered the most derates during the freeze, yet gas-fired generation (the combined red colors in Figure 7) roughly doubled during the days running up to and during the winter freeze. Unfortunately, the grid needed much more. This highlights the importance of always having *operable* generation regardless of circumstances.

FIGURE 7
Generation by resource with load shed indicated, hourly, Feb 2021



Source: ERCOT Fuel Mix Report 2021 (https://www.ercot.com/gridinfo/generation/).

3.4 Administrative Responses

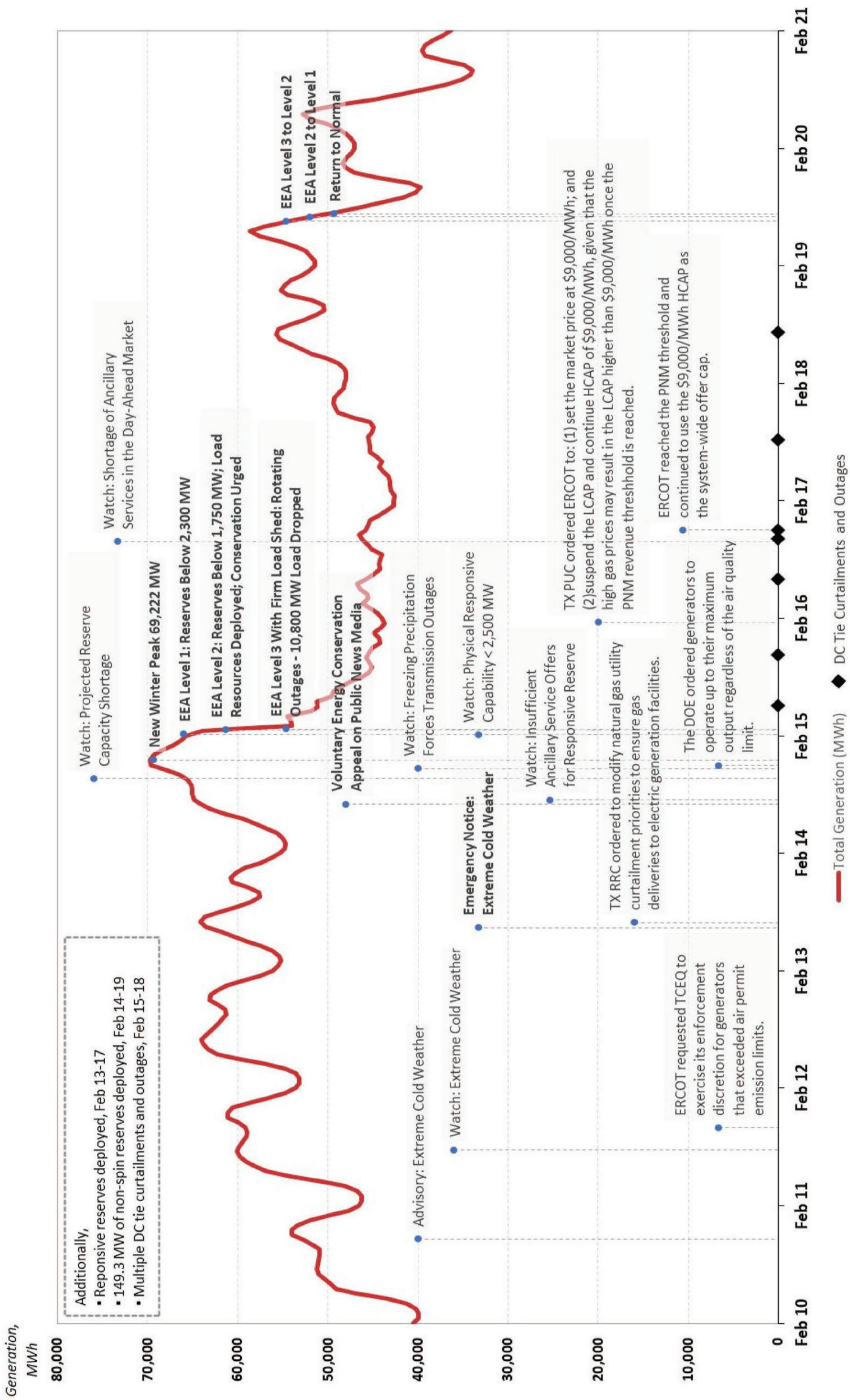
Figure 8 illustrates the timeline of events, actions, outages on DC import/export ties, and total generation over February 10-21. To prevent grid collapse, ERCOT system operators, the Texas Commission on Environmental Quality (TCEQ), the Texas Railroad Commission (TX-RRC), the Public Utilities Commission of Texas (PUCT), and the US Department of Energy (DOE) all took actions to alleviate the generation shortfall. In addition to the actions indicated in Figure 8, ERCOT issued an Operating Condition Notice on February 8 in anticipation of the extreme cold weather. It asked Qualified Scheduling Entities to:

- Update current operating plans and high sustainability limits;
- review fuel supplies, conserve fuel, and notify ERCOT of known or anticipated fuel restrictions;
- delay scheduled maintenance or return plants to operation ahead of schedule; and
- review and implement winterization procedures.

3.5 Demand management and load shed

PowerOutage.us tracks about 12.5 million ERCOT customers. Figure 9 shows that almost 4.5 million of them lost power at the peak of the winter storm. The Dallas-Fort Worth, Houston, and Austin-San Antonio regions saw the highest number of customer outages.

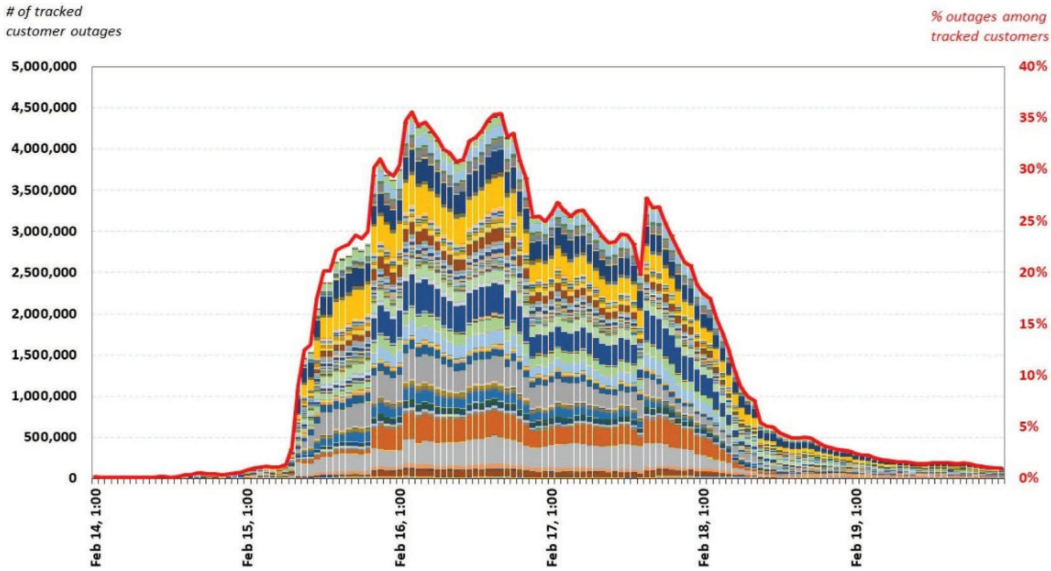
FIGURE 8
Timeline of Critical Events during the period February 10-21, 2021



Source: ERCOT Native Loads (https://www.ercot.com/gridinfo/load/load_hist) and author research.

