**Michael Mabee**
Fort Worth, TX
(516) 808-0883
Email: CivilDefenseBook@gmail.com
Web: https://GridSecurityNow.org/

April 11, 2021

The Honorable Kelly Hancock, Chair
The Honorable Robert Nichols, Vice Chair
Senate Committee on Business & Commerce
Texas Senate, Sam Houston Building, 325
Austin, TX 78711-2068

Subject: Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security

Dear Chairman Hancock, Vice-Chair Nichols and other members of the Committee:

I submit this testimony in support of the Texas legislature passing SB 1606 – All Hazards Grid Security. I am a resident of Texas, a retired U.S. Army Command Sergeant Major, and I maintain the world's most comprehensive grid security database as an unpaid volunteer grid security researcher. I have been quoted by The Wall Street Journal, The Washington Post and many other publications on grid security and have intervened and submitted testimony in over 200 federal dockets on the electric grid security issues.

As of April 6, 2021, the Texas Department of State Health Services (DSHS) estimates that the death toll from the 2021 winter storm is 125.[1] Most of the major causes of death reported, such as hypothermia, carbon monoxide poisoning, medical equipment failure, exacerbation of chronic illness, lack of home oxygen, and fire may be inferred as being the result of the failure of the electric grid in Texas.

I filed a Complaint with the Federal Energy Regulatory Commission (FERC) that the industry and regulators either failed to enforce mandatory reliability standards (which apply in Texas as well as the rest of the country) or that the standards were ineffective and must be improved.[2]

The Electric Utility Industry and their non-profit regulators, the Texas Reliability Entity, Inc. (Texas RE), and the North American Electric Reliability Corporation (NERC) are urging FERC to dismiss the complaint on a technicality. I anticipate this will likely happen. The industry has co-opted FERC, the U.S. Department Energy and the U.S. Congress for years through hundreds of millions of dollars in lobbying and political contributions.[3] Thus, the federal government is likely to do exactly what the industry "advises" them to do.

[1] See: https://dshs.texas.gov/news/updates.shtm#wn
[2] Federal Energy Regulatory Commission Docket No. EL21-54-000
[3] The Center for responsive Politics reports that in 2020 the electric utility industry spent $104,739,895 in lobbying and $28,562,003 in contributions to the U.S. Congress. See: https://www.opensecrets.org/industries/totals.php?cycle=2018&ind=E08

Not surprisingly, the electric industry wants FERC to dismiss 125 deaths in Texas, the massive impact on the economy and the state's critical infrastructures on a technicality in order to divert attention from their lack of preparedness and the lax regulatory environment that precipitated this tragedy.

After the Texas electric grid collapse of 2021, once again, the electric industry and NERC tells us that they have the matter well in hand. Isn't that what they said after the 2011 Texas blackout? The Texas electric grid failed in 1989 and 2011 for largely the same reasons it collapsed 2021. The industry never took effective action after 1989 and 2011 and yet they argue that the Federal Energy Regulatory Commission (FERC) should do nothing more than a "joint inquiry" with NERC.

Ironically, the same industry that has brought us 100 years of scandals – including the Samuel Insull scandal, the Enron scandal and the FirstEnergy bribery scandal – says we should trust them. We should not trust them. We need effective standards and effective regulation. Presently, we have neither.

Texas now has the opportunity to provide leadership on electric grid security that is lacking nationwide The Federal Government's regulators, departments and agencies have had decades to demonstrate this leadership and take effective action to protect critical infrastructures from all hazards and they have failed. Passing SB 1606 will establish a *state-led* effort to protect our people and critical infrastructures from hazards long ignored by the industry and its well-lobbied and lackadaisical regulators. Texas must provide this leadership and example. Our security depends on this committee's actions now, and that of the legislature later to both pass the bill and supervise the work of the *Texas Grid Security Commission*.

I am submitting for the record my federal complaint about the lack of enforcement and/or inadequacy of the mandatory grid reliability standards and the industry's responses. This is a compelling (but disturbingly common) example of the industry arguing that nothing but "the norm" is needed in the face of over 125 deaths Texas. It is a disgusting testament as to why, after decades of our grid being vulnerable to many hazards[4], that today it is still vulnerable to the same hazards. The tail has long been wagging the dog in grid security.

And since "the norm" did nothing to protect us after the 1989 and 2011 blackouts – and at least 125 Texans died in 2021 – only a fool would expect a different result from the industry and the current regulatory regime this time.

Texas must show leadership and pass SB 1606.

Please advise if I can be of further assistance to the Committee.

---

[4] As early as 1981, the General Accounting Office (GAO) has warned that our preparedness for a physical attack against the grid was inadequate. Today the electric grid is still vulnerable to a coordinated physical attack and the industry written physical security standards is completely inadequate. See: "Federal Electrical Emergency Preparedness Is Inadequate." GAO Report No. EMD-81-50. May 12, 1981. http://bit.ly/354ZN4i and contrast to my analysis on Physical Security to FERC in Docket No. EL20-21-000 available here: https://michaelmabee.info/loopholes-in-grid-physical-security-identified/

Michael Mabee

Exhibit A: Complaint of Michael Mabee in FERC Docket EL21-54-000, February 28, 2021[5]
Exhibit B: Motion of Michael Mabee in Docket EL21-54-000, March 14, 2021
Exhibit C: Motion of Michael Mabee in Docket EL21-54-000, April 1, 2021
Exhibit D: Protest of the Electric Industry "Joint Trade Associations" in Docket EL21-54-000, April 5, 2020
Exhibit E: Motion to Intervene of NERC and Texas RE in Docket EL21-54-000, May 5, 2021

[5] Due to file size limitations in electrically submitting my testimony, Exhibit A may have to be attached excluding the exhibits, which I would like to incorporate by reference. The full document with exhibits is available at this link: https://michaelmabee.info/wp-content/uploads/2021/03/FERC-Complaint-Mabee-Final-w-Exhibits.pdf

# Exhibit A

**Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Complaint of Michael Mabee** | **)** | |
| **Related to Mandatory Reliability Standards** | **)** | **Docket No. EL21-54-000** |
| **in the Texas Grid Collapse of 2021** | **)** | |

**COMPLAINT**
Submitted to FERC on February 28, 2021

## Introduction

I am a private citizen who conducts public interest research on the security of the electric grid because I recognize the absolutely vital role of this infrastructure in powering every one of the nation's 16 critical infrastructures and in undergirding not just the well-being but the very survival of our modern society. I am also a resident of Texas and was adversely impacted by the February 15, 2021 Texas grid collapse.

I am filing this complaint under 16 U.S. Code § 824o(d)(5)[1] and 16 U.S. Code § 824o(e)(3)[2] because, the Texas blackout on February 15, 2021 demonstrates that either:

1) The mandatory reliability standards were not followed, or,
2) The mandatory reliability standards were ineffective.

## Request for Investigation

I request that the Commission issue a public notice of this Complaint pursuant to 18 CFR § 385.206(d), investigate this Complaint and issue an appropriate order to the Electric Reliability Organization ("ERO") to correct deficiencies.

[1] "The Commission, upon its own motion ***or upon complaint***, may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section." [Emphasis added.]

[2] "On its own motion ***or upon complaint***, the Commission may order compliance with a reliability standard and may impose a penalty against a user or owner or operator of the bulk-power system if the Commission finds, after notice and opportunity for a hearing, that the user or owner or operator of the bulk-power system has engaged or is about to engage in any acts or practices that constitute or will constitute a violation of a reliability standard." [Emphasis added.]

## Background of Texas Grid Collapse of 2021

On February 11, 2021, the Electric Reliability Council of Texas (ERCOT) issued a press release warning that "Extreme cold weather expected to result in record electric use in ERCOT region."[3] (This press release is attached as Exhibit A.) The press release advised:

> "This statewide weather system is expected to bring Texas the coldest weather we've experienced in decades," said ERCOT President and CEO Bill Magness. "With temperatures rapidly declining, we are already seeing high electric use and anticipating record-breaking demand in the ERCOT region."

On February 14, 2021, ERCOT issued another press release: "Grid operator requests energy conservation for system reliability."[4] (This press release is attached as Exhibit B.) The press release advised:

> "We are experiencing record-breaking electric demand due to the extreme cold temperatures that have gripped Texas," said ERCOT President and CEO Bill Magness. "At the same time, we are dealing with higher-than-normal generation outages due to frozen wind turbines and limited natural gas supplies available to generating units. We are asking Texans to take some simple, safe steps to lower their energy use during this time."

On February 15, 2021, ERCOT issued a third press release: "ERCOT calls for rotating outages as extreme winter weather forces generating units offline - Almost 10,000 MW of generation lost due to sub-freezing conditions."[5] (This press release is attached as Exhibit C.) The press release, in its entirety, advised:

> AUSTIN, TX, Feb. 15, 2021 – The Electric Reliability Council of Texas (ERCOT) entered emergency conditions and initiated rotating outages at 1:25 a.m. today.
>
> About 10,500 MW of customer load was shed at the highest point. This is enough power to serve approximately two million homes.
>
> Extreme weather conditions caused many generating units – across fuel types – to trip offline and become unavailable.
>
> There is now over 30,000 MW of generation forced off the system.
>
> "Every grid operator and every electric company is fighting to restore power right now," said ERCOT President and CEO Bill Magness.
>
> Rotating outages will likely last throughout the morning and could be initiated until this weather emergency ends.

---

[3] Available at: http://www.ercot.com/news/releases/show/224996
[4] Available at: http://www.ercot.com/news/releases/show/225151
[5] Available at: http://www.ercot.com/news/releases/show/225210

## Impact on the People of Texas


The reality on the ground in Texas was a little less sterile than "10,500 MW of customer load was shed."[6]

People died. Critical infrastructures were impacted.

Over 4,000,000 customers lost power during two days of subfreezing temperatures. Many lost power for longer. The picture on the right is the temperature at 5:21 a.m. on February 16, 2021 when many of us in Texas had already been without power for over 24 hours. The Houston Chronicle reported[7] that day that:

> Harris County has seen more than 300 carbon monoxide poisoning cases as temperatures bottomed out Monday in Houston and the state's electricity grid failed, sending people scrambling for heat sources. That includes 90 carbon monoxide poisoning calls to the Houston Fire Department and 100 cases in Memorial Hermann's emergency rooms.

Desperate people, who depended on the electric grid, tried any means they could find to keep their families from freezing – sometimes with catastrophic results. According to the article:

> Several people have already died seeking warmth. A woman and an 8-year-old girl died from suspected carbon monoxide poisoning in Sharpstown, while a man and a 7-year-old boy were taken to a nearby hospital in critical condition. Three children and their grandmother died in a Sugar Land house fire after using the fireplace to heat their home.

The Wall Street Journal reported on February 23, 2021 that "Officials are still counting fatalities from hypothermia, carbon monoxide, other factors as some experts warn accurate total might never be known."[8] The article reported:

> The failure of the state's electrical grid during the weeklong cold snap left more than four million Texans without electricity and heat, many for days on end in subfreezing temperatures. Many residents also lost access to water, and 14.6 million were ordered to boil water to make it safe to drink.
>
> …

---

[6] In fact, Mr. Magness later testified to the Texas State Legislature that 20,000 MW was shed.

[7] Houston Chronicle. "Harris County is slammed with 300+ carbon monoxide cases - and many are kids." March 16, 2021. Available at: https://www.houstonchronicle.com/news/houston-texas/health/article/Memorial-Hermann-sees-60-carbon-monoxide-15954216.php

[8] Wall Street Journal. "Full Death Toll From Texas Storm Could Take Months to Determine." February 23, 2021. Available at: https://www.wsj.com/articles/full-death-toll-from-texas-storm-could-take-months-to-determine-11614107708

> An 11-year-old boy was found frozen in his bed, his family told the Houston Chronicle. A grandmother and three grandchildren died in a house fire as they were trying to stay warm, the Chronicle also reported. At least six deaths occurred near the Abilene area, local media reported, including a patient who couldn't get medical treatment due to a lack of water and three elderly men who were found dead in subfreezing homes.

A copy of this Wall Street Journal article is attached as Exhibit D.

## Impact on Texas Critical Infrastructures

Presidential Policy Directive 21 (PPD-21) "Critical Infrastructure Security and Resilience"[9] identifies the 16 critical infrastructures in the U.S. and mandates that:

> The Federal Government shall work with critical infrastructure owners and operators and SLTT [state, local, tribal, and territorial] entities to take proactive steps to manage risk and strengthen the security and resilience of the Nation's critical infrastructure, considering all hazards that could have a debilitating impact on national security, economic stability, public health and safety, or any combination thereof.

The Texas grid collapse beginning on February 15, 2021 adversely impacted critical infrastructures. Many people may have never heard of PPD-21, but this is what the failure of the critical infrastructures looks like to the people with no power trying to survive in subfreezing temperatures:


Bread isle, Kroger's Fort Worth, TX
February 18, 2021

Water isle, Kroger's Fort Worth, TX
February 18, 2021

[9] Available at: https://fas.org/irp/offdocs/ppd/ppd-21.pdf

Egg case, Kroger's Fort Worth, TX
February 18, 2021

Milk case, Kroger's Fort Worth, TX
February 18, 2021

Here is another example of what critical infrastructure impact looks like to the actual people suffering through it:


QT Gas Station, Lake Worth, TX
February 19, 2021

In addition to the food, agriculture and transportation sectors, the collapse of the water infrastructure has been well covered in press articles.[10] Millions in Texas were under "boil water" orders as the water infrastructure was impacted by the collapse of the grid and many had no water at all. Firefighters watched helplessly as homes burned and they lacked the water to fight the fires.[11]

Some people froze in their homes and those that survived struggled for food and water when the critical infrastructures collapsed along with the Texas electric grid.

This is what the failure of electric reliability standards looks like. People dead, homes destroyed, critical infrastructures failing and the economy severely impacted. [12] (Photo credit: Bexar-Bulverde Volunteer Fire Department.)

## Lessons Learned from 2011 and 1989 Texas Blackouts Ignored

In 2021 we find, as Yogi Berra once said, "It's déjà vu all over again." Almost exactly 11 years prior to the collapse of the Texas grid in February of 2021, a very similar thing happened in February 2011. And before that, another similar blackout occurred in December of 1989. While the causes of the 2021 Texas grid collapse are still under investigation, many similarities between the three tragic incidents are apparent.

The Austin American-Statesman reported[13] on February 18, 2021:

---

[10] NBC News. "Texas water shortage adds to power crisis as new winter storm moves in." February 17, 2021. https://www.nbcnews.com/news/us-news/texas-contending-water-nightmare-top-power-crisis-n1258208

[11] New York Times. "A Texas apartment building burned while firefighters scrambled for water." February 19, 2021 https://www.nytimes.com/2021/02/19/us/san-antonio-fire-hydrants-water.html

[12] Foundation for Resilient Societies. "Causes and Costs of ERCOT Load Sheds in February 2021." February 24, 2021 (Preliminary). https://www.resilientsocieties.org/uploads/5/4/0/0/54008795/ercot_load_shed_causes_and_costs_preliminary_feb_25_2021.pdf

[13] Austin American-Statesman / USA Today. "Winter storm blackouts plagued Texas in 2011, too. Recommendations made afterward went unenforced." February 18, 2021. https://www.usatoday.com/story/news/nation/2021/02/18/state-energy-winter-protections-lacking-reports-have-suggested/4490501001/

> Failing power plants, rolling blackouts and a spike in demand as Texas is hijacked by a harsh February winter snowstorm – this was the scenario exactly a decade ago as blackouts rolled through Texas.
>
> A post-mortem at the time – including a key finding that state officials recommended but did not mandate winter protections for generating facilities – has renewed relevance as Texas is roiled by a record storm that has left millions without power for at least three days amid plunging temperatures.
>
> A combination of those 2011 findings, as well as reports from the state grid operators that generators and natural gas pipelines froze during the current calamity and Austin American-Statesman interviews with current and former utility executives and energy experts, ***suggest a light regulatory touch and cavalier operator approach involving winter protections of key industrial assets.***

(Emphasis added.)

While it appears that a lot of lessons were learned from the 2011 Texas blackout. it also appears that few steps were taken to harden the Texas grid against a similar event in the future (i.e., the 2021 Texas blackout).

According to an August 2011 Joint report of the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC)[14]:

> Between February 1 and February 4, a total of 210 individual generating units within the footprint of the Electric Reliability Council of Texas, Inc. (ERCOT), which covers most of Texas, experienced either an outage, a derate, or a failure to start. The loss of generation was severe enough on February 2 to trigger a controlled load shed of 4000 MW, which affected some 3.2 million customers. On February 3, local transmission constraints coupled with the loss of local generation triggered load shedding for another 180,000 customers in the Rio Grande Valley in south Texas.

(A copy of this report is attached as Exhibit E.) It is important to note, that prior to the 2011 Texas blackout, there had been another blackout in 1989 which bears striking similarities to 2011 and 2021. The Joint FERC/NERC report noted:

> The experiences of 1989 are instructive, particularly on the electric side. In that year, as in 2011, cold weather caused many generators to trip, derate, or fail to start. The PUCT investigated the occurrence and issued a number of recommendations aimed at improving winterization on the part of the generators. These recommendations were not mandatory, and over the course of time implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011.[15]

---

[14] Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011." August 2011. https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfromFebruary2011Report.pdf

[15] id. Page 10.

Benjamin Disraeli famously said: “What we learn from history is that we do not learn from history.” In the present context, the people of Texas have suffered blackouts in 1989, 2011 and 2021 – all bearing remarkable – and preventable similarities. All having at least something to do with the lack of winterization of equipment and ill-preparedness for extreme cold weather.

In 2011, the regulators were comparing the 2011 blackout to 1989. On April 11, 2011, The Austin American Statesman reported[16]:

> The report from the Public Utility Commission of Texas is clear in its analysis of what went wrong:
>
> “The winter freeze greatly strained the ability of the Texas electric utilities to provide reliable power to their customers. Record and near-record low temperatures were felt throughout the state resulting in a significantly increased demand for electrical power.
>
> “At the same time that demand was increasing, weather-related equipment malfunctions were causing generating units to trip off the line.” As a result, it noted, the state suffered widespread rolling blackouts and “near loss of the entire ERCOT electric grid.”
>
> ERCOT is still the Electric Reliability Council of Texas. But the PUC report wasn’t analyzing the power outages that hit a large swath of Texas when temperatures plunged this past February. The report is dated November 1990 and is referring to the record freeze of late December 1989.
>
> The PUC has a single remaining copy of it in its library north of the Capitol.

The report referred to in the article is Public Utility Commission of Texas report: “Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989.”[17] (A copy of this report is attached as Exhibit F.)

The 2011 blackout caused a flurry of investigations, hearings, reports and public outrage. Multiple Hearings, Investigations, Reports — and ultimately inaction.

On February 26, 2021 the Houston Chronicle reported[18]:

> A decade ago, after an Arctic cold spell knocked out power and left millions of Texans shivering in the dark, the Public Utility Commission’s enforcement apparatus swung into action. Their aim: punish the companies that had promised but failed to deliver electricity in an emergency.
>
> Specialists contracted by the state agency worked with an enforcement team the utility commission created four years earlier. More recently, it had added lawyers whose only job was

[16] Austin American Statesman. “February power blackouts across Texas echoed 1989 failures, state report shows.” April 11, 2011. https://www.statesman.com/article/20110411/NEWS/304119704

[17] Available at: https://lrl.texas.gov/scanned/archive/1990/15303.pdf

[18] Houston Chronicle. “'Muzzled and eviscerated': Critics say Abbott appointees gutted enforcement of Texas grid rules.” February 26, 2021. https://www.houstonchronicle.com/politics/texas/article/critics-abbott-power-grid-rules-texas-deadly-storm-15982421.php

> to pursue wrong-doing. The energy companies eventually paid fines and settlements totaling hundreds of thousands of dollars for failing to prepare for the extreme weather.
>
> Two weeks ago, history repeated. Millions of residents were left without power and water in below-freezing temperatures. The damage far exceeded the 2011 storm. Nearly a third of the grid's power plants went offline. Dozens of deaths have been attributed to the event, with a full accounting yet to come.
>
> But the enforcement tools that worked to hold companies accountable for the 2011 failures had been removed under Gov. Greg Abbott's appointees on the utility commission. Hearst Newspapers reported last week that commissioners in November cut ties with the Texas Reliability Entity — the specialists hired — leaving state regulators without an external independent reliability monitor.
>
> Four months before that, the governor's commissioners had also disbanded the Oversight & Enforcement Division. The head attorney was told he no longer had a job; nine other team members were reassigned throughout the utility commission.
>
> Several pending cases were dropped. According to commission records, by the end of 2020 the number of enforcement cases had fallen 40 percent.

The 2011 Joint FERC/NERC report noted:

> On February 14, the Federal Energy Regulatory Commission (FERC) initiated an inquiry into the Southwest outages and service disruptions. The inquiry had two objectives: to identify the causes of the disruptions, and to identify any appropriate actions for preventing a recurrence of the disruptions. FERC stated it was not at that time initiating an investigation into whether there may have been violations of applicable regulations, requirements or standards under FERC's jurisdiction, and that any decisions on whether to initiate enforcement investigations would be made later. Consequently, while this report describes actions which in some cases appear to warrant further investigation, it does not reach any conclusions as to whether violations have occurred.

It seems nobody wants to tell the industry to fix grid security issues in Texas, thus they do not get fixed. This regulatory inaction is causing deaths, impacts to the critical infrastructures, and economic loss — it is unacceptable.

The 2011 Texas blackout was followed by many promises but little action. The Electric Reliability Council of Texas (ERCOT) made many promises, including "ERCOT will be an active participant in the discussion related to the adequate weatherization of generation units."[19]

In 2021, It doesn't seem that this "discussion" was fruitful.

One of the Key Findings in the FERC and NERC Joint 2011 report was:

---

[19] ERCOT "Review of February 2, 2011 Energy Emergency Alert (EEA) Event." February 14, 2011. http://www.ercot.com/content/meetings/board/keydocs/2011/0214/Review_of_February_2,_2011_EEA_Event.pdf

> During the February event, temperatures were considerably lower (15 degrees plus) than average winter temperatures, and represented the longest sustained cold spell in 25 years. Steady winds also accelerated equipment heat loss. However, such a cold spell was not unprecedented. The Southwest also experienced temperatures considerably below average, accompanied by generation outages, in December 1989. Less extreme cold weather events occurred in 2003 and 2010. ***Many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment.***

(Emphasis added.)

Recommendations related to extreme cold weather and winterization in the FERC and NERC Joint 2011 report have apparently not been heeded. Similar recommendations of the Public Utility Commission of Texas after the 1989 Texas blackout were also not heeded.

The Foundation for Resilient Societies has done a preliminary analysis on the costs of the 2021 blackout versus the cost of mitigation.[20] These data demonstrate that it would have cost substantially less to mitigate the 2021 disaster than the disaster has actually cost us. To paraphrase the old adage, "an ounce of prevention is cheaper than a pound of disaster." And yet we continue in this cycle of inaction and disaster. 1989. 2011. 2021.

Somebody is going to have to pay for this disaster. The taxpayers or the ratepayers. Unfortunately, I am both so I will pay. But perhaps I shouldn't complain. Many people have paid for these disasters in 1989, 2011 and 2021 with their lives.

I implore the Commission: Stop asking and recommending. It is time to direct NERC and Texas RE to take action. Violators of reliability standards must be held accountable and we must make sure that this cycle of blackouts, deaths, critical infrastructure impacts and damage to the economy stops.

---

[20] Foundation for Resilient Societies. "Causes and Costs of ERCOT Load Sheds in February 2021." February 24, 2021 (Preliminary). https://www.resilientsocieties.org/uploads/5/4/0/0/54008795/ercot_load_shed_causes_and_costs_preliminary_feb_25_2021.pdf

## If we were not prepared for a known incoming weather event, are we prepared for other events?

I conducted an analysis of the reported electric disturbance events between 2010 and 2020 from the Department of Energy OE-417 Electric Disturbance Reports.[21] (I have attached a copy of my analysis as Exhibit G.)

| All NERC Regions | | |
|---|---|---|
| **Events From 2010-2020** | **Total** | **%** |
| Weather | 961 | 52.6% |
| Cyber Attack | 37 | 2.0% |
| Physical Attack | 721 | 39.5% |
| Fuel Supply Deficiency | 74 | 4.1% |
| Equipment | 15 | 0.8% |
| Natural Disaster | 14 | 0.8% |
| Wildfire | 5 | 0.3% |
| Generation Interruption | 17 | 3.4% |
| Transmission Interruption | 113 | 22.8% |
| Distribution Interruption | 9 | 1.8% |
| Operations | 185 | 37.3% |
| Islanding | 67 | 13.5% |
| Load Shed | 30 | 6.0% |
| Public Appeal | 65 | 13.1% |
| ? | 10 | 2.0% |
| **Total OE-417 Reports** | **2323** | |
| **Cause Known from OE-417** | **1827** | |
| **Cannot Determine Cause** | **496** | |

According to my analysis, 52.6% of OE-417 disturbance reports filed nationwide in the last decade are weather related.

Interestingly, 70.9% of the disturbances reported in the Texas RE region are weather related. The Commission needs to ask why this difference exists and whether mandatory reliability standards are either being followed or are effective.

| Texas RE Only | | |
|---|---|---|
| **Events From 2010-2020** | **Total** | **%** |
| Weather | 83 | 70.9% |
| Cyber Attack | 3 | 2.6% |
| Physical Attack | 28 | 23.9% |
| Fuel Supply Deficiency | 3 | 2.6% |
| Equipment | 0 | 0.0% |
| Natural Disaster | 0 | 0.0% |
| Wildfire | 0 | 0.0% |
| Generation Interruption | 4 | 7.1% |
| Transmission Interruption | 17 | 30.4% |
| Distribution Interruption | 2 | 3.6% |
| Operations | 11 | 19.6% |
| Islanding | 1 | 1.8% |
| Load Shed | 0 | 0.0% |
| Public Appeal | 21 | 37.5% |
| ? | 0 | 0.0% |
| **Total OE-417 Reports** | **173** | |
| **Cause Known from OE-417** | **117** | |
| **Cannot Determine Cause** | **56** | |

If we are not adequately prepared for a weather event that is forecast well in advance, such as the 2021 Texas grid collapse, are we ready for other threats?

Mike Rogers, former chairman of the House Intelligence Committee, recently noted in an article entitled "Why America would not survive a real first strike cyberattack today"[22]:

> The only thing that prevented the Russians from launching a destructive malware attack or inserting malicious code was the Russians themselves. They could have caused a major disruption across our government and private sector networks, changing or deleting data, planting viruses, or simply turning off the networks. Restarting the systems and deleting the offending code alone is not a solution. In 2016, the Ukrainian electricity grid was targeted by the Russians and, until this day, the country is still finding and removing vulnerabilities left behind by Moscow.

[21] See: https://michaelmabee.info/oe-417-database/

[22] Rogers, Mike. "Why America would not survive a real first strike cyberattack today." February 22, 2021. https://thehill.com/opinion/cybersecurity/539826-we-would-not-survive-true-first-strike-cyberattack?rl=1

If we are unable to prepare our electric grid and its dependent critical infrastructures from a cold snap that we see coming over a week away, it begs the question: Are we prepared for a cyberattack?[23] Are we prepared for a coordinated physical attack?[24] Are we prepared for a major geomagnetic disturbance (GMD) event? Are we prepared for an electromagnetic pulse (EMP) attack? Are we prepared for other extreme weather events?

## Relief Sought

1. The Federal Energy Regulatory Commission should direct the North American Electric Reliability Corporation (NERC) and its regional entity, Texas Reliability Entity, Inc. (Texas RE) to conduct a comprehensive investigation into whether reliability standards were followed by all entities registered with Texas RE who had any involvement in the Texas grid collapse of February 15, 2021.

2. If the North American Electric Reliability Corporation (NERC) and its regional entity, Texas Reliability Entity, Inc. (Texas RE) determine that violations of reliability standards did not contribute to the Texas grid collapse of February 15, 2021, then the Federal Energy Regulatory Commission should direct the North American Electric Reliability Corporation (NERC) to improve the reliability standards to prevent catastrophic power outages such as this from occurring in the future.

Respectfully submitted,

Michael Mabee

Attachments: 18 CFR § 385.206 Compliance Information
Draft Notice
Exhibits A-G

---

[23] The Commission dismissed my complaint about inadequate supply chain cyber security CIP standards on October 2, 2020. Docket Number EL20-46-000.

[24] The Commission dismissed my complaint about inadequate physical security CIP standards on June 9, 2020. Docket Number EL20-21-000.

**18 CFR § 385.206 Compliance Information**

I Michael Mabee, hereby state the following:

18 CFR § 385.206(b) Contents. A complaint must:
(1) Clearly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements;

- Contained in Complaint

(2) Explain how the action or inaction violates applicable statutory standards or regulatory requirements;

- Contained in Complaint

(3) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the complainant;

- A widespread power outage in Texas on February 15, 2021 caused the loss of life and substantial damage to the economy.

(4) Make a good faith effort to quantify the financial impact or burden (if any) created for the complainant as a result of the action or inaction;

- A widespread power outage in Texas on February 15, 2021 caused the loss of life and substantial damage to the economy.

(5) Indicate the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction, including, where applicable, the environmental, safety or reliability impacts of the action or inaction;

- A widespread power outage in Texas on February 15, 2021 caused the loss of life and substantial damage to the economy.

(6) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

- I am unaware of any public FERC docket which addresses the Texas Power Outage of 2021.

(7) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

- Contained in "Relief Sought" section of Complaint.

(8) Include all documents that support the facts in the complaint in possession of, or otherwise attainable by, the complainant, including, but not limited to, contracts and affidavits;

- Attached as exhibits to the Complaint

(9) State

  (i) Whether the Enforcement Hotline, Dispute Resolution Service, tariff-based dispute resolution mechanisms, or other informal dispute resolution procedures were used, or why these procedures were not used;

  - N/A

(ii) Whether the complainant believes that alternative dispute resolution (ADR) under the Commission's supervision could successfully resolve the complaint;

- N/A

(iii) What types of ADR procedures could be used; and

- N/A

(iv) Any process that has been agreed on for resolving the complaint.

- N/A

(10) Include a form of notice of the complaint suitable for publication in the Federal Register in accordance with the specifications in § 385.203(d) of this part. The form of notice shall be on electronic media as specified by the Secretary.

- Draft Notice Attached

(11) Explain with respect to requests for Fast Track processing pursuant to section 385.206(h), why the standard processes will not be adequate for expeditiously resolving the complaint.

- N/A

18 CFR § 385.206(c) Service. Any person filing a complaint must serve a copy of the complaint on the respondent, affected regulatory agencies, and others the complainant reasonably knows may be expected to be affected by the complaint. Service must be simultaneous with filing at the Commission for respondents. Simultaneous or overnight service is permissible for other affected entities. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger.

- A copy of this Complaint will be sent electronically to the Electric Reliability Organization ("ERO") and the Texas Reliability Entity, Inc. simultaneously with my filing with the Commission.

Respectfully submitted,

Michael Mabee

**Draft Notice**

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

| | |
|---|---|
| Complaint of Michael Mabee<br>Related to Mandatory Reliability Standards<br>in the Texas Grid Collapse of 2021 | Docket No. |

NOTICE OF COMPLAINT

( )

Take notice that on [date filed], pursuant to section 215(d) of the Federal Power Act, 16 U.S.C. 824o(d) and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206 (2019), Michael Mabee, (Complainant) filed a formal complaint alleging that the Texas grid collapse of February 2021 resulted from either: 1) The mandatory reliability standards were not followed, or, 2) The mandatory reliability standards were ineffective.

Complainant certifies that copies of the complaint were served on the contacts as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,
Secretary.

# Exhibit A

**Complaint of Michael Mabee Related to**
**Mandatory Reliability Standards**
**in the Texas Grid Collapse of 2021**

# News Release

February 11, 2021

## Extreme cold weather expected to result in record electric use in ERCOT region

***Consumers can stay current on grid conditions by downloading the ERCOT app and following ERCOT on Twitter***

AUSTIN, TX, Feb. 11, 2021 – The Electric Reliability Council of Texas (ERCOT) is expecting record electric use as a result of the extreme cold temperatures that have already reached much of the ERCOT region.

"This statewide weather system is expected to bring Texas the coldest weather we've experienced in decades," said ERCOT President and CEO Bill Magness. "With temperatures rapidly declining, we are already seeing high electric use and anticipating record-breaking demand in the ERCOT region."

Consumers can monitor grid conditions in real time by following ERCOT on Twitter (@ERCOT_ISO) and/or by downloading the ERCOT mobile app available on Google Play and in the Apple Store.

On Monday, Feb. 8, ERCOT issued an Operating Condition Notice (OCN) for extreme cold weather expected in the ERCOT region Thursday, Feb. 11 through Tuesday, Feb. 16. Subsequently, ERCOT issued an Advisory on Feb. 10 and a Watch on Feb. 11 for extreme cold weather. A Watch is the third level of communication issued by the ERCOT control room in anticipation of potential tight grid conditions.

Generators have been asked to take necessary steps to prepare their facilities for the expected cold weather, which includes reviewing fuel supplies and planned outages and implementing winter weatherization procedures. The grid operator is also working with transmission operators to minimize transmission outages that could reduce the availability of generation or otherwise impact the ability of the system to serve demand.

Based on the current load forecast, and if temperatures continue to decline, ERCOT could set a new all-time winter peak demand record Monday morning, Feb. 15. The current winter peak demand record is 65,915 MW set on Jan. 17, 2018 between 7 and 8 a.m.

###



**Contact**

media@ercot.com

512-275-7432

# Exhibit B

**Complaint of Michael Mabee Related to Mandatory Reliability Standards in the Texas Grid Collapse of 2021**

# News Release

February 14, 2021

## Grid operator requests energy conservation for system reliability

AUSTIN, TX, Feb. 14, 2021 – The Electric Reliability Council of Texas (ERCOT) is asking consumers and businesses to reduce their electricity use as much as possible Sunday, Feb. 14 through Tuesday, Feb. 16.

"We are experiencing record-breaking electric demand due to the extreme cold temperatures that have gripped Texas," said ERCOT President and CEO Bill Magness. "At the same time, we are dealing with higher-than-normal generation outages due to frozen wind turbines and limited natural gas supplies available to generating units. We are asking Texans to take some simple, safe steps to lower their energy use during this time."

Here are some tips to reduce electricity use:

- Turn down thermostats to 68-degrees.
- Close shades and blinds to reduce the amount of heat lost through windows.
- Turn off and unplug non-essential lights and appliances.
- Avoid using large appliances (i.e., ovens, washing machines, etc.).
- Businesses should minimize the use of electric lighting and electricity-consuming equipment as much as possible.
- Large consumers of electricity should consider shutting down or reducing non-essential production processes.

Given the prolonged, below-freezing temperatures, conservation measures should be implemented safely and within reason.

ERCOT has the tools and procedures in place to maintain a reliable electric system during tight grid conditions. If power reserves drop too low, ERCOT may need to declare an Energy Emergency Alert, or EEA. Declaring an EEA allows the grid operator to take advantage of additional resources that are only available during scarcity conditions. There are three levels of EEA, and rotating outages are only implemented as a last resort to maintain reliability of the electric system.

Click here for more information on ERCOT's emergency procedures during tight grid conditions.

Click here for more information on the additional tools and resources available to ERCOT when it declares an EEA.

**How to track electricity demand**

- View daily peak demand forecast, current load and available generation on ERCOT.com.
- Follow ERCOT on Twitter (@ERCOT_ISO).
- Sign up for the ERCOT mobile app (available for download at the Apple App Store and Google Play).

**Consumer assistance**

Public Utility Commission of Texas Hotline – 1-888-782-8477

###

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to more than 26 million Texas customers -- representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 680+ generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas.

ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. Its members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution providers and municipally owned electric utilities.

**Contact**
media@ercot.com
512-275-7432

# Exhibit C

**Complaint of Michael Mabee Related to Mandatory Reliability Standards in the Texas Grid Collapse of 2021**

# News Release

February 15, 2021

## ERCOT calls for rotating outages as extreme winter weather forces generating units offline

***Almost 10,000 MW of generation lost due to sub-freezing conditions***

AUSTIN, TX, Feb. 15, 2021 – The Electric Reliability Council of Texas (ERCOT) entered emergency conditions and initiated rotating outages at 1:25 a.m. today.

About 10,500 MW of customer load was shed at the highest point. This is enough power to serve approximately two million homes.

Extreme weather conditions caused many generating units – across fuel types – to trip offline and become unavailable.

There is now over 30,000 MW of generation forced off the system.

"Every grid operator and every electric company is fighting to restore power right now," said ERCOT President and CEO Bill Magness.

Rotating outages will likely last throughout the morning and could be initiated until this weather emergency ends.

###

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to more than 26 million Texas customers -- representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 680+ generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas.

ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. Its members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution providers and municipally owned electric utilities.

**Contact**
media@ercot.com
512-275-7432

# Exhibit D

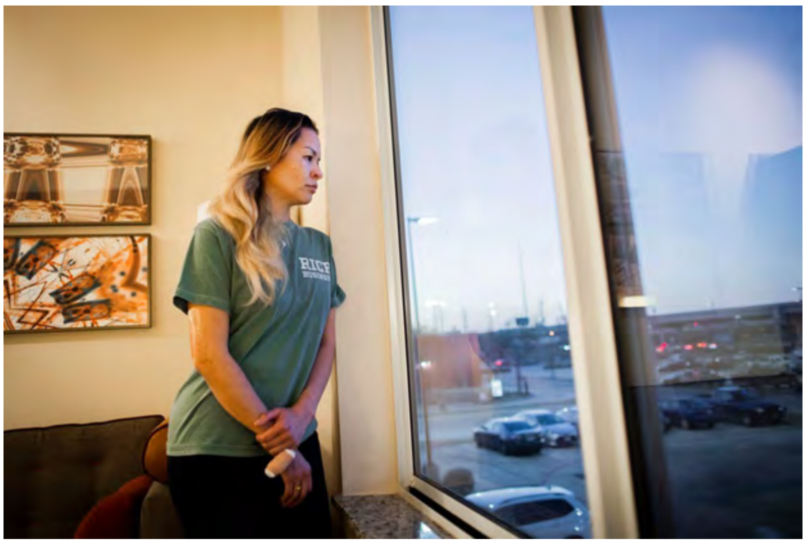
**Complaint of Michael Mabee Related to**
**Mandatory Reliability Standards**
**in the Texas Grid Collapse of 2021**

https://www.wsj.com/articles/full-death-toll-from-texas-storm-could-take-months-to-determine-11614107708

U.S.

# Full Death Toll From Texas Storm Could Take Months to Determine

Officials are still counting fatalities from hypothermia, carbon monoxide, other factors as some experts warn accurate total might never be known



Jackie Nguyen lost her three children along with their grandmother in a house fire in Sugar Land, Texas, during the severe weather that swept the state last week.

PHOTO: MARIE D. DE JESÚS/ASSOCIATED PRESS

*By Elizabeth Findell*

Updated Feb. 23, 2021 3:54 pm ET

**Listen to this article**

5 minutes

The harsh winter storm that hit Texas and other states last week has been blamed for dozens of deaths, though officials said that it would be weeks or months before the human cost of the freezing weather and utility crisis is known and that it might never be fully accurate.

The failure of the state's electrical grid during the weeklong cold snap left more than four million Texans without electricity and heat, many for days on end in subfreezing temperatures. Many residents also lost access to water, and 14.6 million were ordered to boil water to make it safe to drink. Power had been restored in most of the state by Tuesday morning, but 7.5 million people in 204 counties remained under boil-water orders.

So far, nearly 80 people have died a result of the storm and its effects, according to the Associated Press.

SHARE YOUR THOUGHTS

*Have officials responded effectively to the disaster in Texas? Why or why not? Join the conversation below.*

An 11-year-old boy was found frozen in his bed, his family told the Houston Chronicle. A grandmother and three grandchildren died in a house fire as they were trying to stay warm, the Chronicle also reported. At least six deaths occurred near the Abilene area, local media reported, including a patient who couldn't get medical treatment due to a lack of water and three elderly men who were found dead in subfreezing homes.

Harris County, which includes Houston, has confirmed at least 15 hypothermia deaths and one fatal fall on ice, according to its forensics institute. Several others died from carbon-monoxide poisoning after taking unsafe measures to stay warm, according to the county's top executive. In Travis County, which includes Austin, the medical examiner's office is busy processing more than 80 cases from last week to determine causes of death, an official said.

Medical examiners don't determine the circumstances of a death. It will be up to officials such as constables and justices of the peace in each of Texas' 254 counties to investigate any recent deaths and decide whether they might have been related to the storm. Cases that local registrars flag as possibly storm-related will be referred to state epidemiologists to evaluate, said Chris Van Deusen, a spokesman for the Texas Department of State Health Services.

Calculating fatalities from any large-scale crisis is difficult, and totals can be unreliable, said Robert Jensen, chairman of Kenyon International Emergency Services, a London and Houston-based firm that has been hired to help count deaths after events such as Hurricane Katrina in Louisiana in 2005. Authorities there primarily counted bodies left behind as floodwater receded, he said. In a case such as the storm in Texas, the reporting is likely to be based on local authorities' opinions.

> **'Mass fatalities scare people, and they're very political. I don't think it's intentionally misleading, it's just a very screwed-up process.'**
>
> — Robert Jensen, chairman of Kenyon International Emergency Services, on calculating disaster deaths

"Every county will kind of do their own thing," Mr. Jensen said. Individual officials will have to weigh factors such as whether a house fire or a carbon monoxide poisoning occurred because people were trying to stay warm, whether a car crash happened because of ice, or whether a lack of water or power caused an existing medical condition to flare or go untreated.

Mr. Jensen added that there is often little political will among state officials to standardize the process or to determine the true cost of a disaster.

Volunteers handed out water at an apartment complex in Dallas on Tuesday.

PHOTO: LM OTERO/ASSOCIATED PRESS

"Mass fatalities scare people, and they're very political," he said. "I don't think it's intentionally misleading, it's just a very screwed-up process."

Some lawsuits against the Electric Reliability Council of Texas, which manages the Texas energy grid, are seeking to link specific deaths to the storm. An attorney for Doyle Austin, a Houstonian whose family found him unresponsive—a week shy of his 96th birthday—

after two days without power and temperatures down to 11 degrees, said he died of hypothermia due to the storm.

An Ercot spokeswoman said it hadn't yet reviewed the lawsuits, but said it was confident the blackouts that occurred were the right decision to avoid a prolonged statewide blackout. "This is a tragedy," she said. "Our thoughts are with all Texans who have and are suffering due to this past week."

Mr. Austin worked in the Port of Houston all his life and played professional baseball in what were then called "Negro leagues" in the 1940s when teams were still segregated, said Larry Taylor, a Houston-based lawyer representing Mr. Austin's daughters, and a family friend. In his later years, Mr. Austin loved walking the neighborhood and playing dominoes and spades with his relatives.

"He was a hero to many of us in the family and community, as far as how he carried himself and what he was able to do in life and how he treated people," Mr. Taylor said.


## Winter Storm Impact

States deal with the fallout from a major winter storm.

LIVES LOST
**Full Death Toll Could Take Months to Determine**

EXPLAINER
**Why Texas Experienced Power Outages?**

POWER
**Texas Electric Bills Were $28 Billion Higher Under Deregulation**

AFTERMATH
**Texas Grapples With Crushing Power Bills**

INFRASTRUCTURE
**A Grid Built for Heat, Not Cold**

TECH PREP
**Prep Your Tech for Power Outages**

TAXES
**IRS Postpones Tax Deadline For Texans**

STORM RISKS
**Desperate Families Take Risks to Stay Warm**


Mr. Austin's death report is still unfinished, but Mr. Taylor said there is no question in his mind that the weather and utility crisis were to blame.

"I'm healthy, I'm fine, a traumatic freeze comes through, I lose power, my house is at freezing temperatures and I die," he said. "There is no doubt in our minds that he died of hypothermia. We will eventually get more details, but it doesn't take a rocket scientist to know."

**Write to** Elizabeth Findell at Elizabeth.Findell@wsj.com

*Appeared in the February 24, 2021, print edition as 'Tallying Texas Deaths Could Take Months.'*

# Exhibit E

**Complaint of Michael Mabee Related to Mandatory Reliability Standards in the Texas Grid Collapse of 2021**

REPORT ON

# OUTAGES AND CURTAILMENTS DURING THE SOUTHWEST COLD WEATHER EVENT OF FEBRUARY 1-5, 2011

## Causes and Recommendations


Prepared by the Staffs of the
**Federal Energy Regulatory Commission**
and the
**North American Electric Reliability Corporation**


AUGUST 2011

# Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

Prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation

Causes and Recommendations

August 2011

# Table of Contents

**This page intentionally left blank.**

# ATTACHMENTS

**This page intentionally left blank.**

# I. Introduction

The southwest region of the United States experienced unusually cold and windy weather during the first week of February 2011. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to -7 degrees over the period, compared to an average high of 51 degrees and a low of 26 degrees. Dallas temperatures ranged from 14 degrees to 19 degrees, compared to an average high of 60 degrees or above and average lows in the mid-to-upper 30s. Many cities in the region would not see temperatures above freezing until February 4. In addition, sustained high winds of over 20 mph produced severe wind chill factors.

Electric entities located within the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and the Southwest Power Pool (SPP) were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona.

Between February 1 and February 4, a total of 210 individual generating units within the footprint of the Electric Reliability Council of Texas, Inc. (ERCOT), which covers most of Texas, experienced either an outage, a derate, or a failure to start. The loss of generation was severe enough on February 2 to trigger a controlled load shed of 4000 MW, which affected some 3.2 million customers. On February 3, local transmission constraints coupled with the loss of local generation triggered load shedding for another 180,000 customers in the Rio Grande Valley in south Texas. El Paso Electric Company (EPE), which is outside the ERCOT region, lost approximately 646 MW of local generation over the four days beginning on February 1. It implemented rotating load sheds on each of the days from February 2 through February 4, totaling over 1000 MW and affecting 253,000 customers. The Salt River Project Agricultural Improvement and Power District (SRP), located in Arizona, lost 1050 MW of generation on February 1 through February 2 and shed load of 300 MW, affecting approximately 65,000 customers. The New Mexico communities of Alamogordo, Ruidoso, and Clayton lost approximately 26 MW of load, affecting a little over 21,000 customers, when Public Service Company of New Mexico (PNM) experienced localized transmission failures, although these were largely unrelated to the extreme weather.

In total, approximately 1.3 million electric customers were out of service at the peak of the event on February 2, and a total of 4.4 million were affected over the course of the event from February 2 through February 4.

Natural gas customers also experienced extensive curtailments of service during the event. These curtailments were longer in duration than the electric outages, because relighting customers' equipment has to be accomplished manually at each customer's location. Local distribution companies (LDCs) interrupted gas service to more than 50,000 customers in New Mexico, Arizona and Texas; New Mexico was the hardest hit with outages of over 30,000 customers in areas as widespread as Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo and Placitas.

In the wake of these events, the Arizona Corporation Commission, the Public Regulation Commission of New Mexico, the Public Utilities Commission of Texas (PUCT), the Texas Railroad Commission (TRC), the New Mexico state legislature and the Texas state legislature all initiated inquiries or investigations. The PUCT directed TRE, the regional entity authorized by the North American Electric Reliability Corporation (NERC) to cover the ERCOT region, to investigate the decisions and actions ERCOT took in initiating the rolling blackouts.

On February 7, 2011, NERC announced that it would work with the affected Regional Entities to prepare an event analysis that would examine the adequacy of preparations for the event and identify potential improvements and lessons learned. NERC also stated it would review electric and natural gas interdependencies, in light of the shift toward a greater reliance on natural gas to produce electricity.

On February 14, the Federal Energy Regulatory Commission (FERC) initiated an inquiry into the Southwest outages and service disruptions. The inquiry had two objectives: to identify the causes of the disruptions, and to identify any appropriate actions for preventing a recurrence of the disruptions. FERC stated it was not at that time initiating an investigation into whether there may have been violations of applicable regulations, requirements or standards under FERC's jurisdiction, and that any decisions on whether to initiate enforcement investigations would be made later. Consequently, while this report describes actions which in some cases appear to warrant further investigation, it does not reach any conclusions as to whether violations have occurred.

From the beginning of their inquiries into the causes of the outages and disruptions, the staffs of FERC and NERC have cooperated in their data gathering and analysis. On May 9, FERC and NERC announced their staffs would create a joint task force to combine their separate inquiries. This report is a product of that effort.

The inquiry performed by the joint task force was far-reaching. Noted below in summary form are some of the steps taken by the task force to develop its understanding of the electric and natural gas disruptions that were experienced in the Southwest in early February.

**Scope of Data Reviewed**

The task force received approximately 54 GB of data through data requests issued to entities in both the electric and natural gas industries, conducted numerous follow-up calls and meetings, and issued follow-up requests to discuss questions raised by the data responses.

For the electric industry, the task force issued 122 data requests to generator operators, transmission operators, balancing authorities, and a reliability coordinator. The task force also utilized event analysis information which NERC and the affected Regional Entities received from 79 registered entities (72 from TRE, four from WECC and three from SPP). Additional event information was received through a request for information issued by NERC and Regional Entities to those entities affected by the extreme weather event. For the gas industry, the task force issued 92 data requests to pipelines (interstate and intrastate), storage facilities, gas processing plants, producers, and public utilities.

