ERCOT Froze in February 2021. What Happened? Why Did It Happen? Can It Happen Again?

Peter R. Hartley, Ph.D.
George A. Peterkin Professor of Economics, Department of Economics and Rice Faculty Scholar, Center for Energy Studies, Baker Institute for Public Policy, Rice University

Kenneth B. Medlock III, Ph.D.
James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Senior Director, Center for Energy Studies, Baker Institute for Public Policy, Rice University

Elsie Hung, M.Sc.
Research Manager, Center for Energy Studies, Baker Institute for Public Policy, Rice University

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Abstract

A step-by-step examination of various factors that were blamed for the extended power outage on the ERCOT electricity grid in February 2021 reveals that no single factor fully explains the calamity. All forms of generation capacity experienced failures, but bureaucratic failure in identifying and addressing risks along fuel supply chains was a major failure. 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.

Introduction

The February 2021 winter storm severely affected the Texas power grid, operated by Electric Reliability Council of Texas (ERCOT). Between February 14 and 18, freezing temperatures, snow and ice afflicted the state. Multiple cities, including Houston, Dallas, and San Antonio, saw record-low temperatures at 13, -2, and 5 °F, respectively. From February 14 to February 16, blackouts imposed on millions of ERCOT customers for multiple days prevented true demand from being measured. However, forecasted electricity demand matched mid-afternoon 4-hour August peak demands, but for 72 consecutive hours. The winter storm was abnormal in a historical context and tremendously stressed the grid. ERCOT experienced prolonged and widespread generation outages that require deeper analysis to fully understand.

Almost everything in the ERCOT market has been blamed and/or scrutinized following the winter storm. The “blame game” was in full swing well before power was restored. Scapegoats identified in mainstream and social media headlines included:

- wind generators,
- thermal generators,
- natural gas suppliers,
- Texas opposition to inter-connections,
- ERCOT management, and
- ERCOT market rules.

Each of these could fairly share some blame, but none was solely responsible. The extreme cold weather caused outages and derates of all types of power generating resources. No energy source was spared. At the February 16 peak, over 30% of ERCOT’s rated winter capacity was offline. As supply fell below demand, ERCOT shed load across the state to prevent total grid failure. Moreover, emergency orders prevented power exports, via DC interconnections, to neighboring regions also experiencing electrical system failures. In summary, an unprecedented shock severely threatened ERCOT stability by exposing weaknesses in the Texas energy system. Some of the problems were avoidable. All of them have triggered a massive wave of deliberation about possible reforms.

In what follows, we first set the stage by outlining the Texas market. Next, we discuss the demand spike and how system failure ensued. A timeline from February 10 to February 21 summarizes events that unfolded immediately before, during and immediately after the freeze. We also discuss demand management and load shed, the natural gas system and its interdependence with electricity, and lessons learned (some relearned from the 2011 freeze) including portents for the future of power systems as energy transitions.
Setting the Stage

In 1999, Senate Bill 7 was passed, introducing competition into wholesale and retail markets in ERCOT, which serves the majority of Texas power consumers. As illustrated in Figure 1, average daily electricity load was 42% higher in 2021 than it was in 2002, owing to population and economic growth. The day just prior to the power outages caused by Winter Storm Uri, February 14, is also highlighted. It recorded the highest *average* daily load ever seen in ERCOT, although the *peak* load was still below the peaks witnessed in recent summers. The average daily loads in Figure 1 are skewed by the number of hours on any given day that load reaches its peak level.

Figure 1. ERCOT average daily load (1/1/2002 – 11/30/2021)

![Figure 1](https://www.ercot.com/gridinfo/load/load_hist)

Source: Daily averages calculated from ERCOT hourly loads ([https://www.ercot.com/gridinfo/load/load_hist](https://www.ercot.com/gridinfo/load/load_hist)).

As usual in power systems, peaks are more relevant for assessing strain on available capacity. Figure 2 shows that the peak loads experienced during the winter storm, while high, did not reach the levels typically seen during summer. However, grid stability depends on demand relative to available capacity and in Texas the expectation of summer peaks leads to more planned maintenance being done in the normally lower-demand winter months. Moreover, the ERCOT power system has largely been built to reliably handle peak summer loads, which typically last 3-4 hours on any given day. By contrast, load spiked into peak levels for multiple days during the winter storm, which required a different sort of reserve capability. That said, the ERCOT system should have coped better with the stress. Given the winter ratings of installed capacities available to the grid, some load shedding would have been necessary, but the calamity that ensued in February 2021 should not have occurred. The steadily increasing demand shown in Figure 1 means that the economic and social costs of outages have also been rising. This highlights the need for a full understanding of what transpired during the crisis.
ERCOT Resources

As ERCOT load has increased, generation capacity has grown more, and evolved to reflect a greater diversity of generating technologies, as illustrated in Figure 3. Coal generation capacity has declined substantially in recent years. Nuclear and hydroelectric generation capacity has remained unchanged, while wind, utility-scale solar and natural gas combined cycle generation capacity have expanded. Natural gas generation capacity that is not combined cycle (i.e.- gas turbine, internal combustion and steam turbine) has declined over the last decade, but total natural gas generation capacity has increased slightly. In sum, wind and solar generation capacity has grown by almost 36 GWs, and accounts almost entirely for the net increase of installed nameplate capacity in ERCOT over the last 20 years. The generally lower load factor of wind and solar generators also explains why total capacity has increased more than load.
Table 1 details the ERCOT fleet as of December 2020, noting switchable capacity and DC interconnect capacity with neighboring regions. While natural gas represented 47% of total capacity as of December 2020, it was 61% and 64% of “rated” capacity in summer and winter, respectively. Since December 2020, only wind, solar, and some battery storage has been added, so the overall fractions of natural gas capacity have declined.