FIGURE 9

Winter Storm's Tracked Impact, Hourly Customer Outages, Feb 13-19



Note: Colors correspond to counties in Texas. The total # of tracked customers over the period depicted averaged 12,146,948, ranging from 11,707,806 to 12,571,679. A customer is not the same as an individual. The population in Texas is about 29 million, of which about 26 million are served in ERCOT. The average tracked customer total is about 43% of the total population. So, the per capita impact is larger than the indicated per customer impact. Also, the indicated percent outage among tracked customers is for the entire State of Texas, as percentages vary significantly by county.
Source: Data obtained from PowerOutage.US (see https://poweroutage.us/area/state/texas).

The usual response to supply shortages in an electricity network is to (a) dispatch backup capacity (through ancillary service markets or some other means), and/or (b) wheel power in from neighboring regions, and/or (c) reduce native demand via demand-side management.

Demand-side management is deployed when the ratio of load to generation, or operating reserve margins, exceeds certain thresholds. ERCOT issues energy emergency alerts (EEAs) at levels 1 and 2 to request emergency generation from suppliers who can produce above their normal capacity ratings while simultaneously curtailing demand to customers with interruptibility agreements. At level 3, "load shed" orders cut power involuntarily.[4]

Interruptibility agreements typically allow a utility or system operator to reduce power consumption of contracted customers, such as large commercial and industrial consumers, for a specified time with compensation/payment. Some interruptible customers have on-site emergency generation; others can temporarily curtail or cease operations at low cost. Foregone power consumption effectively serves as a virtual supply source, assisting efforts to maintain system stability and avoid involuntary power cuts. ERCOT uses demand-side management most often during peak summer demand periods[5] to abate short-term grid stress. Information on voluntary load reduction participation during Uri is not available, although ERCOT reports that in February 2021 approximately 5,705 MW of load qualified as demand response

4. See https://www.ercot.com/files/docs/2021/03/03/EEA_Tools_One_Pager_Winter_2021_2-13-2021.pdf.

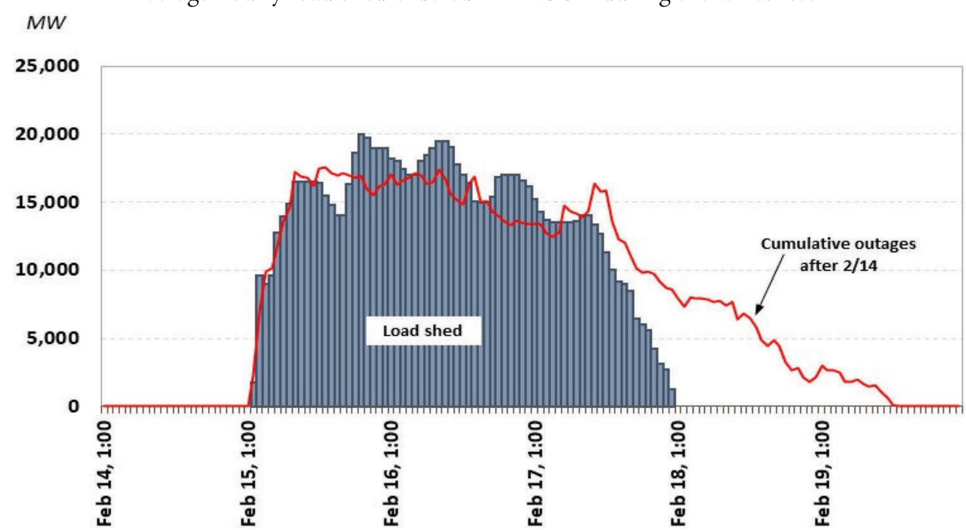
5. See https://www.ercot.com/mp/data-products/data-product-details?id=NP3-110 where it is noted, for example, that ERCOT has additional "weather sensitive" load management programs weekdays between 1 and 7pm from June 1 through September 30.

participating in the Emergency Response Service (ERS).[6] Even so, Uri overwhelmed ancillary service requests and demand-side management capabilities. An EEA level 3, issued at 1:25am on February 15, forced utilities to cut customers involuntarily unless they were "critical load."

Figure 10 graphs average hourly load shed along with "cumulative outages" concomitant with the load shed orders. "Cumulative outages" equals the maximum of zero and total system outage minus the total system outage just prior to the first load shed orders at 12:00am February 15. Natural gas plants comprised most outages occurring after 12:00am February 15. Hence, natural gas has been blamed for much of the load shed during the episode. However, that is partly a function of timing as most wind capacity was already declared inoperable (see Figure 11), which helped trigger EEA level 3. From Figure 10, load shed orders approximately match cumulative outages until midday on February 17. This suggests that *involuntary* load shed with EEA level 3 would have been much less severe if generation resources had remained online.

FIGURE 10

Average hourly load shed ordered in ERCOT during the winter storm



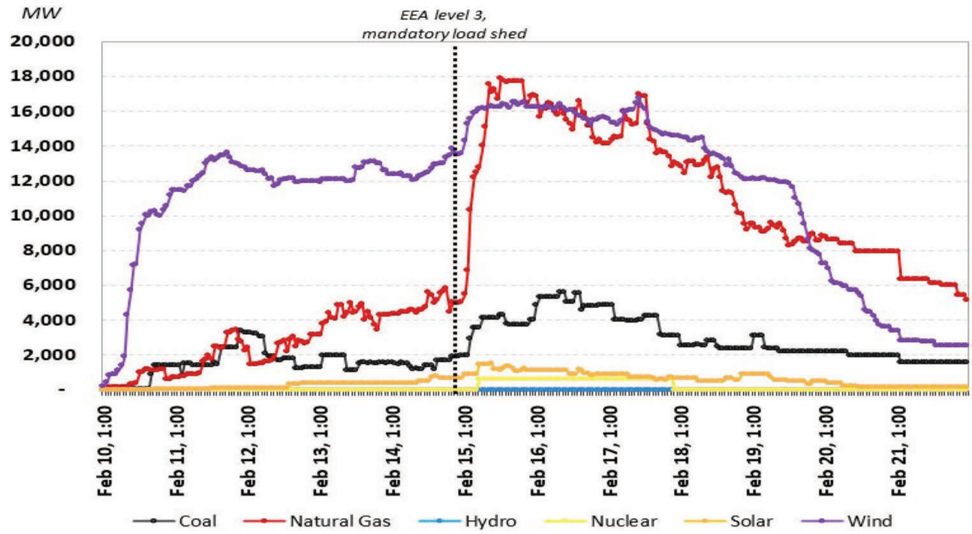
Note: Cumulative outages are calculated as the maximum of zero and total system outage at time t minus the total system outage at 12:00am February 15, which is just prior to the first load shed orders being issued.
Sources: All data obtained from ERCOT. Load shed: 'Available Generation and Estimated Load without Load Shed Data.xls' available at February 2021 Extreme Weather Event website (https://www.ercot.com/news/february2021).
Actual load: ERCOT Native Loads (https://www.ercot.com/gridinfo/load/load_hist).
Outage data: February 2021 Extreme Weather Event website (https://www.ercot.com/news/february2021).