The data compiled by the task force focused on the causes of the outages and curtailments during the February cold weather event, critical entities' preparations for the forecasted cold weather and their performance in connection with the rolling blackouts and natural gas curtailments, and any lessons learned that could be applied in the future. As part of its analysis, the task force also reviewed historical data and recommendations compiled during past cold weather events in Texas and elsewhere in the Southwest, to determine whether the 2011 event was unprecedented or whether entities might have been better prepared to deal with it.

**Electric Facility Site Visits**

Staff from FERC and NERC, together with representatives of TRE and WECC, conducted site visits with various entities involved in the outages, toured facilities and conducted interviews with operations personnel, compliance personnel and company executives. The task force visited ERCOT, four transmission operators in ERCOT, and 15 generators in ERCOT (including coal, natural gas, and wind units); two generators in WECC; and two balancing authorities in WECC. During the generator site visits the task force toured the units, viewing any equipment that led to trips, derates, or failures to start; viewed winterization measures; and discussed maintenance and winterization processes, fuel supply and market participation. During visits to the balancing authorities and transmission operators, the task force toured control centers and discussed the progression of the events, including specifics on load forecasting, market mechanics, system operations, load shedding and load restoration. The task force also discussed transmission system winterization and load shedding procedures with the transmission operators.

### Natural Gas Meetings

The task force conducted numerous meetings with various entities from the gas industry to discuss the curtailments and shortages experienced in early February and the specifics of the entities' winter operations. These meetings included operations and regulatory personnel from two interstate pipelines doing business in Texas, New Mexico, Arizona, Colorado, and California; one LDC/intrastate pipeline located in New Mexico; one LDC from Arizona; and one intrastate pipeline located in Texas. The meetings focused on the companies' preparations for the storm, communications among LDCs, pipelines, marketers, and producers about unfolding events, system operations, underlying causes of the gas supply problems, and lessons learned. In most instances, interviews led to supplemental data requests that provided additional information about the events. The task force also held numerous telephone conferences with companies in the pipeline, LDC, processing and production sectors, both to gather information and to clarify information received in response to data requests.

### Outreach Meetings

Task force staff conducted outreach meetings with the following industry associations and groups: the Electric Power Supply Association, the American Gas Association, the Independent Petroleum Association of America, the Texas Pipeline Association, the Interstate Natural Gas Association of America, the Natural Gas Supply Association, the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the (ERO) Southwest Outage Advisory Panel. The task force shared its preliminary findings and recommendations on a non-public basis with members of these organizations in order to obtain feedback and, with respect to the recommendations, input as to their practicality and feasibility. The feedback and input provided by these organizations was considered and in a number of instances reflected in the findings and recommendations included in this report.

### Coordination with State Inquiries

The task force also reviewed materials acquired in the course of inquiries into the event conducted by legislative bodies and regulatory commissions. The task force followed legislative and regulatory hearings in Arizona, New Mexico and Texas and reviewed transcripts, testimony and webcasts from the proceedings.

Through contacts with state regulatory agencies, staff was able to review responses to data requests issued by those bodies to ensure that the task force was in possession of all potentially relevant materials. Task force staff also monitored legislative efforts taken in response to the February outage, including conferring with sponsors of pertinent legislation concerning, among other things, the anticipated impacts of their proposals. The task force tracked the bills throughout the legislative process. In addition, as regulatory agencies moved forward with their inquiries into the outage, task force staff reviewed draft and final copies of all relevant reports.

The task force also collaborated with ERCOT's Independent Market Monitor (IMM), which conducted an inquiry into potential market manipulation during the event at the request of the PUCT. Task force staff conducted calls with the IMM to discuss market conditions and reviewed its written assessment of the market impacts from the event. The task force also contacted the TRC regarding gas curtailment matters, submitted written questions about the TRC's activities in connection with the event, and reviewed all information the TRC collected concerning the event.

To assist in its analysis of the materials received, the task force commissioned one outside consultant's study to examine impacts of the cold weather event on gas production, reviewed studies conducted on behalf of regulatory and other bodies, and prepared extensive in-house studies by staff analysts.

This report documents the information received by the task force and presents the task force's conclusions as to the causes of the electric outages and natural gas curtailments that occurred during the February 2011 event. It is divided into several sections, beginning with an overview of the electric and natural gas industries that provides background for the event, discusses the event itself and prior cold weather events in the region, and ends with a summary of key findings and recommendations. Also included are a list of acronyms, a glossary, and a number of appendices which treat in fuller detail many of the matters mentioned in the body of the report.

This page intentionally left blank.

# II. Executive Summary

The arctic cold front that descended on the Southwest during the first week of February 2011 was unusually severe in terms of temperature, wind, and duration of the event. In many cities in the Southwest, temperatures remained below freezing for four days, and winds gusted in places to 30 mph or more. The geographic area hit was also extensive, complicating efforts to obtain power and natural gas from neighboring regions.

The storm, however, was not without precedent. There were prior severe cold weather events in the Southwest in 1983, 1989, 2003, 2006, 2008, and 2010. The worst of these was in 1989, the prior event most comparable to 2011. That year marked the first time ERCOT resorted to system-wide rolling blackouts to prevent more widespread customer outages. In all of those prior years, the natural gas delivery system experienced production declines; however, curtailments to natural gas customers in the region were essentially limited to the years 1989 and 2003.

Electric

Going into the February 2011 storm, neither ERCOT nor the other electric entities that initiated rolling blackouts during the event expected to have a problem meeting customer demand. They all had adequate reserve margins, based on anticipated generator availability. But those reserves proved insufficient for the extraordinary amount of capacity that was lost during the event from trips, derates, and failures to start.

In the case of ERCOT, where rolling blackouts affected the largest number of customers (3.2 million), there were 3100 MW of responsive reserves available on the first day of the event, compared to a minimum requirement of 2300 MW. But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW. Combining forced outages with scheduled outages, approximately one-third of the total ERCOT fleet was unavailable at the lowest point of the event. These extensive generator failures overwhelmed ERCOT's reserves, which eventually dropped below the level of safe operation. Had ERCOT not acted promptly to shed load, it would very likely have suffered widespread, uncontrolled blackouts throughout the entire ERCOT Interconnection.

ERCOT also experienced generator outages in the Rio Grande Valley on February 3, again due to the cold weather. This area is transmission constrained, and the loss of local generation led to voltage concerns that necessitated localized load shedding.

Spot prices in ERCOT hit the $3,000 per MWh cap on February 2, the worst day of the event. Given the high demand and the huge loss of generation, this was not a surprising development. In fact, very high prices are an expected response to scarcity conditions, one that is built into ERCOT's energy-only market. ERCOT's IMM reviewed market performance during the event and found no evidence of market manipulation.

EPE and SRP likewise suffered numerous generator outages, necessitating load shed of 1023 MW in EPE's case, and 300 MW in SRP's case. As with ERCOT, many of these generators failed because of weather-related reasons.

A number of entities within SPP also experienced outages during the event. In their case, however, load shedding was not required, principally because the utilities were able to purchase emergency energy from other SPP members. One other utility in the Southwest, PNM, experienced blackouts, but these were localized and the result of transmission outages that were mostly unrelated to the weather.

The actions of the entities in calling for and carrying out the rolling blackouts were largely effective and timely. However, the massive amount of generator failures that were experienced raises the question whether it would have been helpful to increase reserve levels going into the event. This action would have brought more units online earlier, might have prevented some of the freezing problems the generators experienced, and could have exposed operational problems in time to implement corrections before the units were needed to meet customer demand.

The February event underscores the need to have sufficient black start units available, particularly in the face of an anticipated severe weather event. In ERCOT's case, for instance, nearly half of its black start units were either on scheduled outage at the time of the event or failed during the event itself, jeopardizing the utility's ability to promptly restore the system had an uncontrolled, ERCOT-wide blackout occurred.

The majority of the problems experienced by the many generators that tripped, suffered derates, or failed to start during the event were attributable, either directly or indirectly, to the cold weather itself. For the Southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. At least another 12 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching).

Low temperatures returned to the region on February 10. In fact, ERCOT set a new winter peak that day. But no load shedding proved necessary, largely because the temperatures were not quite as cold or sustained as those of the previous week, the winds were less severe, and many of the repairs and protective measures taken by the generators on February 2 remained in place.

Natural Gas

Problems on the natural gas side largely resulted from production declines in the five basins serving the Southwest. For the period February 1 through February 5, an estimated 14.8 Bcf of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas.

The production losses stemmed principally from three things: freeze-offs, icy roads, and rolling electric blackouts or customer curtailments. Freeze-offs occurred when the small amount of water produced alongside the natural gas crystallized or froze, completely blocking off the gas flow and shutting down the well. Freeze-offs routinely occur in very cold weather, and affected at least some of these basins in all of the six recent cold weather events in the Southwest with the possible exception of 1983, for which adequate records are not available. During the February event, icy roads prevented maintenance personnel and equipment from reaching the wells and hauling off produced water which, if left in holding tanks at the wellhead, causes the wells to shut down automatically. The ERCOT blackouts or customer curtailments affected primarily the Permian and Fort Worth Basins and caused or contributed to 29 percent (Permian) and 27 percent (Fort Worth) of the production outages, principally as a result of shutting down electric pumping units or compressors on gathering lines.

Processing plants suffered some mechanical failures, although most of their shortfalls resulted from problems upstream at the wellhead. The production declines, coupled with increased customer demand, reduced gas volume and pressure in the pipelines and in those limited storage facilities serving the Southwest. These entities in turn were unable in some instances to deliver adequate gas supplies to LDCs.

When LDCs suffer declines in gas pressure on their systems, they must reduce the amount of gas being consumed to prevent pressures from falling so low that their entire systems might fail. As a result of the high gas demand and the falling pressures on their systems, four LDCs in New Mexico, Arizona and Texas were forced to curtail retail service or were unable to supply gas to all customers. These curtailments or outages affected more than 50,000 customers in those states, including the cities of El Paso in Texas; Tucson and Sierra Vista in Arizona; and Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo, and Placitas in New Mexico. In contrast to the relative ease of restoring electric service, restoration of gas service was complicated by the necessity to have LDC crews manually shut off gas meters and then relight pilot lights on site.

Winterization

Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed.

The experiences of 1989 are instructive, particularly on the electric side. In that year, as in 2011, cold weather caused many generators to trip, derate, or fail to start. The PUCT investigated the occurrence and issued a number of recommendations aimed at improving winterization on the part of the generators. These recommendations were not mandatory, and over the course of time implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011.

On the gas side, producers experienced production declines in all of the recent prior cold weather events. While these declines rarely led to any significant curtailments, electric generators in 2003 did experience, as a result of gas shortages, widespread derates and in some cases outright unit failure. It is reasonable to assume from this pattern that the level of winterization put in place by producers is not capable of withstanding unusually cold temperatures.

While extreme cold weather events are obviously not as common in the Southwest as elsewhere, they do occur every few years. And when they do, the cost in terms of dollars and human hardship is considerable. The question of what to do about it is not an easy one to answer, as all preventative measures entail some cost. However, in many cases, the needed fixes would not be unduly expensive. Indeed, many utilities have already undertaken improvements in light of their experiences during the February event. This report makes a number of recommendations that the task force believes are both reasonable economically and which would substantially reduce the risk of blackouts and natural gas curtailments during the next extreme cold weather event that hits the Southwest.

Electric and Gas Interdependency

The report also addresses the interdependency of the electric and natural gas industries. Utilities are becoming increasingly reliant on gas-fired generation, in large part because shale production has dramatically reduced the cost of gas. Likewise, compressors used in the gas industry are more likely than in the past to be powered with electricity, rather than gas. As a result, deficiencies in the supply of either electricity or natural gas affect not only consumers of that commodity, but of the other commodity as well.

Gas shortages were not a significant cause of the electric generator outages experienced during the February 2011 event, nor were rolling blackouts a primary cause of the production declines at the wellhead. Both, however, contributed to the problem, and in the case of natural gas shortfalls in the Permian and Fort Worth Basins, approximately a quarter of the decline was attributed to rolling blackouts or customer curtailments affecting producers.

The report explores some of the issues relating to the effects of shortages of one commodity on the other, including the question of whether gas production and processing facilities should be deemed "human needs" customers and thus exempted or given special consideration for purposes of electric load shedding. However, any resolution of the many issues arising from electric and natural gas interdependency must be informed by an examination of more than one cold weather event in one part of the country. For that reason, the report does not offer specific recommendations in this area, but urges regulatory and industry bodies to explore solutions to the many interdependency problems which are likely to remain of concern in the future.

**This page intentionally left blank.**

# III. The Electric and Natural Gas Industries

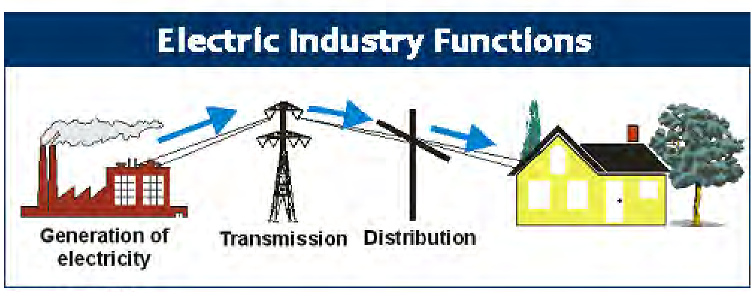
Electricity and natural gas are two of the most essential commodities for the conduct of modern life. However, the industries that produce electricity and natural gas and deliver these commodities from their points of production to consumers differ greatly from one another, as do the regulatory schemes governing them. This section provides an overview of the electric and natural gas industries, their market structures, and the regulatory authorities under which they operate, focusing particularly on the southwest region of the country. This background will be useful in understanding the causes of the outages and curtailments experienced during the first week of February 2011, the actions taken by the entities affected, and the recommendations the task force is suggesting to prevent a recurrence of the widespread service disruptions.

## A. The Electric Industry

This subsection describes the structures under which electricity is generated and transmitted, the regulation of electric service providers, and the characteristics of the electricity markets found in the Southwest. A more detailed description of how electricity is produced, transmitted and delivered can be found in the appendix entitled "Electricity: How it is Generated and Distributed."

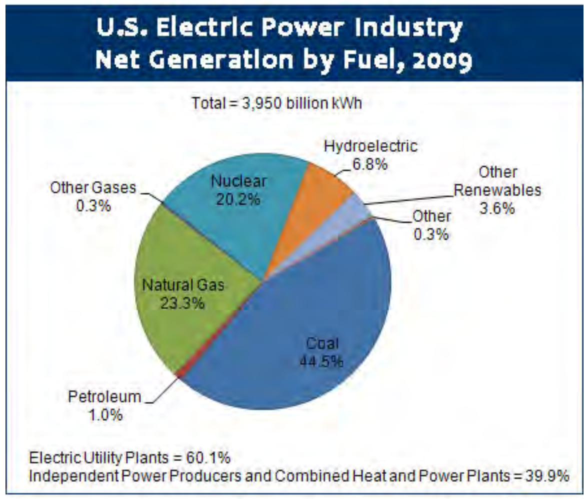
### Overview of Electric Power Production and Delivery

The electric power industry is comprised of three separate functions: generation, transmission, and distribution. These are depicted in the figure below.



Source: EIA

Most of the power produced in the United States uses coal, natural gas, or nuclear fission as the energy source to produce steam or other hot combustion gas that turns a turbine and thereby creates electricity. The figure below shows the fuel source percentages for electricity produced in the US in 2009, with the majority of electricity coming from fossil fuels (coal and natural gas totaling a 68 percent share). While wind and solar energy have experienced fairly rapid growth over the past several years, renewable fuels (including hydroelectric generation's seven percent share) accounted for about 11 percent of the electricity generated in the United States in that year. Wind generation is more common in the Southwest than in most other regions; its share of total generation is about 3.8 percent.[1]




Sources: EIA, Form EIA-923, "Power Plant Operations Report."

Generating units typically fall into three categories: base load, intermediate, and peaking units. Base load units, usually coal-fired or nuclear, have a relatively low operating cost and have fairly slow or expensive ramping rates.[2] These units are seldom cycled on and off, and are instead scheduled to cover the base levels of projected load. Peaking units, which are generally gas-fired, can be started up very quickly and have relatively expensive operating costs. Accordingly, they are generally last in the dispatch order and are used to cover seasonal (and sometimes daily) peak load levels. Intermediate plants fall somewhere in between base load and peaking with respect to operating characteristics, start-up times, and capacity factors.[3]

Generating plants produce power at a relatively low voltage level, so the power must be "stepped up" to a higher voltage in order to be more efficiently

[1] United States Energy Information Administration (EIA), *Electric Power Monthly*, Table 6 - Total Renewable Net Generation by Energy Source and State, 2009 (released August 2010) and *Electric Power Annual*, Figure 2.1 – U.S. Electric Industry Net Generation by State, 2009 (released November 2010, revised January and April 2011).

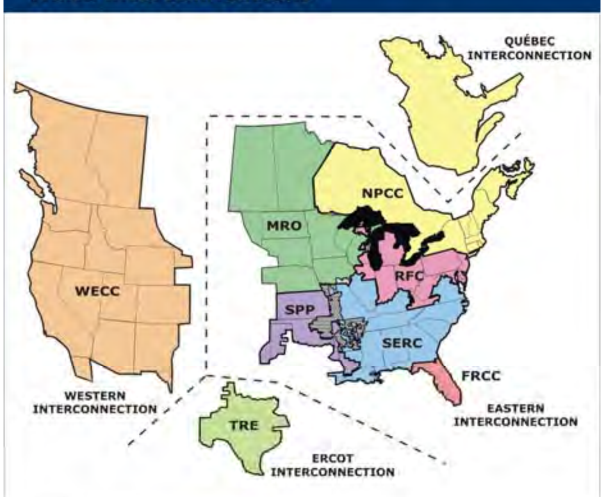
[2] "Ramping" refers to the generator's ability to produce more or less power on request.

[3] "Capacity factor" refers to the ratio of average generation to the capacity rating of an electric generating unit for a specified period (expressed as a percentage).

transmitted to its ultimate point of use. Energy is carried at these higher voltages over transmission lines (usually between 138 kV and 765 kV) to load centers, where voltage is then stepped back down to a distribution level for delivery to end-use customers. While distribution lines are generally considered to be those operating at 69 kV and below,[4] some industrial end-use customers may take service at transmission-level or intermediate-level voltages.

Virtually all of the transmission system in the continental United States is operated as an alternating current (AC) system, although the West and a few other areas make use of some direct current (DC) lines for long-haul transportation of power or for system stability. DC ties are also used to provide limited connectivity between the three electrically independent grids currently found in the United States: (1) the Eastern Interconnection, which covers the eastern two-thirds of the United States and contiguous parts of Canada; (2) the Western Interconnection, which covers the western third of the United States, the Canadian provinces of Alberta and British Columbia, and a small portion of Baja California Norte, Mexico; and (3) ERCOT, which covers most of the state of Texas. (A fourth interconnection, the Quebec Interconnection, is located wholly in Canada.)

**NERC Interconnections**




Source: NERC

[4] The bulk electric system, which constitutes transmission as opposed to distribution, has been described by FERC as those facilities operating at 100 kV or above except for defined radial facilities, with exemptions for those facilities not necessary for operating the interconnected transmission network. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 75 Fed. Reg. 72,910 (Nov. 26, 2010), 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

Within each interconnection, power generally flows freely across the entire grid. An imbalance of generation versus demand that is significant enough to cause instability on one utility's system can ultimately affect the stability of all systems operating in that interconnection.[5]

## Evolution and Regulation of the Electric Industry

Under part II of the Federal Power Act,[6] FERC has jurisdiction over the rates, terms and conditions of wholesale sales of electric energy and transmission services in interstate commerce that are provided by jurisdictional entities (which generally excludes electric cooperatives and federal or state entities, including municipal utilities). Notably, wholesale electric energy sales and transmission services provided wholly within ERCOT are not considered to be interstate under the Federal Power Act, and are therefore not subject to FERC jurisdiction. States generally regulate retail sales of electric energy and distribution services, although publicly-owned and member-owned entities (such as electric cooperatives and municipal utilities) may be exempt from direct state regulatory oversight. In Texas, the PUCT exercises jurisdiction over wholesale sales of energy and the provision of transmission services wholly within the ERCOT footprint.

Historically, all three of the electric sector functions (generation, transmission, and distribution) were provided by one vertically-integrated utility, which was typically granted a monopoly franchise by states to serve retail customers within a given geographic area. While wholesale sales or exchanges of electric energy did occur between utilities, utilities historically planned their systems, both generation and transmission, to serve their own native peak load requirements.

***Entities Providing Electric Services in the United States***

The electric sector in the United States is made up of a variety of entities, including investor-owned utilities, publicly-owned utilities (including municipal utilities, public utility districts, and irrigation districts), member-owned utilities (generally rural electric cooperatives), Federal electric utilities, and

(cont'd)

---

[5] *See generally* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations at 5-10 (April 2004) (2003 Blackout Report), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout.asp#skipnav (last visited Aug. 2, 2011).

[6] 16 U.S.C. § 824 et seq.

independent power producers. Investor-owned utilities (IOUs) are private entities that were historically vertically-integrated, *i.e.,* owning generation, transmission and distribution assets. However, in states with restructured electric markets, many IOUs were required or strongly incentivized to divest or spin-off their generation assets, and now own only transmission and distribution assets as part of the utility company. Based on 2007 data from the United States Energy Information Administration, IOUs serve about 71 percent of the retail customers in the country. Publicly-owned electric utilities and electric cooperatives have generally been exempted from state restructuring initiatives, and have not been required to offer customer choice or to divest generation assets. There are approximately 2,000 publicly-owned utilities in the United States (which own about 9 percent of the installed generating capacity) and over 880 electric cooperatives (which own approximately 4 percent of the installed capacity).

Since the 1970s, a number of changes occurred to alter this traditional, vertically-integrated model. In 1978, Congress created a class of non-utility generators called qualifying facilities (QFs), and in 1992 created a class of independent generators called Exempt Wholesale Generators. This legislation opened the door not only for independent owners to develop generating plants in multiple regions, but also for utilities to develop generating plants in regions outside their service territory.[7]

FERC took a number of steps to further encourage the development of a competitive wholesale market for generation, including by (1) authorizing generation owners to sell wholesale power at market rates if they can demonstrate that they lacked market power in the relevant market; and (2) requiring transmitting utilities to provide open access transmission service for the delivery of power to wholesale customers on terms and conditions comparable to the transmission service the utilities provided themselves in serving their native load customers.[8]

---

[7] Energy Policy Act of 1992, Pub. L. No. 102, 486.

[8] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part*

FERC also encouraged the formation of Independent System Operators (ISOs)[9] and Regional Transmission Organizations (RTOs).[10] ISOs/RTOs serve a number of functions critical to operation of the wholesale market within a given region, including control and operation of the transmission grid, operation of real-time and day-ahead markets, and transmission system planning.[11] Not all regions in the United States have adopted an ISO/RTO structure, although they may rely on other power pool structures. The map below shows the footprint of the nine ISOs or RTOs currently operating in the US and Canada.

---

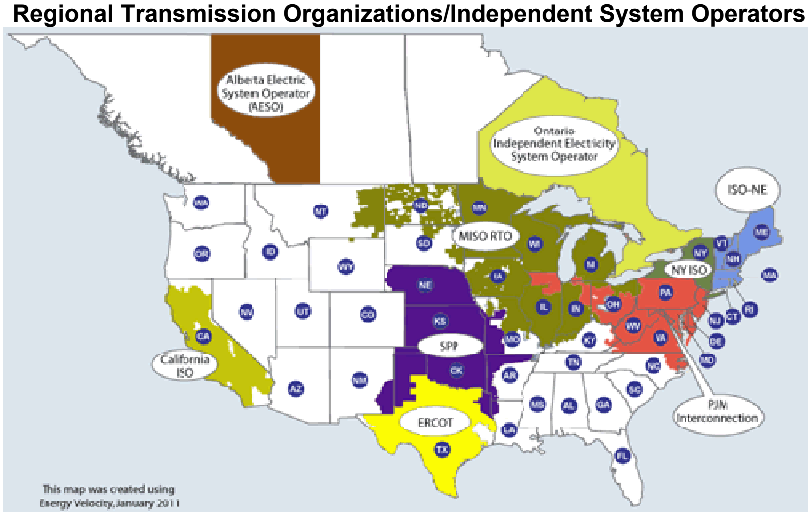
*sub nom*. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom*. New York v. FERC, 535 U.S. 1 (2002) (Order No. 888).

[9] ISOs grew out of Order No. 888, issued in 1996, as a means of satisfying FERC's requirement that jurisdictional utilities provide non-discriminatory access to transmission services. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730; and *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v*. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[10] In 1999, as part of Order No. 2000, FERC created and sought to encourage the voluntary formation of Regional Transmission Organizations to oversee electric transmission and ancillary services and transmission planning services across a broader territory. ISOs and RTOs perform similar functions, but RTOs are only recognized as such if they meet FERC's minimum characteristics and minimum functions as set out in Order No. 2000. In addition, ISOs tend to be smaller in geographic size, or are not subject to FERC jurisdiction. *See* "The Value of Independent Regional Grid Operators: A Report by the ISO/RTO Council," *available at* <http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/Value_of_Independent_Regional_Grid_Operators.pdf>. Order 2000: *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[11] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730 (1996).

**Regional Transmission Organizations/Independent System Operators**




In markets where an ISO/RTO has been approved, the ISO/RTO is generally responsible for dispatching generating units based on hourly energy prices offered by the generation owner or other energy marketer. Initially, these competitive wholesale markets were structured to reflect only energy products and ancillary services,[12] with no compensation for the provision of capacity[13] and no corresponding obligation on the part of generators to offer into a specific market.[14] Many of the markets have undergone modifications over time, including

[12] Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers, and in RTO or ISO-based markets are generally procured through a mechanism or market separate from the energy market. Ancillary services typically include regulation, synchronized or spinning reserves, non-spinning reserves, and black-start services. Among ERCOT's various categories of ancillary services are responsive reserve service (RRS) and non-spinning reserve service (NSRS). RRS are operating reserves intended to help control the frequency of the system. NSRS are reserves intended to cover the uncertainties in forecasting load and wind power output.

[13] Capacity (or installed capacity) refers in this context to the maximum kW or MW of output offered into a capacity market and required to be available except as otherwise provided by the relevant market rules. Payments by load serving entities for capacity are made regardless of whether energy is actually provided, as long as the relevant availability requirements are met. Penalties are generally imposed if a supplier fails to meet the availability requirements or otherwise provide energy when called upon.

[14] After an offer is accepted in a given energy or ancillary services market, the generator or its marketer has the obligation to deliver the energy or to cover the real-time cost of replacement if the generator experiences a forced outage or derate. In addition, even in an energy-only market, certain generators that are deemed essential for reliability (often referred to as reliability must-run generators or RMRs), are paid an amount above the base energy payments to ensure that the unit remains operational and available; these generators are subject to some form of penalty if the unit is not available as provided for under the market rules or specific RMR contract.

implementation of day-ahead markets, virtual bidding,[15] nodal pricing,[16] and separate capacity markets.

***Energy-Only Markets versus Capacity Markets***

In an energy-only market, load serving entities purchase energy on an hourly basis (even if secured or scheduled on a day-ahead or forward basis), and are generally also required to cover minimum ancillary services requirements, including voltage support, regulation, and spinning or non-spinning reserves. These load-serving entities are not obligated to secure capacity to cover their projected peak loads going forward, and generators can only recover their capital costs through payments for hourly energy and ancillary services.

In markets with capacity-based payments, load serving entities are responsible for procuring capacity (including adequate reserves) to cover their peak loads. In the Northeast, capacity prices are set through forward capacity markets, and while generators receive the benefit of a more predictable revenue stream, they must also accept certain obligations to ensure that their unit is available and offered into the energy market when needed, or face penalties for failure to do so.

**Reliability Oversight by FERC, NERC and Regional Entities**

In 1968, following the extensive 1965 blackout in the Eastern United States and Canada, members of the electric utility industry formed a voluntary council (NERC)[17] to coordinate regional planning for the industry and develop operating

[15] A form of transaction where buyers and sellers place trades based on differences between day-ahead prices and real-time prices. Virtual bidding is intended to improve market efficiency as real-time and day-ahead prices converge.

[16] Nodal pricing uses the locational marginal price (LMP, or the cost of supplying the next megawatt of load) at each specific electric location or bus. In a completely unconstrained system, the nodal price will be the same at each node on the system. When transmission constraints occur, the nodal price will reflect the cost of dispatching generating units out of economic merit order in order to serve load within the constrained area. Nodal pricing allows for separate energy prices at each bus, while zonal pricing sets a locational price for much larger, pre-established zones.

[17] The council was originally named the National Electric Reliability Council, but the name was later changed to North American Electric Reliability Council to reflect Canadian

guides and voluntary standards and practices to protect the reliability of the interconnected system.[18] While efforts were undertaken in the 1990s to require adherence to NERC reliability policies and guidelines, mandatory reliability standards were not adopted in the United States until Congress passed the Energy Policy Act of 2005 (EPAct 2005). That act required FERC to certify an independent Electric Reliability Organization (ERO) tasked with developing and enforcing such mandatory reliability standards.[19]

Pursuant to EPAct 2005, FERC certified NERC as the ERO on July 20, 2006.[20] Under implementation procedures adopted by FERC, NERC is permitted to delegate a portion of its responsibilities for enforcement and for regional standards development to Regional Entities, which NERC in turn oversees. NERC has provided such delegated authority to eight Regional Entities in the United States and Canada, each of which has primary authority for enforcement in the regions shown below.[21]

---

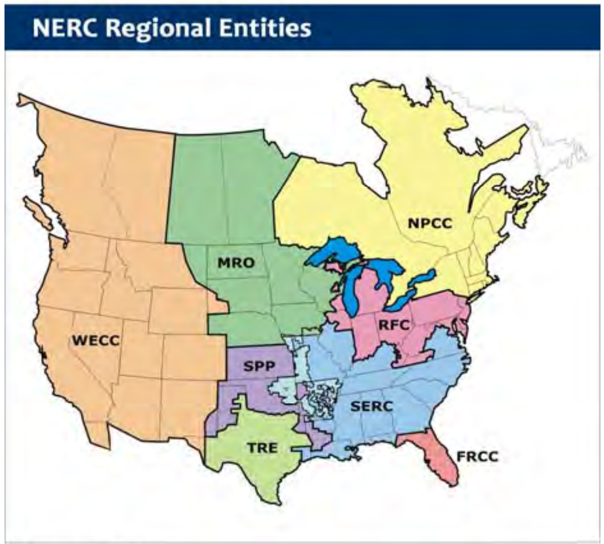
member participation, and changed again to North American Electric Reliability Corporation in 2007 to reflect its new role as the independent Electric Reliability Organization. *See NERC Company Overview: History*, http://www.nerc.com/page.php?cid=1|7|11.

[18] Responsibility for the voluntary standards and operating guidelines was originally given to the North American Power Systems Interconnection Committee (NAPSIC, formed earlier in the 1960s). NAPSIC later became part of NERC. *Id.*

[19] *See* Energy Policy Act of 2005, Pub. L. No. 109-58. The renewed efforts to adopt mandatory reliability standards that prompted this section of the Energy Policy Act came in response to the Northeastern blackout of August 14, 2003, and to the recommendations made in a report prepared by a joint US-Canada task force that reviewed the causes of the blackout. *2003 Blackout Report* at 3 (adopting as its first recommendation: "Make reliability standards mandatory and enforceable, with penalties for noncompliance.")

[20] *N. Am. Elec. Reliability Corp*. 116 FERC ¶ 61,062 (2006).

[21] The eight Regional Entities operating under delegated authority from NERC are Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Southwest Power Pool Regional Entity, Texas Reliability Entity, and Western Electric Coordinating Council.




Source: NERC

Under Section 215 of the Federal Power Act, NERC must submit its proposed Reliability Standards to FERC for approval before they may become mandatory and enforceable. In order to approve a Reliability Standard, FERC must find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest, after giving due weight to the technical expertise of the ERO.[22] In addition, while the ERO has the authority to propose a penalty for violation of a Reliability Standard following notice and opportunity for a hearing, that penalty may only take effect after it has been filed with FERC. FERC can exercise the option to review, set aside, or modify the penalty, on its own motion or on application by the entity subject to the proposed penalty.[23] FERC also has the authority, on its own motion or on complaint, to order compliance with a Reliability Standard or to impose a penalty for violation of a Reliability Standard.[24]

In Order No. 693, FERC approved the first set of 83 Reliability Standards, which became enforceable on June 18, 2007.[25] NERC maintains a Compliance

---

[22] 16 U.S.C. § 824o(d)(1) and (2).

[23] *Id*. at § 824o(e)(1) and (2).

[24] *Id*. at § 824o(e)(3).

[25] NERC and the Regional Entities may assess penalties for non-compliance with the Reliability Standards. In order for such a penalty to take effect, NERC must file a notice of penalty with FERC. Each penalty determination is subject to FERC review. In the absence of an application for review or action by FERC, each penalty filed by NERC is affirmed by operation of law after 30 days.

Registry that identifies all entities subject to compliance with the approved Reliability Standards. Users, owners and operators of the bulk power system are required to register with NERC under the appropriate functional categories, and each Reliability Standard designates each category of entity to which it applies. Currently, there are over 1900 registered entities subject to the Reliability Standards (a number of entities are counted more than once as they are registered under more than one category). The categories of registered entities are set out in the appendix entitled "Categories of NERC Registered Entities."

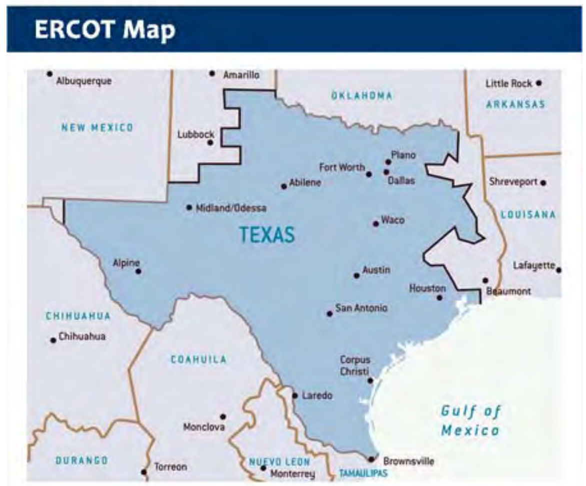
Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the appropriate Regional Entity and to NERC. The Regional Entity and/or NERC in turn undertakes various levels of analysis to determine the causes of the events, assure tracking of corrective actions to prevent recurrence, gather information needed to assess compliance, and provide lessons learned to the industry. The event analysis process also provides input for training and education, reliability trend analysis efforts and Reliability Standards development, all of which support continued reliability improvement. Under NERC's field trial of its event analysis program, the February 2 and February 3 event was classified as a category 4 event due to the overall significance and impact of the event (loss of over 5,000 MW but less than 10,000 MW of load or generation). Based on the scope of the needed analysis, and the fact that it impacted multiple regions, NERC determined that the event review should be coordinated at the NERC level.

**Southwest Electricity Markets, Pools and Reserve Sharing Groups**

The Southwest contains two ISO/RTOs (ERCOT and SPP), and a number of vertically integrated utilities that are located within the WECC region. These are described below.

<u>ERCOT</u>

The Electric Reliability Council of Texas (ERCOT) is an ISO that covers approximately seventy-five percent of the landmass within Texas, excluding the El Paso area, part of the northern panhandle, and part of the region east of Houston. ERCOT manages access to the transmission system within its footprint and operates the Texas energy and ancillary services markets (it does not have a capacity market).




Source: ERCOT

ERCOT schedules power over 40,500 miles of transmission lines and is responsible for the dispatch of more than 550 generating units.[26] It was founded in 1970 as one of the NERC regional reliability coordination councils, and is currently the registered balancing authority for 85 percent of the electric load in Texas.[27] When it became an ISO in 1996 it undertook a number of new responsibilities, including operation of the wholesale competitive electricity market. When Texas restructured its electric industry in 2002, implementing customer choice for most retail customers and requiring divestiture of generation by IOUs, ERCOT also undertook administration of customer switching for those retail customers in Texas that can choose their electric service provider.

ERCOT is a summer-peaking region, and experienced its highest peak demand to date (68,294 MW) on August 3, 2011. Generation in ERCOT is fairly diverse in terms of fuel sources. Natural gas represented the highest percentage of installed capacity in 2009 (at 59 percent), but coal and nuclear power combined to provide over 50 percent of the energy produced for that year. [28]

ERCOT operates as a functionally separate interconnection, although it has five asynchronous ties with other interconnections.[29] Three of the ties allow

[26] For ERCOT background, *see generally* ERCOT 2009 Annual Report, *available at* http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf.

[27] ERCOT is also registered in NERC's Compliance Registry as an interchange authority, planning authority, reliability coordinator, resource planner, and transmission service provider. In addition, it also partners with other transmission operators in Texas and in that capacity is listed as a "coordinated functional registration."

exchanges with Mexico (through the Comisión Federal de Electricidad, or CFE): the Laredo Variable Frequency Tie, the South Tie (also called Eagle Pass), and the Railroad Tie, the latter located near McAllen, Texas. Two of the ties allow exchanges with the Eastern Interconnection through SPP: the North Tie, located near Oklaunion, Texas, and the East Tie, located near Mt. Pleasant, Texas. The maximum amount of energy that can be imported on all the ties is 1090 MW (approximately 2.3 percent of ERCOT's 2010/2011 forecasted winter peak), with most of that attributable to the ties to the Eastern Interconnection.[30]

ERCOT originally employed a zonal market design, under which the region was divided into pricing zones and all generators within a zone received the same price for the power they provided. It shifted to a nodal market design in December 2010, under which prices are assessed at points (nodes) where electricity enters or leaves the grid. The settlement price at each node is referred to as the locational marginal price (LMP). A nodal market design allows for more precise price signals and greater dispatch efficiencies than a zonal market design, and permits direct assignment of congestion costs through the more granular locational marginal prices.

Under its previous zonal market, ERCOT had no day-ahead energy market (although ancillary services were procured on a day-ahead basis to ensure sufficient capacity would be available). Under its current nodal market, ERCOT has a day-ahead energy market, which is co-optimized with ancillary services.

ERCOT has an energy-only market, as opposed to both an energy market and a capacity market. Capacity markets are used to address resource adequacy concerns; typically, a planning reserve margin is established to maintain reliability goals, and the ISO/RTO imposes capacity obligations on load-serving entities that are met through bilateral contracting or a centralized capacity market. In contrast, an energy-only market relies on energy price signals to spur investment in new generation. Thus, by design, ERCOT's energy-only market would be expected to

---

[28] ERCOT reported the following percentage fuel mix of installed capacity in 2009, in declining order: (1) natural gas, 59 percent; (2) coal, 22 percent; (3) wind, 11 percent; (4) nuclear, 6 percent; and (5) hydroelectric and biomass, 2 percent. ERCOT reported the following percentages for energy produced for 2009: (1) natural gas, 42 percent; (2) coal, 37 percent; (3) nuclear, 14 percent (4) wind, 6 percent; and (5) hydroelectric and biomass, 1 percent. ERCOT 2009 Annual Report at 2.

[29] Four are DC interties and one is a variable frequency transformer (VFT) inter-tie.

[30] The maximum MW that can be imported on each of the ties (actual limits may vary based on real-time conditions) is as follows: North, 210 MW; East, 600 MW; South/Eagle Pass, 30 MW; Railroad, 150 MW; and Laredo, 100 MW.

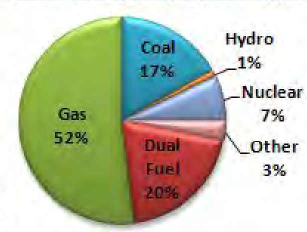
result in higher prices during times of scarcity and produce more volatile prices in general than do dual energy and capacity markets. These price signals are intended to encourage investment in energy resources, such as new generation plants, demand response, and energy efficiency, to meet growing demand.

NERC's regional assessment summary for TRE, which includes the ERCOT control area, for the winter of 2010/2011 is presented in the following chart.[31]

**TRE Regional Assessment Summary**

| 2010/2011 Winter Projected Peak Demand | MW | |
|---|---|---|
| Total Internal Demand | 47,824 | |
| Direct Control Load Management | 0 | |
| Contractually Interruptible (Curtailable) | 331 | |
| Critical Peak-Pricing with Control | 0 | |
| Load as a Capacity Resource | 1,062 | |
| Net Internal Demand | 46,431 | |
| **2009/2010 Winter Comparison** | **MW** | **% Change** |
| 2009/2010 Winter Projected Peak Demand | 42,106 | 10.3% |
| 2009/2010 Winter Actual Peak Demand | 55,878 | -16.9% |
| All-Time Winter Peak Demand | 55,878 | -16.9% |
| **2010/2011 Winter Projected Peak Capacity** | **MW** | **Margin** |
| Existing Certain and Net Firm Transactions | 72,881 | 57.0% |
| Deliverable Capacity Resources | 72,939 | 57.1% |
| Prospective Capacity Resources | 72,939 | 57.1% |
| NERC Reference Margin Level | 52,235 | 12.5% |

On-Peak Capacity by Fuel Type




Source: NERC Winter Reliability Assessment 2010/2011

## WECC Region and Southwest Reserve Sharing Group

WECC is the largest geographically of the eight NERC Regional Entities, with responsibility for coordinating and promoting system reliability throughout the Western Interconnection. WECC's service territory covers Alberta and British Columbia, the northern part of Baja California in Mexico, and all the states in between, constituting an area of about 1.8 million square miles.

WECC's bulk power system generally transfers energy over long transmission lines from remotely located generators to load centers. The lack of redundant transmission facilities demands a high level of operational scrutiny in order to maintain correct voltages and power flows on the many stability limited transmission paths that exist in the Western Interconnection.

[31] NERC 2010/2011 Winter Reliability Assessment, *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf.

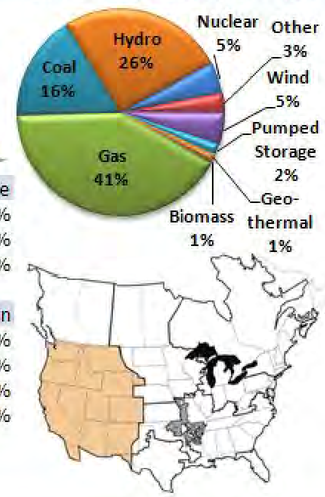
WECC has registered 34 balancing authorities;[32] 52 transmission operators, and 3 reserve sharing groups. The California Independent System Operator (CAISO) is the only balancing authority in the Western Interconnection that operates as an ISO or RTO.

NERC's regional assessment summary for WECC for the winter of 2010/2011 is presented in the following chart.[33]

**WECC Regional Assessment Summary**

| 2010/2011 Winter Projected Peak Demand | MW | |
|---|---|---|
| Total Internal Demand | 104,424 | |
| Direct Control Load Management | 571 | |
| Contractually Interruptible (Curtailable) | 1,814 | |
| Critical Peak-Pricing with Control | 25 | |
| Load as a Capacity Resource | 30 | |
| Net Internal Demand | 101,984 | |
| **2009/2010 Winter Comparison** | **MW** | **% Change** |
| 2009/2010 Winter Projected Peak Demand | 108,132 | -5.7% |
| 2009/2010 Winter Actual Peak Demand | 109,565 | -6.9% |
| All-Time Winter Peak Demand | 113,605 | -10.2% |
| **2010/2011 Winter Projected Peak Capacity** | **MW** | **Margin** |
| Existing Certain and Net Firm Transactions | 157,290 | 54.2% |
| Deliverable Capacity Resources | 159,282 | 56.2% |
| Prospective Capacity Resources | 159,282 | 56.2% |
| NERC Reference Margin Level | 116,874 | 14.6% |

**On-Peak Capacity by Fuel Type**




Source: NERC Winter Reliability Assessment 2010/2011

Two of the entities that experienced rolling blackouts during the February event, SRP and EPE, are located in the WECC region. SRP, one of Arizona's largest utilities, is vertically integrated and a subdivision of the State of Arizona. Serving over 933,500 retail customers, SRP's eleven main generating stations, combined with numerous smaller facilities, have a peak retail load of over 6400 MW, and serve a 2,900 square mile area. SRP is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

---

[32] NERC defines "balancing authority" as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within the BA area, and supports interconnection frequency in real-time.

[33] NERC 2010/2011 Winter Reliability Assessment.

EPE is a vertically integrated electric utility providing generation, transmission, and distribution service in west Texas and southern New Mexico. EPE serves approximately 372,000 customers over a 10,000 square mile service territory via five major generating stations, including three stations local to El Paso, Texas. It has a native peak load of 1616 MW. Like SRP, EPE is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

Both SRP and EPE participate in the Southwest Reserve Sharing Group (SRSG), which provides for the sharing of contingency reserves among its participants pursuant to a Participation Agreement. SRSG was formed in 1998 as the successor to an earlier pool, and has participants in Arizona, New Mexico, southern Nevada, part of southern California and El Paso, Texas. SRSG is a NERC Registered Entity, and administers certain requirements related to disturbance control and emergency operations standards. Its participants are obligated to carry reserves in accordance with a contractual formula, and to provide power within a certain time frame to other participants experiencing a disturbance on their systems.

Southwest Power Pool

SPP is both an RTO and a NERC Regional Entity responsible for the enforcement of Reliability Standards within its region. SPP had its origins in 1941, when eleven regional power companies formed the pool in order to ensure sufficient electric service to aluminum plants needed for the war effort. The pool remained intact after the war and was a founding member of NERC in 1968. SPP implemented operating reserve sharing arrangements among its members in 1991, and became a FERC-approved RTO in 2004.

SPP covers a 370,000 mile area that includes all or portions of nine states: Nebraska, Kansas, Oklahoma, Missouri, Arkansas, Louisiana, Texas, New Mexico, and Mississippi.[34] SPP operates 48,930 miles of transmission lines, and has a coincident peak demand within its reliability coordinator[35] footprint of approximately 55,000 MW.

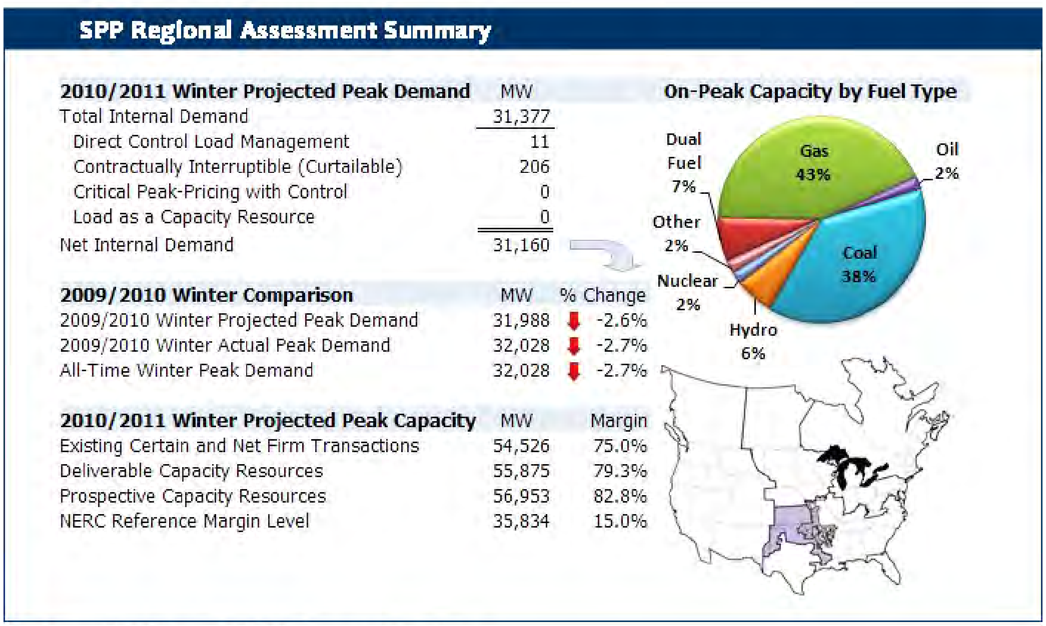
---

[34] SPP actually has five “footprints,” with differing membership and oversight functions, as (1) a NERC Regional Entity; (2) a reserve sharing group; (3) a reliability coordinator area (29 balancing authorities and transmission owners, including certain balancing authorities in SERC and the Midwest Reliability Organization); (4) an RTO (with 15 balancing authorities); and (5) an energy imbalance services (EIS) market region (with 15 balancing authorities). *See* http://www.spp.org/section.asp?pageID=28 (last visited Aug. 2, 2011).

[35] NERC defines “reliability coordinator” as the entity that is the highest level of authority responsible for the reliable operation of the bulk power system, has the wide area view

At present, SPP's market operations are relatively limited, currently allowing participants to buy and sell energy in real time and to settle out any energy scheduling imbalances based on the real-time market price. SPP does not currently operate a separate market for reserves but is working to implement a new integrated marketplace that includes a day-ahead energy and operating reserves market.[36]

NERC's regional assessment summary for SPP for the winter of 2010/2011 is presented in the following chart.[37]




Source: NERC Winter Reliability Assessment 2010/2011

of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

[36] Unlike California, Texas, and the Northeast, most of the states SPP covers have not undertaken a broad restructuring of the electric industry through retail access and/or mandatory unbundling of generation from transmission and distribution. Accordingly, most utilities operating within SPP's footprint still supply a large portion of their customers' electricity needs through their own generation and do not need to access the market to do so.