**Table 1. ERCOT resources as of December 2020**

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Nameplate Capacity (MW)</th>
<th>Summer Rated Capacity (MW)</th>
<th>Winter Rated Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas (combined cycle)</td>
<td>28,705</td>
<td>28,705</td>
<td>28,705</td>
</tr>
<tr>
<td>Natural Gas (all other)</td>
<td>18,665</td>
<td>18,665</td>
<td>18,665</td>
</tr>
<tr>
<td>Nuclear</td>
<td>4,973</td>
<td>4,973</td>
<td>4,973</td>
</tr>
<tr>
<td>Coal</td>
<td>13,568</td>
<td>13,568</td>
<td>13,568</td>
</tr>
<tr>
<td>Hydro</td>
<td>556</td>
<td>479</td>
<td>436</td>
</tr>
<tr>
<td>Wind</td>
<td>30,173</td>
<td>8,023</td>
<td>7,268</td>
</tr>
<tr>
<td>Solar</td>
<td>5,019</td>
<td>4,015</td>
<td>351</td>
</tr>
<tr>
<td>Other (biomass/etc.)</td>
<td>1,389</td>
<td>989</td>
<td>976</td>
</tr>
<tr>
<td><strong>Sub-Total</strong></td>
<td><strong>103,047</strong></td>
<td><strong>79,416</strong></td>
<td><strong>74,942</strong></td>
</tr>
<tr>
<td>DC interconnects</td>
<td>1,220</td>
<td>850</td>
<td>838</td>
</tr>
<tr>
<td>Switchable Natural Gas (combined cycle)</td>
<td>2,948</td>
<td>2,948</td>
<td>2,948</td>
</tr>
<tr>
<td>Switchable Natural Gas (all Other)</td>
<td>542</td>
<td>542</td>
<td>542</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>107,757</strong></td>
<td><strong>83,756</strong></td>
<td><strong>79,270</strong></td>
</tr>
</tbody>
</table>

Source: ERCOT Capacity, Demand and Reserves Report December 2020 (https://www.ercot.com/gridinfo/resource/2020). Switchable capacity are units available to ERCOT that can interconnect with other 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 4 maps the location of all resources that served ERCOT in December 2020 by energy type, along with the oil and natural gas pipeline network.\(^1\) The majority of wind power is located in West Texas, while the Texas Triangle – the area between Dallas, Houston and San Antonio – hosts the majority of natural gas generation capacity. The natural gas pipelines, storage and production are discussed further below in the context of the winter storm.

**Figure 4. Map of ERCOT resources**

Temperatures dropped and demand spiked

The location of generators affected what happened during the storm. North and west Texas, from Amarillo to Dallas, experienced low temperature extremes more than 20 degrees below temperatures experienced along the coast, from Houston to Brownsville (Figure 5). Temperatures in central Texas (Austin and San Antonio) were about midway between those seen along the coast and in north Texas. Thus, the exposure of generation resources to more severe extreme cold temperatures increased with distance from the coast.

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\(^1\) Local distribution infrastructure is not mapped. The “Other” category in Table 1 has been separated into battery installations, petroleum, and biomass and others in Figure 4.
The cold temperature extremes also increased demand. Figure 6 depicts the high, low and average loads for February 12-17 2021 compared against February 2020 and August 2020. February 2020 conformed relatively well to historical loads in ERCOT for that time of year while August 2020 represents the prior summer peak. The extreme cold temperatures over February 12-17 drove demand to levels typically seen on the hottest days in August, but for much longer periods of time. Although demand

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2 While actual loads are graphed for February 12-14, we use day-ahead load forecasts for February 15-17 because the actual loads over those three days reflect widespread system outages.
management programs may have sufficed to avoid load shedding in the absence of supply problems, high demand coupled with supply problems produced disaster.

**Figure 6. Minimum, Average and Maximum Daily Loads, Feb 13-17, 2021, Feb 2020 and Aug 2020**

![Graph showing daily loads for different periods](image)

Note: Day-ahead load forecasts are used for Feb 15-17 because widespread outages occurred during that period.


**A timeline of what happened**

A series of actions were taken to alleviate the widespread generation shortages and ultimately to prevent grid collapse. Figure 7 illustrates the timeline of relevant events and actions taken by ERCOT and other authorities – which include the Texas Commission on Environmental Quality (TCEQ), the Texas Railroad Commission (TXRRC), the Public Utilities Commission of Texas (PUCT) and the US Department of Energy (USDOE) – as well as total generation and occurrences of DC tie curtailments and outages (import/export transmission capacity) over the period February 10-21, 2021.

In addition to the events in Figure 7, on February 8 ERCOT issued an Operating Condition Notice (OCN) in anticipation of the expected extreme cold weather, asking Qualified Scheduling Entities (QSE) to:

- update current operating plans (COPs) and high sustainability limits (HSLs) when conditions change as soon practicable;
- review fuel supplies, prepare to preserve fuel to best serve peak load, and notify ERCOT of any known or anticipated fuel restrictions;
- review planned resource outages and consider delaying maintenance or returning from a planned outage ahead of schedule; and
- review and implement winterization procedures.
Figure 7. 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.
The OCN expresses concern for reliability in an attempt to ensure reliable grid operations. Nevertheless, the steps taken ultimately proved insufficient. PowerOutage.us tracks about 12.5 million of the more than 26 million customers ERCOT serves in Texas. Figure 8 shows that almost 4.5 million of the 12.5 million tracked customers lost power at the peak of the winter storm on February 16. The Dallas-Fort Worth, Houston, and the Austin-San Antonio regions saw the greatest increase in load as well as the highest number of customer outages.