Load shed dropped rapidly as generation came back online (Figure 6) and demand declined with moderation of extreme temperatures. Tracked customer outages dropped below 5% of total tracked customers on February 18 (Figure 9) even though more than 25 GW of capacity remained unavailable to the grid until the following day (Figure 6). This shows the importance of the drop in demand for allowing the grid to rebalance.

The shortfall of generation relative to demand for an extended period yielded extremely high payments to demand-side management customers. Compensating them while smaller

6. See the Monthly ERCOT Demand Response from ERS in the ERCOT Market Information List available at https://www.ercot.com/mp/data-products/data-product-details?id=NP3-107.

FIGURE 11
Outages by generation type, hourly, February 10-21



Source: ERCOT (see https://www.ercot.com/files/docs/2021/03/12/Unit_Outage_Data_20210312.xlsx). Available at February 2021 Extreme Weather Event website (see https://www.ercot.com/news/february2021).

customers suffered involuntary blackouts without compensation became politically contentious. However, demand-side management programs generally work without controversy and have delivered substantial proven benefits in more "normal" emergencies. The performance and role of such programs in ERCOT should be examined carefully before modification is considered.

4. NATURAL GAS SUPPLY CHAIN PROBLEMS

An April 2021 ERCOT report[7] on outages by timing and cause designated "weather" as accounting for more than half of the derates at the maximum. However, "fuel supply limitations" accounted for about one-third, or 6,500 MW, of all natural gas generator outages. If this capacity had been available, the severity of load shed would have been reduced.

The timeline of outages by generation type (Figure 11) helps illuminate what happened. Just before 1:00AM on February 15, 5,518 MW of natural gas generation capacity was already offline. By comparison, 22,677 MW of wind generation capacity was declared inoperable. Over the 12 hours following the EEA level 3 declaration, an additional 12,368 MW of natural gas generation capacity was lost. In those same 12 hours, load shed orders (see Figure 10) exceeded 16 GW.

As previously noted, customers designated as "critical load" can be exempted from involuntary load shedding. Critical load typically includes entities, such as hospitals, who have filed paperwork to show that power interruption could be extremely costly. The winter storm revealed that parts of the natural gas supply chain – such as natural gas compressor stations – were not designated critical load.[8] Cutting their power reduced natural gas flows along the

7. Available at https://www.ercot.com/news/february2021.
8. The Wall Street Journal reported that "Most gas processing plants, pipeline compressors and well had production facilities… shut down during the blackout." See 'As Texas Went Dark, the State Paid Natural-Gas Companies to Go Offline' at https://www.

state's pipeline network. Partial and complete derates at multiple natural gas power generation units ensued. Further load shedding was required, creating a reinforcing feedback loop.

While 12,368 MW of natural gas capacity accounted for 71% of the increased outages in the 12 hours following the EEA level 3 declaration, an additional 1,959 MW of wind, 2,320 MW of coal, 595 MW of nuclear, and 240 MW of solar was lost. So, while the maximum natural gas capacity outage occurred within 12 hours of the EEA level 3 declaration, maximum outages for most other capacity types occurred at different times.[9]

Knowing when and why outages occurred at each generation facility would be very useful, but we could not find such data. A University of Texas study commissioned by the PUCT (King, et al (2021)) that was given access to confidential data noted,

> "Wind turbines suffered some of the earliest outages and derates as freezing precipitation and fog resulted in ice accumulation on blades and – eventually, as temperatures dropped further – in the gearboxes and nacelles. Unit-specific data indicate that other types of generators – mostly those fueled with natural gas – were facing pre-blackout fuel supply issues, and were starting to go offline or derate capacity as early as February 10 due to fuel delivery curtailments." (p21)

ERCOT reported at least 4 GW of natural gas capacity offline due to fuel limitations prior to the EEA level 3 declaration on February 15. The natural gas capacity derates prior to February 15 do not appear *directly* weather-related. Enverus surveyed upstream and midstream firms producing over 50% of natural gas in Texas.[10] A majority of the respondents, even among upstream firms, were grid-connected and identified power outages as the primary cause for reduced flow during Uri. The use of electric drive for compression (driven by environmental and operational motives) has more deeply cointegrated electricity and natural gas markets. Moreover, as wind penetration has increased and coal use declined, gas has become more critical for electricity market balance, meaning the interdependence of the natural gas and electricity systems is now critical for ERCOT.

Apart from power cuts at compressor stations, another cause of reduced natural gas supply may have been lower production resulting from wellhead and equipment freeze-offs. Natural gas production and storage withdrawal data can shed further light on this issue. The US EIA, using IHS Markit data, reported[11] that, "natural gas production in Texas fell almost 45% from 21.3 bcf/d during the week ending February 13 to a daily low of 11.8 bcf/d on Wednesday, February 17." Moreover, the EIA reported that daily production rebounded to 20.9 bcf/d by February 24 as temperatures moderated. A reduction of 9.5 bcf/d of natural gas production, followed by a rebound of 9.1 bcf/d, represents a strong short-term impact of the winter storm.

According to the Texas Railroad Commission, Texas had 375.8 bcf of working gas in storage at the end of January 2021, with a maximum possible cumulative withdrawal rate of just over 17.5 bcf/d.[12] By the end of February 2021, working gas in storage was down to 297.5 bcf. This indicates an average net withdrawal rate of about 2.8 bcf/d. Storage withdrawals

wsj.com/articles/as-texas-went-dark-the-state-paid-natural-gas-companies-to-go-offline-11620385201?mod=djem_EnergyJournal.

9. Solar and hydro are exceptions, but their capacities were not significant for the grid in February 2021.

10. See https://docs.txoga.org/files/2644-4-22-21-enverus_txoga_winter-storm-uri-natural-gas-analysis.pdf. Two referees suggested that this report may be unreliable as it was commissioned by the natural gas industry.

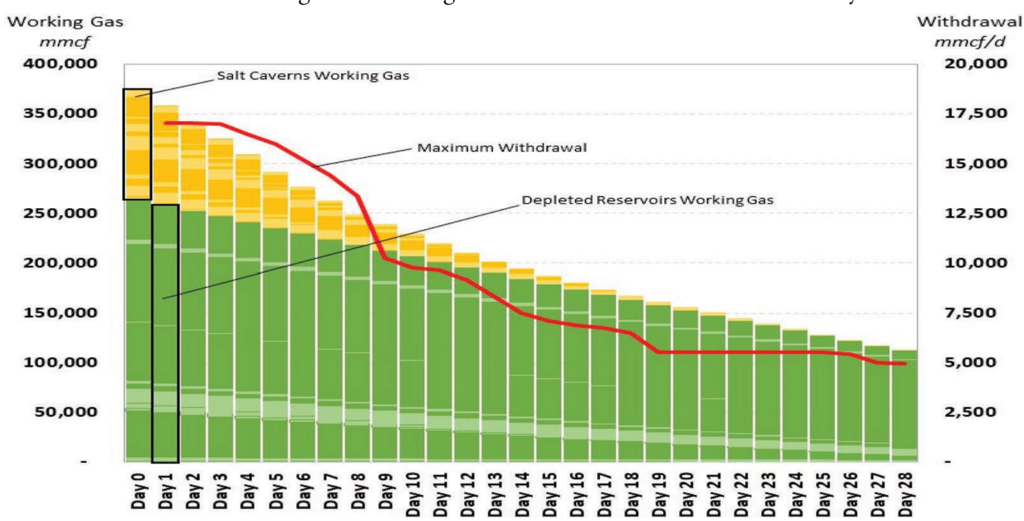
11. See https://www.eia.gov/todayinenergy/detail.php?id=46896.