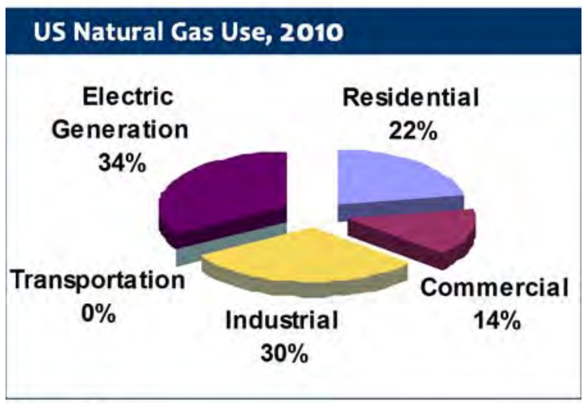
[37] NERC 2010/2011 Winter Reliability Assessment.

## B. The Natural Gas Industry

This subsection provides an overview of the manner in which natural gas is produced and delivered, the jurisdictional structures applicable to the industry, and the various producers and pipelines located in the Southwest. A detailed description of the geology and physics of natural gas production and delivery can be found in the appendix entitled "Natural Gas: Production and Distribution."

### Overview of Natural Gas Production and Delivery

Natural gas is a fossil fuel, formed through the decomposition of organic matter found in underground geological formations. It is a significant source of energy representing 25 percent of the United States energy consumption. In 2010, approximately 22 percent of gas consumption was used for residential heating and cooking, 14 percent for commercial use, 30 percent for industrial processes, 34 percent for electric generation, and less than one percent for transportation.[38]

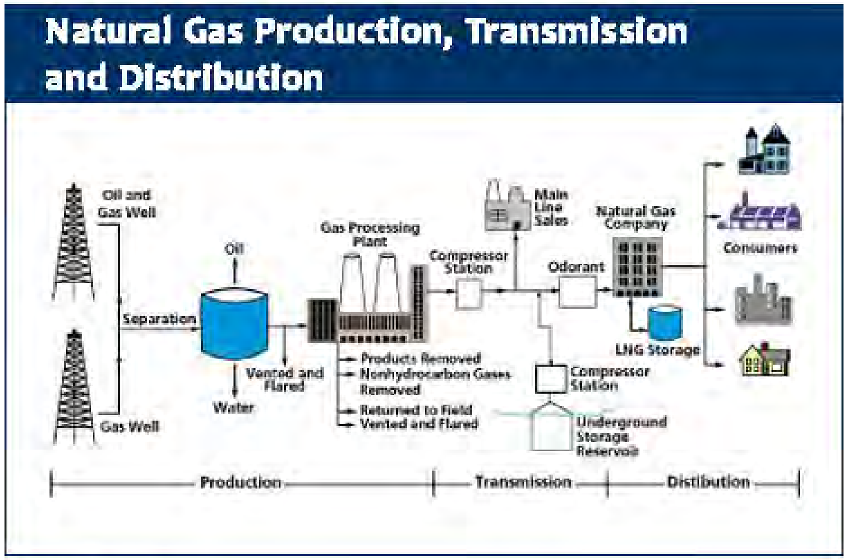



Source: EIA

The delivery framework for natural gas includes production, separation of fluids at or near producing wells, natural gas liquids (NGL) processing, pipeline transmission, storage, and finally distribution by an LDC. The following chart is a simplified schematic of this framework.

---

[38] EIA, *Natural Gas Consumption by End Use*, http://www.eia. gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm (last visited Aug.27, 2011).

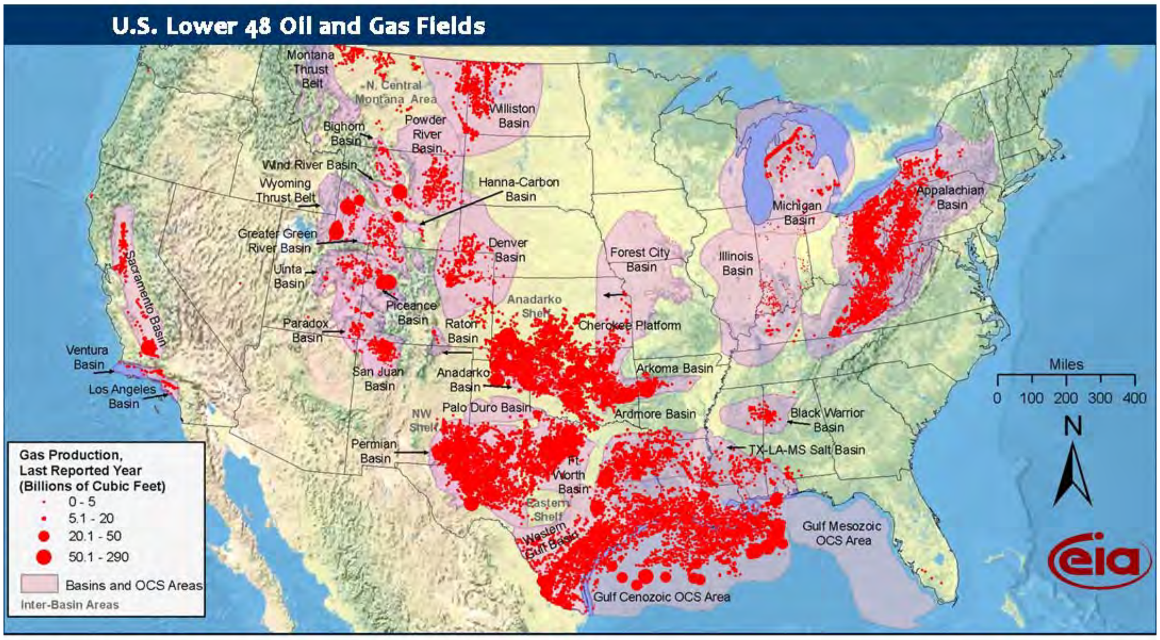



Source: EIA

Natural gas is often produced in locations distant from demand centers. The Energy Information Agency estimates that in 2009 there were 493,100 gas wells in the United States. The majority of these wells were located in the Gulf Coast, Southwest and the Appalachian Basin. The five states with the largest number of wells that year were Texas, 93,507; Pennsylvania, 57,356, West Virginia, 50,602; New Mexico, 44,784, and Oklahoma, 43,600.[39] The following chart shows production basins and the concentration of reported natural gas production.[40]

[39] EIA, *Natural Gas, Number of Producing Wells*, http://www.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm (last visited Aug.2, 2011).

[40] EIA, *Gas Production in Conventional Fields*, http://www.eia.gov/oil_gas/rpd/conventional_gas.pdf (last visited Aug. 2, 2011).



Source: EIA based on data from HPDI, IN Geological Survey, USGS, April 8, 2009

Major oil companies and large independent companies account for a substantial portion of the gas production in the United States. In the first half of 2009, the five largest producers and their daily production were as follows: BP, Inc, 2.33 Bcf per day; Anadarko Petroleum Corporation, 2.33 Bcf per day; XTO Energy, Inc., 2.29 Bcf per day (acquired by ExxonMobil in 2010); Chesapeake Energy Corporation, 2.21 Bcf per day; and Devon Energy Corporation, 2.13 Bcf per day. These producers together accounted for approximately 20 percent of United States production.[41]

In the Southwest, production takes place at the many thousands of wellheads located throughout the basins. The wellhead consists of equipment on top of the well that is used to manage flows of oil and gas, often produced together, arising from the underground formations. The high pressure gas in formations is lighter than air and will often rise on its own through the wellhead to surface pipes. In other gas wells, as well as oil wells with associated natural gas, flow requires lifting equipment. Typical lifting equipment consists of the "horse head" or conventional beam pump. The pumps are recognizable by the distinctive shape of the cable feeding fixture, which resembles a horse's head.[42] They are

[41] Reuters, http://www.reuters.com/article/2009/12/14/xto-exxon-natgas-producers-idUSN1420089920091214; and EIA, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm. "Bcf" refers to a billion cubic feet.

[42] *Well Completion*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/well_completion.asp (last visited Aug. 2, 2011).

often called “pumpjacks” and are seen throughout west Texas and southeastern New Mexico. The following two photographs are of a wellhead and a pumpjack.

Wells and lift equipment are monitored on a daily basis and maintained by oil and gas company employees, who are often referred to as “pumpers” or “gaugers.” Their responsibilities include reporting malfunctions and spills, and ensuring that field processing equipment is operational and that production is correctly measured. Onshore gaugers may drive many miles per day to monitor dozens of wells.

***<u>Processing Natural Gas</u>***

The natural gas used by consumers consists almost entirely of methane. However, produced gas often contains other hydrocarbons such as ethane, propane, butane, pentanes and liquids such as condensates. It may also include water vapor, hydrogen sulfide ($H_2S$), carbon dioxide, helium, nitrogen, and other compounds. Some field processing occurs near production wells to remove the water and condensates, but complete processing usually occurs at a gas processing plant. Natural gas processing plants remove other hydrocarbons to produce what is known as “pipeline quality” dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities. The removed hydrocarbon NGLs are sold separately.

Natural gas is transported to processing plants[43] typically through small-diameter and low-pressure gathering pipelines. There were an estimated 20,552

---

[43] More than 500 processing plants operated in the United States in 2004 with 166, or over 31 percent, in the state of Texas. EIA, *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market*, (Jan. 2006), http://dnr.louisiana.gov/assets/docs/oilgas/productiondata/ngprocess_20060131.pdf.

miles of gathering system pipelines in the United States in 2009.[44]

After gathering and processing, interstate and intrastate transmission pipelines transport gas to LDCs (as well as to directly attached users such as power plants). Within the United States, the pipeline network delivers gas to 65 million residential, commercial, industrial, and power generation customers. It includes at least 210 gas pipeline systems with a total of more than 300,000 miles of transmission pipelines.[45] The pipeline system also includes more than 1,400 compressor stations, 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points.[46]

Pipeline companies monitor and control gas flow with computerized supervisory control and data acquisition (SCADA) systems, which provide operating status, volume, pressure, and temperature information. In addition to real-time monitoring, the SCADA system may enable a pipeline to start and stop some facilities remotely.[47]

The following map shows the breadth and integrated nature of the natural gas transmission grid.[48]

---

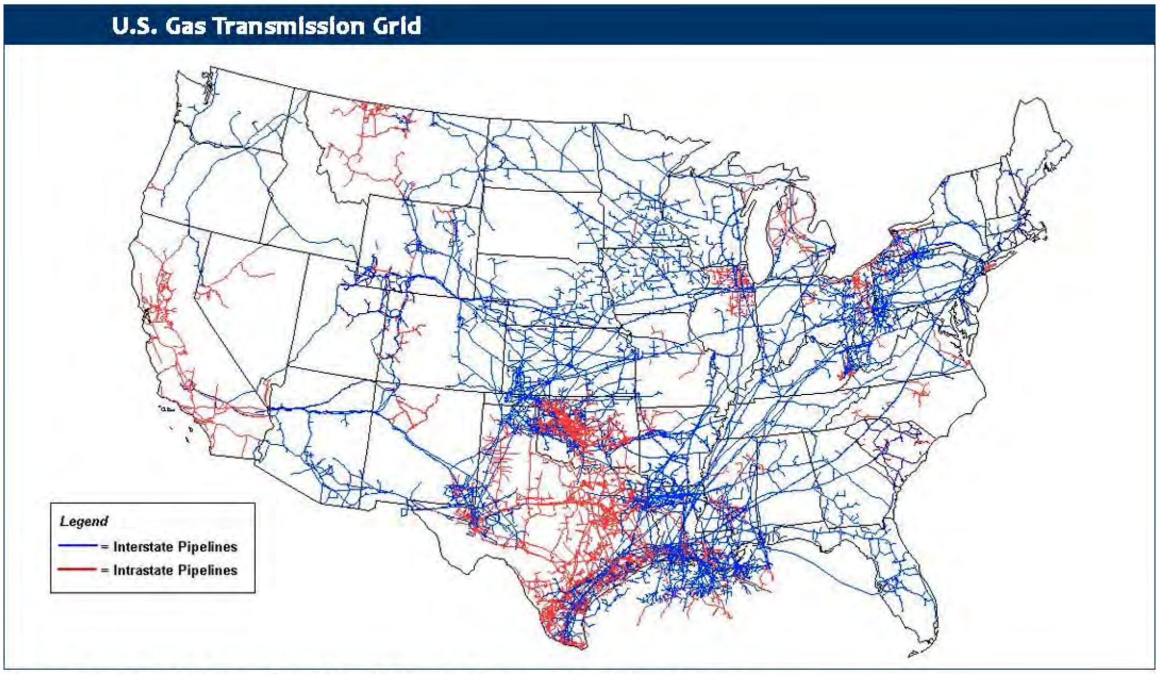
[44] U.S. Dep't of Transp. Pipeline & Hazardous Materials Safety Admin., *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, (Jun. 30, 2011), http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=036b52edc3c3e110VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[45] Am. Gas Assn., *About Natural Gas*, http://www.aga.org/Kc/aboutnaturalgas/Pages/default.aspx (last visited Aug. 2, 2011). These pipelines are high pressure systems and operate at 500 to 1,800 psi. The lines are usually 20 inches to 42 inches in diameter. http://www.naturalgas.org/naturalgas/transport.asp.

[46] EIA, *About U.S. Natural Gas Pipelines-Transporting Natural Gas* (June 2007), http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/fullversion.pdf (EIA: About U.S. Natural Gas Pipelines).

[47] INGAA, *Supervisory and Data Acquisition (SCADA),* http://www.ingaa.org/cms/33/1339/109/134.aspx (last visited Aug. 2, 2011).

[48] EIA: About U.S. Natural Gas Pipelines.




Source: EIA, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

To meet higher gas demand at various times of the year, gas is stored underground in depleted oil and gas reservoirs, aquifers or caverns formed in salt beds.[49] Storage facilities may be interstate and regulated by FERC, or intrastate and non-jurisdictional. There are over 390 underground storage facilities in the United States,[50] of which approximately 205 are under FERC jurisdiction.[51] Depleted oil and gas reservoirs account for 87 percent of the total FERC jurisdictional storage capacity, with salt caverns (3 percent) and aquifers (10 percent) accounting for the rest.[52] A detailed discussion of the types of storage facilities and their characteristics is included in the appendix entitled "Natural Gas Storage."

[49] EIA, *Natural Gas Explained: Delivery and Storage of Natural Gas*, http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_delivery (last updated June 8, 2011).

[50] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html (last updated Aug. 2004).

[51] http://www.ferc.gov/EventCalendar/Files/20060615103625-A-3-TALKING-PTS.pdf.

[52] http://www.ferc.gov/industries/gas/indus-act/storage/fields.asp.

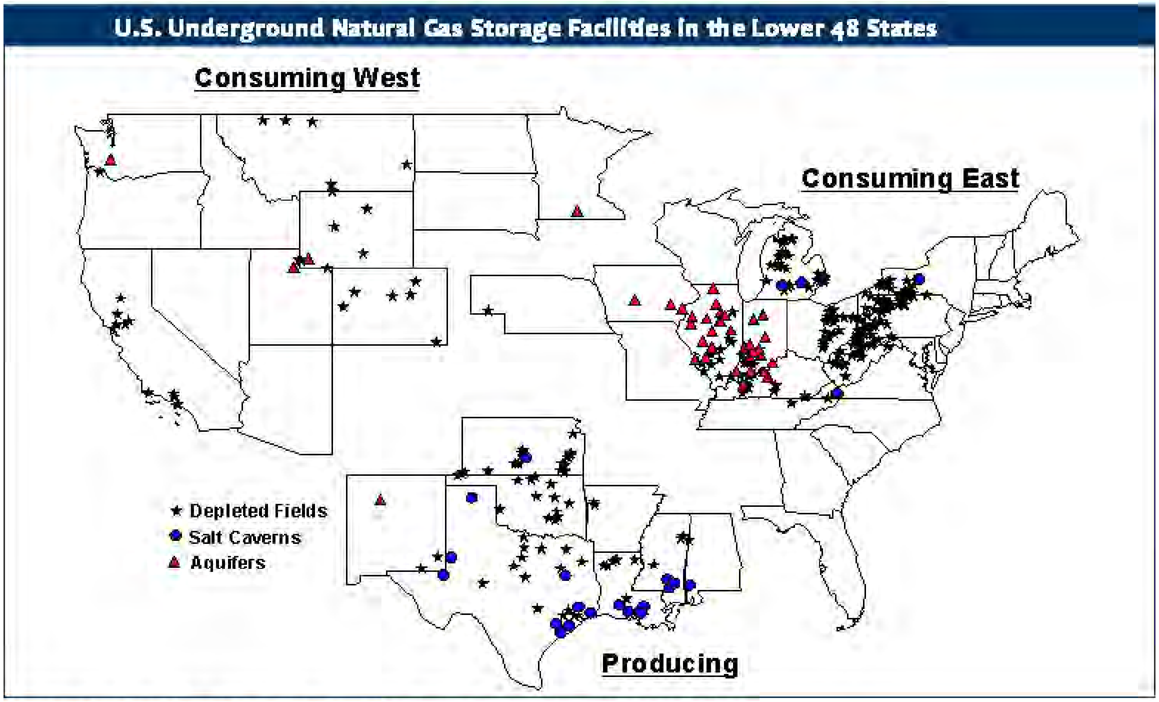
***Gas Storage Facilities***

- Depleted reservoirs consist of porous and permeable underground formations (average of 1,000 to 5,000 feet deep). The gas is divided into two categories, working or top gas, which can be withdrawn, and cushion or base gas, needed as permanent inventory to maintain adequate reservoir pressure and deliverability rates. Gas is generally withdrawn in the winter heating season and injected during the summer, although the demand for gas in summer months is increasing due to an increase in gas-fired generating plants. This type of storage facility can be used for both system supply and peak day demand.

- Aquifer storage fields are bounded partly or completely by water-bearing rocks. They have a high cushion gas requirement, generally between 50 to 80 percent. They also have high deliverability rates and, similar to depleted reservoirs, gas is generally withdrawn in the winter season and injected in the summer season.

- Salt cavern facilities use solution mining to recover minerals in underground salt deposits (salt domes or salt formations). Salt caverns usually operate with only about 20 to 30 percent cushion gas. Working gas can be recycled multiple times per year. Salt cavern storage has high deliverability and injection capabilities and is used for short peak day deliveries. Salt caverns are more expensive to construct due to the increased capital cost associated with leaching and mining the salt.

The following figure shows the location of United States storage facilities.[53]



Source: EIA, EIA GasTran Geographic Information System Underground Storage data Base.

## Natural Gas Regulation

Natural gas production is not comprehensively regulated, and no government agency monitors daily production activity. However, some aspects of production are subject to regulation; gas-producing states monitor well drilling and permitting, and in Texas, for instance, the TRC has jurisdiction over oil and gas wells located in the state and over persons owning or engaged in drilling oil and gas wells located in the state.[54] Congress deregulated the price on natural gas at the wellhead.[55] FERC does not regulate natural gas producers, but does provide

[53] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html.

[54] Among the matters covered by the TRC are space and density of drilling; prevention of waste; approval of water flood permits; location exceptions; intrastate pipelines; environmental and safety aspects of production, including well plugging; regulation of the injection of carbon dioxide into reservoirs; and maintenance of well records including logs, maps and production reporting. Jack M. Wilhelm, Texas Land Institute, *What Every Landman Should Know about the Railroad Commission of Texas* (2005), *available at* http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/wilhelm.pdf.

[55] Natural Gas Wellhead Decontrol Act, Pub L. No. 101-60, 103 Stat. 157 (1989).

that producers have not unduly preferential or discriminatory access to transportation on jurisdictional pipelines, and that no undue treatment bias is exercised with respect to transportation services and gas quality standards. Retail natural gas sales to consumers are regulated by state public utility commissions, not by FERC.

FERC's jurisdiction over the transportation of natural gas,[56] which also includes the provision of natural gas storage services, begins when the gas is delivered to an interstate pipeline and continues until the gas is delivered to the wholesale purchaser, absent some intervening transaction which renders the activity exempt from federal jurisdiction under the Natural Gas Act (NGA) or the Natural Gas Policy Act of 1978 (NGPA). While generally the activities of intrastate pipelines and LDCs are exempt from FERC jurisdiction, when those entities engage in the transportation of natural gas in interstate commerce or the wholesale sales for resale of natural gas, their activities are subject to FERC jurisdiction.

FERC's responsibilities include:

- Issuance of certificates of public convenience and necessity to construct and operate interstate pipeline and storage facilities, and oversight of the construction and operation of pipeline facilities at United States points of entry for the import or export of natural gas.
- Regulation of transportation and sales for resale in interstate commerce that are not first sales.
- Regulation of the transportation of natural gas as authorized by the NGPA and the OCSLA (Outer Continental Shelf Lands Act).
- Regulation of liquefied natural gas facility siting.
- Regulation of the abandonment of jurisdictional facilities and services.
- Establishment of rates and terms and conditions for jurisdictional services.

Pipelines publish FERC-approved tariffs that pertain to services, terms of conditions and rates for gas transportation. The North American Energy Standards Board (NAESB) provides business standards for the pipelines in areas such as the scheduling of pipeline transportation.

[56] FERC also has NGA jurisdiction over sales for resale of natural gas that are not deemed first sales. A first sale does not include the sale by an interstate pipeline, intrastate pipeline, or LDC, or affiliate thereof, unless such sale is attributable to volumes of their own production.

Most interstate pipelines no longer offer sales services. The two broad categories of transportation service on an interstate pipeline are firm and interruptible transportation, subject to specified exceptions such as force majeure clauses. (The pipeline companies sell transportation, not the gas itself, which almost always is purchased separately from the producer by the shipper.) Firm transportation is characterized by a reservation of capacity. Shippers customarily pay a charge for the reservation of guaranteed capacity rights on the pipeline and a separate usage charge; pipeline firm rates thus include cost recovery of pipeline facilities in addition to recovery of variable transportation costs such as fuel. Interruptible service rates are usage charges that are derived from the firm service rates. There is no reservation of capacity under interruptible service, and capacity is provided to a shipper only to the extent it is available.[57]

Prior to the deregulation of wellhead gas prices and open access transportation established under Commission Order No. 436 in 1985 and Order No. 636 in 1992, producers typically sold gas to both intrastate and interstate pipelines; these entities in turn sold the gas to LDCs that delivered the gas to end users. With the issuance in 1992 of Order No. 636, the Commission required interstate pipelines to unbundle their services to separate the transportation of gas from the sale of gas. Thus, today most interstate pipelines do not engage in the buying and selling of natural gas except for operational purposes.

Order No. 636 further required interstate pipelines to set up informational postings to show available pipeline capacity and to ensure that all participants have access to available capacity. Additionally, holders of the firm capacity can, through capacity release, resell those rights on a temporary or permanent basis.

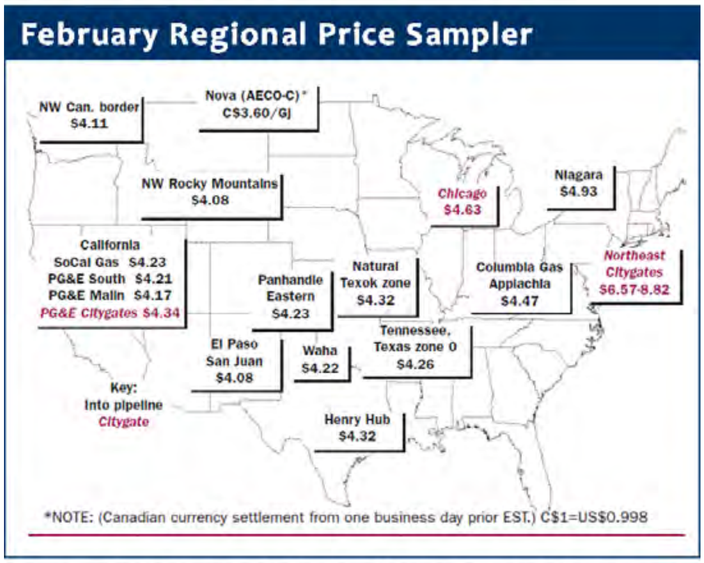
## Natural Gas Marketing

Natural gas marketing mushroomed after the opening of access to pipeline capacity. Producers and marketers, in conjunction with the deregulation of wellhead gas, were granted blanket authorization to make sales at market rates. Marketers may now be affiliates of producers, pipeline companies, or local utilities, or be separate business entities unaffiliated with any other industry players. Marketers may also be associated with financial institutions. Marketing natural gas typically includes ensuring secure supplies and arranging for pipeline

[57] Pipeline Knowledge and Development, *The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model* (August 2010), *available at* www.ingaa.org/File.aspx?id=10751.

transportation, storage and accounting. Marketers also trade financial instruments to hedge commodity price risk and to speculate.[58]

For illustrative purposes, the following map depicts the February 2011 price for some regional gas trading hubs.[59] Waha and El Paso San Juan, shown on the map, are trading prices respectively applicable to the San Juan and Permian Basins. These two basins are important Southwest supply areas and figured prominently in the weather event of February 1-5.




Source: Platts Inside FERC's Gas Market Report February 2011

LDCs often make the final sale and transfer of gas to retail consumers. Unlike the interstate pipeline companies, many LDCs provide bundled sales and delivery services, although some may provide delivery services only. Many commercial and industrial customers contract for their own supply and purchase only transportation service from the LDC. There are more than 1,200 LDCs in the United States. LDCs can be stand-alone gas utilities, combination electric-gas utilities, or parts of integrated energy companies. The largest LDC is Southern California Gas Company (SoCalGas) with more than 20 million customers, followed by Pacific Gas and Electric Company and Atmos Energy Corporation.

---

[58] *Natural Gas Distribution*, NATURALGAS.ORG., http://www.naturalgas.org/naturalgas/marketing.asp (last visited Aug. 2, 2011).

[59] PLATTS INSIDE FERC'S GAS MARKET REPORT (Feb. 2011). Reprinted with permission of Platts.

Natural gas distribution companies typically deliver smaller volumes through smaller diameter pipes and at lower pressures than pipeline companies with systems that end at an individual household or place of business. Compressor stations are generally smaller than those found on the larger pipeline systems. Natural gas traveling through distribution pipelines will often be at a pressure as low as 3 psi to 0.25 psi at the customer's meter.[60]

## Natural Gas Production in the Southwest

Texas and New Mexico are both prolific producers of natural gas, while Arizona has negligible production. In January 2011, Texas produced 31 percent of total United States production and New Mexico produced 6.2 percent.[61]

Texas and New Mexico contain a number of natural gas basins. The most significant of these with respect to the outages and curtailments experienced during the February cold weather event are the Permian, San Juan, and Fort Worth Basins.[62] Together, these three basins are responsible for almost 18 percent of total United States natural gas production.

The San Juan Basin straddles the Colorado and New Mexico border in the Four Corners region, and is a leading coal bed methane producing area. The basin is approximately 270 miles wide and covers over 4,000,000 acres.[63] Production is approximately 2.99 Bcf per day. The Permian Basin is located in West Texas and Southeastern New Mexico. It underlies an area approximately 250 miles wide and 300 miles long,[64] and produces on average 2.52 Bcf per day. The Fort Worth Basin contains the Barnett Shale Formation, with one of the largest producible

---

[60] *Natural Gas Distribution*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/distribution.asp (last visited Aug. 2, 2011).

[61] In 2009, U.S. dry gas production was 20,580 billion cubic feet (Bcf) or 56.4 Bcf per day. Texas produced 17.5 Bcf per day on and off shore, and New Mexico produced 3.5 Bcf per day. EIA, *Natural Gas Withdrawals and Production*, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm (last visited Aug. 15, 2011).

[62] Other onshore basins in the region include East Texas, the Gulf Coast and South Texas.

[63] La Plata Cnty. Energy Council, Gas Facts: San Juan Basin Map, http://www.energycouncil.org/gasfacts/sjbmap.htm (last visited Aug. 2, 2011).

[64] Charles D. Vertrees, *Handbook of Texas Online: The Permian Basin*, TEX. STATE HISTORICAL ASSN., http://www.tshaonline.org/handbook/online/articles/ryp02\ (last visited Aug. 2, 2011).

reserves of any natural gas field in the United States.[65] The basin produces 4.83 Bcf per day.[66]

Gas processing companies in the San Juan, Permian and Fort Worth Basins include DCP Midstream Partners, L.P., Enterprise Products Partners L.P., Williams Partners, L.P., Southern Union Gas Services, and Frontier Energy, L.L.C.

## Natural Gas Pipelines in the Southwest

Intrastate gas pipelines in Texas comprise 45,000 miles out of the 58,600 total miles of gas pipeline in the state. This intrastate network delivers much of the region's natural gas, including deliveries to many large refining and petrochemical facilities, numerous electric generating facilities, and pipeline interconnects.[67] The largest intrastate pipelines in Texas are Enterprise Texas Pipeline LLC (8,750 miles) and the Energy Transfer Partners L.P. (8,800 miles). Other large systems include Atmos Pipeline – Texas (6,162 miles) and the Kinder Morgan Pipeline's Texas Intrastate Natural Gas Group (5,900 miles). Together these pipelines provide for transmission from west Texas supply and market hubs such as Waha, and for gas production in south Texas to the Houston Ship Channel, Katy Hub, the Dallas-Forth Worth area and other markets. Intrastate pipelines have expanded significantly due to increased demand for capacity to transport natural gas from the Barnett Shale Formation in the Fort Worth Basin south to the Katy area or out of the state. The following map shows the Texas intrastate pipeline grid.[68]

---

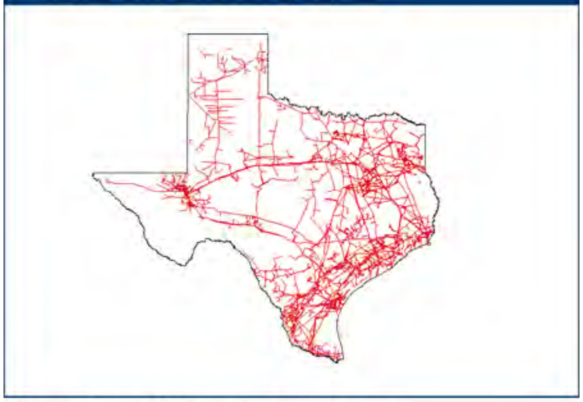
[65] The Perryman Group, *Bounty from Below: The Impact of Developing Natural Gas Resources Associated with the Barnett Shale on Business Activity in Fort Worth and the Surrounding 14-County Area*, at 5 (May 2007), *available at* http://www.barnettshaleexpo.com/docs/Barnett_Shale_Impact_Study.pdf. The Barnett Shale is one of the most significant onshore natural gas fields in North America, with thousands of wells producing hundreds of billions of cubic feet of natural gas each year. Production has risen sharply over the past several years as a result of improvements in recovery techniques.

[66] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek Energy LLC (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; additional materials were also obtained from natural gas pipelines.

[67] EIA, *Natural Gas Pipelines in the Southwest Region*, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/southwest.html (last visited Aug. 2, 2011).

[68] EIA, *About U.S. Natural Gas Pipelines - Transporting Natural Gas:* Intrastate Natural Gas Pipeline Segment, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/intrastate.html (last visited Aug. 2, 2011).

Texas Intrastate Pipelines

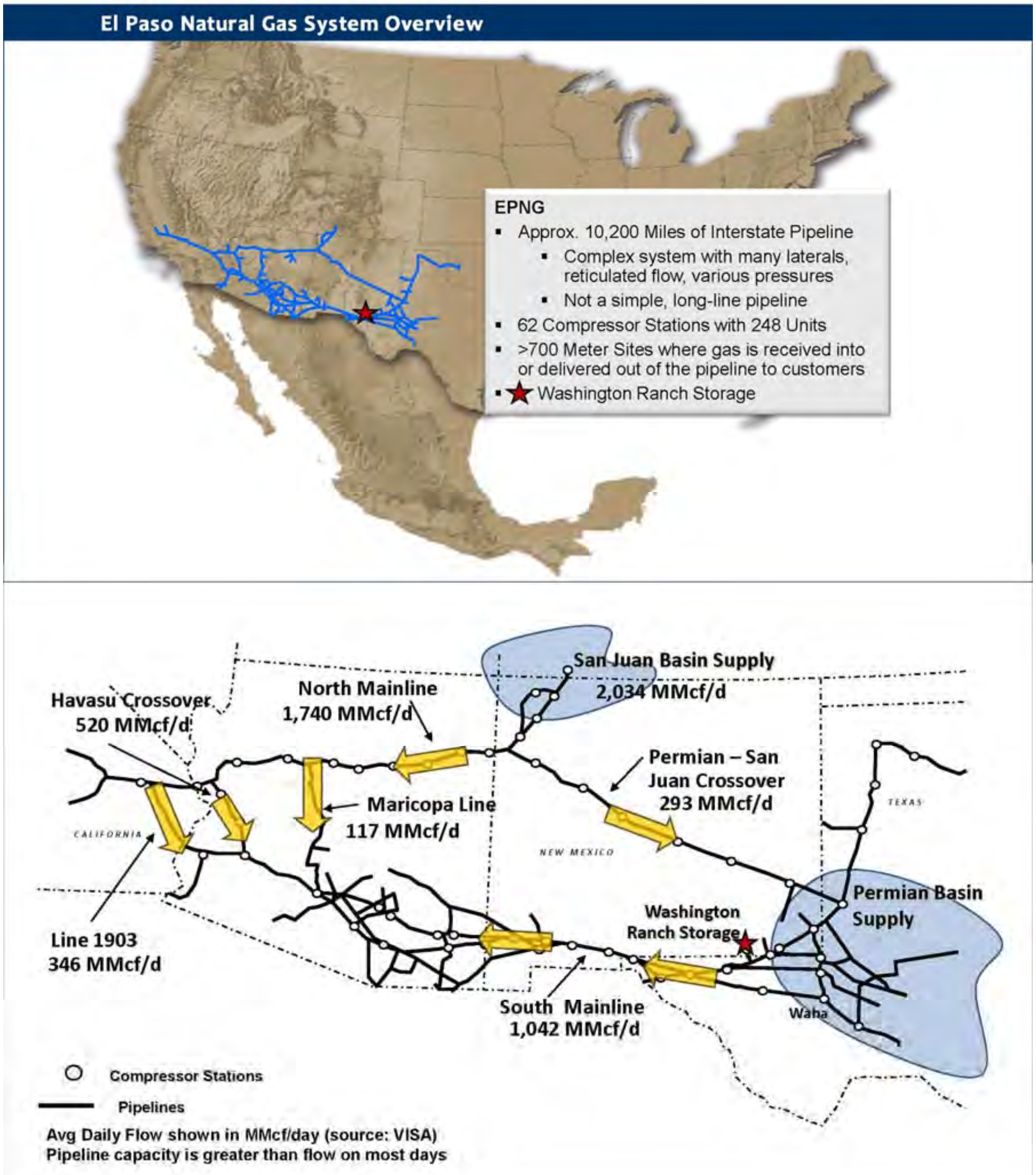


Source: Energy Information Administration

New Mexico and Arizona are supplied largely by two interstate transmission pipelines, Transwestern Pipeline Company, LLC (Transwestern) and El Paso Natural Gas Company (El Paso). These pipelines transport natural gas primarily from the San Juan and Permian Basins to the western regions of the United States. (The many other interstate pipelines that operate in Texas tend to transport gas to the Midwest and Northeast.)

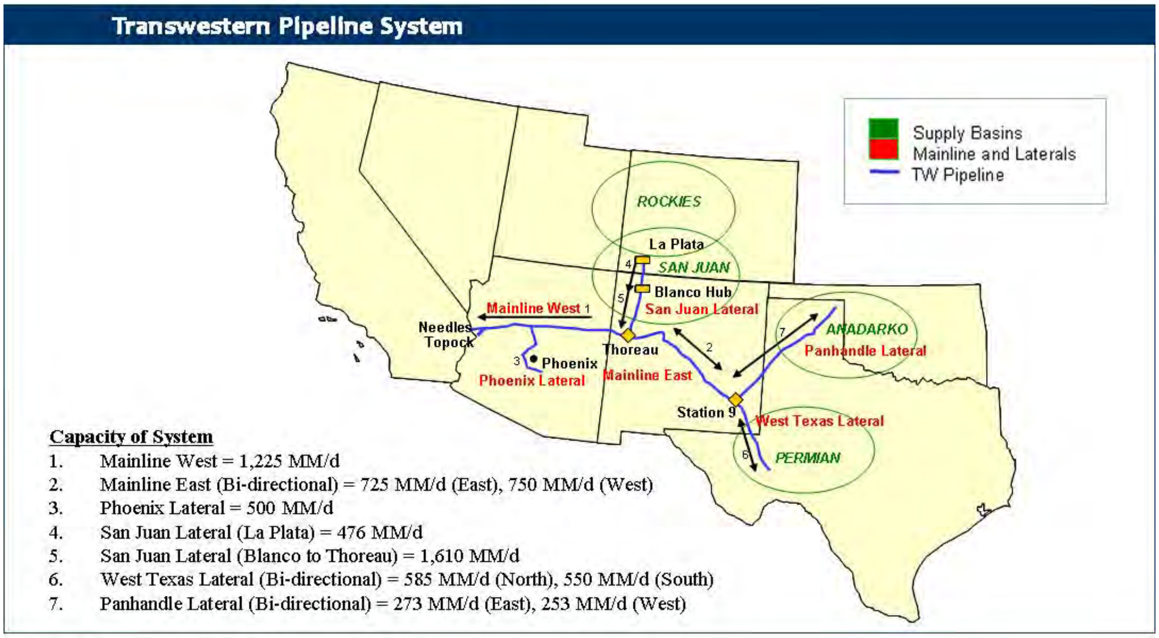
A brief description of these two interstate pipeline systems follows.

**El Paso** owns a transmission delivery system consisting of approximately 10,200 miles of pipeline. It is a complex, highly networked pipeline system with many laterals and interconnections, operating at a variety of flows and pressures. It includes 62 compressor stations and more than 700 meter sites where gas is delivered. It has 53 delivery meters to New Mexico Gas Company (NMGC), 216 meters to Southwest Gas Corporation (Southwest Gas), and 28 meters to Texas Gas Service. The system also includes the Washington Ranch Storage Field, one of the two storage facilities in the area between west Texas and the Arizona-California border.




Source: El Paso Natural Gas Company

**Transwestern** has approximately 2,700 miles of pipeline and 26 compressor stations. Its mainline capacity flowing west is 1,225 MMcf/day, and its San Juan Lateral capacity is 1,610 MMcf/day.[69]

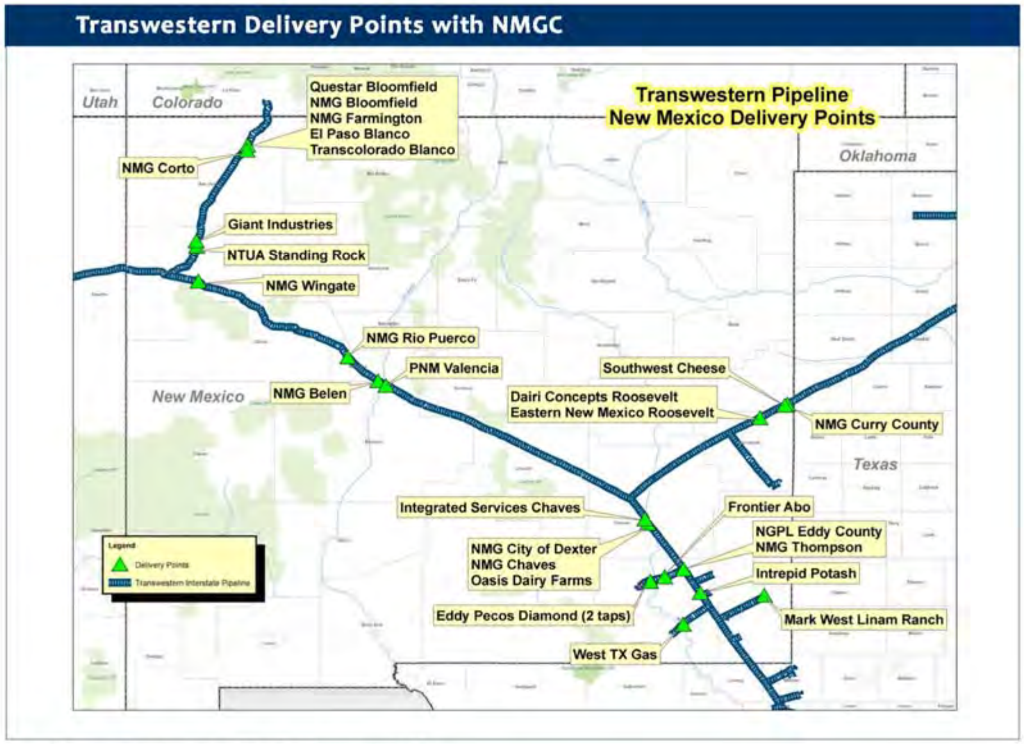



Source: Transwestern Pipeline Company, LLC

Transwestern has at least ten delivery points with NMGC.[70] In terms of flow volumes, the most significant of these during the February cold weather event was the NMG Rio Puerco, as shown in the following map.

[69] Throughout the report, MMcf refers to a million cubic feet, and Mcf to a thousand cubic feet.

[70] http://www.energytransfer.com/ops_interstate.aspx, and materials provided by Transwestern Pipeline Company, LLC to the task force.




Source: Transwestern Pipeline Company, LLC

These two pipeline companies, Transwestern and El Paso, are the interstate providers to those LDCs that experienced customer curtailments or outages in February 2011. Those LDCs are:

- New Mexico Gas Company, headquartered in Albuquerque. It provides gas service to more than 500,000 customers and maintains approximately 12,000 miles of natural gas pipelines.[71]
- Southwest Gas Corporation, providing gas service to more than 1.8 million residential, commercial and industrial customers in Arizona, Nevada and portions of California.[72]
- Texas Gas Service, the third largest natural gas distribution company in Texas. It provides gas to more than 603,000 customers in Austin, El Paso, and Rio Grande Valley areas as well as Galveston, Port

[71] New Mexico Gas Company, *About Us*, http://www.nmgco.com/about_us.aspx (last visited Aug. 2, 2011).

[72] Southwest Gas Corporation, *Profile of Southwest Gas*, http://www.swgas.com/about/aboutus/index.php (last visited Aug. 2, 2011).

Arthur, Weatherford and several communities in the Permian Basin and the Texas panhandle. [73]

- Zia Natural Gas Company, which provides gas service to over 35,000 customers in five New Mexico counties, serving primarily residential and small commercial users. In Lincoln County, where the city of Ruidoso experienced gas outages during the February event, Zia obtains gas from a direct interconnection to the El Paso Natural Gas pipeline.

## Natural Gas Storage Facilities in the Southwest

There are two major natural gas storage facilities in the Southwest:

- **Washington Ranch Storage Field**, part of the El Paso system, is located in Eddy County, New Mexico, approximately nine miles southwest of Whites City. This facility has a working storage capacity of slightly more than 47.6 bcf and a maximum daily withdrawal capacity of 250,000 Mcf.

- **Chevron Keystone Storage Facility**, owned by Chevron Corporation, is located in Winkler County, in west Texas near Midland. This is a salt cavern facility with 6.38 Bcf of working gas. Its maximum daily injection capability is 200,000 Mcf and its maximum daily withdrawal capacity is 400,000 Mcf. It has interconnects to Transwestern, El Paso and the Northern Natural Gas Company's pipeline systems.

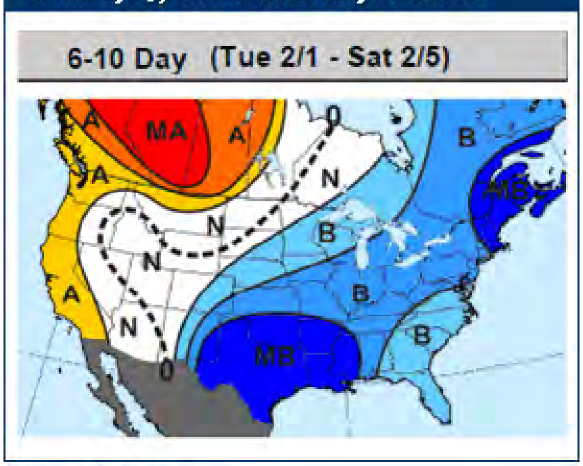
[73] Texas Gas Service, *Profile*, http://www.texasgasservice.com/en/About.aspx (last visited Aug. 2, 2011).

**This page intentionally left blank.**

# IV. Preparations for the Storm

A severe arctic cold front hit the central and northeastern United States and southern Canada on February 1, 2011, and lasted for several days. It was dubbed the "Groundhog's Day Blizzard of 2011."[74] The front was not unexpected. About a week prior to the event, long-range forecasts predicted an outbreak of very cold temperatures for the first week of February, with wind, ice, and snow from Texas to Mississippi. Arctic air was expected to extend southward to the Gulf Coast by February 2, bringing daytime highs to as low as 30 degrees below normal. Sustained winds of 20-25 mph, with higher gusts, were also anticipated.[75]

January 27, 2011: 6 to 10-Day Forecast




Source: MDA EarthSat

[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.][76]

[74] National Oceanic and Atmospheric Administration National Climatic Data Center (NCDC), *State of the Climate: Global Hazards for February 2011*(March 2011), http://www.ncdc.noaa.gov/sotc/hazards/2011/2#winter.

[75] Weather data used in this section is drawn from NCDC data. Raw land-based observation data was obtained at http://www.ncdc.noaa.gov/oa/land.html. Quality controlled local climatological data was obtained at http://cdo.ncdc.noaa.gov/qclcd/QCLCD?prior=N. Additional data, unless otherwise noted, is drawn from materials provided to the task force by BAs, transmission operators, generators, producers, processing plants, pipelines and LDCs.

[76] EarthSat is a private forecasting service used by many entities in the energy industry and by the Commission in connection with its market monitoring efforts.

## A. Weather Conditions During the Event

Actual weather conditions between February 1 and 5, 2011 turned out to be largely as predicted by the National Weather Service's long-range forecasts. However, actual temperatures were a few degrees lower than forecasted, especially in west Texas and New Mexico. In some places, temperatures did not rise above freezing until February 4. Low temperatures in Albuquerque ranged from -7 degrees to 7 degrees over the four-day period, in Midland from 6 degrees to 12 degrees, and in Dallas from 13 degrees to 19 degrees.[77]

As the storm hit during the early morning hours of Tuesday, February 1, temperatures in the western-most cities of the Southwest plummeted dramatically. Daily highs at Albuquerque and Dallas fell 20 degrees (to 28 degrees and 39 degrees respectively) from the previous day, while at Midland the recorded high was 30 degrees, which was 43 degrees below that of the previous day. Houston's temperatures started out on February 1 at 70 degrees, but by 7:00 AM had dropped to 45 degrees.

The wind profile was also changing dramatically. Wind speeds had rarely exceeded 10 mph the preceding day, but by the morning of February 1 Albuquerque was experiencing sustained wind speeds of 20 mph (representing a wind chill index of 4 degrees), with gusts to 27 mph. Winds in Midland hovered around 20 mph and gusted to over 30 mph. Light snow began falling in both cities around midnight. It was also windy in Dallas on February 1, with speeds of up to 25 mph and gusts between 20 and 40 mph.

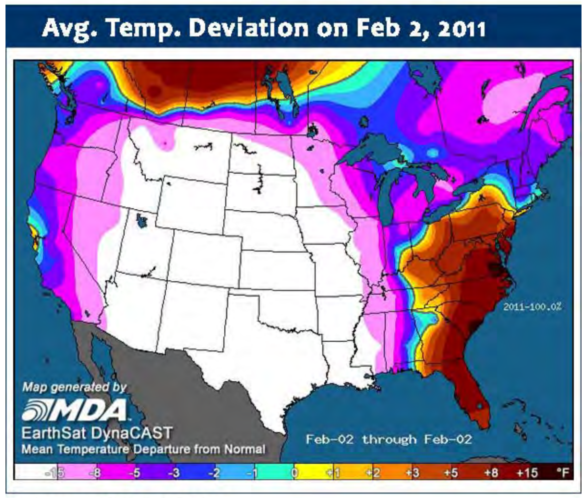
Conditions worsened at all locations through the day, and by midnight temperatures were extremely low. Albuquerque was at 4 degrees, with continuing high winds and snow. Temperatures at Midland were 14 degrees and at Dallas 16 degrees. The cold air finally hit Houston late in the day, with temperatures of 27 degrees and winds of 14 mph, although without precipitation.

By Wednesday, February 2, early morning conditions had become severe. In Albuquerque, the temperature at 8:00 AM was 1 degree, almost 40 degrees below the average for that date, and the wind was blowing at 26 mph. Temperatures in El Paso and Midland hovered around 10 degrees for much of the day, with wind speeds of 15 mph. El Paso set a record low for the day of 6 degrees at 5:00 AM, and recorded the third coldest day in 38 years. In fact, February 2 turned out to be one of the coldest days on record in the last 25 years across the state of Texas, with average temperatures well below freezing and only

---

[77] All temperatures in this report are in degrees Fahrenheit.

Brownsville escaping severe conditions (with average temperatures of about 35 degrees). Significant winds accompanied the frigid temperatures, with wind chill factors dropping the perceived temperatures to -6 degrees in Dallas and 6 degrees in Austin.