**Figure 8. Winter Storm’s Tracked Customer Impact, Hourly Outages, Feb 13-19**

[Graph showing hourly outages from Feb 13 to 19, with peak outages on Feb 16.]

Source: Data obtained from PowerOutage.US (see https://poweroutage.us/area/state/texas).

**Generation Capacity Outages**

Electricity service was steadily restored to most customers throughout the day on February 18. Activities at some generation facilities resumed as deratings subsided (see Figure 9), but demand also moderated due to warmer temperatures. Tracked customer outages dropped below 5% of total tracked customers on February 18 even though more than 25 GWs of capacity remained unavailable to the grid until the following day (see Figure 9). The steeper fall in outages in Figure 8 than unavailable capacity in Figure 9 shows that the fall in demand as the cold subsided was critical to allowing the electricity grid to rebalance.

A total of 263 power plants within ERCOT experienced at least partial outages at some point between February 10 and 21, with 95 plants, accounting for 14.6 GW, experiencing a 100% shutdown. The peak capacity unavailability was over 40 GW on February 15-16 (see Figure 9).³ Natural gas and wind each accounted for about 41% of the peak unavailable capacity, while coal, solar and nuclear accounted for

³ Adding capacity that was offline due to scheduled maintenance would bring total unavailable capacity to 52 GW.
the remaining 14%, 3% and 2%, respectively. Excluding existing outages, ERCOT listed weather (53%), equipment issues (14%) and fuel limitations (12%) as the top three causes of the derated capacity.

Figure 9. Nameplate capacity unavailable to ERCOT by facility and energy source, hourly, Feb 10-21

![Graph showing nameplate capacity unavailable to ERCOT by facility and energy source, hourly, Feb 10-21.](image)

Note, the data depicted do not include planned and existing outages.


All types of generation were compromised. For wind and solar, 139 and 23 units, respectively, experienced outages or derates during the freeze. Eight coal-fired power plants experienced derates or outages, losing a total of 5.6 GW. The partial outage at the South Texas nuclear power plant was caused by low steam generator levels from the loss of two feedwater pumps. One hydro plant and 9 battery storage facilities also experienced derates, although the lost capacity from these plants was minimal relative to the magnitude of overall outages.

Figure 9 depicts total unavailable *nameplate* capacity rather than adjusting for seasonal deratings. It captures the degree to which generation capacity was compromised, not the degree to which seasonal planning was compromised. As Table 1 shows, wind and solar are not rated at their nameplate capacities at any point in the year. According to the Capacity, Demand and Reserves (CDR) report for ERCOT published December 16, 2020, solar resources are rated at 80% of nameplate capacity during the summer, but only 7% during the winter. Wind resources in the Texas panhandle, the coast and other locations are rated at 29%, 61% and 19%, respectively, during the summer, and 32%, 43% and 19%,

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respectively, during the winter. The seasonal deratings, applied to assess “likely” resource availability, are based on the typical solar irradiance and wind velocities in each season and location. Using seasonal ratings as a benchmark for performance would not recognize that underperformance was largely due to facilities being offline due to freeze-related issues, so they could not have delivered power even if solar irradiance and wind velocities were at seasonal highs. Furthermore, wind and solar resources often deliver more than their seasonal ratings, while the total nameplate capacity is used when determining the load factors for those resources. For the thermal plants, measuring unavailability relative to nameplate capacity does not allow for typical planned maintenance schedules by season.

**Figure 10. Generation by resource, Hourly, February 2021**


Natural gas capacity suffered the most outages and derates during the freeze, yet generated significantly more power than is typically seen during February. Figure 10 depicts generation by resource for all of February 2021. The pattern prior to February 8 and after February 19 typifies February in ERCOT. Despite the outages depicted in Figure 9, roughly twice as much gas was used to generate electricity during the days running up to and during the winter freeze. Unfortunately, the grid needed more. This highlights the importance of “resilience” in energy systems, or the ability to respond when needed at all times and under all circumstances.

**Demand management and load shed**

The Texas power grid is designed and operated to handle extreme demand conditions in summer. The demand for electricity during the winter storm fell within the range of peak daily summer demands in August 2020. But in August 2020, those demands typically lasted for only a few hours. Figure 6 shows the high demands in February 2021 persisted for multiple consecutive days. This would have stressed the grid even if it had operated as planned.
The usual response when an electricity network experiences outages is to (a) dispatch backup capacity (through ancillary service markets or some other means), and/or (b) wheel power in from a neighboring region (through transmission interconnects), and/or (c) treat native demand as a resource via interruptibility agreements. The third option, also called demand-side management mechanisms, have become commonplace in electricity markets. They are typically designed so that a utility or system operator can compensate certain pre-defined customers to **not** consume power at the system operator’s discretion. The foregone power consumption is released back to the market, effectively serving as a virtual source of supply. This mechanism allows the grid operator to maintain system stability and avoid forced power outages not contracted in advance. ERCOT uses it most often during peak summer demand periods.