12. The maximum cumulative withdrawal rate is 5,996 mmcf/d for depleted reservoir storage and 11,540 mmcf/d for salt cavern storage. Depleted reservoirs accounted for about 70% of the working gas storage on Jan 31, 2021.

should have been able to offset the lost 9.5 bcf/d production volumes during the winter storm, but daily injection and withdrawals for Texas storages are unavailable. So, we simulated how inventory would have evolved during February 2021 assuming maximum storage withdrawal every day. Figure 12 uses data for working gas in storage by facility as of January 31, and the maximum withdrawal rate at each storage facility, to simulate how total working gas (green and yellow bars, left scale) and aggregate maximum daily withdrawals (red line, right scale) could have evolved under 28 days of withdrawal at maximum rates.[13]

FIGURE 12

Simulated Working Gas in Storage at Max Withdrawal Rate for February 2021



Source: Working gas and reported maximum withdrawal rates are from the Texas Railroad Commission reports on gas storage statistics (https://www.rrc.texas.gov/gas-services/publications-statistics/gas-storage-statistics/).

The simulation reveals that the daily maximum withdrawal rate declines from over 17 bcf/d to about 5 bcf/d by day 28 as facilities deplete. Thus, withdrawals from storage should have been able to offset the production decline of 9.5 bcf/d during the winter storm since this is only about 54% of the maximum daily rate. An aggregate daily withdrawal rate of 9.5 bcf/d would be reached after 12 consecutive days of maximum withdrawals, so end-of-January storage should have been sufficient even if high net withdrawals occurred during the week prior to the winter storm.

This analysis supports the hypothesis that power outages compromised gas deliveries by impacting storage facilities and/or compression on pipelines between those storage facilities and end-users. The three largest storage fields in Texas (West Clear Lake, North Lansing, and Bammel) account for 47% of total working gas capacity, and are powered by electric compressors. Boling, Spindletop, and Markham, which account for 9.2% of active Texas storage capacity, each use gas-fired compressors.[14]

It follows that natural gas storage *and* transportation infrastructure should be designated critical load because both are essential to addressing short term demand-supply imbalances.

13. Note that, operationally, salt cavern storage can be drawn down faster, so daily overall withdrawals decline more slowly as they come more heavily from depleted reservoir storage.

14. We are unaware of any publicly available data on the withdrawal rates at these specific facilities.

The fact that it was not represents a single point of failure in the Texas energy system that failed to recognize the interdependence of natural gas and electricity. On March 18, 2021, ERCOT issued a notice that it had posted an application on its website whereby facilities that supply natural gas to generation units could request designation as critical load.[15] This two-page form shows how a fundamentally simple filing could reduce the risks of catastrophic failure during load shed events.[16]

5. COULD PROBLEMS HAVE BEEN AVOIDED?

Figure 13 compares the load reported by ERCOT with (i) what load would have been if mandatory load shed were added back ('Actual load + load shed') and (ii) what might have been generated without plant outages after February 14 ('Actual load + cumulative outages after 2/14'). It also includes 'load shed' (mandatory load shed after EEA level 3), and 'cumulative outages after 2/14' (the sum of outages by hour that occurred after 11:59pm on February 14) as depicted in Figure 10. The 'total outages' reported by ERCOT reveal the erosion of any back-up or otherwise unutilized capacity that occurred prior to the load shed orders.[17]

Outages approaching 20 GW had already occurred on February 13 and 14, and load spiked to almost 70 GW on February 14. When load shed was ordered early February 15, grid frequency already had plummeted due to demand exceeding generation. Thus, the cumulative outages experienced after February 14 necessitated load shed orders given the demands on the ERCOT system.

Moreover, since 'actual load + load shed' exceeds 'Actual load + cumulative outages after 2/14' multiple times on February 15-17, some (lesser amount of) load shedding would have been necessary even if no capacity outages had occurred after February 14. Resources that were offline prior to February 15 would have been needed to avoid any system-wide emergency alerts, so outages occurring prior to February 15 left the market in precarious balance.

While natural gas generation accounted for most of the incremental outage surrounding EEA level 3 (Figure 11), the system had become stressed without those outages. If gas generation had not failed, there would have been a heightened focus on wind generation because the bulk of the outages would have been from wind (Figures 6, 7 and 11). Furthermore, gas sufficiently coped with other capacity outages until the very early morning hours of February 15. Any subsequent shortfall in generation relative to demand would have rendered the conclusion that gas generation capacity, even if operating without disruption, was insufficient to make up for the shortfall of wind.

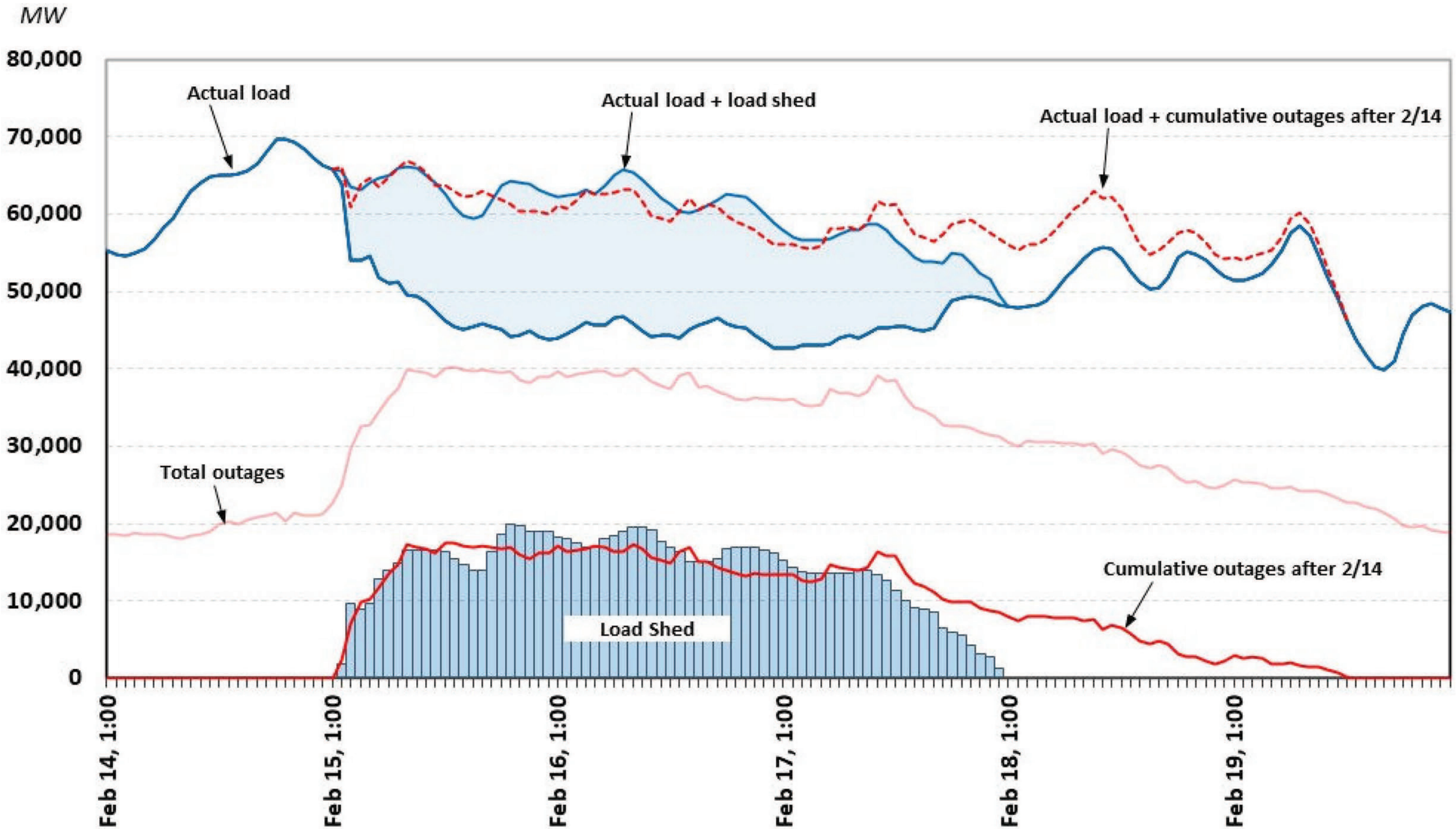
In summary, avoiding the *extent* of the load shed and customer outages experienced during the winter storm would have been possible with a more resilient natural gas supply chain. But avoiding the non-gas generation capacity outages prior to February 15, as well as non-gas gen-