Source: MDA EarthSat

On Thursday, February 3, weather conditions began to marginally improve in some areas, although in Albuquerque and El Paso it would rank as the coldest day in 38 years. Albuquerque, Midland and El Paso were still experiencing highs near 15 to 20 degrees, but the winds had begun to diminish. From Dallas to San Antonio, temperatures moderated about 5 to 10 degrees, but wind speeds remained high.

On Friday, February 4, conditions improved across the region. Temperatures in the western cities finally rose above freezing, and in a few of the eastern-most cities rose above 40 degrees. Nonetheless, during the early morning hours, El Paso hit a low of 3 degrees before reaching a high of 37 degrees, ranking the day as the city's second coldest in 38 years. Four to six inches of snow fell in the Dallas Metropolitan area, causing cancellation of more than 300 flights at Dallas airports just as fans were arriving for the Super Bowl.

Cold weather hit the region again on February 9 and February 10. The coldest temperatures were seen on February 9, when El Paso recorded a low of -2 degrees, and Midland a low of 7 degrees. Daily highs, however, were in the 30s and 40s. Other cities saw lows dip into the 20s and teens, with high temperatures rising into the 40s and 50s.

There is no question that the cold and windy weather during this first week of February was both sustained and severe. Just how severe, when compared to prior storms, is examined in the section of this report entitled "Prior Cold Weather Events."

## B. Preparations for the Storm: Electric

Three balancing authorities in the Southwest shed load during the cold weather event: ERCOT, SRP and EPE. (PNM lost some 26 MW of load as well, although this was the result of localized transmission issues largely unrelated to the storm). Customers in ERCOT were affected the most, by a large margin. ERCOT shed 4000 MW of load, affecting 3.2 million customers, on February 2. It shed another 300 MW on February 3, affecting 180,000 customers. In comparison, SRP shed 300 MW of load, affecting 65,000 customers, and EPE shed a little over 1000 MW of load, affecting 253,000 customers.[78]

The preparations for the storm taken by these three entities are discussed below.

### ERCOT

Going into the winter season of 2010/2011, ERCOT had substantial reason to believe it could meet its projected demand with available generation and imports. ERCOT's peak demand for the winter of 2010/2011 was forecasted to be 47,824 MW, with the peak anticipated to occur in January.[79] (This forecasted peak was 11 percent higher than the forecasted peak for the previous winter.[80]) To meet that peak demand, ERCOT had projected generation capacity plus imports of 72,881 MW.[81] Thus, for planning purposes, ERCOT could anticipate a

[78] In the case of ERCOT, these numbers represent the amount of load the transmission providers were directed to shed. Actual load shed was somewhat higher (5411.6 MW on February 2 and 459.5 MW on February 3), for reasons discussed in the section of this report entitled "The Event: Load Shed and Curtailments."

[79] NERC, *2010/2011 Winter Reliability Assessment*, at 16 (Nov. 2010), *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf. NERC prepares its reliability assessments based on data and information submitted by the applicable Regional Entity, which in ERCOT's case is TRE.

[80] ERCOT modified the forecasting models because it had experienced extreme cold weather in January of 2010, with load tracking notably higher than forecasted.

[81] Resources listed in the NERC 2010-2011 Winter Reliability Assessment consisted of available generation (72,500 MW) and net firm imports (381 MW), and did not include generating units which were known well in advance to have scheduled maintenance outages spanning the expected peak load period. Demand was calculated based on a 50/50 load forecast (47,824 MW), meaning the forecast is expected to be exceeded five years out of every ten.

comfortable reserve margin of 57 percent. This percentage compares favorably with NERC's reference reserve margin for ERCOT of 13 percent, considered by NERC to be the base level required for reliability.[82]

The estimated demand for the season included only firm load, and therefore did not include ERCOT's two categories of contractually curtailable load: Load Resources (formerly designated as Load Acting as a Resource, or LaaR), which may be automatically disconnected when system frequency drops below a prescribed threshold (totaling 1062 MW as of February 2); and Emergency Interruptible Load Service (EILS), which permits curtailment prior to firm load shedding (totaling 331 MW as of February 2).

Although ERCOT seemingly had a generous reserve margin going into the winter of 2010/2011, the reserve margin cited did not take into account planned outages that were not yet known at the time of the forecast. ERCOT is a summer-peaking system, and the high summer temperatures and demand often extend into what would be considered shoulder seasons in more northerly regions. For that reason, it is not unusual for generators in ERCOT to schedule maintenance outages in February. ERCOT does not have the authority to prohibit generators from scheduling such outages or from taking them as scheduled, unless the outage is scheduled eight days or less before the outage date, or the outage would keep ERCOT from meeting applicable Reliability Standards or its own Protocol requirements.[83] At most, pursuant to its Protocols, ERCOT can ask generators to refrain from taking a scheduled outage if it believes it may need the generator's output. ERCOT also does not have authority under its Protocols to require generators that are on planned outage to come back into service early (assuming the generator is even in a condition to do so). Nor are there any market mechanisms to compensate generators for any costs associated with delaying or coming back early from a scheduled outage.

Despite these potential limitations, ERCOT was far from being generation deficient for winter 2010/2011 seasonal planning purposes. Nor, as will be seen, did it appear to be deficient going into the storm itself. A little background is needed to put in context the generation that ERCOT thought it would be able to call upon during the storm.

---

[82] NERC 2010/2011 Winter Reliability Assessment at 16.

[83] ERCOT Nodal Protocols § 3.1 (Nov. 20, 2010), *available at* http://www.ercot.org/mktrules/nprotocols/2010/index. ERCOT is considering revising this provision to permit it to deny an outage request if it is scheduled 90 days or less from the outage date.

ERCOT uses proprietary forecasts (performed both on a seasonal and daily basis) to predict its load.[84] ERCOT used those weather forecasts, coupled with historical and other information, to gauge expected customer demand during the approaching event. A task force review of ERCOT's forecasts determined that they accurately predicted the February storm conditions, and in some cases their weather estimates were even slightly more accurate than those of the National Weather Service.

ERCOT then compared the anticipated demand[85] against its generation capacity, both for purposes of scheduling power in the day-ahead market and for determining whether it would meet reliability and reserve requirements. For operating purposes, ERCOT's Protocols include a responsive reserve requirement (also referred to as Physical Response Capability, or PRC) of 2300 MW. The primary purpose of the responsive reserves is to restore system frequency to 60 Hz within the first few minutes after the system experiences a significant frequency deviation. The 2300 MW amount is based on a 1988 study that determined the reserves that would be needed to prevent the shedding of firm load upon the simultaneous loss of the two largest generation resources in the ERCOT region.[86] (Actual online responsive reserves at any given time typically exceed the 2300 MW requirement.[87])

***<u>ERCOT Protocols</u>***

The ERCOT protocols set forth the procedures and processes used by ERCOT and its market participants for the orderly functioning of the ERCOT system and market. They contain

(cont'd)

[84] ERCOT relies on Telvent DTN and Pattern Recognition Technologies (PRT) for the weather data used in its load forecasts.

[85] ERCOT's load forecast projected loads of 52,673 for February 1 and 57,436 for February 2.

[86] This is a more conservative measurement than that required by NERC Reliability Standard BAL-002-0 R3, which sets a "contingency reserve" requirement to cover the loss of the single largest contingency on a Balancing Authority's or Reserve Sharing Group's system (N-1), not the loss of the two largest contingencies. Because ERCOT is not synchronously linked with other interconnections, a larger reserve amount than N-1 is required to maintain proper frequency response.

[87] ERCOT's daily morning report listed responsive reserves of 4196 MW for February 1 and 5944 MW for February 2, projected for the peak hours of those days.

> policies for scheduling, operations, planning, reliability, and settlements, as well as ERCOT's rules, guidelines, procedures, and standards. The protocols are developed and amended through stakeholder committees for approval by the ERCOT Board of Directors. Once approved at ERCOT, the protocols are submitted to the PUCT for final approval. In addition to its task of enforcing the FERC-approved Reliability Standards, TRE is responsible for compliance monitoring and enforcement of the ERCOT Protocols.

In addition to the responsive reserve requirement, ERCOT must meet a non-spinning reserve requirement.[88] These reserves are intended to address the risks of load uncertainty and wind power output variability. For February 2011, the non-spinning reserve requirement was set at 2000 MW. (The sources counted for non-spinning reserves are not included in the calculation of available resources for purposes of meeting the responsive reserve requirement of 2300 MW.[89])

Notwithstanding the fact that 11,566 MW of generation were on scheduled outage as of February 1,[90] ERCOT had more than 3100 MW of responsive

[88] Non-spinning reserves in ERCOT are generation resources capable of being ramped to a specified output level within thirty minutes and running at that level for at least one hour, or Load Resources that are capable of being interrupted within thirty minutes after being asked for interruption and remaining de-energized for at least one hour.

[89] Wind resources, which are forecasted on an hourly basis, are also not included in the calculation of available resources for purposes of meeting the responsive reserve requirement. One of the most significant differences between the NERC Winter Assessment and ERCOT operations is how wind power is handled. The NERC Winter Assessment assigns a fixed average output of 8.7 percent of nameplate rating as "existing-certain" generation capacity. For the 9317 MW of installed wind capacity (aggregate nameplate rating) in ERCOT, this amounts to 811 MW. Operations, on the other hand, utilizes wind power forecasts derived from highly localized wind speed forecasts, which provide wind power output values for each of the upcoming 48 hours. The forecasts are re-run hourly and the results updated accordingly, yielding a "rolling" 48 hour look-ahead. ERCOT's Current Operating Plan (COP) for wind power uses a conservative estimate which has an 80 percent chance of being met or exceeded, and already takes into account any equipment outages, either scheduled or forced. On the morning of February 2, the aggregate COP for wind power peaked at about 5200 MW at 3:00 AM and decreased steadily each hour down to 3500 MW at 8:00 AM. The actual wind power output followed the same downward trend, but fell short off the COP numbers anywhere from 400 MW to 1000 MW, depending on the specific hour. (This snapshot picture exhibits the variability of wind power.)

[90] This number grew to 12,413 MW on February 2; however, the additional units might have been ones that experienced forced outages on February 1 and then transitioned into scheduled outages.

reserves available throughout the entire 24 hours of that day, running as high as 5600 MW in the early morning and again during the mid-afternoon hours. This exceeded the responsive reserve requirement of 2300 MW by a comfortable amount.[91]

Thus, on paper, ERCOT had reason to believe it had ample generation going into the storm.[92] As it turned out, the large number of generator outages, derates and failures to start that occurred on February 1 and February 2 would reduce that margin below acceptable levels.

Aside from determining it had sufficient operating reserves listed as available, ERCOT took other steps to prepare for the storm. On January 31, ERCOT issued an Operating Condition Notice (OCN) to its market participants, advising them of the expected cold front. On February 1, it issued another OCN at 2:45 AM and an Advisory at 9:05 AM. ERCOT also reported to the PUCT that it was expecting temperatures in the teens to the low 20s and maximum temperatures near or below freezing, with anticipated impacts on 50 percent or more of its major metropolitan areas.[93]

***Notices and Emergency Declarations***

The ERCOT Protocols set out three types of preliminary notices to be issued by ERCOT to inform market participants of a potentially adverse operating condition, including extreme weather conditions such as hurricanes and protracted periods of below-freezing temperatures. The type of notice is determined based on the time available for the market to respond before an emergency condition may occur.

(cont'd)

[91] On February 2, responsive reserves would hover in the range of 2700 MW to 3300 MW in the early morning hours, dropping to around 3000 MW at 4:30 AM and then plummeting rapidly.

[92] In addition to the outages already underway, three planned generation outages were scheduled to begin during the time period covered by the anticipated storm. ERCOT requested one of these generators to delay the outage, as discussed later in the report.

[93] ERCOT did not provide any further market notices or indications of projected capacity shortages until 3:00 AM on February 2, when it issued an OCN and an Advisory reporting that reserves were below 3000 MW. These notices, as well as the other actions that took place on February 2, are discussed in the following section of this report entitled "The Event: Load Shed and Curtailments."

- Operating Condition Notice -- issued to inform participants of a possible future need for more resources due to conditions that could affect system reliability; allows ERCOT to confer with transmission providers and participants regarding the potential for adverse reliability impacts and contingency preparedness when adverse weather conditions are expected.

- Advisory -- issued when conditions are developing or have changed such that more ancillary services will be needed, or when weather or conditions require more lead-time than the normal day-ahead market allows; allows ERCOT to increase ancillary services requirements above the quantities originally specified in the day-ahead market, and to require information from participants regarding their fuel capabilities for the next seven day period.

- Watch -- issued when additional ancillary services are needed in the current operating period, or when forced outages or abnormal operating conditions have occurred or may occur that require operating with transmission security violations; allows ERCOT to instruct transmission owners to reconfigure ERCOT system elements to improve reliability in ERCOT; and allows ERCOT to take steps to procure additional regulation services, RRS services, and non-spinning services.

ERCOT issues the fourth level of Notice, an Emergency Notice, when it cannot maintain minimum Reliability Standards or meet its Protocol requirements during the operating period or is otherwise in an unreliable condition. Depending on the severity level, ERCOT may take additional steps to resolve the system emergency, including relaxing transmission constraints, issuing public appeals for conservation, deploying Load Resources and EILS resources, and requiring firm load shedding.

Between January 28 and January 31, ERCOT cancelled, withdrew, or delayed planned outages on ten 345 kV transmission lines, 27 138 kV transmission lines, two 345/138 kV auto-transformers and one 138/69 kV transformer (outage cancellation rules differ as between transmission and generation). On January 31, ERCOT requested one generating unit (Mountain Creek SES Unit 8 at 568 MW) to begin start-up due to its long start-up lead time, and requested another unit (Lake Hubbard SES Unit at 397 MW) to convert from natural gas to fuel oil in anticipation of possible gas curtailments.[94] ERCOT reports that it did not request any generators to return early from scheduled

[94] Texas Reliability Entity, *Event Analysis Report – Feb.2, 2011 EEA-3 Event* at 16 (Apr. 15, 2011) (TRE Report).

outages, nor did it request any generators to defer scheduled outages that were slated to start during the cold weather event.[95]

In the afternoon of January 31, ERCOT decided to adjust its load forecast to factor in the potential effect of the high winds that had been predicted (ERCOT's forecasts do not normally factor in wind chill effects). ERCOT made a manual adjustment to its load forecast for the remainder of February 1 and for February 2, adding 4000 MW.

The storm hit on February 1. Beginning at approximately 12:00 PM on that day, power plants across Texas experienced problems due to the cold weather. These included freezing instrumentation, freezing pipes, freezing drain lines, natural gas curtailments, and natural gas pressure reductions due to high usage.[96] Between noon and midnight on February 1, two large coal units and 18 natural gas units tripped or failed to start for varying periods of time. Another six natural gas units and 13 wind plants were derated during this period. As of midnight on February 1, unavailable generation capacity in ERCOT (not counting scheduled outages) reached 6022 MW.[97]

In addition to the generation scheduled for February 2 by its economic dispatch model, ERCOT committed 24 additional generating units, totaling 3400 MW, through its reliability unit commitment (RUC) process.[98] By midnight, all available generation had been instructed to run on February 2.

---

[95] ERCOT did discuss with generators deferring scheduled outages planned for the February 10 period, when cold weather was again anticipated. Some of those scheduled outages were postponed.

[96] TRE Report at 7. The details of the types and causes of the forced outages experienced during the February 1-5 weather event are discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions."

[97] This is a net cumulative number; that is, if a failed unit came back online, it is not counted as unavailable.

[98] ERCOT initially committed 13 units through the RUC process on February 1, to be deployed on February 2; it later cancelled six of those unit commitments, leaving a net value of 2049 MW in additional generation as of midnight on February 1. At 3:03 AM on February 2, ERCOT committed 19 units through its RUC process, totaling 1351 MW. Unit generation added on both days through the RUC process for February 2 deployment totaled 3400 MW.

***ERCOT's RUC Process***

After ERCOT completes the run of its day-ahead market, which matches buy and sell offers for energy and ancillary services for the following operating day, ERCOT runs a Day-Ahead Reliability Unit Commitment (DRUC) study to ensure that sufficient capacity is available to serve load. For each hour of the following day, the DRUC examines whether sufficient resources have been committed, through Day-Ahead awards or as otherwise reflected in each resource's Current Operating Plan (COP), to meet the forecasted load for each hour. If ERCOT determines that any additional resources are needed, it can physically commit those resources for the hours needed, with certain payment levels guaranteed to the resources when ordered to run.

ERCOT runs the DRUC study in the afternoon prior to the operating day studied. Hourly RUC (HRUC) studies are run thereafter, comparing resources and load for each hour remaining in the DRUC period and reflecting any changes in resource commitments (such as forced outages or modified COPs) or other changes in system conditions since the DRUC was run.

The RUC process takes into account resources committed in the Day-Ahead market, resources self-committed in the COPs, and resources committed to provide ancillary services. The RUC process can also recommend decommitment of resources where transmission constraints are not otherwise resolvable. ERCOT can order any available resource to come online as part of the RUC process.

If a resource is selected by the RUC, the resource will at a minimum be made whole for its startup and minimum-energy costs. However, if the energy revenues received during the RUC-commitment period are greater than these guaranteed costs, the resource may be subject to a "clawback" under certain conditions.

Could or should ERCOT have done more to prepare for the event? ERCOT procedures specifically include provisions for severe cold weather operations.[99] In anticipation of severe cold weather, ERCOT may issue an OCN, Advisory, Watch, or Emergency Notice. These various alerts allow ERCOT to react to potential operating conditions by: reviewing planned and existing outages; determining if more lead-time is needed for generating resources to meet their commitments than the normal day-ahead market allows; determining if additional ancillary services are required; ordering on additional units; and increasing staffing. Under the

[99] ERCOT Operating Procedure Manual: Shift Supervisor Desk § 7.5 (July 18, 2011), *available at* http://www.ercot.org/mktrules/guides/procedures/. Severe cold weather is defined by expected temperatures in the mid to low 20 degree range with expected maximum temperatures near or below freezing, impacting 50 percent or more of major metropolitan areas.

various alerts, ERCOT's RUC Operator may also confer with transmission operators and QSEs[100] regarding preparedness, fuel capabilities, the need to reconfigure system elements, or to vary from market timing deadlines.[101]

In anticipation of the event, ERCOT arguably could have better utilized these tools to prepare for the severe cold weather, particularly by increasing ERCOT's responsive reserves well in advance of its decision late on February 1 to schedule all available units for the next day.[102] As events proved, the extensive generator outages substantially exceeded ERCOT's reserves, and would have done so even if the reserves had been substantially larger in number. But this was not known by ERCOT going into the event. Furthermore, if generating units had been online and running, they would have been better able to withstand freezing temperatures,[103] a consideration ERCOT might have factored into its decision-making process.

Another strategy that might have improved generator response would have been the use of pre-warming techniques.[104] ERCOT does not currently have the authority to require generators to engage in these actions, but if generators had done so, they might have prevented some of the extensive freezing problems that developed. Running quick start units prior to their scheduled start time could also

---

[100] A "Qualified Scheduling Entity" (QSE) is a market participant qualified by ERCOT as a resource entity or a load serving entity, for purposes of communications with ERCOT and the settling of payments and charges.

[101] ERCOT Operating Procedure Manual, Reliability Unit Commitment Desk, Section 6.1 (July 20, 2011), *available at* http://www.ercot.com/mktrules/guides/procedures/.

[102] ERCOT Protocols formerly required it to increase its spinning reserves by an amount at least equal to its responsive reserves during cold weather alerts. *See* Elec. Reliability Council of Tx., *ERCOT Operating Guide No. 12* ( May 1989). ERCOT advised the task force that this protocol had been changed to account for the variability of wind power. ERCOT now carries non-spinning reserves continuously rather than only during peak hours, as was its former practice. ERCOT stated its belief that the continuous availability of non-spinning reserves serves virtually the same purpose as the former practice of doubling the spinning reserves.

[103] The use of a generating unit's own radiant heat to prevent freezing is discussed in the section of the report entitled "Key Findings and Recommendations."

[104] For conventional gas steam units, pre-warming can be accomplished by establishing a fire in the boiler to produce warming steam for the turbine while it is on turning gear. This keeps metal temperatures warm enough to prevent freezing in piping and instrumentation lines and helps bring lubricating and hydraulic oils up to proper operational temperatures. Combustion turbines can run at full speed no-load operation for short periods of time prior to start up, in order to warm vital parts, instrumentation, and lubricating oils.

have identified problems before the output of the units was needed, giving them time to make corrections.[105]

Had ERCOT and the generators undertaken these additional measures, it is possible that fewer generating units might have failed. ERCOT might still have been forced to shed load, but the extent of the load shed might well have been reduced. Every generator that could have escaped failure on February 1 and February 2 would have improved the situation for Texas consumers.

ERCOT Generators

Most generators in ERCOT's footprint reported having employed freeze protection measures to protect their facilities. These measures generally fell into two categories: physical readiness and operational readiness.

To prepare physical facilities for the cold weather, generators variously reported that they installed portable heaters to maintain ambient air temperature, added extra insulation to exposed components, installed temporary windbreaks to exposed areas, drained non-essential water systems, and determined that the water in essential water systems was circulating.

Some generators also reported adjusting their operations to adapt to the cold weather. They called in more operating and maintenance staff, increased the frequency of operator rounds, performed checks of freeze protection panels and heat tracing circuits, and added windbreaks. Plant staff also tested emergency equipment, added fuel to heaters and emergency generators, stocked extra supplies of fuels as well as food and other emergency items in case deliveries were disrupted, and prepared sleeping arrangements for employees if roads became impassable. Some generators utilized pre-operational warming during the event.[106]

Despite these reports of having taken steps to prepare for the cold weather event, many generating units in ERCOT failed to perform or suffered derates after

[105] On February 1 and 2, approximately 19 simple cycle and combined cycle units in ERCOT tripped for non-weather related causes and were restored within two hours. Many of the simple cycle and combined cycle unit trips occurred immediately during start-up sequences or very soon after synchronization.

[106] On February 10 as well, some generators utilized pre-operational warming for that day's cold weather snap. At least five generators kept their units running, started units earlier or took other measures to keep from having a "cold start." These generators credited these strategies for their improved performance on that date.

the storm hit. And they failed, in the majority of cases, because of weather-related problems. The various generator outages and their causes are examined in the section of this report entitled "Causes of the Outages and Supply Disruptions."

Salt River Project

SRP is a vertically integrated utility and owns its own generation, transmission, and distribution facilities. Its preparations for inclement weather therefore needed to encompass all three functions. In terms of its forecasting, SRP uses an Artificial Neural Network Short-Term Load Forecaster model, which projects control area loads. This model incorporates SRP's own meteorologist's weather forecast as well as hourly historical load data. SRP reported that while weather on February 2 matched its weather forecasts, its load forecast was lower than actual load demands. The disparity, however, was within five percent.

SRP has generating facilities located throughout central and northern Arizona. Winter temperatures tend to be mild in and around the Phoenix Valley but can be noticeably colder in the more remote areas where the company's two coal burning facilities are located. SRP reports that it carries out preventative maintenance for facilities that have winterization equipment, which generally consists of heat tracing[107] and insulation. Gas-fired generating plants in and around the Phoenix valley use winterization equipment to protect against expected conditions, while hydro generating facilities are almost exclusively contained inside protected buildings. SRP's coal generating facilities at the Coronado and Navajo stations have winterization systems that consist mostly of heat tracing and insulation. SRP advised the task force that every year in the fall, planners for the Coronado and Navajo stations develop work orders to inspect and test these winterization systems to verify they are working properly, and that during the winter months, staff conduct weekly winterization and freeze protection equipment checks.

SRP's immediate preparations for the February event were limited. It did not issue a cold weather alert in advance of the storm.[108] SRP reports that management at the Navajo Generating Station did inform its operators at the beginning of shifts that cold weather was approaching, and inquired if there was anything the employees needed to help them do their job. SRP does not employ a

[107] Heat tracing refers to the application of a heat source to pipes, lines, and other equipment.

[108] Indeed, the only alert the SRP Balancing Authority provided to generators was a "Capacity Alert," indicating that maintenance and operations activities on all operating generating units were to be stopped.

formal checklist of activities that should be carried out prior to a winter storm, and the company reported that the Operations and Maintenance Group at the Navajo Generating Station did not take any formal actions to prepare the station for the anticipated severe weather. However, SRP informed the task force that the group did hold meetings at which the need for staff to frequently check the generating equipment for potential weather-related problems was emphasized.

El Paso Electric

Like SRP, EPE is a vertically integrated utility. It reported to the task force that at the beginning of the winter of 2010/2011, as at the beginning of every winter, it took steps to winterize its generating facilities. This winterization included verifying that heat tracing was properly functioning, as well as making sure insulation was properly installed.

EPE also reported that it verified that the equipment in its substations, the part of the transmission and distribution system most susceptible to cold temperature extremes, could withstand the expected cold temperatures.

On January 31, 2011, EPE initiated preparations for the anticipated severe weather, which included verifying winterization of generation, transmission and distribution facilities, reviewing system operations plans, checking on the availability of fuel, preparing for potential pipeline constraints, and placing employees on call as needed during the weather event. The Systems Operations group requested EPE's Power Marketing and Fuels group to keep additional generation online. In response, the Power Marketing and Fuels group made arrangements to leave on Rio Grande Unit 6, to continue with the start-up of Newman Units GT-3 and GT-4, and verified the ability of Newman Unit 3 to operate on fuel oil.

In contrast to some other areas in the region, EPE reported that actual weather during the event was more severe than forecasted (and significantly colder than historical temperatures). For February 2, EPE reported that the actual high temperature in El Paso was 15 degrees compared to a forecasted high of 37 degrees, and the actual low temperature was 6 degrees compared to a forecasted low of 14 degrees. The forecasted high for February 3 was 30 degrees, compared to an actual high of 18 degrees, and the forecasted low was 14 degrees, compared to an actual low of 1 degree. For February 4, the last day of the freeze event in EPE's service territory, the forecasted high of 43 degrees compared to an actual high of 37 degrees, and a forecasted low of 21 degrees compared to an actual low of 3 degrees. EPE did not report the exact location for its temperature statistics, but presumably they occurred in the west Texas and New Mexico regions.

## C. Preparations for the Storm: Natural Gas

Varying levels of preparation for the February cold front were employed by the producers, processing plants, interstate pipelines, intrastate pipelines, and LDCs that together make up the natural gas delivery chain. Depending on the type of facility, preparations included at least one, if not several of the following items: monitoring the weather, increasing staffing, methanol injection, pigging, insulation, tarps, heat tracing, building line pack[109] in pipelines by injecting more gas, over-purchasing gas supplies and enhancing winterization equipment. For the most part, facilities began their preparations by either Sunday, January 30 or Monday, January 31.

This section describes the preparations taken by individual companies in west Texas, the Texas panhandle, north Texas and New Mexico and by the LDCs in Arizona and New Mexico.

### Producers

As discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions," the difficulties encountered by LDCs in trying to meet customer demand stemmed principally from supply declines in the basins, and secondarily from problems encountered at processing plants. The preparations for the cold weather event taken by producers is therefore of special interest.

Of the 15 producers who provided information to the task force on this issue, all reported that they had used winterization techniques of one sort or another. The following table shows by basin the numbers of producers that used one of or more of the listed methods.

[109] Line pack refers to the volume of gas in the system at any given point in time.

| | PERMIAN | SAN JUAN | FORT WORTH | EAST TEXAS | TEXAS GULF |
|---|---|---|---|---|---|
| Methanol Injection or Drip | ✓✓✓✓✓✓✓ | ✓✓✓ | ✓✓✓✓✓ | ✓✓✓✓✓✓✓ | ✓✓✓✓✓✓ |
| Increased Pigging or Clearing of Liquids | ✓✓✓ | ✓ | ✓✓ | ✓ | ✓ |
| Tarps or Cold Weather Barriers | ✓ | ✓✓ | | ✓✓ | ✓✓ |
| Increased Hauling of Fluid | ✓✓ | ✓ | ✓✓✓ | ✓✓✓ | ✓✓ |
| Heated Anti-Freeze | | ✓ | | | |
| Heat Trace | ✓ | ✓✓ | ✓ | ✓✓✓✓ | ✓ |
| Hot Oil Trucks | ✓ | | | | |
| Insulation | ✓✓✓ | ✓ | ✓✓ | ✓✓ | |
| Burial of Lines | ✓ | | | | |
| Heat Lamps or heaters | ✓✓ | ✓ | | | ✓ |

A short description of some of these techniques gives a fuller picture of the actions the producers reported having taken:

- Methanol (an anti-freeze type solution) injection or drip is a common practice for freeze protection of wellbores and pipelines. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. Also, separators (used to separate liquids such as oil from the natural gas) may be filled with heated antifreeze to prevent freezing.

- Pigging refers to the practice of using pipeline inspection gauges or "pigs" inside a pipeline to perform various operations without stopping the flow of gas. Pigging operations are conducted on a year-round basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased to remove liquids that might be prone to freezing.

- Cold weather barriers are a relatively simple weather precaution involving the erection of wind walls around certain compressors to block cold winds that exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines and other locations may also help prevent freezing and the stoppage of fluid flow.

- Hauling oil and produced water from storage tanks is a necessary part of the production process, since tanks that are not emptied can trigger fail safe shut-in devices that will automatically shut down the well. Prior to cold weather, and in anticipation of trucks not being able to reach the facilities, the tanks may be emptied to reduce the likelihood of automatic shut-off.

- Heat can prevent freezing problems; if the gas is never allowed to reach freezing temperatures, ice cannot form. However, heat application involves expensive equipment and requires additional fuel. Heat is also a potential hazard as it can provide an ignition point for the gas. Nonetheless, heat systems can be very effective for a localized freezing problem, and include heating blankets, catalytic heaters, fuel line heaters, or steam systems. Coupling heat systems with insulation is a common technique for protecting flow lines in northern climates.

- Hot oil trucks may be utilized to thaw out flow lines. Typically the hot oil truck will be filled with water, which is then heated and directly sprayed onto lines at risk of freezing.

As it turned out, the various measures producers described as having employed to prepare for the projected cold weather proved inadequate; a substantial number of wells in the affected basins suffered freeze-offs, which had a significant effect on production during the February cold weather event.

## Processing Plants

Individual processing plants reported making anywhere from minimal to extensive preparations. Their winterization included:

- Making equipment checks;
- Adding 24-hour staff and adding to nighttime crews;
- Installing insulation;
- Confirming that heat trace equipment was operational;
- Placing tarps as wind breaks and to capture heat;
- Draining water from cooling systems and fluids from piping low points;
- Coordinating with upstream gathering;
- Reviewing past winter events; and
- Installing hot oil heaters.

A representative sampling of processing plant preparations follows.

The Crosstex Energy-affiliated Silver Creek natural gas processing plant in Weatherford, Texas processes Barnett Shale production from the Fort Worth Basin. In preparation for the weather event, operating personnel reportedly performed checks on all equipment, confirmed that all heat trace equipment was turned on prior to the storm, installed tarps on critical equipment, and drained all air supply low points. (Despite these precautions, the plant did experience a shut down of a steam boiler due to a freezing amine/water mixture.)

Enbridge Energy Company, Inc. operates processing plants in east Texas and in north Texas. Generally speaking, operations in both the east Texas and north Texas plants continued in a routine manner prior to the storm.

Energy Transfer Corporation (Energy Transfer) owns and operates the La Grange processing plant in east Texas and the Godley processing plant in north Texas. As part of its general preparation for cold weather at the La Grange plant, Energy Transfer wrapped air regulators and hung tarps around vessels. In late January, an extra operator was placed on duty. With regard to the Godley plant, Energy Transfer had previously installed louvers on all amine still overhead condensers[110] to assist in cold weather operations. A hot oil heater had also been installed in a still condenser to prevent freezing. In addition, prior to the February weather event, Energy Transfer insulated condenser piping at two plants.

[110] The term "amine still overhead condensers" refers to a piece of equipment used to remove the acid gases from the natural gas stream.

MarkWest Energy Partners has two processing plants in Texas. The company reported that both processing facilities are equipped to run during extreme cold weather and that no additional maintenance, insulation or heat tracing was performed prior to the February cold weather event.

Williams Midstream has four processing facilities, the Markham Cryogenic processing plant in Matagorda County, Texas; the Milagro treating plant in San Juan County, New Mexico; the William FS Kutz (Kutz) processing plant in San Juan County, New Mexico; and the Lybrook processing plant in Rio Arriba County, New Mexico. The company reported that the Milagro plant and related facilities are designed to operate in cold weather. Nevertheless, it is standard practice at the plant to check heat tracing controls and piping insulation in the fall months. For the February event, preparations consisted of round-the-clock staffing for certain facilities and adding staffing for the night crew. Standard winter preparation at the Kutz plant reportedly includes coordination with upstream gathering, draining of water cooling systems, placing catalytic heaters into service, installation of wind barriers and group review of past events. In January and February 2011, additional contractor personnel were provided for night operations and additional heat wagons were placed based on needs. The Lybrook plant had also addressed winter preparation prior to 2011 by upgrading and inspecting piping, tracing, and insulation, and by making repairs to hot oil pumps.

## Pipelines

Pipelines also prepared for the anticipated cold snap. Typical preparations for both interstate and most intrastate pipelines included:

- Maintaining higher than normal line pack;
- Optimizing compressor operations;
- Enhancing internal communication such as cold weather operational meetings;
- Increasing availability of personnel;
- Cancelling scheduled maintenance where possible; and
- Communicating with customers.

### Interstate Pipelines

Individual interstate pipelines reportedly took the following preparations:

EL Paso prepared for the forecasted colder weather by maintaining higher than normal line pack throughout the weekend of January 29 and January 30. (El

Paso considers line pack volumes between 7,200 MMcf and 7,800 MMcf at any given point in time to be in the normal range; at line pack quantities below 7,200 MMcf or above 7,900 MMcf, El Paso generally considers its system to be at or approaching stressed operational conditions.) On Monday afternoon, January 31, El Paso began gas withdrawals from its Washington Ranch Storage Facility, reaching the field's maximum withdrawal rate by the morning of February 1. This was done to compensate for gas supply underperformance in the San Juan and Permian Basins.

Natural Gas Pipeline Company of America (NGPL) uses its Texas facilities to receive gas in Texas and redeliver that gas to markets in the upper Midwest. For February 1 through February 3, NGPL put in place a severe weather operating procedure that provided for management of cold, high winds, ice and snow. This procedure included conferences and communications involving the managers of the gas control and commercial groups of impacted NGPL facilities. Additional actions reportedly taken by the gas control group included adjusting pipeline pressures to meet anticipated load increases, manning facilities on an around-the-clock basis, and carrying out operating procedures designed to keep facilities from freezing.

Transwestern began operating its compression stations to maximize pressures in New Mexico in advance of the cold weather event.

ANR Pipeline Company (ANR) has no facilities in New Mexico, Arizona or California, and only limited facilities in Texas, which are located in the northeast corner of the Texas panhandle (this is the southern-most part of ANR's Southwest Area). To prepare for and respond to operating concerns and ongoing and expected weather events, ANR conducted daily morning operations meetings. An additional "cold weather" operational meeting specifically addressed the week of February 1. ANR reported reduced horsepower at all its Southwest Mainline compressor stations to help flow gas south into the Texas area if scheduled supply decreased, with the aim of maintaining adequate line pack and constant pressures in Texas and Oklahoma.

**Intrastate Pipelines**

Intrastate pipelines in general employed many of the same preparations as did the interstate pipelines. Reported examples are provided below.

Atmos Pipeline –Texas began building line pack on January 31, and advised shippers to be in hourly and daily balance effective 9:00 AM on February 1. This action assisted with maintaining line pack. Electric generation customers were advised that deliveries would be limited to Tier 3[111] beginning at 9:00 AM on February 1. Third-party interruptible storage customers were advised that they would be limited to 50 percent withdrawals effective February 1 at 9:00 AM.

Energy Transfer Partners reported ensuring that critical stations were staffed, spare compressors were placed on standby, line pack was increased, and all scheduled maintenance was postponed.

Enterprise Products Partners reported closely monitoring nominations. Staffing coverage was extended in addition to employees' normal schedules. Operations were also reviewed for potential service adjustments that might be required, although none were anticipated.

The Kinder Morgan Texas Pipes' natural gas pipeline operations and gas control group initiated the Kinder Morgan Gas Pipelines' severe weather operating procedure, designed to manage facilities in the event of severe cold, high winds and frozen precipitation. The procedure prescribes conferences and communications among managers and the gas control and commercial groups, and these communications began several days prior to the cold weather event. The gas control group also adjusted pipeline pressures in anticipation of increased load. In the field, some facilities were reportedly staffed around-the-clock, and procedures were put in place to keep facilities from freezing.

**Local Distribution Companies**

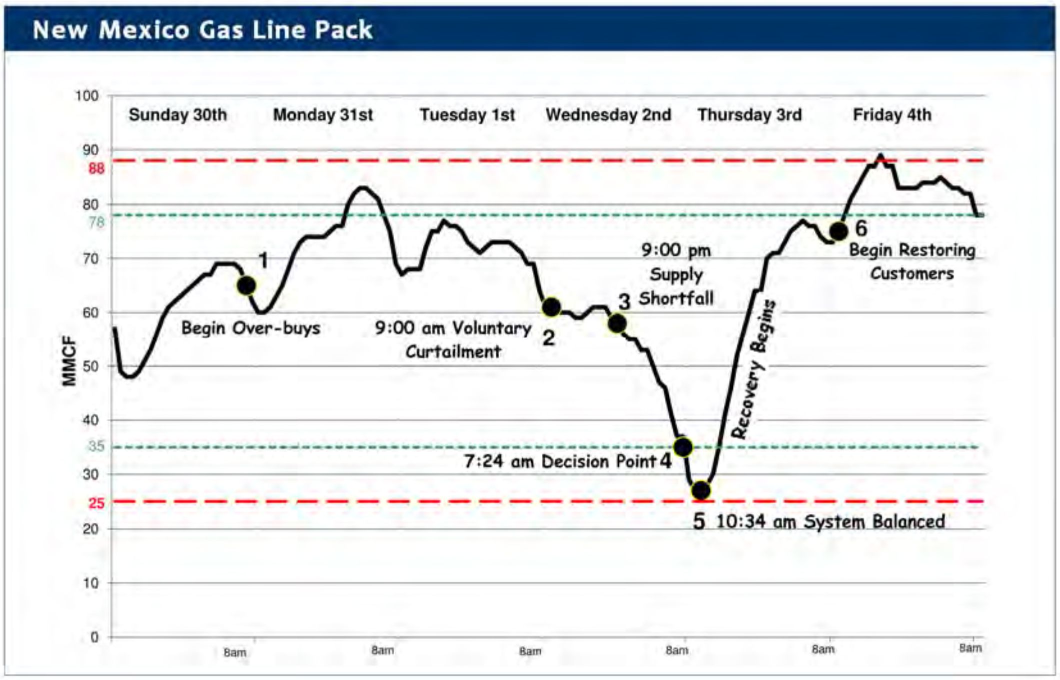
Each of the four LDCs that curtailed customers during the February weather event reported making preparations. They monitored weather forecasts before the event and revised their load forecasts upward. They also increased their purchases of gas to accommodate increased demand and to compensate for freeze-offs, and communicated with suppliers and the pipelines about pending conditions. As conditions worsened, these communications became more frequent.

New Mexico Gas Company packed transmission lines with extra gas, and confirmed that the storage facility it accesses was positioned for withdrawals. Additional gas was purchased for the expected increased demand and in anticipation of freeze-offs. From February 1 through February 3, NMGC had, for each respective day, pre-purchased 36 percent, 55 percent, and 62 percent more gas than its forecasted need. NMGC issued an Alert to all transportation customers concerning the weather forecasts. Given the severity of the anticipated

[111] Tier 3 restrictions applying to electric generating units limit the amount of natural gas the units can take.

storm, at 9:00 AM on February 2, NMGC began requesting that large industrial and commercial customers throughout the state voluntarily reduce or curtail their gas usage. In total, NMGC reported contacting 39 customers, asking for voluntary curtailment.

The following is a chart of NMGC's line pack, juxtaposed with its preparation events.




**Source: New Mexico Gas Company**

Southwest Gas monitored current weather forecasts on January 30 and January 31, which indicated colder temperatures were expected for southern Arizona. On February 1, a scheduled meeting of engineering and technical services personnel was expanded to include discussions concerning cold weather preparations and system monitoring.

Zia Natural Gas Company (Zia), after observing the dramatically dropping temperatures forecasted for February 1 through February 4 for the state of New Mexico, contacted its primary supplier on January 30 to discuss its supply and receipt options. On February 1, Zia discussed maximum volumes that could be nominated on its pipeline transportation contract.

**This page intentionally left blank.**

# V. The Event: Load Shed and Curtailments

When the storm hit the Southwest on February 1, both electric and natural gas facilities began experiencing outages and other production difficulties. These difficulties escalated and ultimately led to load shedding by three electric balancing authorities and service curtailments by four gas LDCs, beginning on February 2. The unfolding events that led to these disruptions, and the conduct of the load shedding and curtailments, are described in this section.

## A. Electric

ERCOT, SRP and EPE all engaged in load shedding during the cold weather event. Other electric entities in the area, although they experienced generation losses, were able to avoid load shedding (with the exception of PNM, which experienced some small, localized load loss from transmission issues). Each affected utility's actions are discussed separately below. (All times referenced are expressed in local time.)

### ERCOT

ERCOT's required responsive reserve level is 2300 MW.[112] This is the amount that ERCOT has determined to be necessary on its system to ensure that the system will maintain frequency and voltage stability; that thermal and voltage limits will remain within applicable ratings; and that there will be no loss of demand, curtailment of firm transfers, or cascading outages.[113] If reserves drop below specified amounts, ERCOT is required by its Protocols to take actions to bring them up again, including the shedding of load.

ERCOT has specified in its Protocols certain triggering events that require taking action to prevent the uncontrolled loss of firm load. In doing so, it has patterned its emergency alert protocol on the Reliability Standard that prescribes

---

[112] As discussed in the section of this report entitled "Preparations for the Storm," this amount was based on a 1988 study designed to determine the amount of reserves needed to prevent shedding of firm load if ERCOT's two largest contingencies occurred.

[113] This minimum level of reserves is based on an N-2 criterion, a more conservative requirement than that required by the FERC-approved Reliability Standard BAL-002-0 R3.1, which requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." ERCOT's N-1 largest single contingency would be the loss of a nuclear-powered generating unit at the South Texas Nuclear Project, rated at 1354 MW.

an energy emergency alert procedure.[114] Both the Reliability Standard and the ERCOT Protocol categorize these triggering events into three levels, Levels 1, 2, and 3; ERCOT further subdivides Level 2 into 2A and 2B.

ERCOT had to make decisions throughout the morning of February 2 regarding the declaration of these various emergency alert levels and actions. That was particularly so with respect to Level 3, which requires the shedding of firm load.

***Energy Emergency Alerts***

Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's reliability coordinator, and are categorized by level of severity:

- EEA 1 - For conditions where all available resources are committed to meet firm load and reserves, all non-firm sales have been curtailed, and the entity is still concerned about sustaining its operating reserves.

- EEA 2 - For conditions when the entity is no longer able to meet expected energy requirements, and is designated an Energy Deficient Entity.

  The entity is to do the following, as time permits:

  Public appeals to reduce demand,
  Voltage reduction,
  Interruption of non-firm loads,
  Demand-side management, and
  Utility load conservation measures.

  Other entities are to provide emergency assistance as appropriate and available.

- EEA 3 - For conditions when the energy available to the Energy Deficient Entity is only accessible with actions taken to increase transmission transfer capabilities.

  At this point, firm load interruption is imminent or in progress.

(cont'd)

[114] *See* Reliability Standard EOP-002-2.1 (Capacity and Energy Emergencies).

**ERCOT:**

ERCOT has particularized this emergency energy alert system to the requirements of its own system. It is required under its Protocols to perform certain actions upon the occurrence of distinct triggering events. These are as follows:

Level / Triggering Event / System Operations Actions

- EEA 1 — Less than 2300 MW of Reserves:
  Use capacity available from DC ties, dispatch uncommitted units.

- EEA 2A — Less than 1750 MW of Reserves:
  Deploy Load Resources (LR); begin block-load transfers of load to neighboring grids.

- EEA 2B — To maintain system frequency at 60 Hz or reserves trending downward or not available:
  Deploy Emergency Interruptible Loads (EILS) if available.

- EEA 3 — To maintain system frequency at 59.8 Hz or greater:
  Instruct transmission operators to shed load via rotating outages in blocks of 100 MW.

As discussed in the preceding section of this report, "Preparations for the Storm," severe weather conditions on February 1 precipitated numerous forced generator outages within ERCOT's footprint. By midnight on February 1, 6022 MW of generation capacity was unavailable due to weather-related forced outages and derates, and conditions worsened overnight.

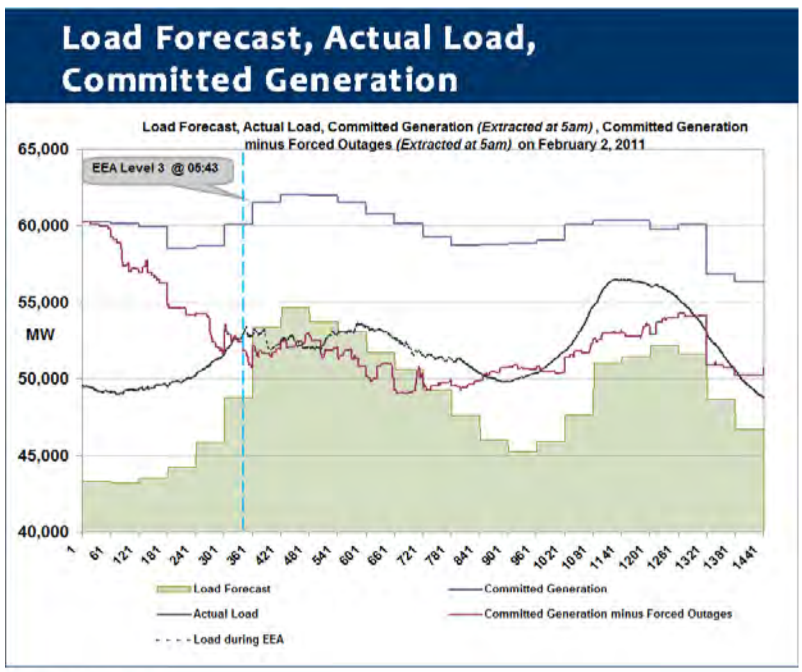
Generation Shortfalls on February 2

By 3:00 AM on February 2, responsive reserves had dropped below 3000 MW. ERCOT issued both an OCN and an Advisory to market participants, notifying them of the severe weather and the falling reserve level.[115] It followed this communication with an emailed report to the PUCT about the falling reserves.

[115] The communication steps taken by ERCOT appear to be consistent with its Operating Guidelines and Protocols. However, a number of transmission providers have stated they could have been better prepared to implement their required load shed if they had had more information about ERCOT's deteriorating system status much earlier during the overnight period of February

At 4:30 AM, ERCOT operators instructed deployment of 1840 MW of non-spinning reserves, principally combustion turbines. (Non-spinning reserves require 30 minutes or longer to come on-line or to ramp up to their next block of power output.) Ten of the units, or a total of 669 MW of capacity, were unable to respond, many because they failed to start. By 5:08 AM, reserves had dropped below 2500 MW, and ERCOT issued a Watch.

ERCOT calculates its operating reserves on a real-time basis by comparing metered demand with its available generation resources. At the same time generation was dropping off during the morning of February 2, demand was rising. The cold weather and winds were placing extraordinary demands for power on the system, and load was running consistently higher than had been forecasted for the day. In fact, at 5:20 AM the demand was 2760 MW higher than on any other day in the history of the ERCOT region at that hour, and was rapidly climbing.[116] The following chart, prepared by TRE, compares actual demand with forecasted demand.




Source: TRE

The actual peak demand for the day, which typically occurs in the morning around 8:00 AM, was artificially skewed downward because of the load shed. The

1 to February 2. They would have liked to have received such information as soon as ERCOT began seeing a high number of forced generator outages.

116 Potomac Economics, Ltd., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, at 3 (April 21, 2011) (Potomac Report), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf.

IMM (Potomac Economics, Ltd.), the market monitor for ERCOT, estimated that the demand that would have materialized absent any load reductions or curtailments would have peaked at 59,000 MW, just after 7:00 AM.[117] This estimate suggests that the high demands already being placed on the system in the early morning hours would likely have continued to escalate.

At 5:09 AM, reserves dropped below 2300 MW, the triggering event for ERCOT's declaration of an EEA 1 (although it was not declared, presumably because events were moving so swiftly). At 5:20 AM, responsive reserves had dropped below 1750 MW, and ERCOT issued an EEA 2A. It also deployed 888.5 MW of Load Resources, with 881.7 MW responding. Load Resources are counted as responsive reserves and, as such, their deployment reduces ERCOT's responsive capability. In this case, however, two factors worked to offset this reduction:

- The dropping of 881.7 MW of load increased the margin between generation and load, and ERCOT allowed a fraction of this increase to be allocated to responsive reserves. (The fraction ERCOT allots is typically 20 percent, but varies based on the specific generation online at any given time.)

- The Load Resources were being deployed over a 10-minute interval during which some additional generation was actually coming online, despite all the problems on the system.