Demand-side management mechanisms are typically deployed when the ratio of load to generation, or operating reserve margins, pass certain thresholds. ERCOT issues energy emergency alerts (EEAs) at levels 1 and 2 to encourage demand response and conservation. At level 3, firm “load shed” orders are issued to cut power involuntarily.\(^5\) Local distribution utilities cut supply first to customers with agreements to accept a cut in return for payment. Those customers are typically large commercial and industrial consumers, some of whom have their own on-site emergency generation plant. Others can cease or modify operations temporarily at low cost. Typically, this is sufficient to abate grid stress, and only lasts for a short period of time. However, the winter storm of February 2021 was an extreme event that overwhelmed demand-side management capabilities. An EEA level 3 issued at 1:25am on February 15 forced utilities to cut customers who were not participants in demand-side management programs and who were not designated as “critical” load.

Figure 1 indicates the average hourly load shed during the week of the winter storm along with “incremental outages” concomitant with the load shed orders. “Incremental outages” is measured as total system outage minus the total system outage at 12:00am February 15, which is just prior to the first load shed orders. Most of the incremental outages after 12:00am February 15 were natural gas, as most wind capacity had already declared inoperable. Hence, natural gas has been blamed for much of the load shed during the episode, but that is partly a function of timing because earlier outages helped trigger the EEA level 3 and every source of generation failed at some point during the winter storm.

Figure 11 shows that load shed orders approximately match excessive outages until midday on February 17. As generation came back into service, load shed dropped much more rapidly. This again reflects moderating demand as extreme temperatures subsided.

In addition to load shed, the shortfall of generation relative to demand for an extended period drove extremely high payments to demand-side management program participants, which became politically contentious. These programs generally work as intended without issue. Their performance during the extreme winter storm is not evidence that they should be abolished. Perhaps there is room for reform, but modifications to accommodate low probability extreme events ought not be at the expense of the proven benefits of such programs in more “normal” emergencies.\(^6\)

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\(^6\) The legislature in Texas meets every other year (odd numbers), with areas of study for future policy direction taken up through interim charges by various committees. This is an area ripe for examination through interim charges if policymakers intend to re-examine the role of demand-side management programs in ERCOT.
Figure 11. Average hourly load shed ordered in ERCOT during the winter storm

*Incremental outages are calculated as the 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.


When load is being shed involuntarily, customers designated as “critical load” can be exempted. Critical load is typically demand from entities, such as hospitals, for whom a power interruption could be extremely costly. To be deemed as critical, the customer must first file paperwork. The winter storm revealed that certain parts of the natural gas supply chain – such as natural gas compressor stations – were not designated as critical load. In consequence, their power was cut, thereby reducing flows of natural gas along the state’s pipeline network and contributing to partial and complete derates at multiple natural gas power generation units. The loss of their output in turn necessitated further load shedding, potentially creating an unstable feedback loop. This represented a single point of failure in the energy supply system.

On March 18, 2021, ERCOT issued a market notice that it “posted an Application for Critical Load Serving Electric Generation and Cogeneration on the Gas Electric Working Group page of its website for premises that supply natural gas to generation units to request designation as ‘Critical Load Serving Electric Generation and Cogeneration’ for premises with electrical load that serve natural-gas to
generation units.” This is a two-page form. It shows how something that is fundamentally simple could reduce the risks of catastrophic failure during load shed events. It also highlights how simple bureaucratic oversights can contribute to widespread system failures, and, more generally, the importance of managing energy systems in a fully-integrated, holistic manner. Interestingly, 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.\(^8\)

**The natural gas supply chain**

Delivered natural gas volumes declined in the wake of power outages and load shedding. In addition to compression issues on delivery infrastructure, lower production due to wellhead and equipment freeze-offs may have contributed. The impact was significant, as ERCOT reported that fuel supply limitations were responsible for a large fraction of natural gas-fired power plant outages. According to the ERCOT report, “weather” was the largest factor responsible for the reported outages, accounting for more than half of the natural gas capacity derates at the maximum. But timing is everything.

As indicated in Figure 12, just before 1:00AM on February 15, a total of 5,518 MWs of natural gas generation capacity was already offline. By comparison, 22,677 MWs of wind generation capacity had already been declared inoperable. Then, as the EEA level 3 declaration triggered mandatory load shed, an additional 12,368 MWs of natural gas generation capacity was lost over the next 12 hours. Incremental outages over the next 12 hours also included 1,959 MWs of wind, 2,320 MWs of coal, 595 MWs of nuclear, and 240 MWs of solar, but natural gas accounted for 71% of the incremental outages in the 12 hours following the EEA level 3 declaration. In fact, the maximum outage of natural gas capacity was reached within 12 hours of the outset of mandatory load shedding, while the maximum outages for other capacity types generally occurred at different times much later during the period.\(^9\)

The rapid pace of natural gas outages in the 12 hours following the EEA level 3 declaration is striking. As indicated in Figure 11, load shed orders in those 12 hours reached over 16 GWs. A confounding factor is that the coldest hours of the winter storm were also reached in morning hours of February 15, as was the peak anticipated demand. Unfortunately, absent data on the reason for outages at each generation facility hinders a deeper investigation of the natural gas-electricity interdependency. A University of Texas study\(^10\) commissioned by the PUC of Texas was given access to confidential data and 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

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\(^8\) TX House Hearing Feb 25-26, [https://house.texas.gov/schedules/committee-schedules/advanced-search/search-results/?startDate=01/01/2019&endDate=20210303&chamber=h&committeeCode=C250&legislature=87](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](https://www.houstonchronicle.com/politics/texas/article/Simple-paperwork-blunder-Texans-cold-winter-storm-16032163.php).