15. See https://www.ercot.com/services/comm/mkt_notices/detail?id=5009a357-5ea6-39d8-a3a7-1b5744805903, which is at ERCOT's February 2021 Extreme Weather Event website (https://www.ercot.com/news/february2021).

16. A Texas House Hearing Feb 25-26 revealed that Oncor, the largest natural gas pipeline operator in Texas, added 168 facilities to the list of critical infrastructure that originally included only 35 gas facilities in the Permian Basin prior to the freeze. https://house.texas.gov/schedules/committee-schedules/advanced-search/search-results/?startDate=01/01/2019&endDate=20210303&chamber=h&committeeCode=C250&legislature=87. This was also reported by the Houston Chronicle, https://www.houstonchronicle.com/politics/texas/article/Simple-paperwork-blunder-Texans-cold-winter-storm-16032163.php.

17. Day ahead load forecasts for ERCOT were also presented in Figure 13 in an earlier iteration of this paper. Of note, the day ahead load forecast crested at over 76 GW during the mid-morning of February 16, touching similar levels on February 15. The constructed series 'Actual load + load shed' never reaches these levels, but exceeds 60 GWs for a substantial number of hours.

FIGURE 13
Load shed ordered, outages, and actual load, hourly, February 14-19



Sources: All data obtained from ERCOT. Load shed: 'Available Generation and Estimated Load without Load Shed Data.xls' available at February 2021 Extreme Weather Event website (https://www.ercot.com/news/february2021). Actual load: ERCOT Native Loads (https://www.ercot.com/gridinfo/load/load_hist).
Outage data: February 2021 Extreme Weather Event website (https://www.ercot.com/news/february2021).
Series for 'Cumulative outages', 'Actual load + cumulative outages', and 'Actual load + load shed' are author calculated (see text).

eration capacity outages after February 15, would have also helped. Hence, all capacity types must be operable to cope with high stress events.

6. RESOURCE ADEQUACY

6.1 A role for capacity markets?

According to ERCOT's CDR reports, the winter reserve margin was 72% of *expected* load in the winter of 2011, but had fallen to 43.2% for the winter of 2021. Does ERCOT have sufficient reserve capacity? Even if resources can reliably manage *average* February demands, extreme outcomes matter most in power systems. Thus, some have suggested ERCOT needs a capacity market to improve reliability. However, historical electric disturbance events[18] across the United States do not appear to reveal a positive correlation between capacity markets and reliability. Furthermore, during Uri, inadequate o*perational* capacity was the issue, not insufficient *nameplate* or *rated* capacity. Even if a capacity market had ensured extra capacity on the ERCOT grid, it also likely would have been inoperable. The events of February 2021 highlight the need to ensure that available capacity is *operational*, as addressed by legislative action on winterization.[19]

6.2 The impact of renewables?

Wind generation failures, most of which occurred prior to February 15 as equipment froze, were also blamed for compromising reliability. The loss of wind output indirectly contributed to the subsequent cascading failures of natural gas generation by compromising electricity supply to gas supply infrastructure not declared as critical, and direct loss of wind output also mattered. We do not assess wind generation failures as the primary reason for widespread outages during Uri, but increased wind generation does pose a growing, but manageable, risk for ERCOT.

Figure 14 reveals growing wind generation capacity and variation in wind output in ERCOT. Unexpected, uncontrollable variation of wind output across short time intervals requires responsive dispatchable generation to maintain system balance. Historically, when wind output is low in ERCOT other generation resources meet load without extensive involuntary load shedding. ERCOT's resource adequacy assessments address the extent to which this status quo can be *expected* to prevail. As such, they must account for installed capacity and expected demand at peak, but also for variability in generation output. Lower capacity ratings by season to allow for the latter may not be sufficient in *extreme* circumstances when averages are irrelevant.

Currently, Texas has more wind capacity and more *planned* wind and solar capacity *additions* than any other state, and it is in second place for *planned* battery capacity additions. However, at the time of writing, little-to-no additional non-battery dispatchable capacity is planned. Growth in demand *and* intermittent resources raises the risk of electricity shortages.

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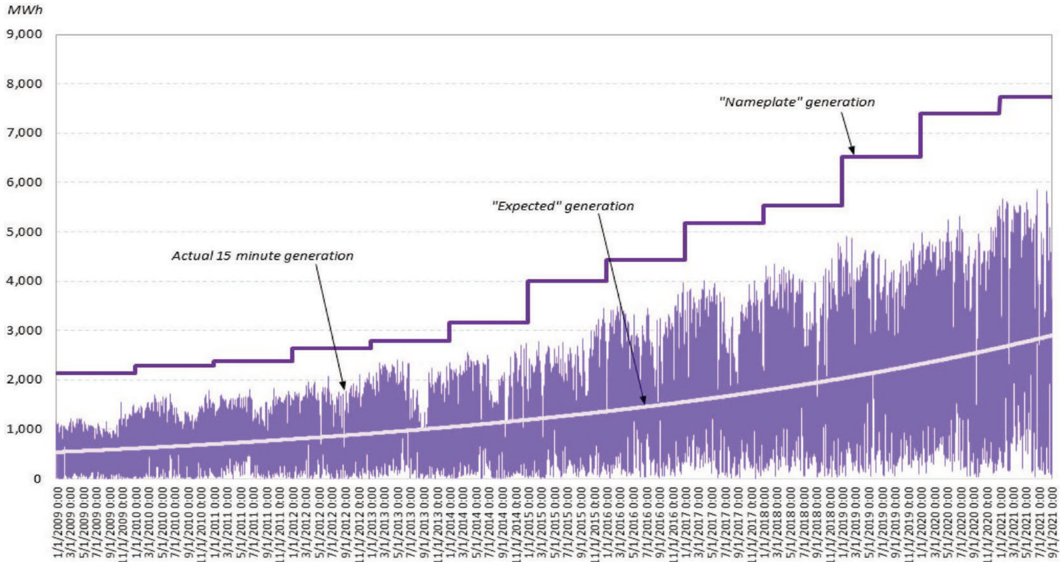
18. The US DOE utilizes the Electric Emergency Incident and Disturbance Report (Form DOE-417) to collect information on incidents impacting electric power markets. This data is available online at https://www.oe.netl.doe.gov/OE417_annual_summary.aspx, and is a subject of ongoing research by the authors.