As a result of these factors, for a short time while Load Resources were being deployed, responsive reserves actually increased by about 200 MW. It was not long, however, before additional forced outages and derates of generation, combined with the normal pick-up of morning demand, again decreased the level of responsive reserves.[118]

At 5:26 AM, ERCOT deployed RRS reserves, a form of interruptible load, which briefly raised the reserve level to above 1400 MW.

---

[117] Potomac Report at 3-5. The estimate was based on several factors, including the actual load and rate of load increase prior to the implementation of the first load curtailments, the load shape on similar days, and ERCOT load forecasts produced just after 3:00 AM on the morning of February 2.

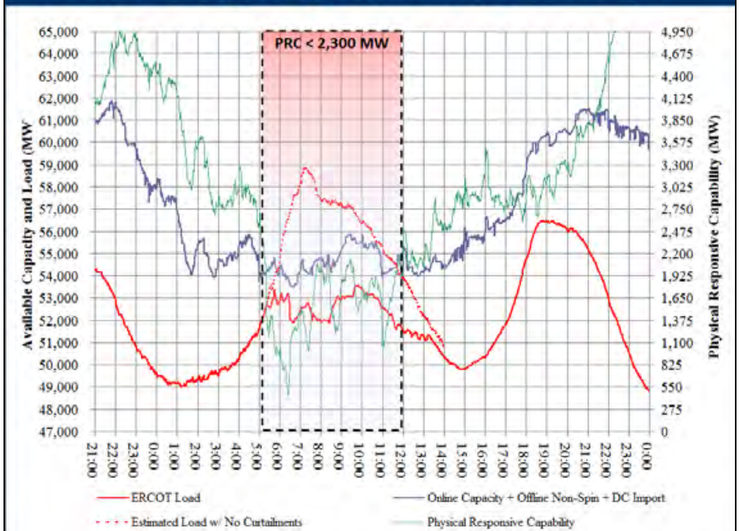
[118] Responsive reserves would ultimately fall to a low point of 447 MW at 6:25 AM, after the load shed had already begun.

More units, however, continued to trip off-line. Responsive reserves briefly dipped below 1354 MW (the N-1 contingency reserve level required for safe operation of the system) twice before 5:40 AM. At that time, the responsive reserves dropped below the N-1 contingency level for an extended 73 minute period.[119]

At 5:43 AM, ERCOT declared an EEA 3 and began the process of shedding load.

The following graph[120] indicates the relationship between ERCOT's available capacity, loads and reserves throughout the day.

**Available Capacity, Load and Reserves**




Source: IMM Report of April 21, 2011 (Potomac Economics, Ltd.)

Counting both February 1 and February 2, a total of 193 generating units in ERCOT tripped, had derates, or failed to start, representing a loss of 29,729 MW of capacity.[121] At the lowest point of available generation, which occurred at 6:12

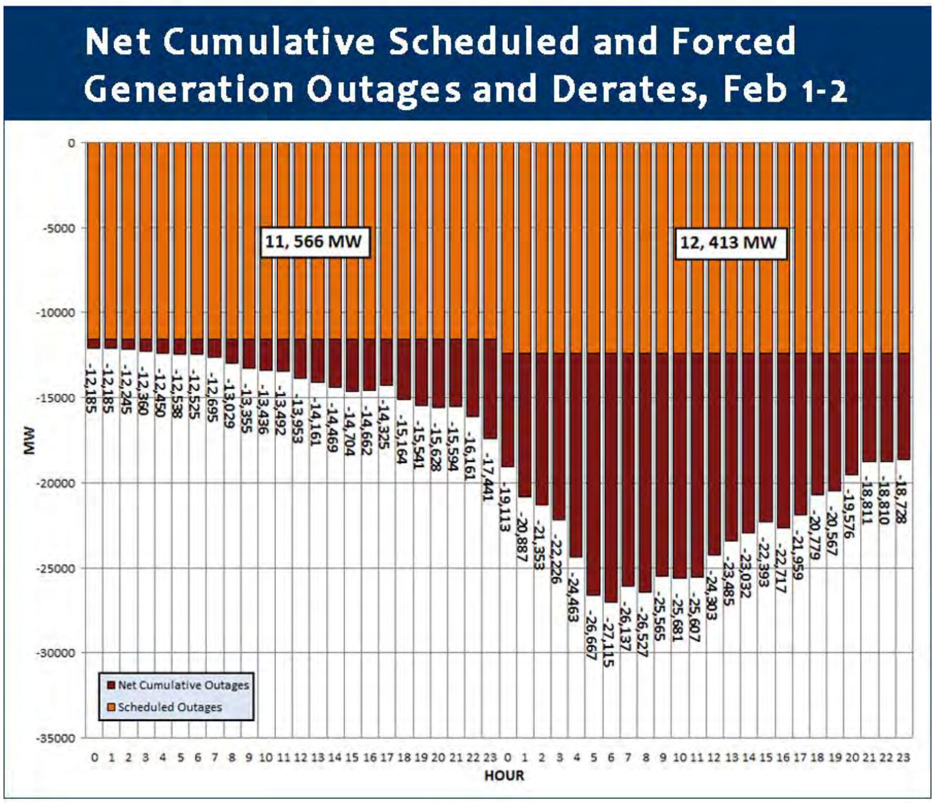
[119] There were six times during the morning of February 2 when ERCOT's response reserves fell below 1354 MW. Those times are: 5:23-5:29 AM, 5:31-5:32 AM, 5:40-6:52 AM, 7:11-7:30 AM, 8:39-8:52 AM, and 10:58-11:15 AM, for a total of two hours and 14 minutes, with the longest interval 73 minutes. (Calculation of the time periods includes the beginning and ending minutes.)

[120] Potomac Report at 6.

[121] This is a gross cumulative number; a unit is counted as having failed regardless of whether it came back online at some point during the event. This measurement gives an

AM, there were 14,702 MW of generation offline from such trips, derates, or failures to start. Adding that number to the scheduled outages for the day of 12,413 MW, means that 27,115 MW, or approximately one-third of the total ERCOT fleet, was unavailable to provide power.

The following two charts depict the net and gross cumulative capacity reduction resulting from forced outages, derates, and failures to start, as added to the scheduled outages, for these two days.[122] Comparing these numbers to total ERCOT generation of approximately 79,700 MW[123] gives a picture of the magnitude of the generation loss, as well as of the difficulties that confronted ERCOT's operators on those two days.

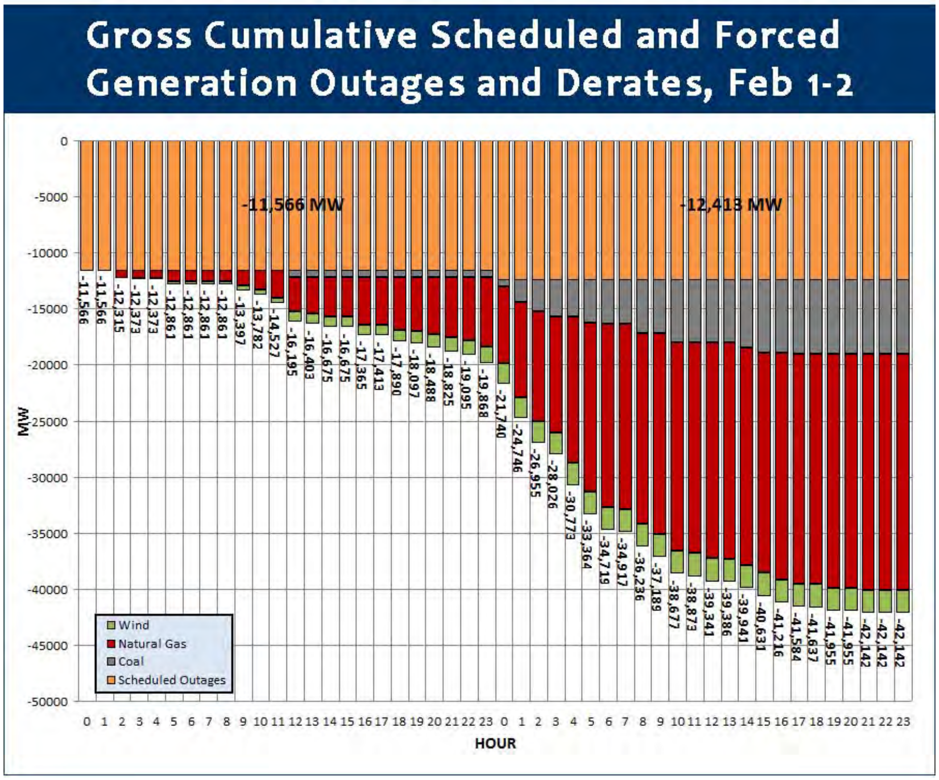



---

indication of the total amount of capacity that failed during the event (rather than the amount offline at any given point in time).

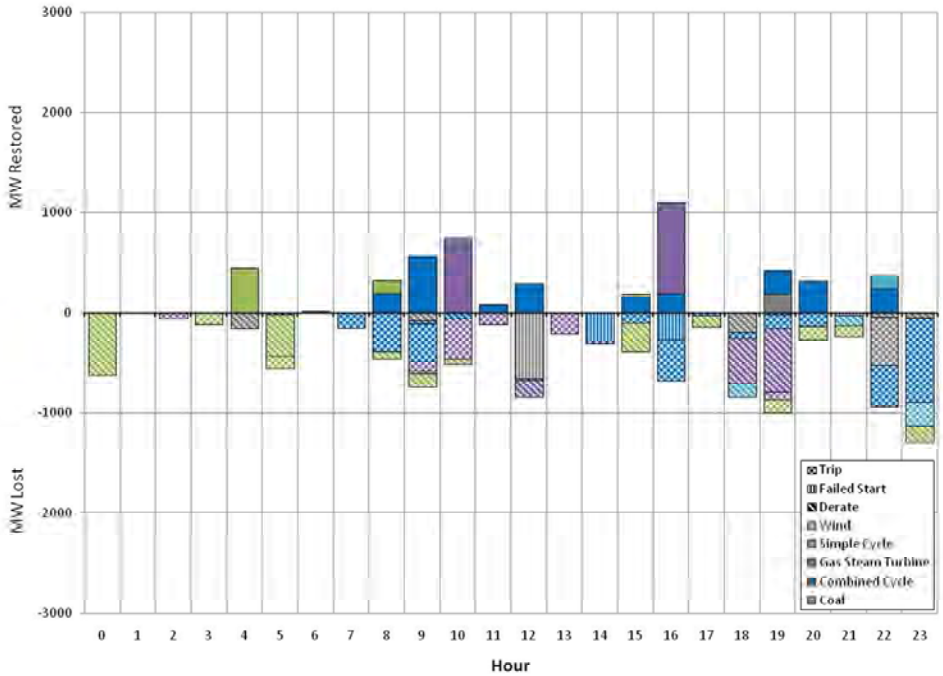
[122] The first chart depicts net outages after subtracting out units that came back online. The second chart shows cumulative outages with no adjustment for units that came back online.

[123] The 79,700 MW number represents total ERCOT fleet capacity, online and offline, measured at 8:00 AM on February 2 (it does not include imports over the DC ties). The wind power capacity embedded in that number, as well as in the capacity reductions for the outages, derates, and failures to start, has been adjusted to reflect the actual hourly wind speed conditions (in lieu of using straight "nameplate" values which pertain only to optimum wind speeds that produce full rated output).

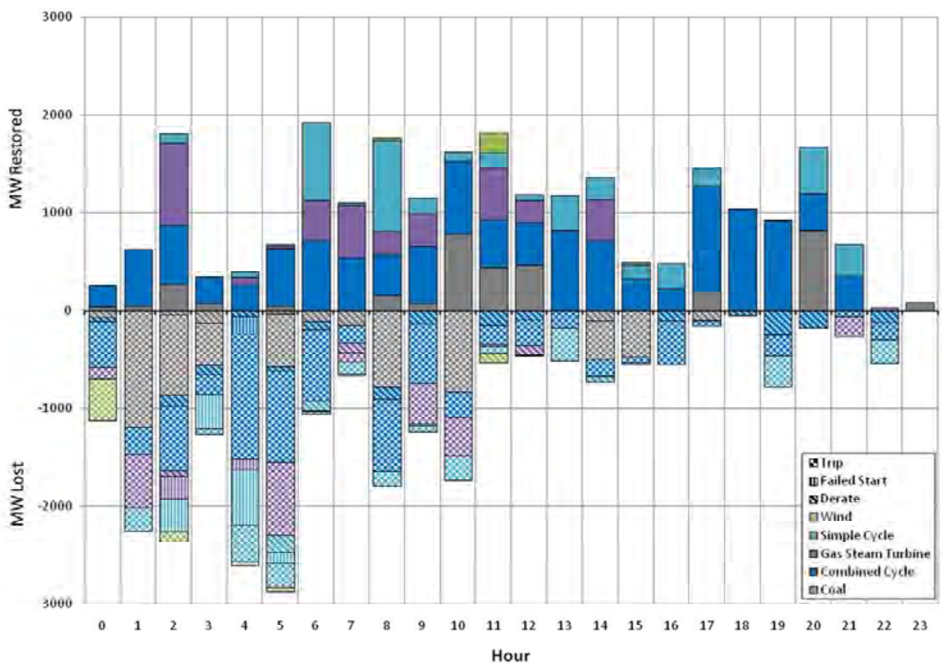



The task force has also prepared charts for February 1 and February 2 that depict, hour by hour, the MWs that failed and the MWs that were restored, both by fuel type and by type of failure (trip, derate, or failure to start). These charts give a running picture of the fluctuations in available capacity, by fuel type, at any given point in time throughout the event.

Capacity Fluctuations by Fuel Type on Feb. 1, 2011




Capacity Fluctuations by Fuel Type on Feb. 2, 2011




The various reasons for the outages, derates and failures to start that occurred during the event (the majority of which were weather-related, either directly or indirectly) are discussed in the following section of this report entitled "Causes of the Outages and Supply Disruptions."

***Adjusted Wind Power Capacity***

The capacity of a wind power installation is typically reported on a "nameplate" basis, with the nameplate value representing what the facility can produce when the actual wind speed is optimum for the particular turbine design. When a wind farm is offline on a scheduled or forced outage, the capacity unavailable to the system is also typically reported on a nameplate basis; the same is true for partial outages, which are reported as derates (collectively, nameplate outage value).

The actual wind speed, however, is seldom sufficient to produce full nameplate output simultaneously throughout ERCOT. Therefore, the nameplate outage values must be adjusted downward to realistically represent the impact of outages and derates of individual wind facilities.

Adjusted Outages and Derates

The total installed wind power nameplate capacity in ERCOT is 9321 MW**.** If the aggregate nameplate outage values reported during February 1 and February 2 are subtracted from this 9321 MW total, nameplate available values are obtained on an hourly basis. Dividing the actual measured aggregate wind power output for any given hour by the nameplate available value for the same hour produces a percentage output that reflects how strongly the wind is blowing compared to full-output levels. Over the course of February 1 through February 2, that percentage varied from 40 to 75 percent (which is atypically high). To determine adjusted outage values, the percentage for any given hour is applied to the nameplate outage value for that same hour. For example, if the reported nameplate outage value for the 5:00 AM hour was 3200 MW, and the percentage output was 50 percent, the adjusted outage value is 1600 MW. This value more realistically represents the additional wind power that would have been supplied to the ERCOT grid had it not been for the wind farm outages and derates.

Although this method does not take into account the fact that the wind speed at a specific location where a forced outage has occurred may or may not correlate with the average value, any errors at individual locations should tend to offset one another. The method also assumes that the reports of forced outages and derates were made on a timely basis, which may or may not have been the case.

(cont'd)

Adjusted Capacity

NERC used 8.7 percent of nameplate capacity in calculating the contribution of wind power to existing generation in its 2010-2011 Winter Assessment of the TRE region. This is a planning number that has merit for the seasonal overview, but is not applicable to the high wind conditions of February 1through February 2. Therefore, in determining the wind power capacity in ERCOT for purposes of this inquiry, the task force multiplied the total installed capacity of 9321 MW by the percentage of output actually achieved by those facilities that remained in service, compared to nameplate capacity. The resulting adjusted capacity represents what the total wind power output would have been in ERCOT had there not been any outages or derates during February 1 through February 2. Since the percentage varies with the wind speed, adjusted capacity values were calculated hourly. At 8:00 AM on February 2, the percentage of output vs. nameplate was 57 percent, yielding an adjusted capacity of 5313 MW (0.57 x 9321 MW). This number was then used as wind power's contribution to the total generation fleet. Counting all units, both online and off, that total came to 79,658 MW for the 8:00 AM hour. (Since the adjusted capacity value changes hourly based on wind speed, so too will the numerical size, in MWs, of the total generation fleet.)

The Load Shed Decision

Load shedding is implemented to correct an electrical power imbalance if load exceeds supply and system operators cannot bring the system back into balance through other measures. Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to recover from an under-frequency condition, or to return voltage to a normal level. The operation can be manual (operator-initiated) or automatic (relay- initiated), depending on how quickly the frequency is decaying or the voltage is falling. For slowly declining frequency or voltage issues, the manual option is usually chosen. For rapidly declining frequency or voltage, the automatic option will respond without operator intervention.

ERCOT utilized operator-initiated load shedding on February 2, which preserved the system's ability to implement automatic load shedding had system conditions continued to deteriorate. Had ERCOT not instituted manual load shedding, automatic under-frequency load shedding would have been a last resort before a possible system collapse. Manual load shedding also helped raise the frequency levels, preventing damage to generator turbines.

The task force considered the question of whether ERCOT's decision to manually shed load prevented more extensive blackouts than were experienced as a result of the load shed itself. While a definitive answer would require extensive modeling and data inputs, the task force concluded, based on the information available, that ERCOT's declaration of an EEA 3 probably prevented widespread, uncontrolled blackouts throughout the ERCOT Interconnection. Because ERCOT operates as a functionally separate interconnection from its neighboring Eastern and Western Interconnections and is linked only by asynchronous ties, the blackouts would not have propagated further.[124]

***Frequency Response and Automatic Under-Frequency Load Shedding***

Frequency as a measure of the reliability status of a power system can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the overall integrity of operations. Maintaining frequency requires balancing a system's aggregate generation output to load moment-to-moment. It also requires having sufficient reserves available at all times to withstand the sudden loss of the largest generator on the system, in order to instantaneously make up for the loss of power and thus reestablish balance.

In spite of the enormous amount of generation that was forced off line in successive waves in ERCOT on February 1 and February 2, especially during the overnight and early morning hours between the two days, the overall frequency response of the system was not problematic during the event. Nonetheless, the need to maintain frequency to prevent a collapse of the system was the fundamental driving force behind ERCOT's decision to shed firm load.

Because ERCOT is not synchronously connected to either the Eastern or Western Interconnections, all frequency response must come from internal resources. And because ERCOT is smaller than the other interconnections, the loss of a generator results in a steeper frequency decline, necessitating a more robust frequency response. For this reason, in 1988 ERCOT established a minimum responsive reserve requirement of 2300 MW, based on an N-2 criterion covering the loss of the two largest generators in ERCOT (one nuclear-powered unit and the next largest unit on the system). This is a larger reserve than the N-1 criterion required by Reliability Standard BAL-002-0 R3.1. On the morning of

(cont'd)

[124] NERC has prepared a study on the reliability implications of the February cold weather event entitled "Analyses of Reliability Impacts on the Bulk Power System." The study discusses the impacts on the WECC Interconnection of the events in SRP, EPE, and PNM, and presents an analysis of frequency response performance during the event by the Eastern Interconnection and the ERCOT Interconnection. NERC plans to make the study publicly available.

February 2, 2011, the largest single contingency was an online nuclear-powered generating unit with a capability of 1354 MW.

ERCOT maintains and closely monitors its responsive reserve levels (also referred to by ERCOT as its Physical Response Capability, or PRC), to comply both with its own 2300 MW criterion and with the 1354 MW minimum criterion.

ERCOT relies on demand side load resources to provide up to 50 percent (1150 MW) of its 2300 MW responsive reserve requirement. These resources automatically disconnect when the frequency declines to 59.7 Hz. The purpose of the responsive reserves, both generation and load, is to arrest frequency declines before they reach 59.3 Hz (the trigger threshold for the first block of automatic under-frequency load shedding (UFLS)), and to restore frequency to 60 Hz within a few minutes following an event. Should either generation or load resources be deployed manually by system operators, they are no longer available to provide frequency response.

Between 5:15 AM and 1:20 PM on February 2, responsive reserves dropped below the 2300 MW N-2 criterion three separate times, of varying durations. Ultimately, responsive reserves dropped below the 1354 MW N-1 criterion. This occurred six separate times between 5:23 AM and 11:15 AM, for a combined total of 134 minutes, with the longest interval being 73 minutes. During the times when responsive reserves were below 1354 MW, had the largest generator tripped, reserves would have been insufficient to reestablish the balance between generation and load. The result would have been an inexorable decline in frequency which, when it reached 59.3 Hz per second, would have triggered the first block of automatic under-frequency load shedding, which would have dropped five percent of the system load, or roughly 2600 MW.

Even though the under-frequency load shedding would have tripped automatically, this response would have taken out firm load and would be in addition to any firm load that operators may have already shed, starting with the first directive ERCOT issued at 5:43 AM. Depending on the particular circumstances surrounding the moment of activation of the automatic under-frequency load shedding, it is possible that an overvoltage condition could have occurred in one or more localized areas, that frequency could have significantly overshot the 60 Hz norm, or that other electrical perturbations could have developed that would have resulted in the tripping of even more generation. Only a detailed dynamic simulation could answer the question as to how widespread the February 2 blackout would have been had the automatic under-frequency load shedding been triggered.

*ERCOT's Black Start Capability*

If the load shed had not prevented an ERCOT-wide blackout, the outages would not only have been more widespread, they might have been of a much longer duration. The task force reviewed the state of ERCOT's black start units to determine whether they could have promptly brought the system back had a collapse occurred. "Black start" refers to restarting the system after a major portion of the electrical network has been de-energized, and generators that have black start capability are those that can be started independently and without external power.

ERCOT has 15 primary and six alternate black start generators. During the event, roughly half of these generators were unavailable: two (totaling 97 MW of capacity) were on planned outage; four (totaling 141 MW) failed to start due to the extreme cold weather; three (totaling 423 MW) tripped offline after starting due to freezing equipment; and one (26 MW) tripped offline due to natural gas fuel curtailment. Had a total blackout of the ERCOT system occurred, the unavailability of 10 of ERCOT's 21 (primary and alternate) black start resources, comprising 687 MW out of a total 1150 MW of black start capacity, could have jeopardized ERCOT's ability to promptly restore the system.

The Load Shed Process

ERCOT accomplishes a controlled load shed by issuing directives to its transmission providers,[125] ordering the load shed to proceed in defined blocks of power (each transmission provider being responsible for its allocated share of the total). On February 2, ERCOT issued its first load shed directive at 5:43 AM and its third and last at 6:23 AM. In total, it directed that 4000 MW be shed.

ERCOT began load restoration at 7:57 AM, and firm load was fully restored at 1:07 PM.

[125] "Transmission provider" is a generic term. ERCOT uses "transmission service provider" to mean an entity that owns or operates transmission facilities to transmit electricity and provide transmission service on the ERCOT grid. NERC uses different terminology to describe the various types of transmission providers, including "transmission service provider," "transmission operator," and "transmission owner." (The definitions of these terms can be found in the appendix entitled "Categories of NERC Registered Entities.") Under NERC terminology, ERCOT is the only "transmission service provider" for its Interconnection. To avoid confusion, the term "transmission provider" will be generally used in the narrative portions of this report to refer to any of those various categories of entities who provide transmission service and who were directed to shed load and took the necessary actions to do so ( including load shedding both within and outside of ERCOT).

The actual load shed process and eventual restoration of the system to an EEA 0 state[126] proceeded as follows:

ERCOT issued its first instruction at 5:43 AM, ordering a load shed of 1000 MW. Shortly thereafter, ERCOT also deployed 384.2 MW of Emergency Interruptible Load Service, ERCOT's form of demand response.[127]

At 6:04 AM ERCOT directed the transmission providers to shed an additional 1000 MW of load. In the next second, 6:05 AM, ERCOT's frequency dropped to 59.576 Hz, its lowest point during the event.

At 6:23 AM ERCOT issued its third and last load shed directive, directing the transmission providers to shed an additional 2000 MW. This resulted in a total load shed directive of 4000 MW.

As the transmission providers were implementing ERCOT's directives to shed load, additional generation became unavailable; between 5:45 and 6:30 AM, 18 generating units tripped offline, were derated, or failed to start, totaling 1643 MW of output. (During this same time, 12 units came back online, totaling 774 MW.)

At 6:25 AM, ERCOT's reserve level dipped to 447 MW, its lowest point of the day.

At 6:59 AM, ERCOT issued a media appeal for energy conservation. This was the first notification to the public of the problems ERCOT was experiencing on its system.[128]

At 7:57 AM, ERCOT issued its first load restoration directive, beginning with a 500 MW block. Three seconds later, a combined cycle unit loaded at 77

[126] "EEA 0" signifies a normal state of operation.

[127] While some EILS customers failed to reduce load as contracted (thus exposing themselves to potential penalties), others responded with a load reduction in excess of their contracted amount. The net result was that total EILS load reduction fell short of obligated levels on February 2 in only one fifteen-minute interval.

[128] ERCOT has acknowledged that it could improve its communications with the general public, which it suggests could be accomplished through use of an automated system for contacting the media, deployment of representatives to meet with the media, and through designation of supplemental communications staff to answer phone inquiries during a period of emergency.

MW tripped offline, causing reserve levels to again fall below 1354 MW. However, ERCOT did not shed any additional load.

At 8:22 AM, ERCOT directed the transmission providers to restore another 500 MW block of shed load. ERCOT would issue six more load restoration directives over the course of the next several hours, completing the process at 1:07 PM.[129]

At 8:53 AM, ERCOT deployed an additional 83.5 MW of EILS, at which point reserves increased above the 1354 MW limit.

At 9:25 AM, ERCOT called all QSEs and instructed them not to take any resources offline unless so instructed.

Additional units, including an 849 MW coal unit, continued to trip offline. At 10:58 AM, reserves again dropped below the 1354 MW limit. This situation lasted until 11:15 AM.

At 12:12 PM, ERCOT reported to the QSEs that the Texas Commission on Environmental Quality (TCEQ) had issued a waiver for certain air permitting requirements that might otherwise have prevented generators from producing power during the emergency. (The TCEQ's actual communication did not mention a waiver, but rather indicated it would exercise its "enforcement discretion.")

At 1:57 PM, ERCOT recalled RRS Block 2 Load Resources (463 MW).

At 2:01 PM, ERCOT returned to a state of EEA 2B.

At 2:55 PM, ERCOT recalled RRS Block 1 Load Resources (437 MW).

At 3:14 PM, ERCOT returned to a state of EEA 2A. Reserve levels rose to approximately 2900 MW.

At 7:15 PM, ERCOT set a record winter peak demand of 56,480 MW.

On February 3, at 10:00 AM, ERCOT declared a state of EEA 0 and recalled all EILS loads.

[129] Directives were issued in 500 MW blocks at 9:25 AM, 11:39 AM, 12:04 PM, 12:25 PM, 12:49 PM, and 1:07 PM.

Summing every transmission provider's peak load shed amount (which did not occur at the same time), the cumulative load shed on February 2 was 5411.6 MW. The largest amount of load shed at one point in time (8:02 AM) was 4947.9 MW.[130]

The load shed process by ERCOT's transmission providers is discussed below.

Conduct of the Load Shed by ERCOT's Transmission Providers

ERCOT communicated its oral dispatch instructions to shed load via hotline calls. The percentage of the total requirement that is to be shed by each transmission provider is based on the transmission provider's previous year peak load, as reported to ERCOT.[131] Under ERCOT's Nodal Operating Guides, transmission providers have 30 minutes to shed their required share of load if the curtailment is implemented remotely by SCADA system, and one hour if implemented by dispatch of personnel into the field to manually disconnect feeders.[132]

*Load Shed Program Design*

Each transmission provider in ERCOT is responsible for determining how load will be shed in order to meet its load shed obligation.[133] The larger transmission providers interviewed by the task force make use of automated systems for shedding load. All transmission providers interviewed pre-designated feeders or blocks that are available for manual load shed. Transmission providers generally take into account the following factors in setting up their load shed system:

[130] Based on TRE data supplied to the task force. (This number does not include Greenville, for which comparable data was not available. Adding 8.8 MW for Greenville would bring the total to 4956.7 MW).

[131] See ERCOT Nodal Operating Guides: Emergency Operation § 4.5.3(5) (July 1, 2011), *available at* http://www.ercot.com/mktrules/guides/noperating/cur.

[132] *Id.* at § 4.5.3(7)(a)-(b). These time frames do not apply if the load shed directive exceeds 1000 MW, as was the case for ERCOT's last load shed instruction on Feb. 2, 2011. *Id*. at § 4.5.3(7)(c).

[133] Actual implementation of load shedding is carried out at the distribution level, which may be done through a separate division of the transmission provider or through a separate, affiliated entity (*e.g.,* a member distribution cooperative of a generation and transmission cooperative). This extra layer of communication appears to have caused some delay in the initiation of the load shed process in at least some cases.

1. Minimizing customer disruptions through target outage rotation periods. Transmission providers interviewed utilize a load-shed scheme with a targeted rotation period between 15 minutes at the low end and 30-45 minutes at the high end. During the February 2 event, transmission providers reported difficulties maintaining a short (15-minute) rotation period over the course of the morning, as ERCOT raised their load shed obligation to the highest levels most transmission providers had experienced. Transmission providers reported having to go through their rotation schedule multiple times, and some transmission providers expressed concern that a limited number of customer groups had to carry a disproportionate amount of the load-shed burden.[134]

2. Avoidance of feeders or lines reserved for under-frequency load shedding (UFLS) requirements. All transmission providers interviewed indicated that UFLS blocks[135] are not generally included as available feeders for manual load shedding under their load shed procedures. However, one transmission provider discovered during the February 2 load shed event that some lines designated as available for manual load shed were also designated for UFLS. Except for this one overlap in blocks, the transmission providers interviewed were able to fully meet their load-shedding obligations while maintaining the required 25 percent of load reserved for UFLS. There were no reported instances of automatic under-frequency trips during the February 2 event.

3. Exemptions for critical customers. Transmission providers utilize a variety of approaches for identifying critical customers or loads that are either exempt from rolling outages or are given a higher priority for preservation of service. Customers that typically receive some form of exemption or higher priority include hospitals, airports, and

[134] TRE Report at 41; materials provided to the task force by transmission operators.

[135] Distribution service providers in ERCOT are required to set up relays to automatically trip load as frequency falls, as follows: (1) at 59.3 Hz, a minimum of 5 percent of load must trip; (2) at 58.9 Hz, an additional 10 percent of load must trip; and (3) at 58.5 HZ, an additional 10 percent of load must trip, *i.e.,* the distribution service providers must have at least 25 percent of its load available for UFLS. (This is independent of any manual load shedding directives.) ERCOT Nodal Operating Guides Section 2: System operations and Control Requirements at 2.6.1(1) and (2). Some transmission providers use these same blocks of load for automatic under-voltage protection. (Note that NERC uses the term "distribution provider" to describe this type of entity. This report will use the term "distribution service provider" throughout to avoid confusion.)

other facilities that may affect public safety, such as police stations.[136] Some transmission providers interviewed indicated that they have a process for checking with gas customers for possible critical loads, such as gas compressor facilities without backup generation. But most acknowledged that the process for identifying "critical" gas facilities could be better standardized or otherwise improved.

4. Exemption of large loads and networks needed for system stability. Major downtown areas are generally exempted from the load shed plan, as cutting off service to these heavily networked systems could affect system stability. Large, high-voltage industrial loads are also generally not available for manual load shedding due to system stability concerns.[137]

After taking into account UFLS blocks, critical/exempt customers, and other load that is not appropriate for manual load shedding, the interviewed transmission providers indicated that they had between 30 percent and 70 percent of their total load available for manual load shedding.

*Experience on February 2, 2011*

The transmission providers' overall load shed response (in MW) was beyond the minimum required by ERCOT and was adequate to protect system frequency.

Most of the larger transmission providers interviewed were able to shed load within a few minutes of receiving each ERCOT directive, and utilized some form of automated system for shedding load. These systems were designed to

[136] The State of Texas also requires transmission providers and distribution service providers to provide notification of interruptions or suspensions of service under certain conditions (set out in their retail delivery tariffs) to customers that meet the criteria for designation as a Critical Load Public Safety Customer (hospitals, police stations, fire stations, and critical water and wastewater facilities), Critical Load Industrial Customer, Chronic Condition Residential Customer, or Critical Care Residential Customer. 16 TEX. ADMIN. CODE § 25.497 (2011).

[137] Some of these high-voltage industrial loads may be under contract as Emergency Interruptible Load Service (EILS) or providing ancillary services (RRS) as Non-Controllable Load Resources (NCLR). *See* TRE Report at 42-44. In such case, those resources would be (and were) called upon by ERCOT through the relevant QSE (at 5:49 for EILS and at 5:20 for NCLR), something that is not communicated to or controlled by the transmission providers or distribution service providers.

look at actual load on the feeders in real time, and were designed to rotate customer blocks by restoring service feeder-by-feeder as the pre-determined rotation period expired. These systems were also designed to ensure that the total curtailment obligation is maintained or exceeded at all times, by restoring a given feeder only *after* another feeder or feeders with off-setting load have been dropped in the next block. At least one of the automated systems in use during the event was designed to take into account cold load pickup prior to restoration of feeders,[138] and therefore may have generated a greater reported level of over-shedding for limited periods of time during the rotation process.[139]

Other transmission and distribution service providers used less sophisticated methods for shedding load during the event, including having a dispatcher record load amounts prior to dropping a given block to calculate the total amount to be reported to ERCOT as having been shed, and using color-coded circuit maps to select lines to be shed.

All but four transmission providers were able to meet or exceed their load shed obligations within 30 minutes of each oral dispatch instruction from ERCOT. Three of the four transmission providers did meet their full load shed obligations at a later point in time. The fourth transmission provider contended that it had not received the dispatch instruction.

*Effect of Load Shed on Gas Delivery or Supply*

At approximately 8:00 AM on February 2, ERCOT notified all transmission providers that gas companies were reporting low gas pressures, and requested that they confirm that no gas company feeds were included in their

---

[138] Cold load pickup is a phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. *Cold Load Pickup Issues: A Report to the Line Protection Subcommittee of the Power System Relay Committee of the IEEE Power Engineering Society*, May 16, 2008, § 2.1, at 3, *available at* http://www.pes-psrc.org/Reports/Cold_Load_Pickup_Issues_Report.pdf .

[139] One transmission provider's automated system includes an expectation of a 60 percent increase in load on any feeder coming off of its pre-determined outage period, and therefore requires that feeders in the next block must cover the expected increase before the first feeder can be restored. That transmission provider did report peak load shed amounts well above its requirement (about 49 percent over the required amount at one point), but attributed the reported over-shedding to several factors in addition to the cold load pickup assumptions used, including (1) restoration failure of a certain percentage of breakers; and (2) loads that did not come back on-line until manually re-set, including certain gas compressors.

outage rotation feeders.[140] At 9:25 AM, as part of its third directive to restore 500 MW of load, ERCOT requested that transmission providers serving west Texas concentrate their restoration efforts in that region due to concerns about the impact of the outages on gas compressor facilities. At 10:45 AM, ERCOT notified some transmission providers that gas compressor stations in two west Texas counties were still without power, and requested that service be restored to those counties as soon as possible.[141] In addition, some transmission providers reported additional requests from ERCOT about restoring power to specific gas facilities or regions, but noted that ERCOT did not appear to have reliable or current information as to which transmission or distribution service provider was providing electric service to those facilities.

The task force found that transmission providers currently have only limited information on overall system conditions in ERCOT, and in real-time can typically see nothing more than ERCOT's responsive reserve (PRC) levels and the status of generators connected to the transmission provider's own system. Many transmission providers indicated that they could perform better with respect to load shedding, particularly in increasing staffing and providing notice to the public, if they are able to get information about deteriorating system conditions from ERCOT earlier in the process.

Some transmission providers indicated they are already working on improvements to their public notification protocols, and believe that certain sensitive loads (including loads with back-up generation) could have benefitted from earlier notification of potential outages.

The task force also found that transmission providers with annual training programs, particularly those that require use of hands-on simulations or drills, tended to perform well during the February 2 load shedding event. Transmission providers with less frequent training, or that fail to simulate expected conditions during a load shed event, tended to have more problems with timely implementation of the required curtailment. Automated systems for shedding load may be helpful for larger transmission providers, but do not appear to be necessary

[140] One transmission provider reported that, upon receiving ERCOT's notice, it restored power to facilities believed to be compression facilities; these were later determined to be regulator stations, for which restoration of power would not affect pipeline pressure.

[141] ERCOT directed one transmission provider to restore power to five specific counties in north/central Texas due to concerns about affected gas facilities, which restoration could only be done by working outside the automated outage rotation system to identify each feeder or circuit serving those counties.

for successful implementation of a load shed program under ERCOT's current time requirements for implementation.

Price Effects of the Cold Weather Event

As discussed in the section of this report entitled "The Electric and Natural Gas Industries," ERCOT is an energy-only market. This type of market relies on scarcity pricing to provide price signals for the addition of needed resources. ERCOT transitioned from a zonal market to a nodal market in December 2010, and as part of its preparation for that transition, adopted rules in 2006 that included a Scarcity Pricing Mechanism that relaxed the then-existing system-wide cap of $1,000 per MWh. ERCOT did this by gradually increasing the cap in accordance with a defined schedule to $1,500 per MWh on March 1, 2007, to $2,250 per MWh on March 1, 2008, and finally to $3,000 per MWh on February 1, 2011, two months after the implementation of the nodal market and, as it happened, on the day before the severe weather impacts caused ERCOT to shed load.[142]

The rapidly dwindling supply of generation on February 2 created a scarcity event and, not surprisingly, caused prices to spike. By 4:55 AM, prices had reached a sustained level of $3,000 per MWh.[143]

These high prices, coupled with the fact they occurred the day after the price cap had been raised to $3,000 per MWh, fueled speculation that market manipulation may have been a factor. Such speculation was probably exacerbated by certain instances of past high prices, as well as two studies finding the existence of market power in the ERCOT markets.

In 2001, prices rose to the $1,000 per MWh cap on the first day of operation of ERCOT's pilot zonal market.[144] During the winter storm of February 2003, high prices of $990 per MWh in the balancing market and $967 per MWh in the ancillary service market were later determined to have been partially caused by "hockey stick bidding."[145] According to two studies evaluating behavior in the

---

[142] Potomac Report at 15.

[143] *Id*. at 20.

[144] The Steering Committee of Cities Served by Oncor and the Texas Coalition for Affordable Power, The Story of ERCOT: The Grid Operator, Power Market & Prices under Texas Electric Deregulation, at 32 (Feb. 2011), available at http//tcaptx.com/downloads/THE-STORY-OF-ERCOT.pdf.

[145] Public Utility Commission of Texas, *Report to the 79th Texas Legislature: Scope of Competition in the Electric Market in Texas*, January 2005, at 32, *available at* http://www.puc. state. tx.us/industry/electric/reports/scope/2005/2005scope_elec.pdf. Hockey stick bidding

ERCOT balancing market, large firms were found to have exercised unilateral market power between 2001 and 2003.[146] And in March of 2008, two days after the market cap rose to $2,250 per MWh, prices hit the cap for three consecutive 15-minute intervals.[147]

Given these historical events, suspicions concerning the causes of the high prices on February 2 were understandable. The Executive Director of the PUCT directed the IMM for ERCOT, Potomac Economics, Ltd., to investigate whether there was any evidence of market manipulation or market power abuse.

In its April 21 report to the PUCT, the IMM concluded there had not been any market manipulation during the cold weather event on February 2. The IMM further concluded that the ERCOT real-time and day-ahead markets operated efficiently, and that the shortage conditions were properly accompanied by scarcity level pricing, a phenomenon consistent with ERCOT's energy-only market design.[148]

The IMM reached its conclusion by examining whether there had been any economic or physical withholding. The IMM's test for economic withholding was to determine whether energy had not been produced when the capacity would have been economic, given the prevailing price. Since all available capacity was being utilized when prices spiked, the IMM concluded there had been no economic withholding.[149] The IMM's test for physical withholding was to determine whether resources were made unavailable that were actually capable of providing energy and were economic at prevailing market prices. This determination

---

involves offers of a small, expendable quantity of energy or capacity well in excess of its marginal cost, which can set the marginal clearing price at times of short-term demand when all offers must be accepted. See Daniel Hurlbut, Keith Rogas, and Shmuel Oren, *Protecting the Market from "Hockey Stick" Pricing: How the Public Utility Commission of Texas is Dealing with Potential Price Gouging,* THE ELEC. J., April 2004, at 26-27.

[146] Ali Hortacsu & Steven L. Puller, *Understanding Strategic Bidding: A Case Study of the Texas Electricity Spot Market* (June 2007), http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.73.9947&rep=rep1&type=pdf; Ramteen Sioshansi & Shmuel Oren, *How Good are Supply Function Equilibrium Models: An Empirical Analysis of the ERCOT Balancing Market*, 31(1) J. REG. ECON. 1 (2007).

[147] Eric S. Schubert, Shmuel Oren & Parviz Adib, *Achieving Resource Adequacy in Texas Via an Energy-Only Electricity Market*, in ELECTRICITY RESTRUCTURING: THE TEXAS STORY 70, 92 (L. Lynne Kiesling & Andrew N. Kleit, eds., AEI Press, 2009).

[148] Potomac Report at 1-2, 8.

[149] *Id*. at 8-9.

required a review of the causes of outages and derates. After conducting this review, the IMM found no evidence that the outages and derates were caused by anything other than the physical inability of the generators to produce power.[150]

The IMM observed that the scope of the outages and derates was widespread in geography, generating unit type, and by class of market participant.[151] It also observed that those market participants that were able to operate their generation fleet at greater than 90 percent availability during the morning of February 2 were financially successful that day, and the market participants affected by significant generation outages were unprofitable.[152] Furthermore, those market participants that lost significant generating capacity and were unprofitable on February 2 did not achieve gains on February 3 that significantly exceeded the previous day's losses, despite high day-ahead prices.[153] These findings suggested to the IMM that market participants had every incentive to offer their units' capacity into the market, had they been physically able to do so.

Based both on the IMM's study and on the task force's independent evaluation of the causes of the generator outages, there does not appear to be evidence that the high prices on February 2 were the result of market manipulation. Rather, they appear to be the natural result of scarcity pricing in an energy-only market.

### Rio Grande Valley Event: February 3-4

In addition to the ERCOT-wide load shed on February 2, ERCOT experienced more localized difficulties on February 3 and February 4 that necessitated local load shedding. The area affected was the southernmost tip of Texas along the Rio Grande River, designated as the Lower Rio Grande Valley (LRGV).

The weather in the LRGV is typically mild. Temperatures in February for Brownsville, the largest city in the LRGV, average a high of 72 degrees and a low of 53 degrees. For February 2011 as a whole, Brownsville had a high of 90

---

[150] *Id*. at 12.

[151] *Id*. at 10.

[152] *Id*. at 14.

[153] *Id.*

degrees; on February 3, however, the high reached only 36 degrees, with a low of 28 degrees.[154]

Load in the LRGV generally exceeds available local generation, making the area dependent on imports. The Rio Grande Valley import capability consists of a group of five elements, three 138 kV and two 345 kV transmission lines, owned and operated by American Electric Power (AEP), that allow for the import of energy into the LRGV area. The Rio Grande Valley import limit is a contingency import limit based on the loss of either of the two series compensated 345 kV lines that transmit electricity into the LRGV. The contingency limit is 1200 MW, with economic redispatch occurring at 1100 MW. This limit was exceeded for short periods during the evening hours of February 2, and for over 30 consecutive hours beginning on February 3 and concluding on February 4.

Two types of events can trigger load shedding to prevent an uncontrolled loss of load: under-frequency and under-voltage. Under-frequency load shedding is designed to rebalance load and generation within an electrical island following a system disturbance. Under-voltage load shedding is designed to prevent local area voltage collapse. While the ERCOT-wide February 2 event was the result of under-frequency concerns, the issue in the LRGV was one of under-voltage. Had the entities in the LRGV not implemented manual load shedding on February 3, a subsequent contingency could have resulted in the activation of automatic under-voltage load shedding.

On February 3, the LRGV area hit an all-time winter peak demand of 2734 MW.[155] A total of 829 MW of local generation was on scheduled outage that day, and the picture was further complicated by the loss of the three Frontera units, totaling 486 MW. The two Frontera combustion turbines CTG-1 and CTG-2 tripped due to frozen control equipment pneumatics at 9:47 PM and 9:59 PM, respectively, followed by the steam turbine CTG-3 at 10:00 PM. The import limit of 1200 MW had already been exceeded, beginning at 6:23 AM. When the three Frontera units tripped in rapid succession, the import level rose to 2074 MW (172.8 percent of the limit of 1200 MW). Additionally, the bus voltages at some substations dipped to 91 percent to 93 percent of nominal, which is outside the normal AEP Texas operating voltage range of 95 percent to 105 percent nominal. (The automatic under-voltage load shedding system in the LRGV activates when the voltage declines to 90 percent for three seconds.)

---

[154] Weather Underground, *Almanac for Brownsville,* http://www.wunderground.com/history/airport/KBRO/2011/2/3/Daily History.html.

[155] Texas Reliability Entity, *Event Analysis: February 3-4, 2011 Lower Rio Grande Valley Load Shed Category 2f.1 Event* at 4 (April 15, 2011) (LRGV Event Analysis Report).

The transmission providers for the LRGV area are AEP, Public Utilities Board of Brownsville (BPUB), and the South Texas Electric Cooperative (STEC). AEP had previously developed a procedure with ERCOT, STEC, and BPUB that specified the load allocation for any necessary manual load shed in the event of the loss of one of the 345 kV transmission lines. The entities decided to use that plan for this event, even though it was not caused by the loss of a line but rather by the loss of Rio Grande Valley generation. AEP initiated the load shedding and the three entities each manually shed their portion of the target 300 MW load shed, beginning the process at 10:06 PM on February 3.[156] The maximum actual load shed of 459.5 MW occurred at 10:59 PM. (Power was fully restored to most customers in the early morning hours of February 4.)

Approximately 115,000 customers were affected by the rolling blackouts, with AEP contributing 60 percent of the load shed obligation and BPUB and STEC each contributing 20 percent. The task force determined that load shedding was executed well by all three entities and the required levels of load shedding were reached within ERCOT's specified 30-minute period. The entities attempted to rotate the load shed through different circuits, but due to the size of the allotments of BPUB and STEC relative to their total load, as well as the number of critical loads on their systems, the rotation periods for each circuit of load shedding were longer than desired and more frequent than during the ERCOT-wide load shed of February 2.

Some of the transmission providers in the LRGV region expressed concerns about communications with ERCOT. AEP initiated the first phase of the load shed and then requested ERCOT to notify the other transmission providers to shed their portion, as opposed to ERCOT directing the simultaneous shedding of load. As a result, AEP proceeded alone for the first phase of the load shed. The transmission providers also observed that a public announcement made by ERCOT on February 3, advising customers that further outages appeared unlikely, did not accurately reflect the situation in the LRGV and complicated the conduct of their localized load shed.

The task force concluded that in order to prevent similar problems in the future, additional generation or transmission lines are needed to reinforce the LRGV area. This is in accord with ERCOT's Regional Planning Group analysis, which concluded that there is a need for transmission or market solutions in the LRGV to meet forecasted load beyond 2014.[157] AEP Service Company has

---

[156] LRGV Event Analysis Report at 20.

[157] *Lower Rio Grande Valley (LRGV) 345 kV Project Analysis*, ERCOT (May 13, 2011), http://www.ercot.com/content/meetings/rpg/keydocs/2011/0513/ERCOT_Lower_Rio_Grande_Valley_345_kV_Project_Analysis.pdf.

proposed a new 345 kV transmission line from the Laredo area into the LRGV; however, improvements at this time are in the early planning stages.

### February 10, 2011

In analyzing the implications of the February 2 blackouts, it is instructive to compare that day with February 10, when ERCOT did not shed either firm or interruptible load despite setting a new winter peak.[158] Cold weather was again expected on that day, and actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12 degree wind chill. (This compares to a low on February 2 of 19 degrees with wind chill of 4 degrees; however, low temperatures during the earlier event were more persistent, remaining in the low twenties for four days with wind chills between 10 and 14 degrees.) The average high temperature in the ERCOT region on February 10 was over 42 degrees (compared to an average high between February 2 and February 5 that remained below freezing).

ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages. ERCOT reports that 11 units, totaling 2160 MW of generation, were forced offline at some point during the day. The biggest difference between February 2 and February 10 was the number of units forced offline on February 2 just during the early morning hours. The cumulative net outages on that morning exceeded 14,700 MW,[159] whereas for the entire day on February 10, only 2160 MW were forced offline. The equivalent total outages for the entire day of February 2 was 21,400 MW, a ten-fold difference.

The majority of the forced outages in ERCOT on February 2 were weather-related, while on February 10, few were weather-related (those few were the result of frozen valves, a frozen transmitter and automatic temperature cut-offs at some wind farms). Representative causes of forced outages on February 10 included control issues, a condensate pump that was out of service, the loss of a vacuum pump, a low head level in a cooling lake, frozen valves, low gas header pressure, and a boiler tube leak.