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

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)

Figure 12. Outages by generation type, hourly, February 10-21

The fuel supply issues for natural gas thus began well in advance of the EEA level 3 declaration on February 15. They do not appear to be primarily directly weather-related, although weather certainly played a role in reducing wind capacity availability in advance of February 15. Nevertheless, ERCOT reported a timeline of outages by cause in its April 2021 release, where it noted that the sharp increase in outages was largely the result of “weather related” issues.11 About 6,500 MWs, or about one-third, of the incremental outages are attributed to fuel limitations to natural gas generators. Having this capacity would have reduced the severity of load shed, but it would not have eliminated it.

Natural gas production and storage withdrawal data should be reconciled with the ERCOT data to determine how, and to what extent, natural gas supply chain issues affected, and were affected by, the outages. The US EIA reported12 data from IHS Markit 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, they reported that daily production rebounded to 20.9 bcf/d by February 24 as

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temperatures moderated. A reduction of 9.5 bcf/d of natural gas production represents a very strong impact of the winter storm.

Enverus surveyed firms representing over 50% of natural gas production in the upstream and midstream in Texas. A majority of the respondents, even among upstream firms, were grid-connected and identified power outages as the primary cause for reduced flow during the winter storm. By reinforcing the conclusion that stable electricity service from well-site to end user is necessary to deliver natural gas to end-users, including power stations, this again highlights the interdependence of the natural gas and electricity systems.

Whether the production decline was material depends on how much was offset by storage withdrawals. The fact that ERCOT reported upwards of 4 GWs of natural gas capacity offline due to fuel limitations prior the EEA level 3 declaration suggests lost production prior to February 15 may have had some impact. 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. By the end of February 2021, this working gas in storage was down to 297.5 bcf. Withdrawals and injections will certainly vary through the month as dictated by market conditions, but the average cumulative rate of withdrawal across all storage in Texas for February 2021 was about 2.8 bcf/d.

Figure 13 uses data for working gas in storage by facility as of January 31 and the reported maximum withdrawal rate at each storage location to simulate how total working gas volumes (green and yellow bars) and cumulative withdrawals (red line) could have evolved for a full 28 days at maximum withdrawal rates, if so required. The cumulative withdrawal rate declines as facilities deplete. Salt cavern storage typically has higher turn rates than depleted reservoir storage, which is why it depletes faster under the max withdrawal rate scenario depicted. Cumulative withdrawals decline from just over 17 bcf/d to just under 10 bcf/d in 10 days, but the rate of decline subsides as withdrawals come more heavily from remaining working gas in depleted reservoirs, dropping to about 5 bcf/d by day 28. Given natural gas production declined to 11.8 bcf/d by February 17, storage withdrawals would have needed to reach 9.5 bcf/d to offset the production decline over the prior 4 days. Since this is only about 54% of the maximum cumulative rate, and it is the level reached after 12 days of maximum withdrawals, storage should have been able to fully offset the production decline during the week of the winter freeze, even if some storage was already drawn down due to higher demands during the previous week. If, however, power outages impacted storage facilities and/or compression on pipelines between those storage facilities and end-users, then gas deliveries from storage could have easily fallen short. Indeed, West Clear Lake, North Lansing, and Bammel, which are the three largest storage fields in Texas accounting for 47% of total working gas capacity, are each powered by electrically-driven compressors. Boling, Spindletop, and Markham, which account for 9.2% of the active Texas storage capacity, each use gas-fired compressors. This, yet again, highlights why natural gas storage and transportation infrastructure should be designated as critical load when natural gas, and especially natural gas storage, is being relied upon to address short term demand-supply imbalances in the power market. It also

14 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.
15 We are unaware of any publicly available data on the withdrawal rates at these specific facilities.
highlights why better communication between gas and power regulators and greater transparency of daily facility operations is needed to identify critical issues as they arise.

**Figure 3. Simulated Working Gas in Storage at Max Withdrawal Rate for February 2021**

![Simulated Working Gas in Storage at Max Withdrawal Rate for February 2021](source)


**Everything matters**

To gain further insights, Figure 4 combines graphs of load shed ordered, total outages, actual load, and a day ahead load forecast with three constructed data series: ‘Incremental outages’, ‘Actual load + incremental outages’ and ‘Actual load + load shed’. Incremental outages are defined as the total system-wide outage minus the total outage that existed at the time load shed orders began in the early AM hours of February 15. For hourly intervals when the constructed measure is negative, the series takes a value of zero.

Outages approaching 20 GWs had already occurred on February 13 and 14, and system load had spiked to almost 70 GWs on February 14. Load shed orders were not initiated until early February 15, at which time grid frequency plummeted due to demand exceeding generation.

Series for ‘Incremental outages’, ‘Actual load + incremental outages’, and ‘Actual load + load shed’ are author calculated (see text).
The day ahead load forecasts are determined at a regional, or load zone, level and then aggregated across all ERCOT regions. They are based largely on zonal population and industrial activity and the expected temperatures in each zone. The forecasted load crested at over 76 GWs during the mid-morning of February 16, but touched similar levels on February 15. It exceeded 70 GWs for a combined total of 17 hours, and was above 60 GWs for 85 of the 120 hours covering February 15-19. Adding either incremental outages or load shed to actual load implies that ERCOT still would have been short by about 10 GWs at the peak of forecasted demand, and the system still would have been heavily stressed. Additional resources that were offline, either as scheduled or unplanned outages that occurred prior to February 15, would have been needed to avoid any system-wide emergency alerts. Moreover, since natural gas generation accounted for most of the incremental outage surrounding EEA level 3 (Figure 12), if the system had remained stressed without those outages there no doubt would have been a heightened focus on wind generation. This shows that it is important to maintain the operability of ALL capacity types during high stress events.