19. Senate Bill 3, 87 (R), Texas 2021 (https://capitol.texas.gov/BillLookup/History.aspx?LegSess=87R&Bill=SB3) which went into effect on 6/8/2021 requires weatherization measures by certain energy facilities, including power plants; House Bill 2000, 87, Texas 2021 (https://capitol.texas.gov/BillLookup/Actions.aspx?LegSess=87R&Bill=HB2000), in the Senate at the time of writing, would allocate $2 billion of the state funds to subsidize weatherization measures.

FIGURE 14

Wind – Actual and "expected" generation (15-minutes) and Annual nameplate generation



Source: Data compiled from ERCOT. "Expected" generation is the best fit over time to the actual 15-minute generation, and is only for illustration. "Nameplate" generation converts the annual average wind capacity, in MW, to MWh assuming it is 100% utilized every 15 minutes. Resource planning utilizes seasonally rated capacity, which is different by season.

This should increase the desire for "insurance" (or backup), but as Figure 2 shows retirements of dispatchable capacity have prevailed.

Texas wind generation is at seasonal maximum in the spring,[20] while demand peaks in the summer. Planned battery installations are short duration. While they significantly assist frequency management, they can neither efficiently store energy for months at a time nor provide supply during multi-day events like Uri. Higher reserve margins of flexible, dispatchable generation will be needed to ensure reliable electric power if load growth and intermittent capacity continue to expand similarly to the last 20 years.

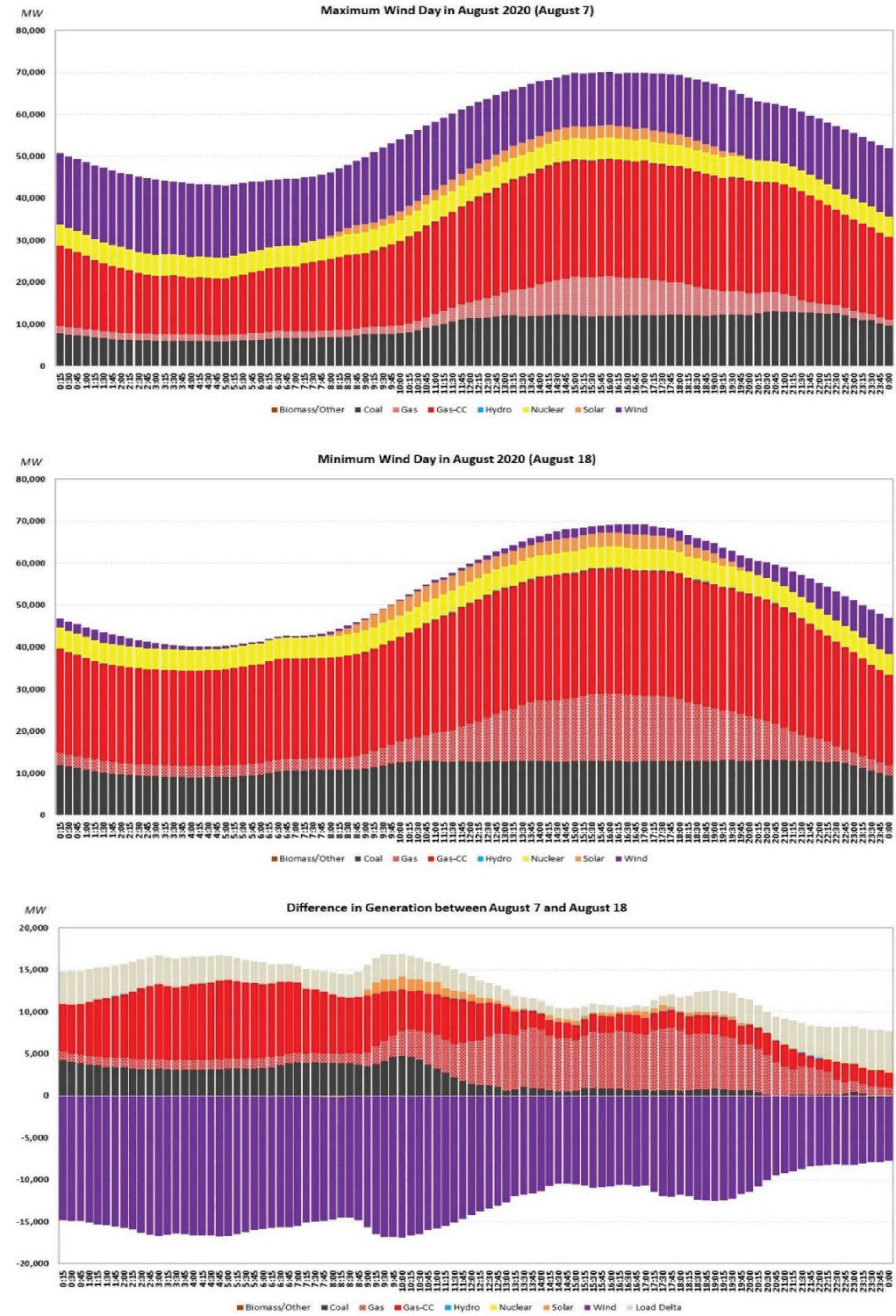
Figure 15 depicts ERCOT generation by source in 15-minute intervals on days of maximum (August 7) and minimum (August 18) wind generation in August 2020. Peak load was 70.1 GW on August 7 and 69.3 GW on August 18. The third panel shows the differences in generation between the two dates. Multiple sources helped balance the market, but natural gas offset an average of 62% of the difference in wind generation. As wind generation dropped and demand increased leading up to February 15, 2021, involuntary load shed may have been avoided if resources had responded as they did in August 2020.

Figures 14 and 15 show that wind generation regularly fluctuates, making seasonal capacity ratings a poor guide for generation requirements. When wind delivers *above* its seasonal rating, as often happens, price is depressed as higher operating cost plants are displaced. If wind is the marginal supply, price can be driven to minus the value of wind production subsidies. When wind delivers *below* its seasonal rating, as often happens, price still may not increase much above the marginal operating costs of intermediate plants, depending on system load. Thus, dispatchable capacity that may frequently be idle but serves as system-wide insurance must be sufficient to meet any combination of wind generation and system-wide demand. At

20. See Figure 14 and https://www.eia.gov/todayinenergy/detail.php?id=20112

FIGURE 15

Generation in ERCOT on the MAX and MIN wind generation days for August 2020



Source: ERCOT generation data from "Fuel Mix Reports" (https://www.ercot.com/gridinfo/generation).

present, the *social benefit of reliability* provided by available, dispatchable generation capacity may be under-valued in current market designs.

7. WOULD CONNECTING ERCOT TO NEIGHBORING REGIONS MAKE A DIFFERENCE?

Stronger interconnections with neighboring regions have been proposed as a remedy to the problems of February 2021. However, as noted in Figure 8, the DC ties connecting ERCOT with neighboring regions were curtailed many times February 15-18. Furthermore, capacity outages and emergency load reductions were simultaneously occurring in neighboring regions.