There appear to be three reasons ERCOT was not forced to shed load on February 10: repairs made and protective measures taken during the event of February 2 remained in place; the temperatures on February 10 were not quite as

---

[158] The peak of 57,915 MW occurred at 7:15 AM.

[159] "Cumulative net outages" subtracts out those units that were successfully brought back online.

cold and the cold temperatures were of shorter duration; and the wind chill was, in the main, not as severe.

In interviews with the task force, generator operators mentioned that on or after the earlier event they had installed wind breaks, including tarps or enclosures, added portable heaters or heat lamps, repaired or added insulation, and repaired or added heat tracing. One generator changed its procedures for monitoring the reliability of its heat tracing. Some generators also continued their increased level of staffing to address freeze protection issues, and others changed elements of their control logic to prevent units from automatically tripping.

Some of the vulnerabilities identified and addressed the week before included re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals. At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing.

The storm on February 10 was concentrated in Oklahoma and northern Texas, unlike the more widespread storm of February 2. Temperatures by and large were somewhat less severe, especially during the day when they rose above freezing. A number of generator operators told the task force that the difference in temperatures and the shorter duration of the cold spell on February 10 were significant factors in the improved performance of their units.

Lastly, the wind chill in some areas was not as extreme on February 10 as during the preceding week. Some generator operators cited the lower wind speed as a significant factor in their improved performance, an assessment with which ERCOT concurred.[160]

### Salt River Project

ERCOT was not the only entity in the Southwest that was forced to shed load during the storm of February 1 through February 5. SRP shed 300 MW of load on February 2, affecting 65,000 customers. However, only some of the generation losses leading to SRP's load shed were weather-related.

[160] Of special interest to wind units was the absence of precipitation that would ice their turbine blades. Several wind farm operators mentioned this absence as a factor in their improved performance.

SRP's problems began at 6:54 PM on February 1, when Unit 1 at the Navajo Generating Station (NGS) in Page, Arizona, tripped offline.[161] Page was experiencing colder than average temperatures, reaching a high of 36 degrees and a low of 17 degrees, and facing average wind speeds of 10 miles per hour. NGS Unit 1 tripped due to these freezing conditions when a sensing line leading to a waterwall pressure transmitter froze. The trip resulted in a loss of 330 MW of generation for the SRP balancing authority area.[162]

In response to the trip, SRP called on the SRSG for assistance and imported its allowed amount of 170 MW. It also deployed 80 MW of spinning reserves and curtailed 48 MW of interruptible load. At 8:10 PM, SRP restored the interruptible load.

To make up for the loss of NGS Unit 1, SRP's system operator scheduled Santan Generating Station (SGS) Unit 6, a 275 MW combined cycle unit (consisting of a combustion turbine and a steam turbine), to start at 5:00 AM on February 2 (it had not been included in SRP's day-ahead plan). Understanding that it might need additional generation on February 2, SRP also decided to keep SGS Unit 5, a 570 MW unit, online for the following day.

On February 2, SRP's difficulties resumed at 2:56 AM, when Coronado Generating Station (CGS) Unit 2, which is coal-fired, tripped offline due to a non-weather related mechanical problem with its coal pulverizers. Although the unit was running at only 130 MW at the time of the trip, it was scheduled for its full 389 MW output for the morning peak. The loss of CGS Unit 2 also tripped Coronado 500 kV breakers 945 and 948.

SRP lost another 75 MW at 3:20 AM, when Unit 4 at the Four Corners Power Plant (FC) tripped due to control valve problems (all 750 MW of the unit was lost, of which SRP has a ten percent share). The FC unit trip was weather-related and occasioned by frozen sensing lines. SRP dispatched SGS Units 1, 2, 5 and 6 to replace the loss of FC Unit 4 for the morning peak.

SRP was able to close the Coronado 500 kV breaker 945 at 4:21 AM, and brought Coronado 2 back online. Shortly thereafter, at 5:07 AM, SRP dispatched SGS Units 1 and 2 at 90 MW each to meet increasing system loads, and at 5:15 AM ramped SGS Unit 6 to 236 MW.

---

[161] Details are based on information provided to the task force by SRP.

[162] NGS Unit 1 is a 750 MW unit that is owned by the Salt River Project, U.S. Bureau of Reclamation, Los Angeles Department of Power & Light, Arizona Public Service, NV Energy, Inc., and Tucson Electric Power. SRP has a 21.7 percent ownership in the unit. NGS Unit 2, discussed below, has the same ownership structure and total output.

At 5:18 AM, SRP dispatched duct firing on SGS Units 5&6.[163] A few minutes later, at 5:22 AM, the SGS Unit 6 steam turbine tripped, although the unit's combustion turbine was able to continue supplying generation. The steam unit had an output of 80 MW. At this time, SRP system operators told the generator operators at SGS that they needed the steam turbine back online as quickly as possible. The system operators were not aware, and were not advised by the generator operators, that in order to get the steam turbine back online, the combustion turbine would have to be ramped down significantly. Between 5:22 AM and 5:44 AM, as a result of the ramping down of the combustion turbine, the output of SGS Unit 6 was reduced from 159 MW to 15 MW.

SRP experienced a flurry of activity between 5:22 AM and 6:00 AM. After the loss of the SGS Unit 6 steam turbine, SRP dispatched the Mormon Flat Hydro (MFH) Unit 2 to come online at 50 MW, interrupted 38 MW of instantaneous interruptible load, and at 5:30 AM dispatched Horse Mesa Hydro (HMH) Units 1, 2 and 3, for a total of 30 MW additional generation. SRP's system operators also directed its merchant group to purchase 100 MW for the 7:00-8:00 AM hour. At 5:31 AM, SRP called on MFH Unit 1 for 10 MW, and also requested that a large interruptible customer drop 100 MW of 10-minute interruptible load. At this point SRP's reserves were diminishing, and SRP used the interruptible load to increase its spinning reserves.

At 5:39 AM, SRP was able to bring SGS Unit 2 online at 92 MW, and at 5:40 AM, SRP's merchant group called on another interruptible customer to drop 29 MW of contracted interruptible load in the 6:00-7:00 AM hour. However, Tucson Electric Power contacted SRP at the same time to report that it had lost Springerville Unit 3, which diminished SRP's available capacity by another 25 MW. At 5:44 AM, SRP determined that SGS Unit 6 would not be able to return to service, resulting in a total loss of 236 MW of capacity.

SRP was able to bring on SGS Unit 2 online at 40 MW at 5:45 AM, and SGS Unit 1 at 40 MW at 5:57 AM. At 6:00 AM on February 2, SRP system load was running at 3557 MW, which was 161 MW higher than its day-ahead schedule.

At 6:02 AM, SRP dispatched Units 4, 5, and 6 at the Agua Fria Generating Station (AFGS), at approximately 70 MW each, to recover reserves and meet forecasted load. SGS Unit 2 also reached full load of 100 MW at this time. Two minutes later SRP dispatched Kyrene Generating Station (KGS) Units 5 and 6, at 60 MW each. Unit 6 was brought online at 6:11 AM and Unit 5 at 6:14 AM. SRP

[163] Duct firing is a process involving additional burners being fired for a heat recovery steam generator (HRSG) to increase steam production and output. The output of the burners combines with the hot exhaust gas from the gas-fired turbines to create steam.

dispatched the 41 MW KGS Unit 4 at 6:08 AM and HMH Units 1, 2 & 3 at 10 MW each at 6:09 AM. At this point all available SRP generating units were dispatched, and SRP purchased an additional 100 MW to begin at 6:20 AM.

SRP issued a Capacity Alert at 6:17 AM. (A Capacity Alert is an internal alert telling operators in the balancing authority that SRP believes that if another unit were to trip, the balancing authority would have trouble recovering.) A Capacity Alert is a precursor to a NERC EEA-1.

Five minutes later, NGS Unit 2 tripped due to frozen waterwall pressure sensing lines. The trip resulted in the loss of 350 MW for the SRP balancing authority area, and constituted the event that triggered load shedding. In response to the NGS Unit 2 trip, SRP again called on SRSG for assistance and was supplied with 128 MW, 82 MW less than anticipated. EPE, a neighboring balancing authority experiencing its own difficulties, told SRP that it could not deliver the assistance it was obligated to provide under the SRSG Agreement.

Immediately after the NGS Unit 2 tripped at 6:22 AM, SRP's system operator determined, based on the information available to him, that the remaining reserve and emergency assistance was insufficient to recover SRP's ACE in a timely manner.[164] The operator concluded that 300 MW of firm load needed to be shed to insure stable operations of the bulk electric system should additional generation trip offline. The system operator contacted its reliability coordinator, WECC's LRCC (Loveland Reliability Coordination Center), to notify it of the impending load shed. At 6:24 AM LRCC directed SRP (as transmission provider) to shed 300 MW. At the same time, KGS Units 5 and 6 reached full load of 62 MW each, and SRP's merchant group purchased 190 MW for the 7:00-8:00 hour.

At 6:29 AM, SRP called on the last of its 10-minute interruptible load, curtailing 136 MW. At the same time, SRP's distribution service provider initiated its rotating load shed program. Once initiated, load shed is to take place within one minute; however, SRP's distribution service provider encountered problems, requiring five full minutes to initiate the sequence. At 6:31 AM, LRCC declared an EEA 3 for SRP, which was seven minutes after SRP had initiated the shedding of 300 MW of load.

SRP reports that the 300 MW load shed event affected approximately 65,000 customers.

[164] ACE, or area control error, refers to the instantaneous difference between a balancing authority's net actual and scheduled interchange with other balancing authorities, taking into account the effects of frequency bias and correction for meter error.

Immediately after the load shed was initiated, SRP's ACE returned to normal. At this time SRP also restored its reserves to meet its SRSG reserve requirement. At 6:34 AM, Springerville Unit 3 tripped offline due to high furnace pressure, cutting 75 MW of generation (although this did not affect SRP's operations).

AFGS Units 4, 5 and 6 remained online and ramping to full load, and at 6:34 AM SRP's system operator instructed the distribution service provider to restore 100 MW of firm load. However, instead of restoring only the 100 MW, the distribution service provider mistakenly restored all 300 MW of the load that was shed. At 6:45 AM, the distribution service provider realized its mistake and, without further instruction, shed 200 MW of the load that had been restored. Prior to the second load shed of 200 MW, SRP's ACE had returned to normal.

At 6:52 AM, KGS Unit 4 came online and began ramping to full load, and the system operator directed the restoration of another 100 MW of shed load. At 6:55 AM, SGS Unit 6 returned to service and a minute later the system operator directed that the final 100 MW of shed load be restored. By 6:57 AM, approximately a half-hour after the initial load shed, SRP was able to restore service to its customers.[165] At 7:05 AM, LRCC declared a return to an EEA 0 condition effective as of 6:59 AM.

## El Paso Electric Company

During the cold weather event, EPE experienced forced outages of all but one generator in its El Paso area fleet. Because of the significant loss of its local generation (six out of seven operational units) and the resulting loss of dynamic reactive support, EPE was limited in the amount of generation that could be imported on its transmission system.[166]

With limited import capability and limited local generation, EPE had to operate its system in such a way as to prevent cascading due to voltage instability. It was therefore necessary for EPE to reduce loads in its service area by manual load reduction. Load shedding occurred four times between February 1 and

[165] Although SRP had directed that all load be restored at this time, some of the distribution service provider's breakers would not close, leaving 4000 customers without service until 9:43 AM.

[166] EPE utilizes WECC Path 47 to import power from Palo Verde and Four Corners. The capability of this path is limited by post-contingency voltages. EPE can also utilize the Eddy DC tie in New Mexico to help regulate the flows on Path 47 by importing up to approximately 200 MWs from Southwestern Public Service (SPS) to the East.

February 4, totaling up to approximately 1023 MW and affecting 253,000 customers. Two of the load shed events occurred on February 2, one on February 3 and one on February 4 (all due to voltage instability concerns).

The four-day sequence of events is set forth below.[167]

Tuesday, February 1, 2011

On February 1, an arctic air mass moved in across the Las Cruces and El Paso area. Temperatures hovered in the low 40s between midnight and 4:00 AM, but dropped as the wind changed direction. The temperature dipped below freezing at approximately 8:51 AM and then plummeted into the middle teens by the late evening hours. Maximum temperature for the day was 43 degrees and the minimum was 14 degrees.

As the colder air moved in, gusty winds picked up in the late evening, measuring up to 26 mph at the El Paso International Airport. These gusts, combined with air temperatures in the middle teens, produced wind chill values below zero. The peak wind gust reached on February 1 was 43 mph (during the 1:00 AM hour).

*Timeline of Events*

- At 6:34 PM, the Coyote-Dell City 115 kV line tripped (reportedly as a result of gunshot damage to a conductor).
- At 8:07 PM, the first of EPE's gas-fired generators, Newman No. 3, tripped (loss of 40 MW).[168]
- At 10:15 PM, Rio Grande No. 6 tripped (loss of 50 MW).
- At 10:15 PM, system controllers contacted LRCC, EPE's reliability coordinator, and advised it of the loss of local generation.
- At 10:52 PM, system controllers requested that interruptible loads be interrupted due to the extreme weather conditions and the loss of local generation.

---

[167] Details are based on information provided to the task force by EPE.

[168] The various causes of EPE's unit trips are discussed in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

- At 11:45 PM, the Copper Generator was brought online.

Wednesday, February 2, 2011

The air temperature continued to drop during the morning of February 2, falling from 13 degrees at 1:00 AM to 8 degrees by 8:00 AM. Temperatures moderated during the afternoon, reaching 15 degrees. On February 2, the maximum temperature was 15 degrees (45 degrees below normal) and the minimum temperature was 6 degrees.

The maximum temperature for the day was the coldest maximum (high) temperature ever recorded in El Paso, Texas. A few wind gusts up to 24-26 mph occurred around mid-day. This, combined with the frigid air temperatures, produced wind chill values of -9 to -10 degrees. The peak wind speed reached on February 2 was 26 mph.

*Timeline of Events*

- At 12:10 AM, Newman 5 GT3 tripped.

- At 12:26 AM, Newman 5 GT4 tripped.

- At 1:49 AM, Rio Grande No. 8 tripped.

- At 1:53 AM, system controllers contacted LRCC, which declared an EEA l.

- At 2:02 AM, EPE purchased power from SPS; the Eddy DC tie was opened and ramped to 100 MW.

- At 2:27 AM, a switching order was given by the system controller to synchronize PNM's Luna Energy Facility (Luna) to the grid, permitting the transmittal of power EPE had purchased from PNM.

- At 3:17 AM, Newman Generator No. 4 GT1 tripped.

- At 3:20 AM, Four Corners Unit No. 4 tripped.

- At 5:07 AM, the HVDC terminal at the Eddy DC Tie experienced a runback[169] from 100 MW to 48 MW.

- At 5:12 AM, system controllers again contacted LRCC, and the EEA level was heightened to EEA 2. This Alert advised other utilities that EPE was placing its load management procedures in effect due to its energy deficient condition. Actions taken pursuant to this Alert included public appeals to reduce demand, made through media announcements, and other demand-side management procedures.

- At 6:28 AM, the Coyote-Dell City 115 kV line was restored.

- At 7:12 AM, the Newman No. 4 steam turbine (ST) tripped, and the Newman-Butterfield 115 kV line opened at Newman (tripping the line).

- At 7:16 AM, the Newman No.4 GT2 unit tripped. With the loss of Newman No.4 GT2, the Copper unit was the only local unit remaining online that could supply dynamic reactive support (it was producing 55 MW of power).

- At 7:22 AM, system controllers initiated load shedding in order to balance load with generation and maintain voltage stability. Area load was at 982 MW at the time, and approximately 170 MW of firm load was shed.

- At 7:23 AM, EPE again contacted LRCC and EPE's EEA status was increased to an EEA 3. This alert advised other utilities that EPE had implemented firm load interruptions.

- At 7:55 AM, system controllers saw that Luna had lost approximately 130 MW of generation. Another 103 MW of load was shed, with load stabilizing at 710 MW.

- At 8:16 AM, Luna ramped up to 235 MW.

- At 9:51 AM, the combustion turbine portion of PNM's Afton combined cycle generator was placed online (the steam turbine portion of this generator experienced problems and remained unavailable throughout the

[169] "Runback" is a manually or automatically controlled decrease in output designed to protect against loss of thermal transfer capability or transient angle instability.

event). EPE made arrangements to obtain power from that unit on an hourly basis.

- At 12:17 PM, controlled load shedding ended, with load at 977 MW.
- At 12:19 PM, LRCC was contacted and EPE's EEA alert level was decreased to EEA 2.
- At 6:04 PM, the terminal at the Eddy DC tie tripped (opening the Amrad-Eddy 345 kV line).
- At 6:11 PM, load shedding resumed, and continued for approximately two hours and 45 minutes. Load shed amounts varied between 100 and 250 MW during this period.
- At 6:15 PM, EPE contacted LRCC, which again placed EPE under EEA 3 status.
- At 8:58 PM, load shedding terminated because of reduced load demand. EPE contacted LRCC, which changed the EEA alert level back to an EEA 2.
- At 11:04 PM, the Eddy DC tie (and the Amrad-Eddy 345 kV line) resumed operation. (According to SPS, operating agent for the DC Terminal, the tie had tripped due to loss of thyristors.[170])

Thursday, February 3, 2011

The lowest temperatures of the event were experienced in the El Paso area during the morning of February 3, 2011. Temperatures remained in the single digits from midnight through 10:00 AM, slowly climbed into the teens during the late morning, and reached a maximum of 18 degrees at 2:51 PM. The high temperature for the day was 18 degrees, and the low was 1 degree. (The high temperature was 43 degrees below normal, and the low was 34 degrees below normal). The peak wind speed reached on February 3 was 20 mph. The combination of frigid air temperatures and wind speeds produced wind chill values from midnight to 11:00 AM of -10 to -17 degrees.

[170] A thyristor is a semiconductor with an anode, a cathode and a gate. Thyristors have the ability to switch high voltages and withstand reverse voltages, and are used in switching applications, especially in AC circuits, for AC power control, and overvoltage protection for power supplies.

*Timeline of Events*

- At 3:45 PM, PNM's Afton CT tripped.
- At 4:23 PM, PNM put the Afton CT back online.
- At 5:00 PM, as the evening load increased, LRCC was contacted, and EPE's alert status was elevated to EEA 3.
- At 5:30 PM, controlled rotating load shedding resumed for just over five hours. During this period, the load shed amounts varied between 100 MW and 250 MW.
- At 6:52 PM, Newman 4 GT1 was brought online.
- At 7:20 PM, Newman 4 GT1 tripped.
- At 9:32 PM, Newman 4 GT1 returned online.
- At 10:30 PM, Newman 4 GT2 was brought online.
- At 10:30 PM, EPE terminated the controlled rotating load shedding.
- At 10:40 PM, LRCC lowered the EEA level to Alert Level 2.

Friday, February 4, 2011

On February 4, although skies were clear and winds relatively calm, temperatures were as low as 3 degrees during the early morning hours. By late morning, temperatures moderated, reaching the middle 20s by 12:00 PM. The temperature continued to rise during the afternoon, and the high for the day was 37 degrees. Winds, with speeds under 10 mph, were generally light and variable in direction. The low for the day was 3 degrees. (The maximum air temperature was 24 degrees below normal and the minimum air temperature was 32 degrees below normal).

*Timeline of Events*

- At 2:02 AM, Newman 4 GT2 tripped.
- At 2:04 AM, Newman 4 GT1 tripped.

- At 3:17 AM, PNM's Luna steam turbine tripped.
- At 3:23 AM, one Luna gas turbine dropped from 90 MW to 11 MW.
- At 3:51 AM, the Luna steam turbine was brought back online and slowly ramped up.
- At 6:30 AM, LRCC issued an EEA Level 3 for EPE. With Copper again as the only local unit online, controlled rotating load shedding of between 100 MW and 250 MW resumed.
- At 6:49 AM, Newman 4 GT2 was brought online.
- At 12:05 PM, the controlled rotating load shedding ended.
- At 12:12 PM, the RC changed EPE's alert status to an EEA Level 2.
- At 3:57 PM, Newman 5 GT4 unit was brought online and remained stable at 50 MW.
- At 5:12 PM, the Rio Grande 8 unit was brought online.

Due to the added generation, which provided the necessary dynamic reactive support, no controlled rotating load shedding was required for the Friday night peak load period or thereafter during the event.

<u>Saturday, February 5, 2011</u>

- At 4:07 PM, Newman 5 GT3 came online.
- At 4:30 PM, LRCC modified EPE's alert status to an EEA Level 1.

<u>Sunday, February 6, 2011</u>

- At 9:46 AM, LRCC decreased EPE's alert status to an EEA Level 0.

**<u>Public Service Company of New Mexico</u>**

PNM set a new record winter system demand during the February cold weather event and experienced outages on some of the generating units it owns, co-owns, or from which it purchases power.[171] PNM was generally able to meet its system load requirements and also to provide energy assistance to another utility. On February 3, however, PNM was forced to implement a localized rolling blackout in the Alamagordo and Ruidoso areas in southern New Mexico, and experienced an outage in the town of Clayton in northeastern New Mexico.

In the Alamogordo and Ruidoso areas, the February 3 rolling blackout was implemented at 5:21 AM by the PNM Distribution Operations Center, as a result of a transmission line outage. The PNM Amrad to Alamogordo 115 kV transmission line locked out due to a failed conductor clamp, a condition that was apparently unrelated to the weather. As a result, the Las Cruces to Alamogordo 115 kV transmission line, owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), became overloaded and required load relief from PNM and Tri-State. PNM implemented its share of the load curtailment by sequential curtailment of two separate feeder lines. Approximately 20,207 customers were affected, with an estimated load loss of up to 22.1 MW. All circuits were fully restored at 8:08 AM.

The outage in Clayton began at 5:03 AM as a result of the outage of a Tri-State 69 kV transmission line that serves PNM's Van Buren substation, located in Clayton. A static wire, stretched by the extremely cold weather, snapped and fell on one of the phases of the line, interrupting service to the town. All service was restored at 6:54 AM. The estimated load lost was 3.7 MW.

## Southwest Power Pool

SPP also experienced severe weather conditions over much of its footprint during the February cold weather event. However, none of its entities was forced to shed load. Three BAs within SPP declared varying levels of EEAs due to tripping or derating of generating resources or deficiencies in natural gas supply. In one instance, SPS requested an EEA 1 following the trip of a 250 MW gas-fired generating unit. SPS had all of its available resources in use and issued public appeals for energy conservation. In a second instance, Oklahoma Gas & Electric Company (OG&E) experienced multiple generation losses on February 2 and February 3, and requested four separate EEA 2 declarations during the week. It was unable to meet its energy commitments to the reserve sharing group run by SPP. In the last instance, Sunflower Electric Cooperative (Sunflower) requested an EEA 3 on February 2 following the loss and subsequent derating of a large coal

[171] Generating units affected, to a greater or lesser degree, included Four Corners Unit 4, Reeves Unit 1, Reeves Unit 3, Delta Person CT, Valencia, Afton, LGS Units 1 and 2, and Luna Unit 2.

generating unit. The failure to start of a gas-fired combustion turbine aggravated the situation, which continued until the afternoon of February 3. During this period, Sunflower was unable to meet its energy commitments to the SPP reserve sharing group. However, following declaration of the EEA 3, Sunflower obtained sufficient transmission service to purchase energy and was able to meet its own firm energy commitments, thereby avoiding the need to shed load.

In SPS's case, its purchases over the Blackwater Tie (a connection between the Western and Eastern Interconnections) were lost between 9:00 AM and 10:00 AM on February 2, due to capacity emergencies in the Western Interconnection. SPS replaced this purchase with a 100 MW purchase from Public Service Company of Colorado, importing it over the Lamar Tie (another one of the connections between the Western and Eastern Interconnections). SPS ultimately increased this purchase to 210 MW, and was later also able to make limited purchases through the Blackwater Tie.

Notwithstanding SPS's transactions over the ties, the majority of the purchases made by the energy-deficient utilities within SPP were made from other SPP entities. Thus, even if SPP had been separated from its neighbors by asynchronous ties, as is ERCOT, it probably would not have had to shed load during the February event. This suggests that the problems ERCOT experienced did not directly relate to its functionally separate interconnection status, but rather to the ability and preparedness of the generators within its footprint to operate as scheduled during the severe weather conditions.

## B. Natural Gas

The extreme cold experienced in early February 2011, particularly on February 2 and February 3, caused widespread production declines. These reductions were typically the result of freeze-offs,[172] mostly at wellheads but also in nearby processing plants. To a lesser extent, other equipment reliability issues contributed to the problems, both at the wellhead and at processing and treating facilities. The rolling power blackouts in ERCOT also played a role in the Fort Worth Basin, as did customer curtailments in the Permian Basin. These supply reductions had adverse effects all the way down the delivery chain.[173]

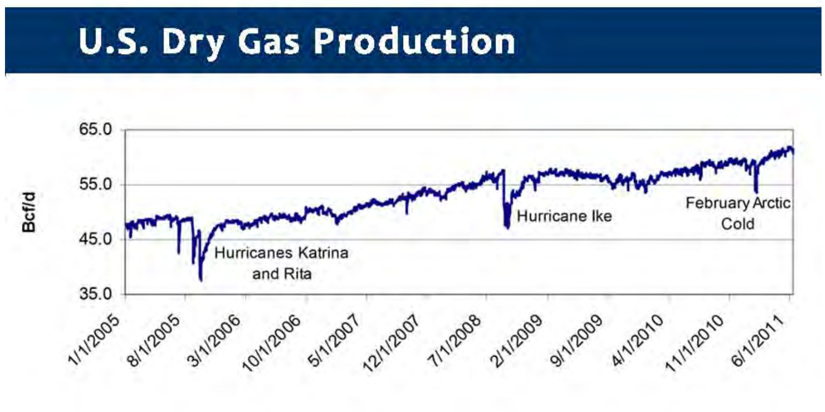
[172] A "freeze-off," as described earlier, occurs when water produced alongside the natural gas crystallizes or freezes, completely blocking off the flow and shutting down the well.

[173] Unless otherwise noted, the entity-specific data was obtained from materials submitted to the task force by producers, processing plants, pipelines, and LDCs.

This subsection summarizes the supply shortfalls resulting from production declines in the basins, discusses the resulting reduced gas volumes and pressures experienced by the pipelines, and ends with a detailed examination of the retail curtailments made by LDCs in the affected states of New Mexico, Arizona, Texas, and California.

## Producing and Processing Facilities

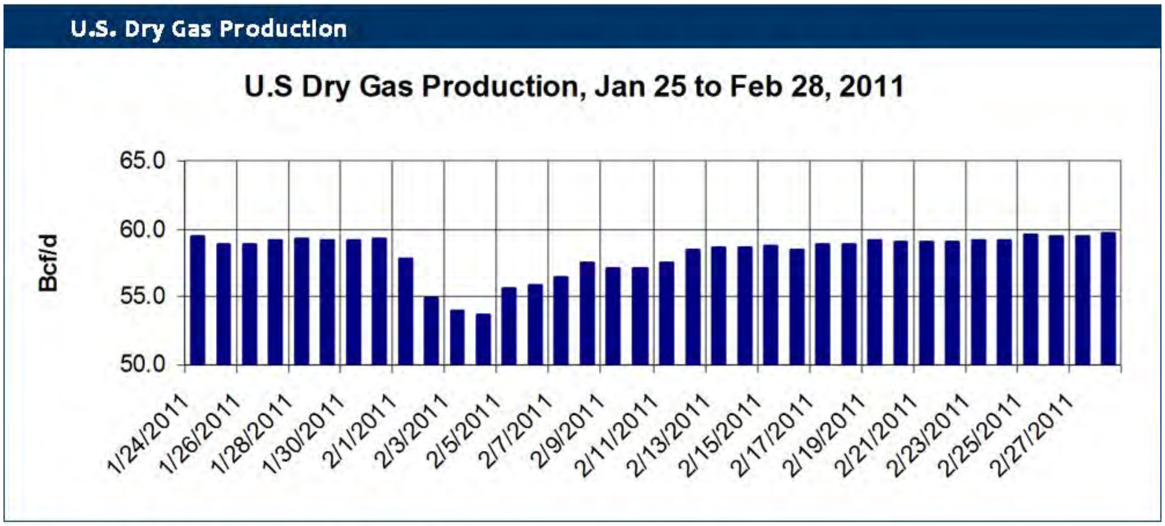
The reductions in supply experienced during the cold weather event were comparable in magnitude to production shut-ins during hurricanes. The following chart illustrates this point.




Source: Task Force chart based on Bentek data

Relative to average dry gas production of 59.22 Bcf per day on January 31, 2011, Bentek estimates that production in the first week of February declined by 5.55 Bcf per day, a reduction of 9.4 percent. The decline began on February 1 and reached its lowest level on February 4.[174]

[174] Data is based on task force analyses using supply and demand history from Bentek.




Source: Task Force chart based on Bentek data

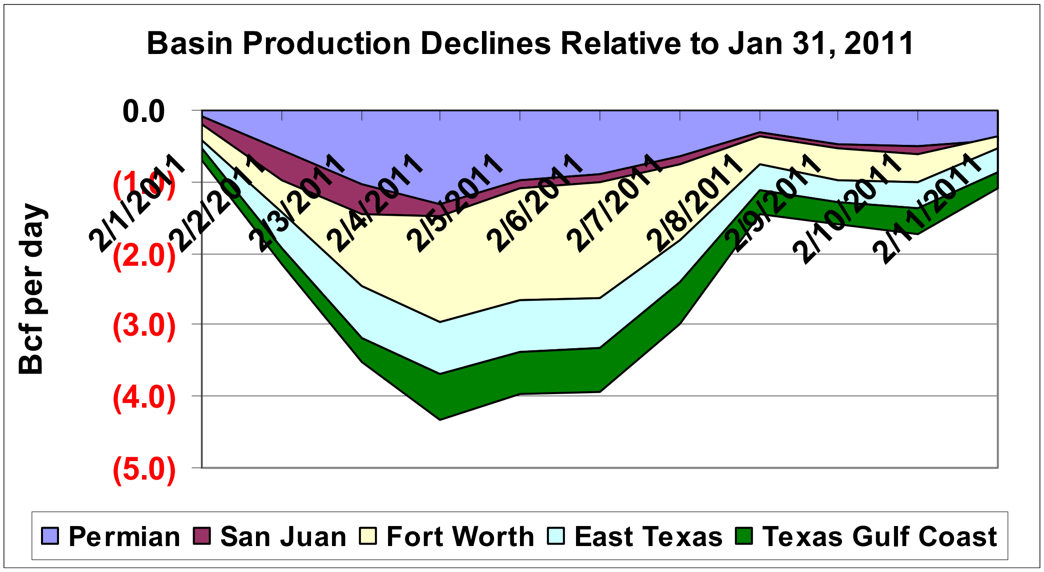
Of the 5.55 Bcf per day decline during the first week in February, 79 percent, or 4.36 Bcf per day, occurred in production basins in Texas and New Mexico (where production declined by 21 percent). Both the San Juan Basin in northern New Mexico and the Permian Basin in west Texas and southeastern New Mexico tend to experience production declines with low temperatures, and the February event was no exception. The declines in these basins, together with the large increases in demand, were almost exclusively responsible for the gas curtailments in Texas, New Mexico and Arizona.[175]

This weather event was so extreme that production freeze-offs were experienced not only in the San Juan and Permian Basins, but throughout Texas and as far south as the Gulf Coast. Based on scheduled pipeline receipts, the task force estimates that production in the Fort Worth Basin declined by 1.63 Bcf per day compared to the last week of January, 2011; East Texas Basin production declined by 0.72 Bcf per day; and Gulf Coast Basin production declined by 0.65 Bcf per day. [176] The shortfalls in these additional Texas basins, while not directly a cause of the natural gas curtailments, did contribute to fuel-related electric

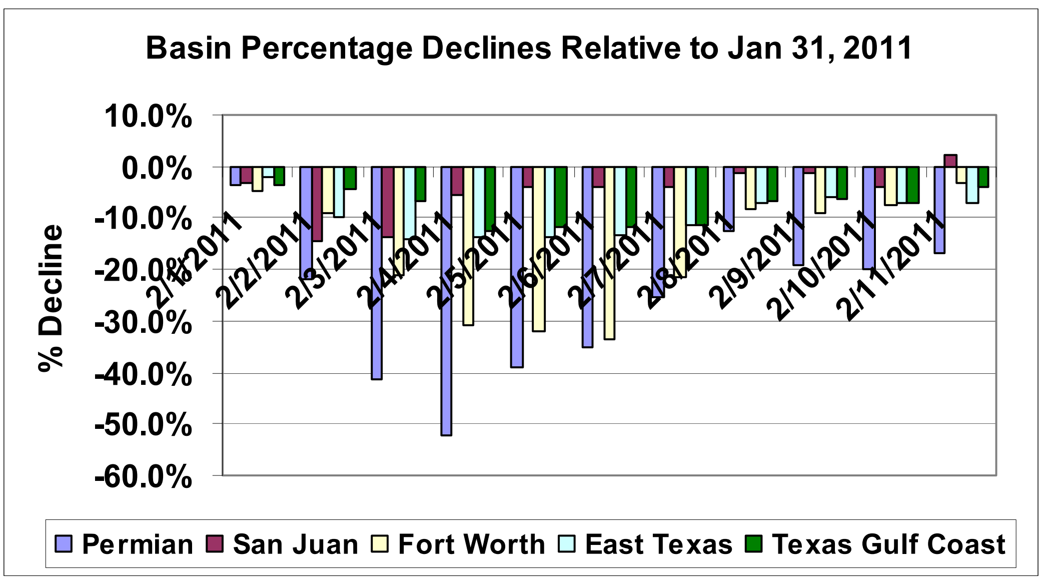
[175] Production declined by 0.43 Bcf per day in the San Juan Basin and by 1.31 Bcf in the Permian Basin, based on task force analyses of Bentek supporting data, pipeline receipts and flow data from El Paso and Transwestern.

[176] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); s*ee also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; materials submitted to the task force by pipelines. Note that basin level production reductions may not be equal to the total February 4 reduction as not all basin level maximum reductions occurred on February 4.

generation failures in ERCOT. The following charts demonstrate absolute and percentage declines by production basin.




Source: Task Force chart based on Bentek data




Source: Task Force chart based on Bentek data

The causes of these production declines are examined in detail in the following section of this report, entitled “Causes of the Outages and Supply Disruptions.”

## Effects on the Pipelines and Storage Facilities

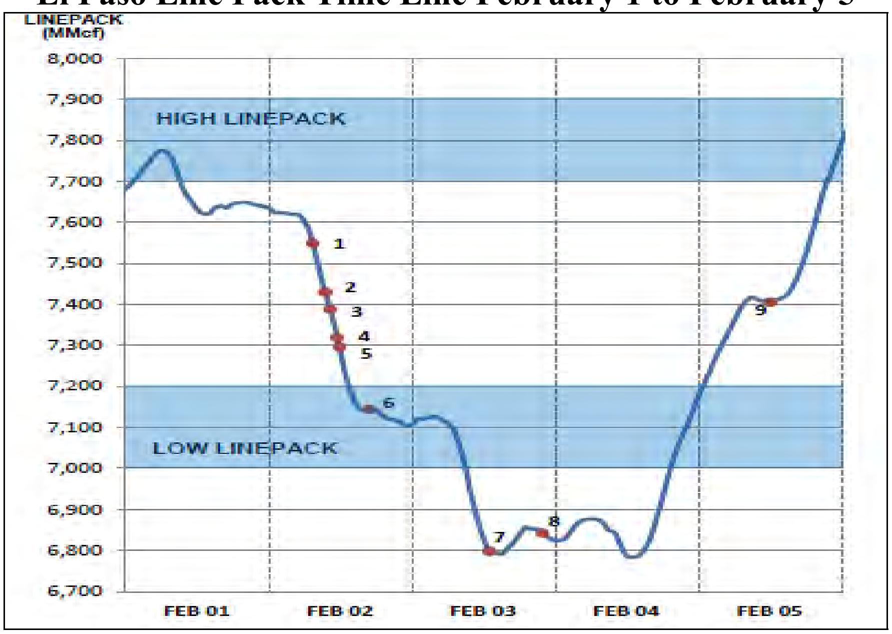
At the same time that gas supplies flowing into the pipelines were reduced, shippers requested increased volumes of gas. The reduced supply relative to higher deliveries (a situation known as a draft condition) resulted in lower line pressures and reduced line pack, which for most pipelines began on February 2.[177]

Between February 1 and February 4, pipelines responded to this draft condition through a variety of approaches. To the extent possible, deliveries to shippers were met by relying upon line pack. Pipelines with storage used increased withdrawals to build line pack. El Paso, for instance, used its Washington Ranch Storage Field to support its south system when gas supplies failed to arrive.

El Paso

The effect of the draft conditions on El Paso's line pack is depicted in the following graph (the numbered dots reference various occurrences on El Paso's system during the cold weather event):

**El Paso Line Pack Time Line February 1 to February 5**




**Source: El Paso Natural Gas Company**

[177] Generally by February 4, line pressures and line pack began rising again, as the previous day's scheduled receipts were received into the system. By February 5, line pack grew to a level above that prevailing on February 1.

El Paso system demand increased from 3,416 MDth[178] on January 31 to 3,675 MDth on February 2. For the same period, supply from all sources, including pipeline interconnects, decreased from 3,264 MDth to 3,040 MDth. As supply decreased and demand increased, El Paso used line pack to attempt to maintain deliveries. As a result, line pack fell from almost 7.8 Bcf on February 1 to approximately 6.8 Bcf at 2:00 PM on February 3.

As line pack fell, pipeline pressure on the western edge of the system dropped below 600 pounds per square inch gauge (psig). Pressure on the east side of the system had already dropped below 600 psig, as of 12:00 noon on the previous day. At 10:51 PM on February 3, El Paso issued a low pressure force majeure announcement, suspending its contract obligations and declaring that operating pressure on portions of its system could not sustain contract levels.

***Pipeline Communications***

Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2011)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

**Critical notices** describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

**Operational flow orders (OFO)** are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition.) OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also

(cont’d)

[178] “MDth” is a thousand dekatherms.

limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

**Force majeure**, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

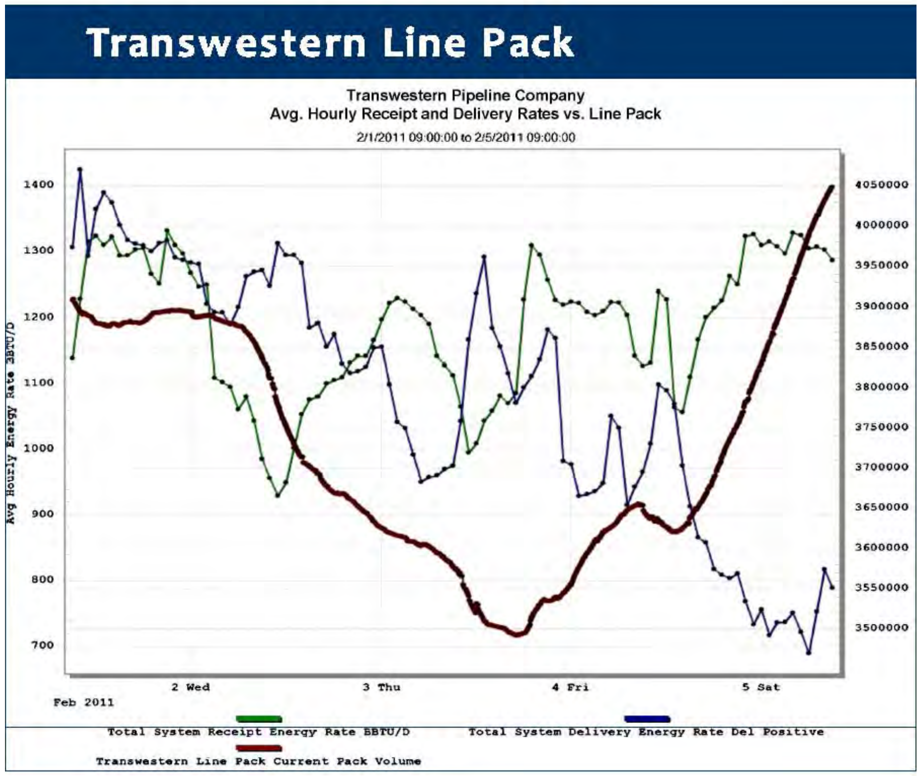
Based on data responses to task force inquiries, the number of companies making use of these various communications and directives for weather-related reasons in the Southwest during the first week of February is as follows:

| Type of Pipeline | Number of Data Responses | Number of Companies With a Critical Notice | Number of Companies With an OFO | Number of Companies Declaring Force Majeure |
|---|---|---|---|---|
| Interstate | 24 | 6 | 3 | 1 |
| Intrastate | 21 | 5 | 5 | 3 |

El Paso Natural Gas issued a force majeure declaration on February 3, stating that it had experienced system operating pressure on portions of its mainline and some laterals that could not sustain contract levels. The other interstate pipeline most affected by the supply shortfalls, Transwestern, did not declare a low pressure force majeure.

Transwestern

The effect of the draft conditions on Transwestern's line pack is depicted in the following graph.




**Source: Transwestern Pipeline Company, LLC**

Scheduled deliveries on Transwestern from January 31 to February 2 increased from 1,426 MDth to 1,526 MDth. Supplies dropped by approximately 400 MDth by midday on February 2; however, Transwestern continued to make scheduled deliveries from line pack. Accordingly, line pack decreased from 3.9 Bcf on February 1 to a low of 3.5 Bcf on February 3. Transwestern, unlike El Paso, did not declare a low pressure force majeure.[179]

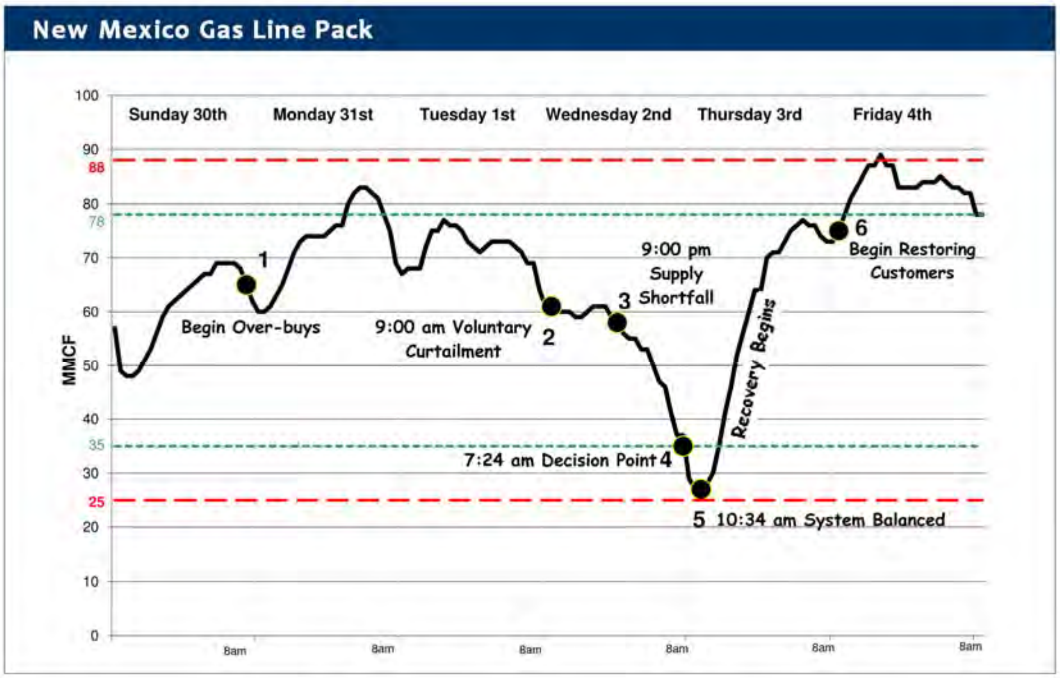
New Mexico Gas Company

NMGC also experienced significant line pack problems on its distribution system. On January 31, NMGC bought additional supply for its north segment and its south/remotes segment, for delivery on the following day. On February 2,

[179] By midday on February 3, pressures and line pack were beginning to increase, and on February 4, NMGC's line pack was over 4 Bcf.

NMGC contacted 39 large industrial and commercial customers, requesting them to reduce or curtail their gas usage. By 9:00 PM on February 2, NMGC reported to supplying pipelines that pre-ordered gas was not being delivered as scheduled.

The effect of events on NMGC's line pack is depicted in the following graph.




Source: New Mexico Gas Company

The vast majority of the shortages experienced on NMGC's north segment on February 2 and 3 was attributable to supply failures at the Transwestern Rio Puerco and El Paso's Wingate interconnection points. An NMGC representative has stated that the failure of Transwestern to deliver scheduled flows of 127,454 MMBtu on February 2 and 146,438 MMBtu on February 3 "was devastating to NMGC and its customers."[180]

Transwestern responded by observing that it scheduled much greater volumes of gas at Rio Puerco than NMGC historically flowed (and equal to the amount nominated by NMGC and other shippers to the point). NMGC was unable to flow all of the scheduled volumes, suggesting there were difficulties on NMGC's system in taking away the gas from the Rio Puerco delivery point. On February 2,

[180] Transcript of Testimony of Tommy Sanders at 13, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Mar. 17, 2011) (No. 11-0039-UT).

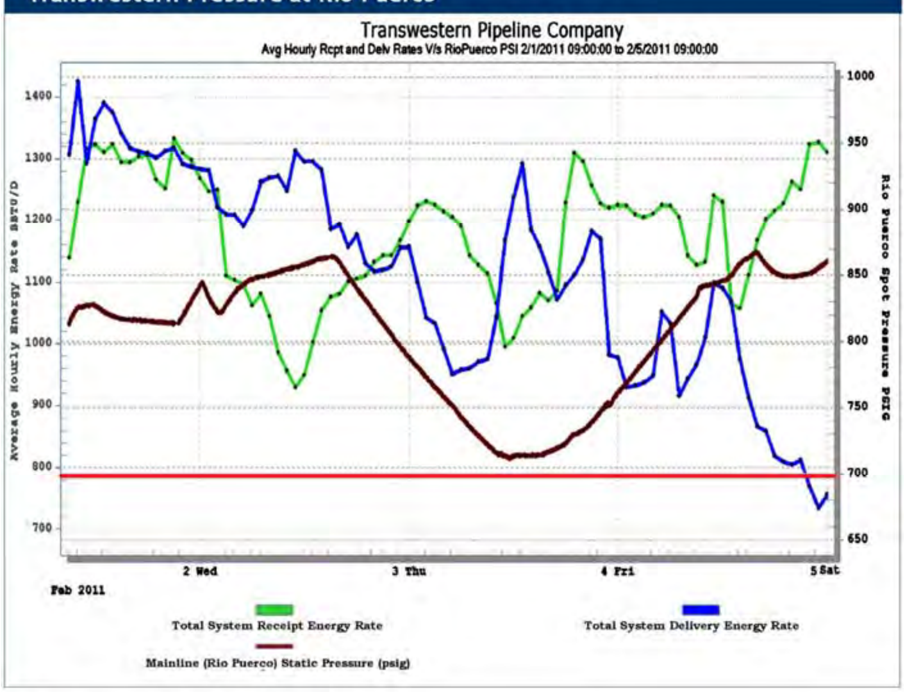
for example, Transwestern scheduled 305,000 MMBtu/d and NMGC took 182,000; on Feb. 3 Transwestern scheduled delivery of 298,000 MMBtu/d at Rio Puerco, and NMGC took 128,000.

NMGC also reported lower pipeline pressure than those on which it typically relies. On an average winter day in the north segment, pressure ranges from 800 to 900 pounds per square inch atmosphere (psia) at Rio Puerco. The average pressures were lower during the week of January 31 and, from February 1 to February 4, the loss of pressure caused NMGC to experience significant pressure losses on its own system. For example, the interstate pipeline pressure at NMGC's interconnection at Rio Puerco fell to a low of 724 psia from a normal operating pressure of 850 psia.

Notwithstanding this decline in pressure, Transwestern's contractual obligation with respect to pressures at Rio Puerco (as opposed to its typical operating pressures) is 700 psia, and Transwestern reports that pressure never fell below that obligation.

The following chart provided by Transwestern depicts the pressure at Rio Puerco (fluctuating brown line) relative to contractually obligated pressure (non-fluctuating red line), total receipts (green line) and deliveries (blue line) on the Transwestern system. According to the chart, pressure did not fall below the contractual obligation of 700 psia.

Transwestern Pressure at Rio Puerco




Source: Transwestern Pipeline Company, LLC

***Coordination Among Pipelines to Address Supply Problems***

Flows between and among pipelines through redirected supplies and incremental transactions at least partially alleviated supply shortage conditions during the first week of February, 2011. These flows were the result of active coordination among the involved counterparties to address shortfalls. The redirection of gas came too late to avoid the curtailments in New Mexico and Arizona that occurred on February 2 and February 3. However, in the Texas intrastate markets, the increased purchases of gas at pipeline interconnects was an important factor in maintaining pressure in the Dallas-Fort Worth area and also served to move gas east to west in response to reduced supply at Waha.

Changes in gas deliveries do not occur instantly. Operation Balancing Agreements (OBA) contractually specify how gas imbalances between flows and scheduled amounts are to be managed. (Interstate pipelines are obligated by FERC regulations to have OBAs at interconnects with other interstate pipelines and with intrastate pipelines). These agreements enabled counterparties to make operational changes and revise nominations.