The past carries important lessons

A cold snap in 2011 caused power outages in ERCOT and triggered a number of concerns and subsequent analyses.\textsuperscript{16} Priority recommendations were winterization and improved fuel supply security. Other recommendations were to

- plan for peak winter events as diligently as peak summer events,
- re-evaluate planned outage schedules for winter months,
- increase responsive reserve capability,
- increase the winter reserve margin, and
- improve communication between balancing authorities and transmission operators.

For the winter event of February 2021, communications between ERCOT and LDCs appeared satisfactory. However, communications between different regulatory agencies as the event approached were inadequate. Transparency regarding the location of natural gas supply infrastructure was atrocious. This has since been addressed by calls for a standing committee of personnel from various agencies. An alternative would be the creation of a single “Texas Energy Agency” with direct oversight of all relevant agencies.

From 2011–2021, responsive reserve capacity increased from 1062 MWs to 1570 MWs, that is, from 2.4% to 2.6% of forecasted peak load. The events of February 2021 suggest that this needs to be increased, and its operational capability warranted. According to ERCOT’s capacity, demand and reserves 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. Some have called for adding a capacity market in ERCOT to

improve reliability. However, a brief examination of historical electric disturbance events across the entire United States does not reveal that capacity markets are positively correlated to reliability. We suggest that this should be carefully examined before dramatically changing market structure in ERCOT.

February 2021 has also prompted legislative action to increase winterization. The 2011 FERC investigation also cited inadequate protections for most generators regardless of type. The Public Utility Commission of Texas also recommended improved winterization of generators following a 1989 cold weather event in Texas. 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.” In the end, winterization was not directly required for generators.

Even though deficient fuel supply was not a major cause of outages in the 2011 winter event, subsequent reports noted interdependence of electricity and natural gas markets in Texas and the importance of protecting natural gas production from cold-weather related disruption. Natural gas production and use in Texas have increased in the interim, as has the use of electric drive for compression (driven largely by environmental and operational motives). The latter has more deeply integrated electricity and natural gas markets. Moreover, gas has become more critical for balancing the electricity market as wind penetration has increased and coal use declined. There is no question that the natural gas production, gathering, storage and distribution facilities should be identified as critical load customers.

At the close of its 2011 study, the FERC concluded that although extreme winter weather events were very infrequent in ERCOT, more research to allay concerns related to grid reliability and resilience was warranted. Such concerns may have increased since.

The total resources available to the ERCOT grid are more than sufficient to reliably handle average February demands, but extreme outcomes matter most in power systems. ERCOT resource adequacy assessments stress-test outcomes under extreme conditions, but not as extreme as those experienced during the winter storm of 2021. Moreover, resource adequacy assessments have not typically accounted for fuel supply disruptions on the scale witnessed in February 2021. A more wholistic approach to resource assessment along the entire supply chain, from fuels to electrons, is warranted.

Would connecting ERCOT to neighboring regions make a difference?

Deeper interconnection with neighboring regions has also been proposed as a remedy to the problems of February 2021. The thought seems to be that ERCOT could have imported power to lessen or avoid the crisis, but this ignores the fact that outages were simultaneously occurring in neighboring regions. The storm also caused capacity outages and emergency load reductions in the Southwest Power Pool.

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17 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 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.
(SPP) and the Midcontinent Independent System Operator (MISO), two neighboring regions that serve portions of North and East Texas.

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 shed on February 15 and 16.20 SPP’s assessment of the winter freeze reported up to 59 GWs of generating nameplate capacity was offline, and at peak demand on February 16, about 30 GWs of capacity was unavailable due to forced outages, 47% of which were due to fuel supply issues at natural gas facilities.

MISO serves part of east Texas, Louisiana, Arkansas, and other states throughout the Midwest and interconnects with SPP to the west and multiple regions, including PJM, to the east. MISO also ordered load shedding February 15 to February 16. MISO’s post-event analysis noted that, “At one point during the Arctic Event, PJM pushed as much as 13,000 MWs into MISO’s system, which MISO and SPP used to maintain economic pricing and support grid operations.”21 Nevertheless, load shed was required.

Furthermore, as noted in Figure 7, the DC ties that allow relatively small amounts of transmission between ERCOT and neighboring regions, including with Mexico, were curtailed at multiple times between February 15 and February 18. Electric grids across the entire central US were stressed during the winter storm. Transmission between regions was utilized when available, but was insufficient to avoid extensive forced load shed.

This does not imply that greater interconnection between ERCOT and neighboring grids is not worthy of exploration. Indeed, a longer run view raises other questions. For example, stronger transmission links between ERCOT and neighboring regions established decades ago would have affected investment in generation infrastructure in Texas and neighboring regions. Given the regulatory environment in Texas, and the robust wind and natural gas resource endowments, it is likely that more generation capacity would have been built in Texas, making it a large exporter of electricity to neighboring grids. In the absence of appropriate weatherization of generators and hardening of fuel supply chains, the severity of the February 2021 crisis then would have spilled out from ERCOT onto neighboring grids. In any case, further research is needed to assess the cost-benefit of expanded interconnection between ERCOT and neighboring regions before any conclusions can be reached with confidence.

**ERCOT as a case study for large scale renewables deployment**

Renewable generation has also been blamed for compromising reliability during the winter storm. The majority of wind generation capacity derating occurred prior to February 15, as equipment froze and generators were declared inoperable. This played a role in the subsequent cascading failures of natural gas generation by compromising electricity supply to field operations and supply infrastructure, but the story is hardly so simple because many other factors also contributed. In fact, during other periods

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when wind generation drops, which is a normal occurrence, fuel supply remains robust as other resources fill the power generation void.