Southwest Power Pool (SPP) covers parts of north and east Texas, Oklahoma, and states north to Canada. SPP initially served its native load with its own resources plus imported power from neighboring grids. However, supply from neighboring grids declined as native loads in those regions also grew. SPP ordered mandatory load shedding February 15-16.[21] SPP subsequently assessed that up to 59 GW of generating nameplate capacity was offline during the winter freeze. At peak demand on February 16, about 30 GW of capacity was unavailable due to forced outages, 47% of which were due to fuel supply issues at natural gas facilities.

Midcontinent Independent System Operator (MISO) serves parts of east Texas, Louisiana, Arkansas, and other states throughout the Midwest. It interconnects with SPP to the west and multiple regions, including PJM, to the east. MISO's post-event analysis noted that, "At one point during the Arctic Event, PJM pushed as much as 13,000 MW into MISO's system, which MISO and SPP used to maintain economic pricing and support grid operations."[22] Nevertheless, MISO also ordered load shedding February 15-16.

Outages in SPP and MISO would have compromised the role of transmission, as Uri was a widespread event. But stronger interconnections between ERCOT and neighboring grids also raises other questions. For example, if such links were established decades ago, they would have affected investment in generation infrastructure in Texas *and* neighboring regions. The regulatory environment, and robust wind and natural gas resource endowments in Texas, would have likely encouraged more generation capacity to be built there, making Texas a large *exporter* of electricity to neighboring grids. Insufficient weatherization of generators and fuel supply problems in ERCOT might then have exacerbated the crisis. In any case, it is naïve to envision expanded interconnections as a panacea by assuming nothing else would change.

8. DID ERCOT LEARN FROM THE 2011 EVENT?

Power outages in ERCOT from a 2011 winter storm triggered several postmortems.[23] Winterization and improved fuel supply security were priority recommendations along with

- planning for peak winter events as diligently as peak summer events,

21. See "A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations," by Southwest Power Pool, published July 19, 2021. (https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf)

22. See "The February Arctic Event, February 14-18, 2021: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative." (https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf)

23. See "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations," prepared by Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), August 2011 (see https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfromFebruary2011Report.pdf). Additional analyses on the 2011 winter event are available on NERC's February 2011 Southwest Cold Weather Event website (see https://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx).

- re-evaluating planned outage schedules for winter months,
- increasing responsive reserve capability,
- increasing the winter reserve margin, and
- improving communication between balancing authorities and transmission operators.

From 2011–2021, responsive reserve capacity increased from 1,062 MW to 1,570 MW, or from 2.4% to 2.6% of forecasted peak load. However, as noted in Sections 5 and 6, growth in the fraction of non-dispatchable generation required more.

The 2011 FERC investigation cited inadequate protections from freezing weather. Notably, the PUCT recommended improved winterization of generators following a 1989 cold weather event, and it was noted in the 2011 aftermath that, "These [winterization] recommendations [from the 1989 cold weather event] were not mandatory, and over the course of time, implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011."[24]

Even though deficient fuel supply was not a major cause of outages in 2011, postmortems noted the interdependence of electricity and natural gas markets in Texas and the importance of protecting natural gas production from cold weather.

At the close of its 2011 study, FERC concluded that although extreme winter weather events were infrequent in ERCOT, more research to allay concerns related to grid reliability and resilience was warranted. *Déjà vu*.

9. RECOMMENDATIONS AND CLOSING REMARKS

We opened with a list of scapegoats for the February 2021 disaster in ERCOT: wind generators, thermal generators, natural gas suppliers, Texas opposition to interconnections, ERCOT management, and ERCOT market rules.

Wind underperformed relative to its *nameplate* capacity, but this is always true (Figure 14). Wind generation capacity is "rated" at a discount to nameplate capacity based on expected wind resources. It often outperforms or underperforms relative to that rating. During the winter storm, wind underperformed since output was below what would have been anticipated given the forecasted and actual wind speeds.

Texas wind generators are not winterized. Winterization is not free, and the benefit depends on the likelihood it is needed. There may be a stronger case for winterization in the Texas panhandle than in coastal regions.

Wind's underperformance during the winter storm only mattered for grid stability because resources that typically back-up wind were unavailable. This highlights the need to fully evaluate availability of back-up resources in planning scenarios.

A related issue is whether the increased value of reliability as the fraction of non-dispatchable resources increases is adequately reflected in prices. *A resilient, reliable electricity system requires price signals adequate to ensure sufficient investment in all types of capacity and the right mix of generation capacity*.

Thermal capacity deratings varied across generation types. A facility-by-facility assessment is needed, with some remedies likely to be facility-specific. *Winterization of thermal capacity can be an important first step, especially under a favorable cost-benefit analysis. If all thermal capacity*

24. Reliability Standard EOP-001 R.4 and R.5, which refer to winterization as part of the emergency plans, apply to only balancing authorities and transmission sectors.

had remained operable during Uri, load shed likely still would have been necessary, but remained voluntary, thereby avoiding the EEA level 3 declarations.

Fuel supply issues must be addressed. Variability in wind generation requires flexibility in back-up sources of generation including the supporting infrastructure such as pipelines, storage and processing facilities, and wellhead production. During the February 2021 event, natural gas generation was needed far in excess of a *typical* February day, but power cuts negatively impacted the fuel supply chain and compromised generation. *Fuel supply infrastructures should be mandatorily designated as critical load*.

Interconnecting ERCOT with SPP, MISO and WECC might have yielded some short-term benefits. But surrounding regions were also stressed, as existing interconnectors were curtailed multiple times February 15-18. Longer term, increased transmission capacity would alter the location of capacity investments, and the impacts on reliability are uncertain. *A study of the long-term effects of expanding interconnections between ERCOT and neighboring regions is warranted*.

Assessments of **ERCOT's management of the grid** need to account for the fact that ERCOT doesn't own, operate, or regulate generation assets. To maintain system stability, it schedules generation and invokes previously arranged voluntary load reductions. During Uri, ERCOT's real-time management avoided catastrophic failure. *Long-run planning, however, can be faulted for not adequately assessing the impact of extreme events across the entire energy supply chain. Better coordination among state regulatory agencies would allow long-run planning to extend beyond the electricity market into the various fuel supply chains.*

Market structure rules might be improved to ensure adequate reserve capacity. *Factors such as the social value of reliability, the value of lost load, and increased demand management need to be more actively integrated in market rulemaking*. A full exploration of changes in market rules to cope with zero marginal cost, subsidized, non-dispatchable generation is beyond the scope of this paper, but such exploration would usefully contribute to future planning.