Chevron Keystone Storage Facility

In addition to the pipelines, at least one storage facility experienced weather-related difficulties. These difficulties, however, stemmed not from freeze-offs upstream, but from the rolling blackouts on ERCOT's system and from the facility's own operational problems.

The Chevron Keystone Storage Facility (Keystone), which has interconnections with El Paso, Transwestern, and Northern Natural Gas Company, was affected by two rolling blackouts on February 2, at 6:30 AM and 10:00 AM. It was shut down completely for six hours (from 6:30 AM to 9:30 AM and again from 10:00 AM to 1:00 PM).

Keystone remained at less than 100 percent capacity through February 6, due to line and equipment freeze-offs. Keystone declared force majeure at 9:00 AM on February 2. As a result, during the period February 2 through February 4, Keystone was unable to deliver 100 percent of nominated volumes to its three interconnecting pipelines. Keystone lifted the force majeure effective 9:00 AM on February 7.

Keystone's difficulties did not meaningfully contribute to the curtailments of natural gas customers, but they did affect supplies to gas-fired generators of EPE and SRP. (The failures of EPE's generating units stemmed from other causes,[181] so they would not have been able to utilize the gas in any event; SRP was able to obtain gas from another source.) In order to estimate reduced output per customer, the task force prepared the following table, which compares customer scheduled deliveries with contractual withdrawal rights for the Keystone storage facility. It appears that on the coldest day, February 2, shortfalls were most significant not for NMGC, but for EPE, SRP and the two marketers Sequent and Tenaska.

**Keystone Storage Scheduled Deliveries Relative to Contractual Rights**

| Total (MMbtu) | WD Rights | Scheduled Deliveries | 2-Feb | 3-Feb | 4-Feb |
|---|---|---|---|---|---|
| Arizona Electric Power | (6,000) | | - | (1,687) | (6,000) |
| Atmos Energy | (20,000) | | (5,096) | (2,009) | (20,000) |
| BP Energy Company | (17,000) | | (2,500) | (7,706) | (17,000) |
| El Paso Electric | (26,000) | | - | (12,730) | (26,000) |
| New Mexico Gas | (140,000) | | (140,000) | (140,000) | (52,510) |
| Salt River Project | (35,000) | | (11,667) | (24,791) | (35,000) |
| Sequent Energy | (27,000) | | (4,793) | (19,125) | (27,000) |
| Tenaska Marketing | (55,500) | | (14,718) | (24,112) | (55,500) |
| **Total** | (326,500) | - | (178,774) | (232,160) | (239,010) |

## Natural Gas Curtailments to Retail Customers

The retail customer is the last link in the natural gas delivery chain, taking gas for home or business consumption from LDCs. LDCs receive their gas from interstate or intrastate pipelines at a delivery point called the "citygate." They distribute the gas through a large network of increasingly smaller diameter pipes to homes and businesses in the distribution area. LDC distribution networks operate at much lower pressures than transportation pipelines, but must maintain certain minimum pressures in order to deliver gas to end users. Some large LDCs use compressors to help maintain minimum delivery pressure, but others rely solely on pressure supplied by the upstream pipelines.[182]

When receipt pressures from the pipelines fall, or when consumer demand for gas exceeds the volume being delivered to the citygate, gas pressure within the LDC network will decline correspondingly. In such instances, LDCs must reduce

[181] The causes of the generating unit outages experienced by EPE are described in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

[182] NaturalGas.Org, *Natural Gas Distribution*, http://www.naturalgas.org/naturalgas/distribution.asp.

the amount of gas being consumed to prevent pressures from falling to the point where the entire system could fail. LDCs typically do this by first seeking voluntary curtailment from large users. If voluntary curtailment fails to stabilize gas pressure in the system, they will further reduce consumption by cutting off sections of the network, usually beginning with remote sections that would be the first to fail under strained conditions.[183]

**State Regulation of Curtailment**

Arizona, New Mexico, Texas, and California all regulate curtailments by LDCs in their states, but generally grant LDCs a great deal of discretion in determining how curtailments are implemented.

In Arizona, for example, the Arizona Administrative Code directs utilities to file, as a part of their general tariffs, a procedural plan for handling severe supply shortages or curtailments.[184] The definitions of customer classes and the priority of curtailment are left to the utilities. Southwest Gas's Arizona curtailment rule places residential and other human needs customers at the highest service priority. Electrical generators are classified below that, at priority 2 or 3, depending on the amount of gas they consume.

New Mexico also requires LDCs to create and file a list of customer classifications prioritizing curtailments during a system emergency, but does not prescribe how customers should be ranked.[185] NMGC Original Rule 21 sets forth the company's curtailment priorities, assigning the highest priority to residential and other human needs end users, including suppliers of service to human needs customers.[186] Under the NMGC plan, electrical generators fall within this highest priority category. Zia gives the highest curtailment priority to residential and small commercial or industrial customers.[187]

---

[183] Transcript of Testimony of Timothy A. Martinez at 15, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Apr. 20, 2011) (No. 11-00039-UT).

[184] ARIZ. ADMIN. CODE § 14-2-308(H) (2010).

[185] N.M. CODE R. § 17.10.660.10(E)(1) (2011).

[186] N.M. Gas Co., Original Rule No. 21 IV (2009), *available at* https://www.nmgco.com/Regs/Rule21.pdf.

[187] Zia Natural Gas Co., Second Revised Rule 21 (C) (1997).

In Texas, state law provides that the highest priority of service should be given to "residences, hospitals, schools, churches, and other human needs customers," but LDCs have the authority to set their own priorities, which override the general provisions if the TRC approves the LDC's plan. The TRC-approved plan of Atmos Energy, for example, classifies electric generators several levels below residential customers.[188] Texas Gas Service's curtailment plan gives top priority to residential customers, ranking all commercial and industrial users below them.[189]

The California Public Utility Commission allows LDCs to set curtailment priorities, subject to PUC approval, and it has specifically declined to mandate priority service for electric generators.[190] Both San Diego Gas & Electric Company (SDG&E) and SoCalGas assign the highest priority of service to all residential customers and to small core commercial customers (including some electric generators) that use less than 20,800 therms per month.[191]

**Restoration of Gas Service Following a Curtailment**

Restoration of gas service to residences following curtailment is a lengthy process that must be performed by trained, qualified personnel. The first step is to shut off each individual gas meter. The LDC's distribution lines and lines from the meters to homes must then be purged of air and re-pressurized with gas. Once this is done, workers visit each home, inspect gas appliances for safety, open meter valves, relight pilot lights, and confirm that the appliances are operating safely. This can only be done when the customer is home, and if workers find that any appliances are not operating properly, service cannot be restored to that home until repairs have been made.

---

[188] *In re Curtailment Program of Lone Star Gas Co.,* Order No. 496, Docket No. 496 (Texas Railroad Comm'n Oct. 15, 1973).

[189] Curtailments, El Paso Texas Gas Service Area Gas Tariff, Third Revised, § 14.2.

[190] Pub. Util. Comm'n of Cal., Opinion Declining to Provide Service Priorities to Electric Generators in the Event of a natural Gas Shortage, No. 01-12-019 (2001), available at http://docs.cpuc.ca.gov/published/Graphics/11821.pdf.

[191] Annual Notice, San Diego Gas & Electric, Information on Natural Gas Services and Programs (Feb. 26, 2010) (on file with author); *Continuity of Service and Interruption of Delivery Rule 23(B),* SOUTHERN CALIFORNIA GAS CO. at 1, http://www.socalgas.com/documents/business/23.pdf. A therm is 100 MMBtu.

## The February 2011 Curtailments

From February 2 through February 4, 2011, LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas. Areas affected included the cities of El Paso, in Texas (863 customers) Tucson (14,620) and Sierra Vista (4,596) in Arizona, and Hobbs (406), Ruidoso (50), Alamogordo (2,385), Silver City (290), Tularosa (1,445), La Luz (475), Taos (8,505), Red River (557), Questa (548), Española (12,367), Bernalillo (3,172), and Placitas (1,114) in New Mexico.

### The New Mexico Curtailments and Outages

#### Zia Natural Gas Company

The city of Hobbs, in southeastern New Mexico, was the first to experience gas outages. Its LDC, Zia Natural Gas Company, receives gas from DCP Raptor Pipeline, LLC, (DCP) an intrastate pipeline that receives its supply from processing plant tailgates and wellheads. Zia serves approximately 11,000 retail customers in the Hobbs area.

On February 1, 2011, DCP fell behind for a two-hour period on deliveries to Zia because of wellhead freeze-offs and other supplier issues. However, the pipeline made arrangements with the Northern Natural Gas (NNG) pipeline to reverse the flow of gas at a DCP/NNG interconnect near Hobbs, making additional supplies available. Thus, according to both Zia and DCP, DCP's temporary supply shortage did not adversely affect customers in Hobbs.

At approximately 3:00 AM on February 2, an electrical blackout affected approximately 2,065 homes in the northeast area of Hobbs.[192] Zia was not notified of the blackout until approximately 7:30 AM, but at 5:55 AM, the company received a low pressure alarm from a regulator station on the northeast end of the system. Personnel sent to the site reported that pressure was well below normal levels, and Zia immediately contacted DCP, which informed them that a plant had gone out of service due to a cold weather-related mechanical failure and that DCP was attempting to address the problem. The DCP plant in question did not return to service until February 6.

Zia reported that it was able to continue supplying gas to all its customers in Hobbs until approximately 7:30 AM that day, when electric power was restored. At that point, there was a surge in demand as gas appliances that had been unable

[192] SPS is the city's electrical supplier.

to operate without electricity simultaneously came back in service. Almost immediately, Zia began receiving calls from customers reporting that they had no gas or very low gas pressure. In all, 406 customers called in to report supply problems.

Zia believes the reason for the outages was the sudden surge in demand when electric power came back online, coupled with the low line pressures that resulted from the DCP plant outage. That morning, Zia began the process of relighting the primarily residential customers that were affected, and the company was able to restore all gas service by 10:00 PM the same day.

Zia customers in the Ruidoso, New Mexico area also lost gas service as a result of the cold weather events. During the early morning hours of February 3, the Ruidoso area experienced power outages that lasted until 8:00 AM. At the same time, receipt pressures from El Paso were declining.

At approximately 7:30 AM, Zia began receiving complaints of no gas or low gas pressure. Personnel sent to the area reported extremely low pressures, and did what they could to boost flow by bypassing regulator stations. Through a local radio station that was operating on backup power, the company asked the community to cut back on gas use. Pressures were critically low through most of the morning but began to rise just before noon. However, when electrical power was restored, there was a surge in demand that further strained the system. A total of 50 customers at the far reaches of the distribution system lost gas service that day, but their service was fully restored by the end of the working day.

According to Zia, it has no industrial or large load single customers; almost all of its customers are residential or small commercial users. Thus, it was not possible for Zia to reduce demand by curtailing large commercial accounts. Zia believes the Ruidoso outages were caused by high demand on the system, combined with low supply pressures and the surge in demand that occurred when power was restored.

New Mexico Gas Company

NMGC serves more than 500,000 retail customers in towns, pueblos, cities and rural areas throughout New Mexico. NMGC's distribution system is divided into two areas: (1) the north segment, serving the Albuquerque metropolitan area and communities to the north; and (2) the south/remotes segment, consisting of (a) the southeast system, which serves the towns of Roswell, Artesia, Carlsbad, Lovington, Eunice, and surrounding areas, and (b) remote locations, including Alamogordo, Silver City, Clovis, Portales, Tucumcari, Hatch, and Truth or Consequences. The north and the south/remotes segments are served by the

Transwestern and EL Paso interstate pipelines and by other third-party pipelines. The remote locations that lost gas service during the period in question were supplied solely by El Paso.

NMGC: The North Segment

On February 2, 2011, NMGC personnel monitoring the company's north segment, which serves the Albuquerque metropolitan area and communities to the north, noted that gas volumes at the company's receipt points with El Paso and Transwestern were not increasing, indicating that much of the company's nominated gas was not being received. However, although line pack was decreasing, the system was still operating within sustainable limits. Based on additional gas purchases made during the day, the company expected pressures at receipt points to increase at 9:00 PM that night and at 8:00 AM the following morning.

As a precautionary measure, the company began telephoning large commercial users on the morning of February 2, seeking voluntary reductions of gas consumption. NMGC employees, working from a list of the company's 200 largest customers, placed phone calls or sent emails to points of contact on the list. Customers were informed that the company was expecting a gas shortage and that cutting back on gas usage was necessary to maintain service to home, hospitals, and other top priority consumers.

In some instances, large customers agreed to reduce their gas use, either by switching to alternative fuel supplies, lowering thermostats, or shutting down equipment or manufacturing processes. However, some of the customers (approximately 10 percent of those contacted) indicated that they could not or would not reduce their usage.

One of the large customers NMGC contacted was PNM, which operates two gas-fired generating plants in the Albuquerque area. Contacted at 9:42 AM on February 2, PNM responded by stating that no curtailment options were available to it, and that the plants would be increasing their gas consumption to meet power generation requirements.

In other instances, NMGC was unable to reach a point of contact for its large customers and could only leave messages requesting cutbacks or return calls. NMGC estimates that it was ultimately able to contact 30 percent of the top 200 users to request voluntary curtailment.

NMGC was expecting the supply problems to improve at 9:00 PM on February 2, because of the extra gas it had purchased. When line pressure did not improve at that time, due to the inability of suppliers to put the purchased gas on the system, the company began contacting other pipelines and suppliers in an effort to purchase more gas.

During the early morning hours of February 3, NMGC personnel monitoring line pressure on the north segment, from both the company's gas control center and field locations, believed the system would have enough gas to meet the anticipated morning demand, based on the amount of gas that had been used the previous day. However, beginning at 7:12 AM, the demand for gas rose to unprecedented levels, even though temperatures were only slightly higher than the day before.[193]

Even at this point, however, the company concluded that if pressures at receipt points began to rise at 8:00 AM, as expected based on the additional gas that had been purchased, they would be able to meet the increased demands on the system.

However, pressures continued to decline at 8:00 AM, leading NMGC to conclude that it was in immediate danger of losing the entire system and that they must immediately reduce demand by cutting off sections of the system. At around this time, the company also began receiving reports of no gas or low gas pressure in the Albuquerque area, further indicating that its system was near collapse.

Because NMGC needed to act quickly, and because the distribution systems in the larger metropolitan areas of Santa Fe and Albuquerque were not configured so as to allow curtailment of large numbers of customers by closing just a few valves, the company decided to curtail the areas served by the Taos mainline, which runs from the company's north-south mainline at Otowi junction, located approximately 80 miles north of Albuquerque. That line serves the communities of Española, Dixon, Taos, Questa, and Red River. The Otowi Junction valve was closed at 8:37 AM, cutting off service to those communities.

The company also curtailed two additional communities just north of Albuquerque by closing two valves that supplied the town of Bernalillo at 8:55 AM and 9:14 AM, and by closing one valve to the town of Placitas at 9:29 AM.

[193] NMGC told the task force that although temperatures were slightly warmer on the morning of February 3, compared to the previous morning, demand was nevertheless higher, despite NMGC's efforts to seek voluntary curtailment from large users, and despite appeals through the media for residential customers to conserve gas. NMGC does not know the reason for the increased demand.

If pressures continued to decline, the next step anticipated by NMGC was curtailing sections of the Albuquerque metropolitan area. Curtailment options in that area were limited, however, because of the lack of shut off valves capable of curtailing a large block of customers at one time. The company nevertheless prepared for curtailments by sending a crew with a backhoe to two sections of pipeline that served 2,000 customers, with the intention of digging up the pipes and pinching them off.[194]

At 9:20 AM, following discussions between NMGC and PNM about system conditions, PNM decided to switch its Delta Person (Cobisa) power plant from gas to backup fuel oil. PNM was unable to make the changeover because of a faulty valve, and as a result the plant went out of service and did not draw gas from the system for the duration of the cold weather event.

By 10:30 AM, pressure on the north segment had stabilized and had begun to increase. The restoration process was already underway at that point, as NMGC teams began shutting off meter valves to individual customers so that the lines could be purged and recharged.

NMGC: The South/Remotes Segment

On February 2, line pressure on El Paso's delivery pipeline to NMGC's south/remotes segment steadily declined, dropping below contract pressure[195] at approximately 10:00 AM. As the day progressed, NMGC personnel monitored line conditions and began considering the possibility that if conditions worsened, they would have to curtail certain areas.

At approximately 3:00 PM, NMGC started calling large customers on the south segment to ask them to voluntarily reduce their gas consumption. Some of the larger customers, such as Western New Mexico University, Silver City School System, and the Alamogordo School System, agreed to reduce usage, but two other large users -- Holloman Air Force Base and the White Sands Missile Range -- could not be reached that day, reportedly because the bases were closed because of the weather conditions and the contact persons were not present. (Holloman Air Force Base was successfully contacted the following day at approximately 1:00 AM, and agreed to reduce its usage at that time.)

[194] Transcript of Testimony of Doug Arney at 4, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers,, NMPRC (Mar. 17, 2011) (No. 11-00039-UT).

[195] Contract pressure is the minimum gas pressure, measured in pounds per square inch, that a pipeline agrees to provide to a customer at a given delivery point.

Shortly before 5:00 PM on February 2, NMGC received notice from El Paso that line pressure was not expected to improve during the next 24 hours.

At 1:50 AM on February 3, NMGC began cutting off service to schools and non-essential government buildings in Alamogordo. At 2:36 AM, seeing that conditions were continuing to deteriorate, the company declared a system emergency on the south segment.

At 3:00 AM, NMGC cut off service to the communities of Tularosa and La Luz, which are located at the end of the NMGC distribution pipeline that serves Alamogordo. Line pressures continued to decline, however, and at 5:05 AM, the company shut off one section of Alamogordo. At 6:00 AM, the Alamogordo area experienced an electrical blackout. When electricity was restored at 8:00 AM, the resulting surge in demand for gas caused pressure to drop to zero on the southern part of the Alamogordo system, forcing NMGC to cut off that section as well. In all, more than 4,300 customers lost gas service in Alamogordo, Tularosa and La Luz, out of a customer base of approximately 15,000. By 9:25 AM, pressures in the Alamogordo area began to stabilize, and by 3:00 PM that day, the company began restoring service to curtailed areas.

Another community on the NMGC south/remotes segment that lost a portion of its gas service on February 3 was Silver City. According to NMGC, the Silver City distribution network lacked the capacity to meet the unprecedented demand for gas on February 2 and February 3, due to system limitations. NMGC stated that in 2007, it determined that the system's maximum operating pressure should be reduced from 40 psi to 30 psi for safety reasons. With that limitation, the system could not transport the volumes demanded by customers.

Although two large users in that area, the Silver City Consolidated School District and Western New Mexico University, agreed to curtail gas use on February 2, mitigating demand on the system to some extent, pressure continued to drop. NMGC curtailed a section of Silver City at approximately 6:00 AM the following day, February 3, in order to avoid total collapse of the system. Pressure began to recover by 11:00 AM, and restoration efforts began shortly thereafter. A total of 271 out of approximately 9,200 customers in the area lost gas service due to the curtailments.

NMGC has informed the task force that it is in the process of making improvements to the Silver City distribution system that should allow it to meet peak loads of the sort that occurred during the February event.

Restoration of Service

Closing individual gas meters, which is the first stage of restoring service, began shortly after NMGC cut off service on the morning of February 3. In some areas, NMGC personnel began shutting off meters within minutes of the curtailment. As restoration efforts got underway, the company sought additional help through its mutual assistance agreements with the American Gas Association and the Southern Gas Association, whereby member LDCs agree to help each other in emergency situations. That morning, NMGC asked other member LDCs by email and by conference call to send personnel to help them restore service in the affected areas. Out-of-state LDCs responded by sending qualified service personnel, who began to arrive the following day. NMGC also sought help from other New Mexico LDCs, and hired local contractors and plumbers to help restore service. Police, fire department, and National Guard personnel all eventually played roles in the effort to restore service.

Relighting continued through the weekend and into the following week, with a workforce of more than 700 persons participating. Service was restored to some areas as early as February 5, but the statewide relighting effort was not substantially completed until the following week, on February 10.

The Arizona Curtailments and Outages

Southwest Gas, a multistate LDC whose service areas include the cities of Tucson and Sierra Vista in Arizona, was forced to curtail service to parts of those cities on February 3 due to low pressures at receipt points with El Paso. After El Paso declared a system-wide Critical Operating Condition at 11:52 AM on February 2, due to declining line pack and drop offs in gas supply, Southwest Gas's management met at 1:00 PM to plan for increased monitoring of the distribution systems. Shortly thereafter, at about 2:00 PM, the company started calling large commercial customers to alert them to possible curtailments.

At 10:00 PM, as conditions on the El Paso pipeline continued to deteriorate, Southwest Gas concluded that it might be necessary to cut off some customers in order to preserve system operability. When pressures on the Sierra Vista system reached a critical stage at approximately 3:30 AM on February 3, the company identified several sections of the system that should be shut down to reduce demand. At approximately 6:30 AM, crews began closing valves in Sierra Vista and Tucson. Out of a total of 17,801 customers in Sierra Vista, 4,596 were shut off; out of a total of 279,362 customers in Tucson, 14,620 were shut off.

Starting at approximately 5:00 AM on February 3, the company began curtailing several large commercial customers, including an electric power plant in

Tucson. Other commercial users voluntarily curtailed or reduced their use throughout the day.

By 8:30 AM, pressures began to stabilize and recover, and the restoration process was initiated. Southwest Gas brought in 130 employees from other divisions in California, Nevada, and Central Arizona to help with the relighting process, and service was fully restored on the afternoon of February 7, 2011.

The Texas Curtailments and Outages

Texas Gas Service (TGS) serves several communities in Texas, with a total of 616,462 residential, commercial, and transportation customers. The City of El Paso is one of those communities, and during the week in question it was the only city in Texas to experience gas curtailments, with 863 residential customers (out of approximately 231,000) losing service.

Gas is delivered to TGS by the El Paso and ONEOK WesTex Transmission, L.L.C. (ONEOK WesTex) pipelines. Beginning around February 2, TGS received cuts from its suppliers and had to make alternative arrangements to obtain gas for the anticipated cold weather demand, including buying compressed natural gas (CNG) for expedited delivery by tanker truck from Arizona. The company also experienced low delivery pressures from El Paso later that week. However, those factors were not responsible for the service disruptions that occurred. According to TGS, the El Paso system experienced unprecedented demand during the winter event, as much as 41 percent higher than the previous historical peak.[196] The company's distribution system was simply unable to handle that much volume.

Beginning on February 2, at approximately 8:00 AM, residential customers began reporting low pressures. Shortly thereafter, customers in low pressure areas of the system began losing service. TGS responded to each reported outage, and in some instances service was restored the same day. A total of 863 customers lost service during an approximately 24 hour period. Service was fully restored by February 5. The restoration process was hampered by icy road conditions, and by the fact that TGS workers could not restore service when customers were not at home.

In order to alleviate pressure on the system during the period of peak demand, TGS asked ten large transportation customers to reduce consumption at

[196] On February 3, 2011, TGS delivered 258,853 MMBtu to its customers in El Paso. The previous peak at that location was 184,088 MMBtu, in January 2007.

approximately 10:00 AM on February 3. The company also restricted service to 36 commercial customers in areas that were experiencing low pressure, and on February 3, extended a gas main to boost pressures in one of the affected areas. In addition, TGS used two CNG tankers to help deal with low pressure issues. One was used to maintain service to a hospital, and the other was deployed to assist in the restoration process in one of the affected neighborhoods.

TGS plans to make additional system improvements to increase delivery capacity by extending gas mains in several areas that experienced low pressures during the period in question. The cost of these improvements is expected to total more than $1.7 million and the company estimates that they will be completed by September 30, 2011.

The California Curtailments

SoCalGas and SDG&E are separate utility companies, both owned by Sempra Energy. SoCalGas serves approximately 20 million customers in Central and Southern California; SDG&E serves approximately 3.4 million customers in Orange and San Diego Counties, California. SoCalGas operates the natural gas transportation systems of both companies.[197]

Beginning on January 31, 2011, SoCalGas monitored weather developments in the Southwest and was aware of the supply problems that had developed because of the severe cold weather. The company responded to supply shortfalls by increasing withdrawals from on-system storage and by purchasing operational gas to support the southern system, which cannot be served by storage gas. Delivery shortfalls were highest on February 2 and February 3. SoCalGas estimates that the net cost of the operational gas it purchased was $3.81 million, representing the purchase price of the gas less the price at which SoCalGas was later able to sell it.

On the morning of February 3, the company issued a curtailment advisory to non-core (lower priority) customers, informing them that curtailments could occur. At 1:15 PM, due to the continuing severe weather and its effect on production, the company declared a system emergency and curtailed transmission service on its southern system for all interruptible and some firm non-core customers by limiting the amounts they could withdraw from the system.

SoCalGas curtailed 19 interruptible retail non-core and electric generator customers, and 40 firm non-core and electric generator customers. SDG&E

[197] Sempra Energy, *Our Companies*, http://www.sempra.com/companies/companies.htm.

curtailed all its interruptible load and all its firm service to three electric generator customers. SoCalGas reported that its non-core customers and electric generator customers generally complied with curtailment limits during the emergency. When the CAISO informed the two companies that approximately 500 MW of total generation was needed from two of the curtailed electric generators in order to ensure reliable grid operations, SoCalGas and SDG&E adjusted the curtailments so that the two plants could provide the necessary generation.

Resumption of Production

Weather conditions moderated slightly in the Southwest on February 3 and improved further on February 4, rising above freezing for the first time in days. Although production did not return to pre-event levels for several weeks, consumer demand slackened with the warmer weather, and line pack and system pressure rose steadily on the interstate pipelines. As a result, El Paso issued a warning of a system pack condition on February 5, and declared a system -wide Strained Operating Condition for high line pack February 6, 2011.[198]

## Impacts of the Event on Natural Gas Prices

Gas prices responded to the winter weather and associated freeze-offs, although the increases were short-lived and not exceptionally dramatic. Some points in the midcontinent and southwest regions did post increases of approximately two dollars to three dollars per MMBtu, which were gains of 40 to 60 percent relative to February 1. West Texas prices were particularly strong with a basis at Waha of $2.60 relative to Henry Hub.[199] Southern California prices at Ehrenberg and Needles also traded higher by $1.77, reflecting upstream supply shortfalls.

The price gains in east Texas and south Texas were more muted, despite the freeze-offs extending to the Gulf Coast, and limited to $0.50 to $0.60 per MMBtu. The Houston Ship Channel, however, had an increase of almost $1.57.

The NYMEX (New York Mercantile Exchange) futures contract was flat to declining for the week. Cash prices at Henry Hub increased by only $0.29.

Most gains were gone by February 5, at which time warmer weather had returned. Prices on February 8 actually traded below those of February 1.

---

[198] Production figures from Bentek, supporting documentation for *Deep Freeze Disrupts U.S. Gas, Power, Processing* ( Feb. 8, 2011); information provided to the task force by pipelines.

[199] Basis is the price differential between, in this case, Henry Hub and Waha.

The following table shows spot prices at a variety of locations for February 1 to February 8.[200] Daily closing prices are also listed for the NYMEX March gas futures contract, which is based on delivery at Henry Hub. The NYMEX price was relatively unaffected by the spot price increases during February 1 to February 8, suggesting that traders viewed the increases as a temporary, weather-related event.

Spot Prices

| Flow Date | 1-Feb | 2-Feb | 3-Feb | 4-Feb | 5-Feb | 6-Feb | 7-Feb | 8-Feb |
|---|---|---|---|---|---|---|---|---|
| Waha | $ 4.47 | $ 4.79 | $ 5.80 | $ 7.30 | $ 4.76 | $ 4.76 | $ 4.76 | $ 4.25 |
| El Paso-Permian | $ 4.40 | $ 4.75 | $ 5.74 | $ 7.23 | $ 4.86 | $ 4.86 | $ 4.86 | $ 4.19 |
| Transwestern-San Juan | $ 4.35 | $ 4.66 | $ 5.73 | $ 6.40 | $ 4.49 | $ 4.49 | $ 4.49 | $ 4.11 |
| El Paso-San Juan | $ 4.30 | $ 4.51 | $ 5.77 | $ 6.52 | $ 4.51 | $ 4.51 | $ 4.51 | $ 4.10 |
| East Texas, Carthage Hub | $ 4.36 | $ 4.42 | $ 4.63 | $ 4.89 | $ 4.49 | $ 4.49 | $ 4.49 | $ 4.28 |
| Houston Ship Channel | $ 4.40 | $ 4.37 | $ 4.61 | $ 5.91 | $ 4.43 | $ 4.43 | $ 4.43 | $ 4.29 |
| South Texas, Tennessee Zone 0 | $ 4.38 | $ 4.39 | $ 4.62 | $ 5.03 | $ 4.40 | $ 4.40 | $ 4.40 | $ 4.28 |
| Oneok Oklahoma | $ 4.49 | $ 5.31 | $ 7.06 | $ 6.28 | $ 4.59 | $ 4.59 | $ 4.59 | $ 4.40 |
| SoCal Gas | $ 4.40 | $ 4.50 | $ 5.47 | $ 6.17 | $ 4.52 | $ 4.52 | $ 4.52 | $ 4.22 |
| Henry Hub | $ 4.42 | $ 4.43 | $ 4.55 | $ 4.70 | $ 4.48 | $ 4.48 | $ 4.48 | $ 4.33 |
| NYMEX Contract | $ 4.42 | $ 4.35 | $ 4.43 | $ 4.34 | $ 4.31 | $ 4.31 | $ 4.31 | $ 4.10 |

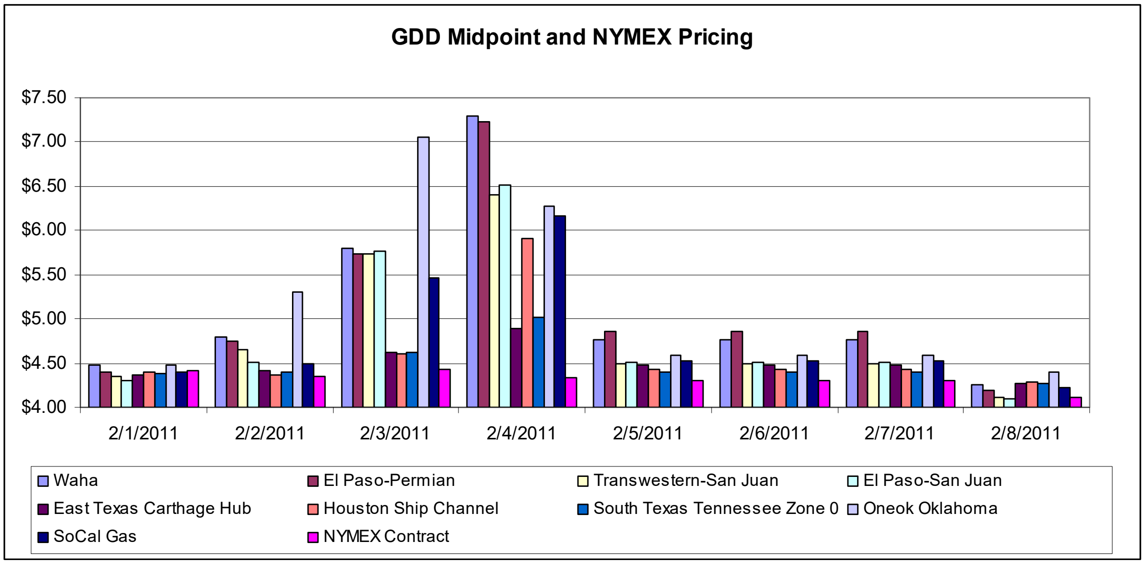
The following table shows the basis for the same locations relative to cash prices at Henry Hub.

Basis

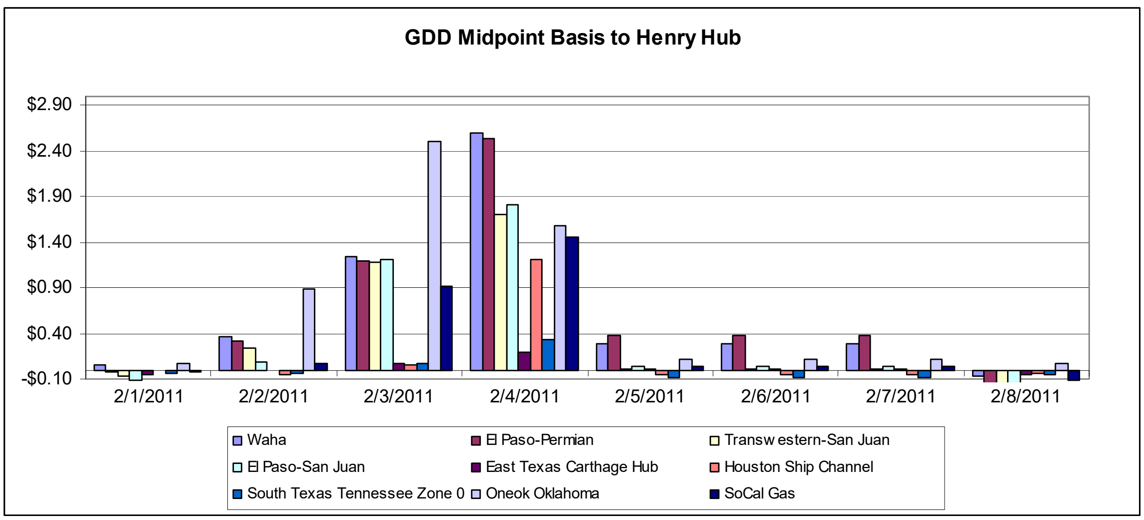
| Flow Date | 1-Feb | 2-Feb | 3-Feb | 4-Feb | 5-Feb | 6-Feb | 7-Feb | 8-Feb |
|---|---|---|---|---|---|---|---|---|
| Waha | $ 0.05 | $ 0.37 | $ 1.25 | $ 2.60 | $ 0.29 | $ 0.29 | $ 0.29 | $ (0.08) |
| El Paso-Permian | $ (0.02) | $ 0.32 | $ 1.19 | $ 2.53 | $ 0.38 | $ 0.38 | $ 0.38 | $ (0.14) |
| Transwestern-San Juan | $ (0.07) | $ 0.24 | $ 1.18 | $ 1.70 | $ 0.02 | $ 0.02 | $ 0.02 | $ (0.22) |
| El Paso-San Juan | $ (0.12) | $ 0.08 | $ 1.22 | $ 1.82 | $ 0.04 | $ 0.04 | $ 0.04 | $ (0.23) |
| East Texas Carthage Hub | $ (0.05) | $ 0.01) | $ 0.08 | $ 0.19 | $ 0.01 | $ 0.01 | $ 0.01 | $ (0.05) |
| Houston Ship Channel | $ (0.01) | $ (0.06) | $ 0.06 | $ 1.21 | $ (0.05) | $ (0.05) | $ (0.05) | $ (0.04) |
| South Texas Tennessee Zone 0 | $ (0.04) | $ (0.04) | $ 0.07 | $ 0.33 | $ (0.08) | $ (0.08) | $ (0.08) | $ (0.05) |
| Oneok Oklahoma | $ 0.07 | $ 0.88 | $ 2.51 | $ 1.58 | $ 0.12 | $ 0.12 | $ 0.12 | $ 0.07 |
| SoCal Gas | $ (0.02) | $ 0.08 | $ 0.92 | $ 1.47 | $ 0.04 | $ 0.04 | $ 0.04 | $ (0.11) |

[200] *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 1, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 2, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 3, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 4, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 5, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 6, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 7, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 8, 2011, at 1-2. Reprinted with permission of Platts.

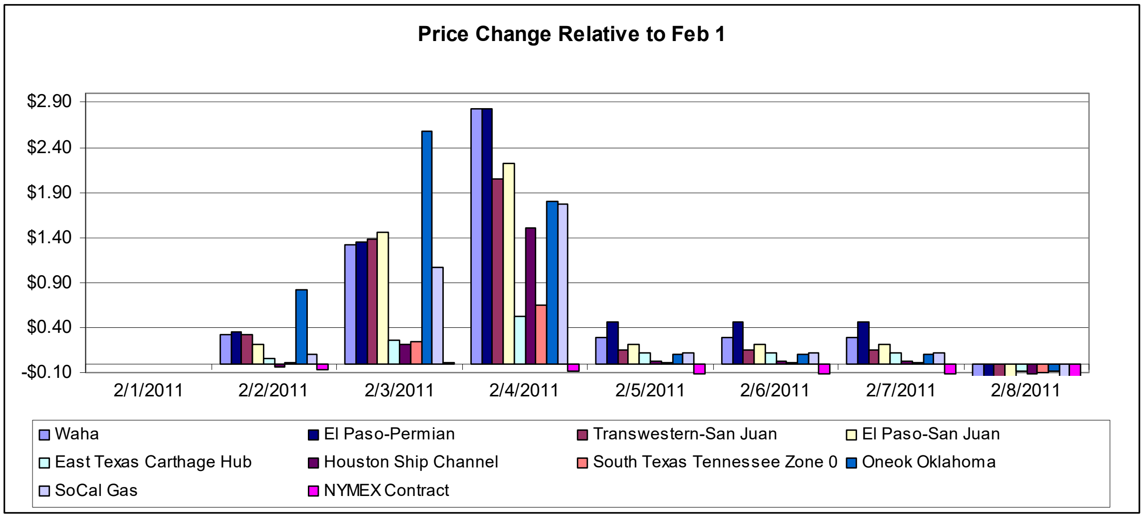
The following three charts show the absolute prices, basis, and price change of natural gas during the week of the event.




**Source: Task Force analysis based on Platts data**




**Source: Task Force analysis based on Platts data**




**Source: Task Force analysis based on Platts data**

The causes of the electric generator failures and the natural gas shortfalls described above are examined in the following section of this report, entitled "Causes of the Outages and Supply Disruptions."

# VI. Causes of the Outages and Supply Disruptions

The precipitating cause of the rolling blackouts experienced in Texas and Arizona during the February 2011 cold weather event was the large number of electric generator outages. The principal cause of the gas service curtailments experienced in several southwestern states was the production declines in the supply of natural gas, which led to volume and pressure reductions in the pipelines. The task force has analyzed in detail the causes of these outages and declines, and found that the majority of them were directly or indirectly related to the weather, particularly so with respect to production declines in the gas supply. This section of the report describes in detail those causes, both weather and non-weather-related.

While the storm itself was an uncontrollable event of force majeure, the question arises as to whether the facilities affected should have been better prepared to withstand the severe weather. Was the cold spell so unprecedented that the entities responsible for those facilities could not reasonably be expected to have taken preventative actions? Or did entities fail to take into account lessons that could have been learned from past cold weather events in the Southwest? These questions are addressed in the next section of this report, entitled "Prior Cold Weather Events."

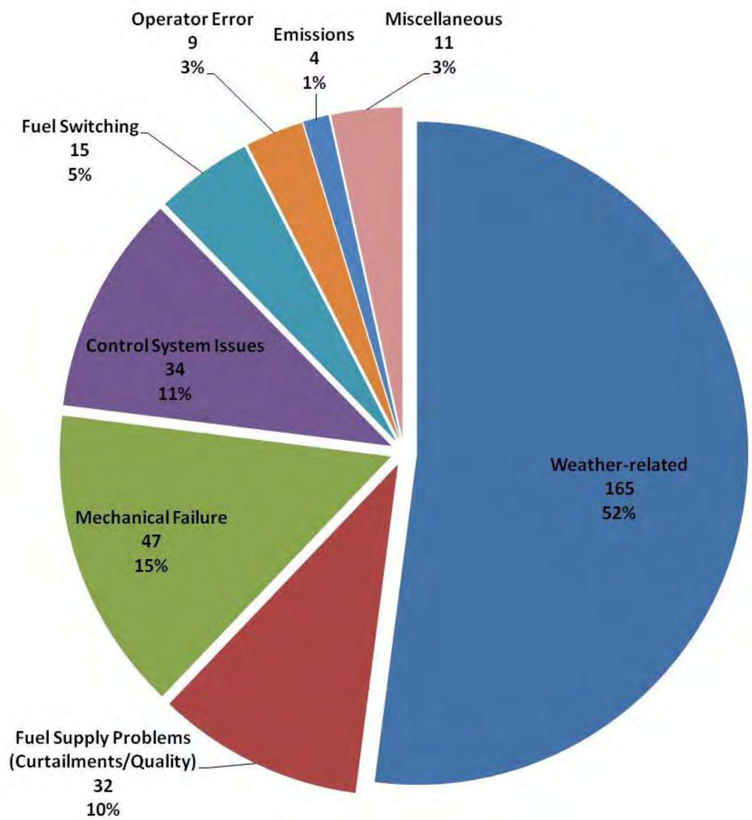
## A. Electric

The rolling blackouts that utilities implemented during the cold weather event, which centered in Texas (ERCOT, EPE) and Arizona (SRP), were almost entirely the result of trips, derates, and failures to start of the generating units in those regions. The localized blackouts experienced by PNM in New Mexico, however, were caused by transmission trips. Units in Oklahoma and Kansas also experienced generator outages, but these did not result in blackouts.

The task force has analyzed these various generator outages to determine their underlying causes. By far, the most common cause of the outages was the cold weather, most commonly when sensing lines froze and caused automatic or manual unit trips. There were also several outages that were due to operator error or non-weather-related equipment failures. In a lesser number of cases, an interruption in the supply of natural gas prevented gas-fired units from providing power.

The following two charts[201] and supporting table depict the various causes of the trips, derates, and failures to start[202] for generating units throughout the Southwest, both by number of units and by MWhs.

**Southwest - Number of Units Tripped, Derated, and Failed to Start - Feb. 1 - 5, 2011**

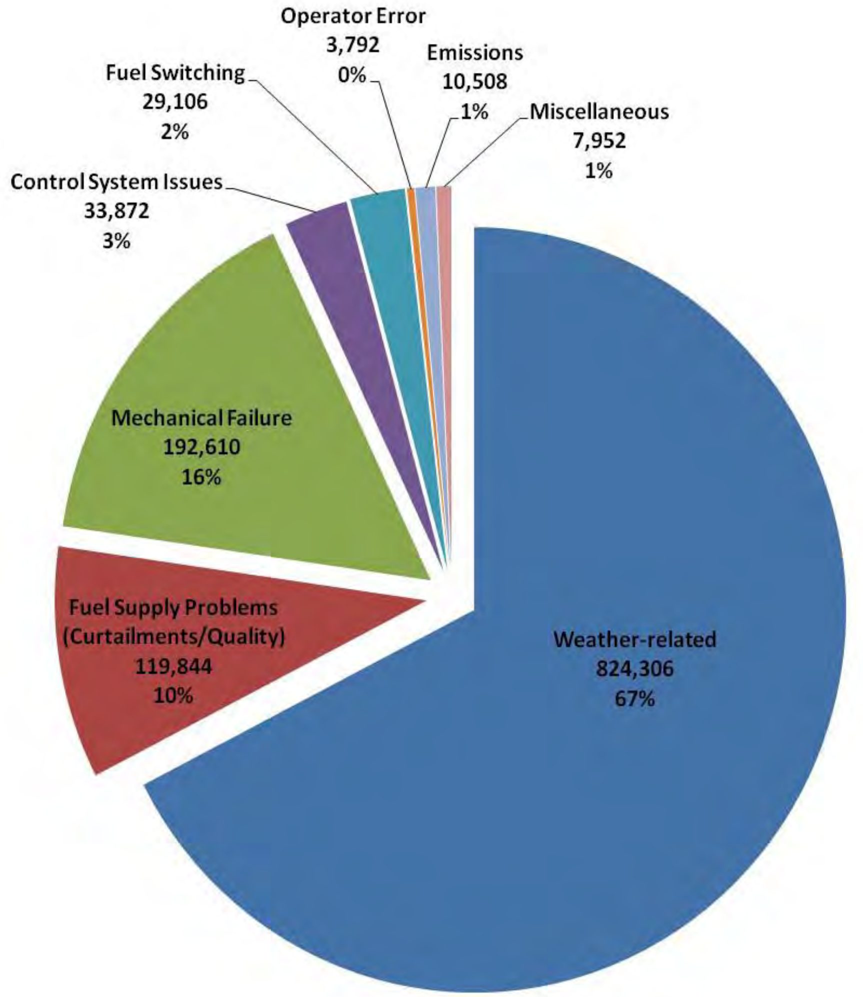



| | |
|---|---|
| Total Entries in Pie Chart: | 317 |
| Total Number of Units Forced Out, Derated, or Failed to Start: | 268 |

[201] Data includes generation in Texas (ERCOT and non-ERCOT), New Mexico, Arizona, and SPP. Units on the first chart are counted more than once if they failed multiple times from different causes (75 units failed on more than one occasion during the event); however, they are only counted once per cause. Data used in the preparation of this chart are drawn from materials submitted to the task force by balancing authorities and generators. Data throughout the section are drawn from materials submitted by transmission operators, generators, producers, processing plants, and pipelines.

[202] Trips totaled 167 units (30,376 MW), derates totaled 57 units (5024 MW), and failures to start totaled 44 units (4743 MW).

## Southwest – MWh[203] of Generation Unavailable - Feb. 1 - 5, 2011




Total MWh in Pie Chart*: 1.2 Million
Total MWh of Load Served in affected Southwest Areas: 6.7 Million
Generation unavailable as a percentage of Total MW-hours Load Served: 18%
*Total time period is 106 hours (Midnight going into Feb. 1 through 10 AM Feb. 5)

[203] Megawatt hours were used for this chart to give an indication of the time impact of the outages, derates, and failures to start. (From an operator's perspective, a smaller unit out for a longer time might have a greater impact than a larger unit out for a short time, depending on the circumstances.) To capture this time factor, each instance of unavailable capacity was multiplied by the associated duration of the particular outage or derate and the results were summed.

## Supporting Table (Southwest):

| Cause | # of Unique Units | MWh |
|---|---|---|
| Total Frozen Sensing lines: | 89 | 432,897 |
| Frozen - Drum level sensing lines | 48 | 150,000 |
| Frozen - Other Sensing lines | 41 | 282,896 |
| Frozen Equipment (General) | 21 | 153,393 |
| Frozen Water lines | 14 | 80,091 |
| Frozen Valves | 12 | 20,603 |
| Blade Icing (Wind Turbines) | 10 | 53,989 |
| Low Temperature Limits (Wind Turbines) | 17 | 80,389 |
| Transmission Loss | 2 | 2,944 |
| Fuel Supply Problems (Curtailments/Quality) | 32 | 119,844 |
| Mechanical Failure | 47 | 192,610 |
| Control System Issues | 34 | 33,872 |
| Operator Error | 9 | 3,792 |
| Emissions | 4 | 10,508 |
| Fuel Switching | 15 | 29,106 |
| Miscellaneous | 11 | 7,952 |

The large percentage of weather-related outages speaks in part to the design and construction of generating facilities in the Southwest. Unlike facilities in cold climates, generating stations in the Southwest are typically designed and constructed so that their boilers, turbines, and other auxiliary systems are exposed to ambient weather conditions. This design prevents heat build-up from occurring in the hot summer months. A more detailed discussion of generating plant design is contained in the appendix entitled “Power Plant Design for Ambient Weather Conditions.”

Sub-freezing temperatures can have adverse operational effects on generating stations if systems containing water do not have sufficient freeze protection, if pneumatic air systems do not have sufficient air drying capacity or freeze protection, or if equipment lubricants are not maintained above prescribed minimum temperatures. Generators with exposed elements typically employ a combination of heat tracing, insulation, wind breaks or enclosures, and heat sources to prevent freezing and to maintain minimum lubricant temperatures. Frozen sensing lines were a particular problem during the February cold weather event, when many generators automatically tripped offline due to faulty readings from transmitters whose sensing lines froze (most notably steam drum[204] level transmitters).

A detailed examination of the causes of the generator outages experienced within ERCOT, SRP and EPE during the February event, both weather and non-weather-related, is set forth below.

## Generation Outages in ERCOT

As a preliminary matter, the task force categorized by age and fuel type the ERCOT units that failed, to determine whether there was any statistical indication that older units or units of a given fuel type were more prone to developing problems. With respect to age, no strong correlation was found. The failure percentage of units with in-service dates before 1981 (19 percent) was actually less than their percentage contribution to the ERCOT fleet as a whole (22 percent).[205] The failure of units with recent in-service dates (between 2001 and 2010) represented 55 percent of the failures, which was slightly more than their contribution to the fleet as a whole (48 percent).

The results are more equivocal with respect to type of unit, where a more significant correlation was found with respect to combined cycle units. Otherwise, however, no significant correlation was found between failure and type of unit. Of ERCOT's combined cycle units, 48 percent failed, compared to their 35 percent of the total. For wind units, 16 percent failed, compared to their 15 percent of total units. For simple cycle units, 21 percent failed, compared to their 20 percent of total units. For gas-steam and coal units, the percentage that failed exactly matched their percentage contribution of total units (13 percent and 7 percent, respectively). Nuclear facilities account for only 1 percent of the total fleet, and no nuclear units failed.[206]

[204] Steam drums are used in boilers (excluding once-through supercritical boilers) to take in a mixture of steam and water coming from the boiler's waterwall tubes. The drum separates the steam from the water by gravity and mechanical separation (such as baffles). The water level in the drum is controlled to keep water in the waterwall tubes and to prevent water carrying over into the steam section of the boiler. The drum also functions to remove solids from the steam.