Historically, a diversity of resources was used to provide lowest cost dispatchable generation to serve loads at different times of the day. Over the last decade plus, wind generation capacity has grown substantially in ERCOT, and the variation in wind output has increased along with it (see Figure 15). Although wind generation has desirable environmental attributes with regard to emissions, it is non-dispatchable, and its output varies across short time intervals in unexpected ways. This places greater demands on dispatchable generation resources to be sufficiently responsive to maintain system balance. In ERCOT, natural gas generation has served this role. Moreover, the periods of highest grid stress historically occur during summer peak demand periods, where a combination of dispatchable resources – mostly natural gas – and demand-side management accommodate fluctuations in wind generation.

Figure 15. Wind – Actual and “expected” generation (15-minutes) and Annual nameplate generation

![Wind generation graph](image)

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 MWs, to MWhs assuming it is 100% utilized every 15 minutes. Resource planning utilizes seasonally rated capacity, which is different by season.

The consistent delivery of reliable electric power is the most sophisticated engineering and logistics problem in energy. Not only does demand vary within and across days, the availability of generation resources varies as well. Hence, there needs to be sufficient generation capacity that is capable of responding in real time to these fluctuations to maintain system balance. Reliability matters, and coordination across energy sectors, as well as across generation technologies, is essential.

As a specific example of how other generation is affected by variable wind output consider Figure 16, which depicts generation by source in 15-minute intervals for ERCOT on August 7 and August 18, 2020. August 7 experienced maximum, and August 18 the minimum, wind generation during the month. On August 7, peak load was 70.1 GWs, while on August 18, it was 69.3 GWs. Natural gas compensated most for the wind shortfall, offsetting an average of 62% of the difference in wind generation across the two days, although multiple options were used to balance the market.
As noted in Table 1, wind has a seasonal rating based on “expected” generation. But, as indicated in Figures 15 and 16, wind generation varies significantly over time. Thus, the seasonal capacity ratings are useful for resource planning, but not day-to-day system-wide generation requirements. To ensure
adequate dispatchable capacity is available for any possible combination of wind generation and system-wide demand, incentives to invest in capacity that may frequently be unused must be adequate.

The diversity of available resources to meet unexpected changes in net load is important. Especially in the lead up to February 15, 2021, wind generation dropped and demand was high. If resources on the ERCOT grid had responded in February 2021 as they did in August 2020, market balance may have been possible without involuntary load shed. However, that possibility could not be realized due to a lack of adequate winter weather preparations and fuel supply deficiencies resulting from lack of coordination between the electricity and natural gas systems.

The debate around wind generation and its role in the winter storm outages thus has highlighted a critical issue in power systems with increasing penetration of non-dispatchable resources. When wind delivers above its seasonal rating, as it often does, price is driven down as wind displaces plants with higher operating costs. In the extreme, if wind is providing marginal output, price can be driven to minus the value of wind production subsidies (including renewable production credits). Wind generators are willing to pay up to that much to avoid simply spilling their output. When wind delivers below its seasonal rating, as it often does, price may not increase very much, depending on demand relative to available resources, due to the competition between generators at the margin. Thus, the net impact of variability in wind generation, ceteris paribus, can be to reduce incentive to invest in all types of capacity on the grid, which can compromise reliability over time. In effect, the social benefit of reliability associated with available, dispatchable generation capacity, regardless of type, is left unaccounted if it is not fully priced into a market where load net of non-dispatchable generation becomes increasingly variable. Questions of market design, and the pricing of reliability, as the proportion of non-dispatchable capacity on the grid increases are fundamental to the future of grid design, but a full exploration is beyond the scope of this paper.

Recommendations and Closing Remarks

We opened with a list of scapegoats for the disaster that struck the ERCOT system in February 2021:

- wind generators,
- thermal generators,
- natural gas suppliers,
- Texas opposition to inter-connections,
- ERCOT management, and
- ERCOT market rules.

We have addressed the culpability of each of these by examining the resources available to ERCOT and the events that transpired during the week of February 14. We have also laid out recommendations to mitigate the risk of such an event occurring again, which we recap here.

Wind underperformed relative to its nameplate capacity, but this is always true. While the narrative around the incredible growth of wind is usually framed around installed nameplate capacity, expectations for wind generation should not be based on nameplate capacity because that amount of energy is rarely, if ever, delivered on a day-to-day basis. The more relevant benchmark for expected performance is rated capacity. Wind generation capacity is “rated” at a discount to nameplate capacity that is inherently based on the expected availability of wind resources from day-to-day, which is why wind is referred to as a “non-dispatchable” resource. Wind often outperforms expectations, or exceeds
its capacity rating, but it also often underperforms relative to its capacity rating. During the winter storm, wind underperformed on that metric. A major driver during the winter storm was the lack of winterization, which meant that wind generators performed below what would have otherwise been anticipated given the wind speeds. Winterization is not free, however, which means the cost-benefit of winterization of wind turbines in Texas critical. Moreover, the temperature extremes faced in the Texas panhandle are very different than those faced in coastal regions, which may argue for a differentiation in winterization protocol across regions in Texas.