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House Bill 2000, Session 87(R), Texas 2021 is in the Senate at the time of writing, would allocate $2 billion of the state funds to subsidize weatherization measures. See https://capitol.texas.gov/BillLookup/Actions.aspx?LegSess=87R&Bill=HB2000),

Data Sources

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Load shed data from 'Available Generation and Estimated Load without Load Shed Data.xls' (https://www.ercot.com/news/february2021)
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Local Climatological Data at NOAA's National Center for Environmental Information (https://www.ncdc.noaa.gov/cdo-web/datatools/lcd)
PowerOutage.US (https://poweroutage.us/area/state/texas)
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APPENDIX

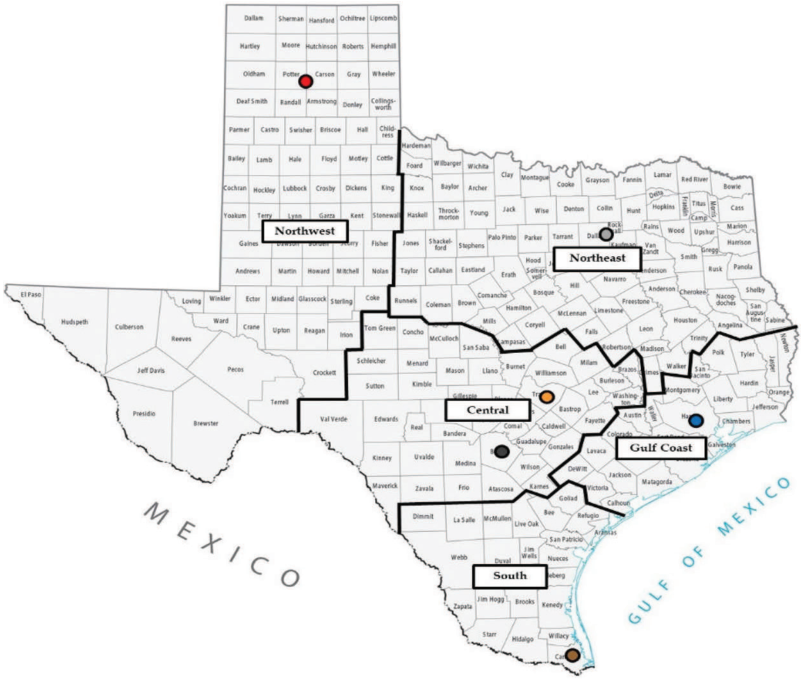
TABLE A1

Regional nameplate capacity, outages and detail by energy source

		Texas	Region (see Figure A1 for detail) Northwest	Northeast	Central	Gulf Coast	South
All Energy Types	Nameplate Capacity (MW)	111,810	24,686	39,253	17,553	18,271	12,047
	# of plants	441	139	113	82	50	57
	# of units	*805*	*224*	*220*	*148*	*122*	*91*
	# of plants impacted by Winter Storm Uri	271	102	68	39	25	37
	Maximum outage (MW)*	67,766	16,967	21,738	10,026	11,215	7,820
Natural Gas	Nameplate Capacity (MW)**	50,771	4,081	20,413	10,543	12,165	3,570
	# of plants	92	8	30	19	27	8
	# of units	*344*	*39*	*112*	*73*	*95*	*25*
	# of plants impacted by Winter Storm Uri	81	8	27	18	21	7
	Maximum outage (MW)*	32,806	3,643	12,199	7,185	7,828	1,951
Coal	Nameplate Capacity (MW)	14,408	---	7,023	4,216	2,514	655
	# of plants	12	---	5	5	1	1
	# of units	*23*	---	*10*	*8*	*4*	*1*
	# of plants impacted by Winter Storm Uri	8	---	3	3	1	1
	Maximum outage (MW)*	7,853	---	3,780	1,514	1,904	655
Nuclear	Nameplate Capacity (MW)	4,973	---	2,400	---	2,573	---
	# of plants	2	---	1	---	1	---
	# of units	*4*	---	*2*	---	*2*	---
	# of plants impacted by Winter Storm Uri	1	---	-	---	1	---
	Maximum outage (MW)*	1,353	---	-	---	1,353	---
Hydro	Nameplate Capacity (MW)	556	---	128	393	-	36
	# of plants	17	---	4	12	-	1
	# of units	*29*	---	*6*	*20*	-	*3*
	# of plants impacted by Winter Storm Uri	1	---	-	1	-	-
	Maximum outage (MW)*	17	---	-	17	-	-
Wind	Nameplate Capacity (MW)	31,290	15,534	6,468	1,589	151	7,549
	# of plants	175	86	37	9	1	42
	# of units	*250*	*131*	*51*	*10*	*1*	*57*
	# of plants impacted by Winter Storm Uri	147	75	34	9	-	29
	Maximum outage (MW)*	23,431	11,710	5,547	960	-	5,214
Solar	Nameplate Capacity (MW)	7,637	4,906	1,307	536	666	223
	# of plants	90	32	25	21	9	3
	# of units	*99*	*41*	*25*	*21*	*9*	*3*
	# of plants impacted by Winter Storm Uri	22	14	3	4	1	-
	Maximum outage (MW)*	2,224	1,580	197	327	120	-
Other	Nameplate Capacity (MW)	954	165	295	277	202	15
	# of plants	53	13	11	16	11	2
	# of units	*56*	*13*	*14*	*16*	*11*	*2*
	# of plants impacted by Winter Storm Uri	11	5	1	4	1	-
	Maximum outage (MW)*	82	34	15	23	10	-

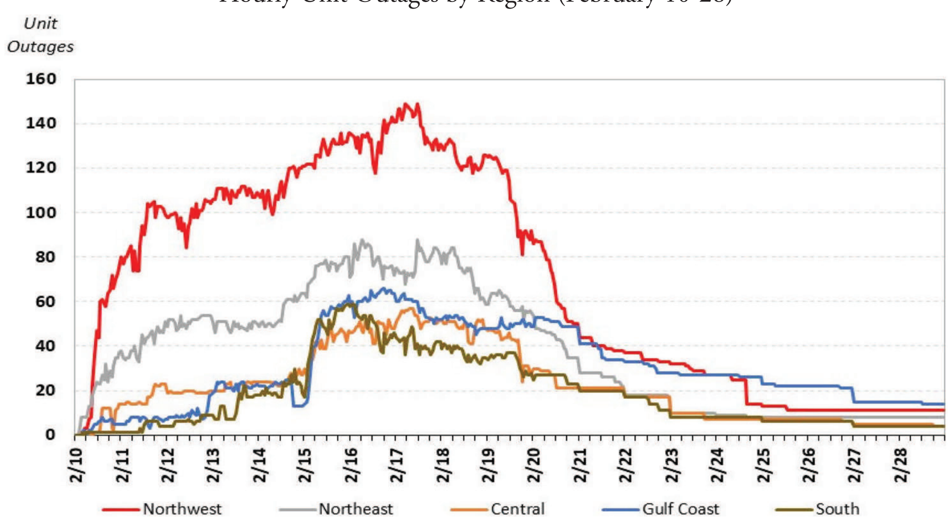
* - Maximum outage reflects the sum of the maximum derated capacity during the month at each unit. Derates across all units occurred at different times, so the maximum outage will exceed that was actually witnessed in any given hour. Figure 6 reveals the MW outages in each hour.
** - The reported nameplate capacity includes switchable capacity, which are natural gas units.
Note, the capacities of DC ties are not included in this table.
Source: Data are compiled from the ERCOT *Capacity, Demand and Reserves Report*, December 2020 and the ERCOT *Unit Outage Data* published March 12, 2021.

FIGURE A1
County-to-Region Mapping



Note: County designations to each region do not represent ERCOT load zones or weather zones, which are available at https://www.ercot.com/news/mediakit/maps. There is some overlap, but the outlines were constructed for illustrative purposes, and match more closely to oil and gas production basins.

FIGURE A2
Hourly Unit Outages by Region (February 10-28)



Source: Data compiled from the ERCOT *Unit Outage Data* published March 12, 2021.
Note: Regional definitions are as identified in Figure A1. The unit outage counts include partial and total derates.

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