All this stated, the reason for wind’s underperformance during the winter storm, as opposed to other times of year, was only important for grid stability because other resources were also not available. It is well known by grid operators and power market participants that wind varies frequently, so planning should ensure the availability of other flexible resources that can respond quickly and reliably to maintain supply when wind is unavailable. As the fraction of supply coming from non-dispatchable resources increases, the social value of reliability, the value of lost load and demand flexibility become more important issues that must be addressed and internalized by market participants, regulators and ultimately consumers. A resilient, reliable electricity system requires resources to be appropriately priced to ensure adequate levels of investment in all types of capacity. None of this means that we should not invest in wind. It does raise questions, however, about what drives investment in various forms of generation capacity (i.e.- subsidies, mandates, commercial returns, environmental preference, etc.) and whether capital is being appropriately directed, but that is beyond the scope of this paper.

**Thermal capacity** suffered significant deratings, but the reasons varied across generation types. A facility-by-facility assessment is needed to ensure similar types of outages do not recur. A lack of transparency on all facility-specific derates means that regulators must address this issue with facility owners. As noted above with regard to wind capacity, *winterization of thermal capacity can be an important first step. If all capacity in ERCOT had remained operable during the winter storm, load shed would have likely been necessary, but remained voluntary, thereby avoiding the EEA level 3 declarations. Nevertheless, the value of winterization may vary in different parts of the state and across generators, so a careful analysis of reliability standards that accounts for location and age is needed to drive a better long-run outcome.*

Fuel supply issues also must be addressed. This concerns all forms of thermal capacity, except nuclear, but in ERCOT is predominantly a **natural gas supply** chain issue. As noted above, variability in wind generation requires flexibility in back-up sources of generation that extends beyond the generating units to include the support infrastructure for those units. For natural gas, this includes pipelines and distribution networks, storage and processing facilities, and wellhead production. If any part of the supply chain fails and there is inadequate redundancy to cover the loss, generation will fall short. During the February 2021 winter freeze, natural gas generated more power than any other source, and natural gas generation exceeded what it would have been on an average February day. But the winter storm of February 2021 was not average; it was extreme. Power cuts to infrastructure along the natural gas supply chain played a major role in the failure of natural gas generators. Hence, to avoid a single point of failure along the circular, interdependent natural gas-electricity value chain, *fuel supply chain infrastructures should be mandatorily designated as critical load customers.*

**Interconnecting** ERCOT with SPP, MISO and WECC might have yielded some short-term benefits all else equal, but it is not guaranteed because surrounding regions were also stressed at the same time. Interconnection requires significant investment in transmission capacity, but it would likely result in a
different trajectory for capacity investment in ERCOT. For example, if ERCOT had been more deeply interconnected for the last 30+ years, very different investment patterns in new generation capacity would have occurred. But, given the causes of the outages that occurred during the winter storm, it is debatable if the additional generation capacity or interconnecting transmission capacity would have helped ERCOT. A detailed long-run study of expanding interconnections between ERCOT and neighboring regions is warranted, and it should allow for different investment patterns in generation capacity and include a counterfactual to evaluate how the winter storm of February 2021 would have played out differently had such investments been made decades ago. Ad hoc statements based on dated, tangential or non-existent analyses are insufficient.

Discussions about ERCOT’s management of the grid during the winter storm need to account for the fact that ERCOT neither owns or operates generation assets on the Texas grid, nor does it regulate them. Rather, it manages flows on the grid by scheduling generation resources and managing load with existing assets to maintain system stability. During the winter freeze of February 2021, ERCOT’s management of the grid avoided catastrophic failure, which at one point was estimated to be only minutes away. ERCOT thus performed well in terms of real time management of the grid. But it can be faulted on its long-run planning to deal with such emergencies. In retrospect, ERCOT’s resource adequacy assessments need to be further enhanced to better account for extreme winter events.

The buck does not stop with ERCOT. Long-term planning and execution also involve other state regulatory agencies and extends beyond the electricity market into the various fuel supply chains that serve dispatchable thermal generation. As such, better coordination among state agencies is needed. Perhaps a single “Texas Energy Agency” could have ensured better coordination by establishing greater accountability and transparency through agency derived protocols across various offices. Regardless of the approach taken, better coordination and information sharing is needed. The effectiveness of steps taken to date, such as establishing a standing committee comprised of representatives from different state agencies, remains to be seen.

Market structure rules might also be improved. Immediate calls for a capacity market in the wake of the winter freeze ignore the fact that neither nameplate nor rated capacity adequacy was the issue. Operational capacity adequacy, or ensuring existing capacity is operational, was the problem. Even if a capacity market had ensured more capacity were on the ERCOT grid, the other problems we identified suggest that capacity would have likely been inoperable too. Winterizing existing generation and energy infrastructure along with correcting fuel supply issues would have abated the crisis that unfolded.

Nevertheless, a careful analysis of reserve margins as intermittent capacity expands is warranted. Currently Texas is #1 in the nation in terms of existing wind capacity. It is also #1 in terms of planned capacity additions for wind and solar, and #2 in the nation for planned battery capacity additions. However, there is little-to-no planned capacity addition for other forms of dispatchable generation. This could become an issue for reliability. For example, wind generation in Texas is at seasonal maximum in the fall, while demand is a maximum in the summer. Battery installations currently planned are short-duration and will convey significant benefits for frequency management. However, during events such as the winter freeze of February 2021, or even more regular occurrences of meeting peak summer demands when the wind is not available, other types of backup capacity are needed. If the load growth in ERCOT over the last 20 years continues, as is projected, resource inadequacy could become a more frequent issue. Hence, factors such as the social value of reliability, the value of lost load and increased
demand management need to be more actively discussed and integrated in market rule-makings so that they can be appropriately priced to ensure adequate levels of different types of investment.

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Bills

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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

ERCOT

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