[205] This statistic and those immediately following are based on number of units, rather than on capacity. (Coal units, for instance, have a larger capacity contribution to the fleet as a whole than seven percent, which is their percentage contribution based on number of units.)

[206] The totals do not add up to 100 percent because certain other facilities have not been taken into account, such as hydro facilities and storage facilities.

For purposes of further analysis, the task force sorted by unit[207] the ERCOT generator trips, derates, and failures to start into three broad categories: weather-related, non-weather-related, and fuel supply. (The weather-related category considers only failures directly related to the weather; problems of insufficient fuel supply as well as outages and derates resulting from fuel switching, although indirectly related to the weather, are listed separately.) Direct weather-related causes accounted for 52 percent of the total failures, non-weather-related causes for 40 percent, and problems with fuel supply for nine percent.[208] Sub- categories within these major groupings, as well as specific examples of the various types of failures, are provided below.

## ERCOT Weather-Related Outages and Derates

The task force identified the various specific causes for the trips, derates, or failed starts in ERCOT between February 1 and February 5 that were due directly to the cold weather.[209] (Some of the other failures experienced by ERCOT generators, such as reduced supplies of natural gas, were indirectly related to the weather.) The task force has identified the specific causes of these weather-related failures, by number of units and number of MWs:

| Cause | No. of Units Lost | MW Lost |
|---|---|---|
| Frozen Sensing Lines (Total) | 68 | 15,255 |
| Frozen Drum Level Sensing Lines | (43) | (9438) |
| Frozen Other Sensing Lines | (25) | (5817) |
| Frozen Equipment (General) | 13 | 2942 |
| Frozen Water Lines | 12 | 1072 |
| Frozen Valves | 8 | 1501 |
| Blade Icing (Wind Turbines) | 10 | 709 |
| Low Temperature Limits (Wind Turbines) | 17 | 1237 |
| Transmission Loss | 2 | 89 |
| **Total Weather-Related** | **130** | **22,805** |

[207] A unit that failed multiple times for different reasons is counted under each separate reason; if it failed multiple times for the same reason, it is counted once. That convention applies as well to the three charts detailing ERCOT's weather, non-weather, and fuel failures.

[208] Numbers add up to slightly higher than 100 percent due to rounding.

[209] The weather effects stemmed not only from the prolonged cold, but from high wind chill factors. Although typically thought of as applying to living beings, wind chill also more quickly cools inanimate objects, such as water pipes, bringing them down to the current air temperature. Wind also causes the loss of radiant heat, which otherwise can protect equipment from freezing. This phenomenon is discussed at more length in the appendix entitled "Impact of Wind Chill."

A sample of the ERCOT generating units that experienced weather-related failures, categorized by the specific cause of failure, provides some insight into the variety of concerns with which the generator operators had to contend during the event, and illustrates the complexity of the protections needed for generating plant systems.

- **Frozen Sensing Lines:** Instrumentation provides operational data necessary to monitor and control the generator's systems. Typically, sensing lines containing a standing water column sense changes in pressure and a transducer produces an electronic signal that is transmitted to instrumentation or controls. In sub-freezing temperatures, if freeze protection is not employed on critical unit systems, the water in the sensing lines freezes, causing faulty signals and subsequent unit trips or derates. During the February event, frozen sensing lines were the leading cause of outages, with steam drum sensing lines being the most prevalent (43 units tripped from this cause alone).

  - ✓ JK Spruce Unit 2, a 785 MW coal unit, tripped due to frozen sensing lines that caused a false high water level reading in the steam drum.

  - ✓ Ingleside Cogeneration lost two units due to frozen sensing lines. The lines were heat traced, but the ground fault interrupter breakers protecting the heat trace circuits tripped, resulting in a loss of 176 MW.

  - ✓ Another unit tripped due to frozen sensing lines on feedwater heater level controls. The freezing caused a high condensate level in a feedwater heater, which in turn incorrectly initiated a trip of the unit.

  - ✓ Non-drum sensing line failures included a unit whose vacuum system became erratic when the sensing line to the auxiliary steam pressure indication froze. Another unit tripped when the sensing lines to the rotor air cooler level transmitters froze.

***Sensing Lines and Frozen Transmitters***

There were many reports of frozen transmitters causing generating units to be forced offline during the cold weather event. In almost all cases, it was not the transmitters themselves that froze, but rather sensing lines filled with standing (non-flowing) water routed between the transmitters and the points the sensing lines are measuring.

(cont'd)

Transmitters

The transmitter assemblies perform three distinct functions. First, they detect the difference in pressure between two water lines, typically with a diaphragm-type sensor that deflects in the direction of, or towards, the lower pressure. Second, they serve as transducers that translate the pressure difference into an electrical signal. Third, they boost or otherwise process the signal for transmitting to the plant's control room, generally using electronics.

Differential Pressure Measurement

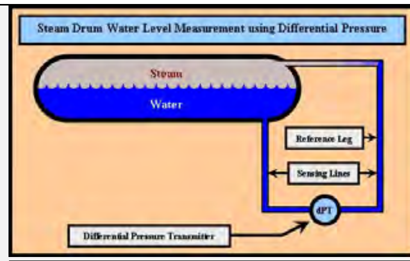
The technique of measuring the pressure difference (differential pressure) between two sensing lines filled with water has widespread application throughout power plants, especially in steam-powered generating units. This is due to the fact that differential pressure can be used to provide not just a measure of pressure itself, but also of water levels and flow rates. Significant applications include the following:

- **Pressure Measurement**
  - Between a boiler feedwater pump and the steam drum
- **Water Level Measurement**
  - In feedwater heater tanks
  - In the deaerator tank
  - In the steam drum
- **Water Flow Measurement**
  - Feedwater flow
  - Generator stator cooling water flow

Water Level Measurement

Differential pressure can be used to measure water level by virtue of the force of gravity, which results in greater pressure as the water level increases. This is akin to the hydraulic head resulting from water in an open reservoir, which is a measure of water pressure compared against standard atmospheric pressure. The method needs to be modified, however, to account for the fact that the space within a tank above the water is pressurized. Hence the use of differential pressure measurement, with one sensing line connected to the bottom of the tank to sense the water pressure, and the other to the top of the tank to sense the water vapor or steam pressure. The line at the top of the tank is known as the reference line. Even though the reference line connects to the top of the tank, which is above the water level, it will itself still fill up with water because the vapor/steam condenses in the line due to the much cooler ambient air temperature external to the tank.

(cont'd)




Water Flow Measurement

Differential pressure can be used to measure water flow by virtue of Bernoulli's principle: an increase in the speed of a flowing fluid is accompanied by a decrease in pressure. This increase in speed can be forced by placing a constriction such as an orifice plate or nozzle inside a pipeline, reducing its effective diameter. In order for the rate of flow in gallons per minute, for example, to remain the same, the velocity of the fluid must increase to make up for the fact that it is travelling through a smaller opening. This phenomenon is known as the Venturi effect. The higher velocity translates into lower pressure by Bernoulli's principle. Thus, measuring the differential pressure on either side of the constriction provides a measure of the rate of flow through the pipeline.

For exact flow measurement, the design and dimensions of the constriction are critical. In some cases, however, the concern lies more with changes in flow rate, indicative of blockages in the piping or overall flow path. This concern is important when strainers are used to filter out undesired particles from the fluid, especially in generator stator cooling systems. The strainers provide constriction to the water flow, resulting in a pressure difference. When the strainers are clogged, the pressure difference increases.

Steam flow can also be measured using the Venturi effect. But in that case, long sensing lines are not needed, as pressure immediately on either side of the orifice plate or nozzle is measured.

The Freezing Problem

Since differential pressure measurement requires gauging the difference in pressure between two separate sensing lines, if the water in either or both of those lines freezes, the measurement will be false. When a sensing line is plugged with ice, it cannot convey the intended water pressure to the transmitter location.

The fact that the water in the sensing lines is not flowing makes freezing all the more likely, and emphasizes the need for proper freeze protection methods such as insulation and heat tracing. Some sensing lines must run long distances through areas exposed to outdoor ambient air, which significantly exacerbates the risk of false readings.

- **Frozen Equipment (General):** Many other critical systems besides sensing lines experienced problems from the low temperatures. These included emissions systems, feedwater systems, control air systems, lubricating oil systems, and the like. Emissions systems sometimes rely on water, which is susceptible to freezing. Control air systems contain moisture-laden air; if the moisture is not removed, freezing can occur. Changes in the viscosity and properties of lubricants that are not kept at specified temperatures can adversely affect the operation of equipment.

  - ✓ Two units at one plant were derated when the NOx water storage tank lines froze.

  - ✓ At a City of Garland unit, 78 MW were lost from a draft fan failure, which was caused by frozen damper controls and a resulting low air flow trip.

  - ✓ A wind facility lost six units when lubricating oil fell below the minimum operating temperature and automatically tripped the units.

- **Frozen Water Lines:** The condensate and boiler feedwater systems of steam-cycle generating units (coal, conventional gas, and combined cycle) utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are susceptible to freezing, absent freeze protection measures. (This is especially true if the unit is offline at the onset of freezing temperatures.)
  .

  - ✓ One facility lost a 160 MW unit when air compressor drains froze. Another unit was shut down because of high boiler "superheat" temperature when its superheat spray lines froze.

- **Frozen Valves:** The operation of valves can become sluggish when exposed to severe cold weather. Depending on the particular application of these components, sluggish valves can cause instability in the boiler or turbine controls, which can eventually lead to a unit trip.

  - ✓ Kiowa Power Partners attempted to free up a frozen valve and, in the process, shut the valve completely, cutting off steam to the turbine and tripping 307 MW of capacity.

  - ✓ Another generating unit experienced a frozen valve on a fuel gas temperature controller, which caused gas temperatures to become erratic. A bypass valve on another unit's fuel gas temperature controller froze, preventing the unit from reaching full capacity for a period of time.

- **Blade Icing:** Blade icing caused problems for wind generators. Precipitation and condensation during cold weather can cause layers of ice to form on turbine blades, causing potential balancing, bearing, and other equipment problems (as well as safety problems resulting from "ice throws").

  ✓ Turkey Track Wind Energy lost 27 turbines and 40.5 MW of capacity during the event due to blade icing problems.

- **Low Temperature Limits:** Wind turbines are typically designed to operate within a designated range of temperatures, and have an automatic shutdown feature to protect their components if the range is exceeded. Although manufacturers offer a "cold weather package"[210] that allows a turbine to continue operating in colder temperatures, it does not appear that the package is used in the Southwest.

  ✓ McAdoo Wind Energy suffered outages of 90 of its 100 turbines when the turbines, designed to shut down when the temperature drops below five degrees, performed as expected. Although McAdoo's turbines restarted automatically when the temperatures rose above the shutdown point, other units, such as Bull Creek Wind, did not come back online as temperatures rose.

- **Transmission Loss:** Generators can also be affected by external outages of transmission facilities.

  ✓ At one generating plant, cold grease in a breaker appears to have caused slow clearing of the breaker, tripping six units.

[210] Press Release, General Electric, GE Energy's 2.5xl Wind Turbine Now Offers Extreme Cold Weather Capabilities for Challenging Applications in North America and Europe (Sept. 21, 2009), *available at* http://www.genewscenter.com/content/Detail.aspx?ReleaseID=8415& NewsAreaID=2.

## ERCOT Non-Weather-Related Outages and Derates

While the majority of the ERCOT generator failures during the February event were weather-related, other causes also played a part. This is not surprising, as on any given day generating units can and do experience problems. To determine whether the amount of non-weather-related failures during the February cold weather event was typical, the task force reviewed ERCOT's 2010 daily forced outage data. During that year, forced outages ranged from 900 MW to 6300 MW per day, averaging 3200 MW per day or 16,000 MW for a five-day period. Therefore, the task force concluded that the 14,386 MW of non-weather-related failures experienced by ERCOT generators between February 1 and February 5, 2011 were comparable to what might be expected over a normal five-day period.

The causes (other than fuel supply) of the non-weather-related outages between February 1 and February 5 included difficulties with mechanical equipment, control equipment, operator error, emissions limitations, and fuel switching failures. The task force identified six general categories of non-weather-related causes of generator trips, derates, and failed starts over these five days:

| Cause | No. of Units Lost | MW Lost |
|---|---|---|
| Mechanical Failure | 37 | 7588 |
| Control System Issues | 28 | 3624 |
| Fuel Switching | 12 | 909 |
| Operator Error | 9 | 980 |
| Emissions | 3 | 358 |
| Miscellaneous | 11 | 927 |
| **Total Non-Weather-Related** | **100** | **14,386** |

Representative problems within these categories are discussed below.

- **Mechanical Failure**: A number of generators experienced mechanical equipment problems that were not related to the cold weather. For instance, several had combustion turbines trip due to high exhaust temperature spreads, which is an indicator of internal problems with the combustion turbine (or with the thermocouple[211]). Another common combustion turbine problem encountered during the event was high blade path

[211] Thermocouples are used to measure process temperatures and consist of two dissimilar metal wires soldered together at the tip, which produce an electrical current in response to temperature changes. Thermocouples can fall out of calibration over time or fail suddenly due to broken wires or damaged lead wire insulation.

spread,[212] which resulted in several more trips. Other trips, derates, and failures to start resulted from such problems as boiler and heat recovery steam generator leaks, plugged suction strainers on condensate pumps, improper boiler feed water pump oil pressure, gas pressure regulation issues (which were mainly resolved by the pipelines), and an assortment of gas turbine tuning issues.

- ✓ Greens Bayou CT 81 (54 MW) tripped due to a high combustible gas alarm, which was triggered by a leak in a coupling.

- ✓ San Miguel Unit 1 (395 MW) tripped due to a waterwall tube leak.

- **Control System Issues:** A prominent problem with control equipment appears to have been failed thermocouples. Control parameters, logic, and dynamics probes also resulted in several trips. Other problems included, but were not limited to, malfunctioning flame detectors and sheared air register pins,[213] loose wiring, a failed speed sensor, broken control linkages and faulty flow meter switches.

  - ✓ Deer Park CT 1 (195.5 MW) tripped due to a blade path temperature spread resulting from a failed sensor in the plant's distribution control system logic.

  - ✓ One facility experienced problems with its 46 relay,[214] which caused an outage. Another unit had a false indication of a ground fault on a generator rotor, which prompted the operator to take the unit offline.

- **Fuel Switching:** ERCOT has approximately 90 generating units with fuel switching capabilities, permitting them to switch from natural gas to an alternate fuel when natural gas is in short supply. (Generators may wish to switch fuel for other reasons as well, such as economics.) During the February event, 20 units attempted to switch from natural gas to their

---

[212] Blade path spread is a measurement, utilizing thermocouples, designed to identify turbine exhaust temperatures. A temperature spread beyond allowable limits will initiate an alarm or a trip. However, the alarm or trip can also be triggered by a defective thermocouple, rather than by actual fuel problems or air cooling problems.

[213] The failed flame detectors and air register pins caused burners inside the boiler to malfunction.

[214] A 46 relay (negative sequence relay) is used to detect unbalanced load on a generator that may cause excessive rotor heating and result in significant damage to the generator.

alternate fuel, with 15 units managing the switch successfully. The other units encountered various failures in their switching equipment. Derates also resulted from fuel switching.

- ✓ The Decker CT 2 (54 MW) tripped when attempting to burn fuel oil.
- ✓ The GEUS steam plant was derated by 5 MW due to operating on fuel oil.

- **Operator Error:** Several generators experienced minor problems associated with operator error. In some cases, the problems arose when operators switched control systems from automatic to manual mode. In other cases, generators tripped as the result of improper maintenance procedures.
  - ✓ A flameout of the boiler at one unit forced the burner valves to close but left the main gas trip valve open. In attempting to close the trip switch before restarting the unit, an operator selected the trip switch for the second unit, putting the second unit out of service.
  - ✓ An operator noticed that the fuel forwarding system for two units were operating in the incorrect mode. In attempting to rectify this situation, the operator correctly selected the automatic mode for one pump (it was operating in manual), but mistakenly selected "lagging" instead of "leading." This caused both units to give low pressure alarms and trip offline.
  - ✓ Hydraulic oil heaters at a generating unit had been left unplugged since the summer of 2009 (they had been unplugged at that time to avoid overheating). During the February event, trips resulted from low hydraulic oil temperatures.

- **Emissions:** At approximately 12:00 PM on February 2, ERCOT informed generators that the Texas Commission on Environmental Quality (TCEQ) was temporarily waiving air permit requirements that were preventing some generators from operating at full capacity during the emergency. (Although ERCOT characterized the action as a waiver, the TCEQ actually stated that it was exercising enforcement discretion.) This decision had little effect on the situation within ERCOT, as it was not announced until after half of the shed load had been restored.
  - ✓ Prior to issuance of the notice, Calpine's Clear Lake facility, which consists of three combustion turbines and two heat recovery steam

generators, was forced to manually shut down its GT102 and GT104 turbines in order to avoid exceeding NOx Limits.

- ✓ On February 3, another Calpine unit, Freestone Unit GT4, was derated so as not to exceed its NOx permit limits.

- **Miscellaneous:** A variety of other problems was also experienced, such as the following:

  - ✓ **Switchyard Equipment Problems:** Some generators encountered switchyard problems that led to units failing during the event. One entity was unable to start certain units because a standby transformer was not energized.

  - ✓ **Low Frequency Related Issues:** Two facilities reported frequency-related issues as causes for their units tripping. One facility's three generators tripped as a result of a low frequency turbine protection relay operating improperly. At another facility, the decline in frequency during the event caused the turbine control system to initiate an increase in fuel pressure to increase turbine speed, but it overshot its set point.

**ERCOT Gas Supply Outages and Derates**

Fuel supply problems did not significantly contribute to the amount of unavailable generating capacity in ERCOT during the first week in February. The outages and derates from inadequate fuel supply totaled 1282 MW from February 1 through February 5. (For comparison, the overall net generating capacity reduction in ERCOT peaked at 14,702 MW on the morning of February 2.) The fuel supply problems also did not occur all at the same time. The following table summarizes generation capacity reductions in ERCOT due to fuel curtailment and fuel quality problems.

| Generator | Trip Time | Unit | Gen MW | MW Reduction | Pipeline (s) |
|---|---|---|---|---|---|
| Bosque Power Company | 2/2 9:26 AM | Bosque Power: Unit 1, Unit 2, Unit 3, and Unit 4 | 597 | 154 | Enterprise Texas Pipeline, Markwest Lateral |
| Calpine | 2/4 7:55 AM | Corpus Christi: GT1, GT2, and ST1 | 516 | 174 | South Cross CCNG Transmission |
| City of Austin (Austin Energy) | 2/2 7:30 AM | Decker : Unit 2 | 450 | 100 | Enterprise Texas Pipeline / Atmos Texas Pipeline |
| Power Resources | 2/2 5:14 PM | Cal Energy: Unit 1 | 212 | 7 | ONEOK WesTex Transmission |
| Luminant | 2/1 10:00 AM | Lake Hubbard: Unit 1 | 441 | 174 | Atmos-Texas Pipeline |
| GEUS | 2/1 9:00AM | GEUS Steam Plant | 112 | 112 | Atmos-Texas Pipeline |
| Exelon | 2/1 7:30 PM<br>2/2 11:00 AM<br>2/2 3:00 PM<br>2/2 6:00 PM | Mountain Creek: Unit 6, Unit 7, and Unit 8 | 808 | 476<br>396<br>476<br>396 | Atmos-Texas Pipeline and Energy Transfer Fuel |
| Frontera Generation | 2/2 8:16 AM | Frontera: Unit 1, Unit 2, and Unit 3 | 485 | 85 | Kinder Morgan Tejas |

- **Bosque Power Company:** MarkWest PNG Utility operates an intrastate, 30-mile, 18 inch diameter lateral in Hill, Johnson, and Bosque Counties, Texas. The lateral has an operating pressure of approximately 700 psi, and has no compressor stations. Gas is transported from Enterprise Texas Pipeline, a second intrastate pipeline, to the Bosque County Power Plant, the only electric generation facility served by the pipeline.

Bosque Power Company's QSE, EDF Trading North America (EDF), manages all transportation and gas supply purchases, nominations, and scheduling, including capacity on the Enterprise Texas Pipeline. EDF has only interruptible capacity on the Enterprise Texas Pipeline. The majority of its receipt points are in Waha and West Texas.

The power plant's units are programmed to automatically shut down if pipeline pressure drops below a certain point. On February 2, gas pressure steadily dropped to near the automatic shut down point. To mitigate the effects of lower gas pressures, the plant began reducing energy output on all four of its units.

MarkWest informed the task force that there are no compressors on their pipeline, and therefore the declining pressure was likely a gas supply issue. The pipeline had no capacity constraints.

- **Calpine:** The Calpine Corpus Christi facility is supported by one pipeline system, the Southcross CCNG Transmission pipeline (Southcross). Calpine Energy Services (CES), a subsidiary of Calpine Corporation, is an energy marketer that arranges for natural gas supplies for generation facilities owned by Calpine, including the Corpus Christi facility.

  On February 3 and 4, CES delivered gas into Southcross at four separate locations. However, at approximately 7:55 AM on February 4, the Calpine units tripped off line due to declining pipeline pressure on the Southcross system. The pressure on Southcross fell below the minimum delivery pressure obligation of 560 psig that is stated in both of CES's firm and interruptible agreements. Southcross reported that the low pressures on its system were due to supply freeze-offs that reduced expected deliveries into its system.

  Calpine was able to restart one of its units in less than one hour and run the facility at a derated level. Later in the day on February 4, once Southcross restored its line pack pressures, Calpine successfully brought all units back online.

- **City of Austin (Austin Energy):** The city of Austin has firm capacity on the Enterprise Texas Pipeline and is connected to the Atmos Pipeline-Texas (Atmos), both intrastate pipelines. Under the terms of the city's agreement with Atmos, its capacity rights are reduced when freezing weather is forecasted, pursuant to a specific formula in the contract. Most of the gas supply for the transportation is from Waha.

The plant did not experience curtailments. However, given the limitations on Atmos, usage was limited on February 2. Austin Energy exceeded its contractual hourly take on Enterprise Texas Pipeline and was requested by Enterprise to reduce flows to the hourly take (this is referred to as "back on rate"). This reduction caused a 100 MW derate of the Decker unit.

- **Power Resources:** Power Resources' Cal Energy Plant ramped down one hour early due to low gas pressure on its supplying pipeline, ONEOK WesTex, an intrastate pipeline located primarily in west Texas and the Texas panhandle.

  ONEOK WesTex states that it did not interrupt service but did experience operational difficulties and supply reductions. Beginning on February 1, increased gas usage by towns and power plants reduced the pipeline pressure, and several interconnecting gas processing plants also experienced supply difficulties. Normal operating pressures were restored by the afternoon of February 2.

- **Luminant and GEUS:** These plants are connected to the Atmos system, which traverses the Fort Worth, Permian, and East Texas Basins, all of which experienced supply losses due to freeze-offs.

  Transportation for power generation feeding off Atmos is only offered as an interruptible service, and is subject to electric generation restrictions, called "Tier 3 restrictions." Atmos instituted Tier 3 restrictions beginning at 9:00 AM on February 1, restricting gas flow to zero for the GEUS steam units and for Luminant's Lake Hubbard generating station. On February 2, increased demand resulted in continued loss of line pack and declining pressures at citygate points in Dallas-Fort Worth. Additionally, suppliers experienced well freeze-offs and equipment problems.

  On the morning of February 2, ERCOT initiated rolling blackouts to maintain the grid. The TRC contacted Atmos at approximately 10:00 AM to ask if additional volumes could be delivered to the Lake Ray Hubbard Electric Generating Station to assist with electric grid issues. Atmos explained to the TRC that such action would result in the loss of service to firm residential and commercial customers served by LDCs located to the north of the electric generation station on the pipeline system, and that therefore such deliveries could not be made to an interruptible customer.

- **Exelon:** Exelon has a firm gas transportation contract with Energy Transfer Fuel (ET Fuel) for the Handley Generating Station and an interruptible gas transportation contract with Atmos for Handley Generating Station and Mountain Creek Station. Atmos implemented a Tier 3 restriction during the extreme weather event, which limited hourly flow to both the Handley and Mountain Creek stations.

The fuel curtailments at Handley did not affect operations until Unit 3 was called on the evening of February 2. Gas supply during the day was enough to allow Units 4 and 5 to run at full load. When Unit 3 was brought on line, it fuel switched Unit 4 to run partially on oil to allow Units 3 and 5 to increase output. Mountain Creek Units 6 and 7 ran at minimum load due to fuel restrictions. Mountain Creek Unit 8 ran at full load (but did have other non-gas related derates that affected output).

- **Frontera Generation:** The Frontera Generation plant is on the Kinder Morgan network of pipelines (collectively, KM Texas Pipes). The KM Texas Pipes receive natural gas from producing fields in south Texas, east Texas, the Gulf Coast, the Gulf of Mexico, and the Permian Basin. They also own or control gas storage capacity.

  Frontera has firm transportation service with deferred account service. "Deferred account service" is a balancing service that enables a shipper to acquire supply during low demand and deliver it to the KM Texas Pipes for future redelivery during peak demand, subject to contractual limits on hourly, daily, and total quantities.

  During the morning of February 2, the KM Texas Pipes contacted those customers that were taking more than their firm contractual rights, including both of the Frontera plants, requesting they stay within their contractual rights because pipeline pressures were falling and putting all firm services at risk. Later that day, ERCOT, along with the TRC, advised the KM Texas Pipes that ERCOT had declared an emergency condition. ERCOT then advised the KM Texas Pipes that the power grid in the Rio Grande Valley was in a critical state. ERCOT and the TRC requested the KM Texas Pipes to allow the Frontera electric generating plant to pull supplies in excess of their firm contractual rights. The KM Texas Pipes complied with this request.

## Generation Outages in Salt River Project

The SRP balancing authority suffered several generator outages during the cold weather event, which severely affected its ability to serve load. On February 1 and 2, SRP lost a total of seven units. The failures of three of them were related to weather. On February 1, SRP lost Unit 1 at its Navajo Generating Station due to a frozen transmitter sensing line, reducing generation capacity by 330 MW. On February 2, SRP lost additional generation due to weather-related problems: it lost 75 MW, its 10 percent share, from Unit 4 at Four Corners Generating Station (operated by Arizona Public Service Company), which failed due to a frozen sensing line that served the throttle pressure transmitter; and it lost Unit 2 at Navajo Generation Station, which tripped due to frozen waterwall pressure transmitter sensing lines.

SRP also suffered generation losses from the trips of four units on February 2, due to non-weather related issues: Coronado Generating Station Unit 2 , which experienced a mechanical problem with a coal pulverizer, losing peak load of 389 MW; the combustion turbine and the steam turbine units at Santan Generation Station Unit 6, which suffered an internal mechanical failure on the heat recovery steam generator and an accompanying runback of the combustion turbine; Springerville Unit 3 (operated by Tucson Electric Power), which developed high furnace pressure, causing a loss to SRP of its 75 MW share of the plant's 400 MW.

## Generation Outages in El Paso Electric

The EPE balancing authority shed approximately 623 MW of firm load over the course of the February event, due to the loss of 646 MW of local generation. Unlike SRP, almost all of EPE's's outages were due to the cold weather.

On February 1, EPE lost its Newman Unit 3 because of frozen condensation on the fresh air inlet, and lost Rio Grande Unit 6 because of a frozen gas transmitter. The loss of these units resulted in a 152 MW reduction of capacity.[215]

On February 2, EPE lost 495 MW of capacity from its Newman and Rio Grande plants. Newman Gas Turbines 1 and 2 at Newman Unit 4, each with a capacity of 73 MW, tripped due to faulty drum level readings resulting from the cold weather. Gas Turbines 3 and 4 at Newman Unit 5, each with a 70 MW capacity, also tripped due to frozen drum level instrumentation sensing lines. Newman Unit 4 Steam Turbine, a 64 MW unit, tripped on February 2 due to frozen instrumentation associated with the condenser vacuum. Finally, EPE lost Rio Grande Unit 8, a 145 MW unit, due to frozen transmitter sensing lines that caused a low gas pressure signal.

[215] The Newman plant is not enclosed; the Rio Grande plant is enclosed.

El Paso attempted to bring its units back online on February 3 and February 4, with limited success. Newman Unit 4's GTs were restarted, only to trip on subsequent occasions for similar weather-related issues. (Luna and Afton, PNM remote generating facilities from which EPE was receiving energy, also experienced outages on February 3 and February 4.)

During the event, two EPE units, Newman Unit 1 and Rio Grande Unit 7, were offline and EPE tried to bring them online to assist with the shortages. Both units, however, failed to start due to frozen components and, in the case of Newman Unit 1, frozen drum drain lines and transmitter.

## B. Natural Gas

Most of the natural gas supply problems experienced in the Southwest during the cold weather event were caused by freeze-offs, principally at the wellhead or, to a lesser degree, at nearby processing plants. Other equipment failures also played a role, as did the rolling blackouts and customer curtailments in the ERCOT region.

In order to analyze the causes of the supply shortfalls, the task force reviewed daily shortfalls at receipt points on pipelines. Most of these receipt points were at processing plants. The following table summarizes the information received from 13 processing companies, which overwhelmingly pointed to upstream supply outages as the major cause of the reduced volumes. (The second column is the maximum estimated production shortfall by basin; the third column is the percentage of shortfall of the processing plants that provided information; the final column lists the causes of the shortfalls.)

**Processing Plant Outages Relative to Daily Production Shortfalls**

| BASIN | MAXIMUM DAILY PRODUCTION OUTAGE | PROCESSING RESPONSES AS A % OF THE DAILY OUTAGE | CAUSES |
|---|---|---|---|
| Permian | 1.31 Bcf on Feb 4 | 0.44 Bcf (34%) | 85% Upstream Supply Freeze-offs, 15% Mechanical/Electricity Outages |
| San Juan | .43 Bcf on Feb 2 and Feb 3 | 0.21 Bcf (52%) | Upstream Supply Freeze-offs, Minimal Amount due to Mechanical |
| Fort Worth | 1.63 Bcf on Feb 6 | 0.17 (11%) | Upstream Supply Freeze-offs, Minimal Amount due to Mechanical |
| East Texas | .72 Bcf on Feb 3 and Feb 5 | NA | NA |
| Gulf Coast | .65 Bcf on Feb 4 | NA | NA |

The task force further explored these upstream production outages by surveying 15 of the larger producers in the San Juan, Permian, Fort Worth, East Texas, and Gulf Coast Basins. These producers accounted for almost 40 percent of the total production for the five basins, with the highest percentages from the Fort Worth, San Juan, and Permian Basins.

For February 1 to February 5, an estimated 14.8 Bcf of production was lost from these five basins due to weather-related reasons. Of that amount, the surveyed producers lost 7.1 Bcf, equal to 48 percent of the total.

These production losses occurred for a variety of reasons. Some of the most common occurrences reported to the task force included:

- Freeze-offs (in some circumstances winterization was only designed for temperatures in the 20s),
- Icy roads that hampered logistics such as hauling away water produced by treatment equipment, and
- Rolling blackouts and customer curtailments.

Rolling blackouts were a problem particularly in the Fort Worth Basin, where they caused outages of compressors on gathering lines. In the Permian Basin, deployment of Load Resources by ERCOT during the event caused disruption to electric pumping units. According to information received from the surveyed producers, 27 percent of the outages in the Fort Worth Basin were due to the rolling blackouts, and 29 percent of the outages in the Permian Basin were due to rolling blackouts or the curtailment of interruptible load.

The following table itemizes the reasons stated by these 15 producers for the supply shortfalls (the check marks indicate how many separate producers submitted information for each category):

| | Permian | San Juan | Fort Worth | East Texas | Texas Gulf |
|---|---|---|---|---|---|
| Rolling Black Outs/ Curtailed Load | ✓✓✓✓ | | ✓✓ | | |
| Icy Roads | ✓✓✓✓ | ✓ | ✓✓✓✓✓✓ | ✓✓ | |
| Freezing of Compressors | | ✓✓ | ✓✓✓ | ✓✓ | ✓✓ |
| Freezing Meters | | ✓ | | | ✓ |
| Wellhead Freeze-offs | ✓✓✓✓✓ | ✓✓ | ✓✓✓ | ✓✓✓✓✓ | ✓✓✓✓ |
| Processing Facility Shut-in | ✓ | ✓ | ✓ | ✓ | |
| Ice Plugs in Gathering Lines | ✓ | | | | |
| Frozen Salt Water Disposal Facilities | ✓ | | | | |

A basin-by-basin description of the gas production declines, and the resulting reduction in flows, follows.[216]

## Permian Basin

The Permian Basin suffered production losses from February 1 through February 5 of 3.98 Bcf, with a maximum daily decline of 1.31 Bcf on February 4. The reasons provided for these declines are based on information received from

[216] The information is drawn from materials provided to the task force by producers and processing plants.

processors representing 34 percent of the maximum daily outage and producers representing 28 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso, Transwestern, Northern Natural Gas Company, and Enterprise Texas pipelines that had reductions exceeding 20,000 MMBtus per day, and thirteen processing plant points that had reductions of approximately 0.6 Bcf per day.

The receipt points on the El Paso pipeline with flow declines exceeding 20,000 MMBtus per day from February 1 to February 3 are all processing plant/gathering locations. They include Enterprise Waha (reduction of 120,681 MMBtus per day); Southern Union Jal#3 (reduction of 35,966 MMBtus per day); DCP Midstream GPS Eunice, reduction of 32,055 MMBtus per day; DCP Midstream Goldsmith Plant (reduction of 29,562 MMBtus per day); Southern Union Keystone (reduction of 28,515 MMBtus per day); Versado Gas Processors Texaco Eunice (reduction of 26,407 MMBtus per day); DCP Midstream Pegasus (reduction of 23,475 MMBtus per day); and Versado Gas Processors, Warren Monument (reduction of 21,460 MMBtus per day).

Transwestern's supply shortfalls in the Permian Basin were modest, relative to El Paso's, and were most significant at the Frontier Maljamar Gas Plant (reduction of 33,000 MMBtus per day) and at the Agave producer gathering connection (reduction of 44,000 MMBtu per day). Northern Natural processing plant receipt points with large reductions were the Atlas Midkiff Plant (reduction of 63,997 MMBtus per day) and the DCP Linam Ranch Plant (reductions of 106, 406 MMBtus per day). Finally, on Enterprise Texas Pipeline, the Crockett Gas Plant had a production shortfall of 34,376 MMBtus per day.[217]

Explanations varied for the reductions from the processing plants located in the Permian Basin.[218] The largest supply reduction to El Paso was the Enterprise Waha treating plant, which has a capacity of 280 MMcf per day. Enterprise reported that volumes delivered to the Waha Treating Plant decreased from 120 MMcf per day to approximately 40 MMcf per day, due to gas supply freeze-offs on February 2 and February 3. The plant's GE turbine then went down on

[217] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6.

[218] The task force received materials from a number of processing plants located in the basin. The material cited represents a sampling of data from those materials.

February 3, due to high discharge pressure when El Paso closed its valve at the plant tailgate (because of a high dew point in the gas stream).

On February 2, DCP's Linam Ranch plant in east New Mexico experienced freezing air ducts, resulting in a modest reduction to El Paso of 4,865 MMBtu per day from February 1 to February 3 (the reduction is 24,092 when measured from January 31). The plant then experienced a delay returning to service because of gas supply shortages from well freeze-offs, resulting in a lack of gas to restart the plant. The plant returned to normal operations on February 6 and supply returned to normal levels on February 7. Reductions in volume at three other DCP plants, Goldsmith, Pegasus, and Eunice, were the result of supply shortages from wellhead freeze-offs. Goldsmith and Pegasus experienced rolling blackouts that resulted in only brief outages, with gas being at the time either processed at the plants or delivered directly into pipelines.

Four DCP Texas processing plants were impacted by the rolling blackouts on February 2, but only one of them had resulting operational problems. The power outage caused the cooling water used for compression at the Roberts Ranch Plant in west Texas to freeze, leading to a plant shut down. (The plant was back in service on February 5.) The remaining plants did not experience any operational issues from the power outages. When the brief power outages occurred, the upstream gas bypassed the plants and was delivered without being processed.

Southern Union operates the Keystone and Jal #3 plants that together flowed reduced volumes of 64,481 MMBtu per day to El Paso. Southern Union reported that it experienced major property damage and significant financial losses due to freezing and failure of wells, pipes, and other facilities. The weather event ultimately resulted in the cessation of operations at many plants and field facilities, with corresponding reductions in deliveries to downstream pipelines. Some of Southern Union’s issues were a direct result of rolling power outages at the Keystone facility at 7:25 AM and 9:05 AM on February 2, lasting 34 and 30 minutes, respectively.

Producer Declines in the Permian Basin

Producers representing a customary production level of approximately 0.75 Bcf per day[219] (approximately 30 percent of total basin production), reported production losses for the period February 1 through February 5 of 1.1 Bcf,

[219] This number represents the producers’ usual production level, absent reductions experienced during the event.

estimated to be approximately 28 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Power disruptions to electric motors on pumping units (29 percent of the total losses, or 0.32 Bcf),
- Icy roads,
- Ice plugs in gathering lines,
- Freeze-offs, and
- Downtime at processing plant.

Occidental Energy Marketing reports that on February 2, because of its status as a Load Resource on ERCOT's system, electric service to its production facilities were interrupted when ERCOT deployed it as a Load Resource. This interruption resulted in significant production losses. Power began to be restored approximately 1.5 hours after the disruption occurred.

ConocoPhillips Company reports that a significant percentage of its production losses in the Permian Basin were attributable to rolling blackouts that knocked out processing plants and pumps and lifts. The majority of its Permian Basin production comes from oil wells that rely on electric pumps and lifts to maintain oil flow. When the pumps failed, the natural reservoir pressures were unable to sustain flow, the oil congealed, and the wells and flow lines froze.

## San Juan Basin

The San Juan Basin suffered production losses from February 1 through February 5 of 1.3 Bcf, with a maximum daily decline of 0.43 Bcf on February 3 and February 4. The reasons provided for these declines are based on information received from processors representing 52 percent of the maximum daily outage and producers representing 71 percent of the cumulative losses.

### Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso and Transwestern that had reductions exceeding 20,000 MMBtus per day, and eight processing plant receipt points with a reduction of approximately 0.35 Bcf per day (when netted against increased flows elsewhere).

Receipt points off of El Paso that had flow reductions exceeding 20,000 MMBtus per day are the BP Florida River Plant, with a reduction of 155,691 MMBtus per day, and two Williams Field Services processing plant/gathering locations; Milagro, with a reduction of 66,764 MMBtus per day, and #37, with a reduction of 24,047 MMBtus per day. Transwestern's most significant supply shortfalls in the San Juan Basin for February 1 through February 3 were the William FS Kutz Plant, with reductions of 36,000 MMBtus per day, the Red Cedar Arkansas Loop gathering facility, with a reduction of 33,000 MMBtus per day, the Valverde Gas Plant, with a reduction of 48,000 MMBtus per day, and the Enterprise Chaco Plant, with a reduction of 87,000 MMBtus per day. These reductions were partially offset by increased flow of 100,000 MMBtus per day from the Williams FS Ignacio Plant.

Williams Fields Services reported that they had no operational problems, and the reduced volumes at Milagro and Kutz were due to upstream production shut-ins. With regard to the Chaco Plant, Enterprise reported it was operating at less than full capacity during the first week of February primarily because: (i) gas supplies were limited, (ii) ConocoPhillips moved approximately 100 MMcfd[220] from Chaco to their own San Juan processing plant on February 1, and (iii) winter production shut-ins occurred. In addition, the plant tripped on February 2 due to a hazardous gas supply alarm, and Enterprise's attempts to restart it were impeded by the combination of the lower volumes being nominated by producers and the cold weather experienced at the time.

Producer Declines in the San Juan Basin

Producers representing a customary production level of 2.0 Bcf per day (approximately 67 percent of total basin production), reported production losses for February 1 through February 5 of 0.9 Bcf, estimated to be approximately 71 percent of the total basin production losses for the five days.

None of the producers cited power outages as a cause of production losses. The losses were attributed to the following:

- Problems with compressor units,
- Freezing of wellhead meters,
- Cold weather, Freeze-offs,
- Icy roads, and
- Downtime at a processing plant.

## Fort Worth Basin

The Fort Worth Basin suffered production losses from February 1 through February 5 of 4.7 Bcf and a maximum daily decline of 1.63 Bcf on February 6. The reasons provided for these declines are based on information received from

[220] MMcfd is a million cubic feet per day.

processors representing 11 percent of the maximum daily outage and producers representing 80 percent of the cumulative losses.

<u>Reduced Flows at Processing Plant Pipeline Receipt Points</u>

The Fort Worth Basin experienced supply reductions of almost 1.3 Bcf per day. Energy Transfer Fuel (ET Fuel) and Crosstex North Texas Pipeline (Crosstex) both receive gas from the Fort Worth Basin, and experienced reduced receipts.

ET Fuel had reduced receipts of 0.35 Bcf per day from January 31 through February 4. The largest reductions on the system occurred at the following receipt points: Chesapeake Energy production, with a reduction of 71,314 MMBtus per day; EOG Resources production, 127,418 MMBtus per day; Quicksilver Gathering, reduction of 69,675 MMBtus per day; and an ET Fuel processing plant, reduction of 61,668 MMBtu per day.[221]

Crosstex had a flow reduction estimated at 0.14 Bcf per day. The reduced volumes were due largely to the weather-related shut-down of the Silver Creek processing plant. Primarily due to freeze-offs, production at the plant declined by approximately 110,000 MMBtus per day from a normal flow rate of 185,000 MMBtus per day, to a five day average of 75,000 MMBtus per day on the outlet.

Atmos reported that intermittent supply reductions from nominated volumes were 0.13-0.17 Bcf per day.

The Energy Transfer Corporation Texas (ETC Texas) Godley area plant in north Texas experienced weather related difficulties on February 1 when one of its amine systems froze. ETC Texas was able to flow amine again on February 5. From February 1 through February 5, the inlet volume of the Godley Processing Plant decreased by 100 MMcfd, due to the loss of third party production from freeze-offs.

<u>Producer Declines in the Fort Worth Basin</u>

Producers representing a customary production level of 3.3 Bcf per day (approximately 69 percent of total basin production), reported production losses from February 1 through February 5 of 3.8 Bcf, estimated to be approximately 80

[221] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); pipeline scheduled volumes.

percent of the total basin production losses for the five days. The losses were attributed to the following:

- Rolling blackouts primarily affecting compressors on gathering lines (27 percent, or at least 1.0 Bcf),
- Icy roads, and
- Freeze-offs.

One large producer in the basin reported production losses for the period February 1 through February 5 as a result of electrical compression being shut down on a gathering system in the Dallas/Ft. Worth area. After power was restored, production was slow to return to standard rates. It therefore appears likely that a significant percentage of the lost production even after February 2 was due to the loss of power during the rolling blackouts.

**East Texas**

Producers representing a customary production level of 1.2 Bcf per day (approximately 24 percent of total basin production), reported production losses from February 1 through February 5 of 0.9 Bcf, estimated to be approximately 33 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Equipment freeze-offs,
- Icy roads,
- Downtime at processing plants,
- Freezing of equipment, and
- Wellhead freeze-offs.

**Gulf Coast**

Producers representing customary production level of 0.7 Bcf per day from February 1 through February 5 (approximately 14 percent of total basin production), reported production losses from February 1 through February 5 of 0.36 Bcf, estimated to be approximately 18 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Compressors freezing,
- Frozen meters, and
- Freeze-offs.

**This page intentionally left blank.**

# VII. Prior Cold Weather Events

The arctic cold front that descended on the Southwest during the first week of February 2011 was indisputably severe. Many cities in Texas and New Mexico experienced a 50 degree drop in temperature over an eighteen-hour period. Temperatures dropped to the low teens in Texas and below zero in New Mexico. Much of north Texas experienced record setting sleet and snow, totaling up to seven inches. Exacerbating the effects of the cold temperatures were accompanying sustained winds of 30-40 mph, with gusts as high as 51 mph.

The 2011 winter weather event has been determined by at least one weather service to be a one in 10 year occurrence for some regions of Texas, in terms of low temperatures and duration.[222] Adding the sustained winds to these low temperatures, the resultant convective heat loss (wind speed plus ambient temperature) for some generators was estimated to approach a one in 25 year severity. Specifically in El Paso, only four prior recorded cold weather events approached 2011 in severity, making the storm the worst weather event in the El Paso area in 49 years.[223]

This cold weather event was thus unusual in terms of temperature, wind, and duration. It was not, however, entirely without precedent. The Southwest experienced other cold weather events in 1983, 1989, 2003, 2006, 2008, and 2010. In fact, two of those years, 1983 and 1989, had lower temperatures than 2011.[224] But only in l989 were the severity, geographical expanse, and duration of cold temperatures and high winds comparable to the February 2011 event.

In most of those prior years, utilities avoided any significant outages or curtailments. In other years, however, that was not the case. This section examines pertinent prior winter weather events to determine if there were lessons that could have been learned that might have prevented or ameliorated the service disruptions experienced in 2011.

---

[222] Key Document, Severe Weather Readiness Workshop Formerly Generation Weatherization Workshop, Winter Weather Readiness for Texas Generators, (June 8, 2011), http://www.ercot.com/calendar/2011/06/20110608-OTHER (citing Weatherbank, Inc).

[223] Forensic Weather Consultants, LLC, Forensic Weather Investigation of the Weather Conditions and Air Temperatures for the Period 1911-2011 (100 Years) in El Paso, Texas, May 12, 2011, at 1.

[224] Based on data from the National Weather Service.

## A. Electric

The two prior cold weather events of most significance for the ERCOT region occurred in 2003 and 1989; generators experienced weather-related outages in both of those years, and rolling blackouts were implemented in 1989. The winter of 1989 in particular resembles that of 2011, both in the severity of the weather and in loss of load.

These two events are described below, beginning with the most recent.

### 2003 Event

On Friday, February 21, 2003, weather forecasts predicted a cold front over a large part of Texas. The front moved in earlier and was more severe than projected. Statewide, temperatures ranged from 15 to 27 degrees below normal. On Monday, February 24, with freezing temperatures as far south as San Antonio, the demand for electricity reached 42,029 MW, exceeding ERCOT's forecast by 4218 MW, or 11 percent. Owners of gas-fired generating units were short on gas and tried to acquire more gas on the intraday market. At the same time, the demand for gas increased as a result of heating needs.

#### System Events

By 6:00 PM on February 24, ERCOT issued a Market Alert to increase available energy and capacity, and ordered all Reliability Must Run (RMR) units raised to maximum output levels. Temperatures remained below freezing in Austin and Dallas into Tuesday. By 7:30 AM on Tuesday, ERCOT issued a Market Advisory requesting more bids. At the same time, gas companies informed customers that they were activating tariff provisions to curtail gas for purposes other than "human need." At the request of three QSEs, the ERCOT Chief Operating Officer signed affidavits stating that gas needed for electric generation met the qualification of human need.

At 9:08 AM on February 25, gas curtailment to a power plant caused three units to trip, resulting in the loss of 745 MW of generation. System frequency dropped to 59.81 Hz and could not be restored. The ERCOT system control error (SCE) was -1,500 MW and increasing. At 12:01 PM, ERCOT declared Emergency Electric Curtailment Plan (EECP) Step 1 (EECP was the predecessor to today's Emergency Energy Alerts). Step 1, invoked when reserves fall below 2300 MW, entailed instructing all available generation to come on line, and securing emergency power from neighboring electrical grids through the DC ties.

The EECP Step 1 succeeded in rebalancing the system within 30 minutes. Step 1 remained in effect for about seven hours and 30 minutes.[225]

**Gas Supply Problems**

Generator owners reported to the PUCT that they had problems acquiring natural gas to run their gas-fired units. Natural gas was suddenly in short supply, but equally significant was the fact that the structure of the natural gas market limited the way generators were able to respond to fuel shortages in real time. Specifically this involved the following:

- **Depleted reserves:** The amount of gas in storage declined rapidly starting in November 2002, faster than the usual drawdown over the winter period, dropping from a five year high to a five year low in just four months.

- **Timeline for gas nominations:** Natural gas trading closed for the weekend, meaning that fuel for Monday must be procured on Friday, thereby not allowing leeway for late changes in the forecast.

- **Fuel shortages and curtailments:** Delivery constraints reduced the fuel supply to some plants, forcing their electric generating capacities to be derated.

- **Lack of on-site storage:** Natural gas pipeline companies have the bulk of their storage underground, but most of the former vertically integrated electric utilities had their own gas storage facilities. Independent power producers generally do not have their own gas storage; in a deregulated environment, most believe it is uneconomical to maintain it.

In 2003, almost three-quarters of the installed electric generating capacity was fueled by natural gas. Of those units, 16 percent had dual fuel capability, the other fuel being oil. Many units switched from gas to oil on February 24 and February 25, but most had to be derated in the process, and some experienced operating problems. Of the total of 5500 MW of capacity that was lost due to gas curtailments, ERCOT estimated that only 3200 MW was regained on back-up fuel oil, yielding a net loss of 2300 MW.

---

[225] Prices spiked to $990 per MWh on February 24 and February 25, 2003, as the result of hockey stick bidding. For a discussion of this phenomenon, see the earlier section of this report entitled “The Event: Load Shed and Curtailments.”

**PUCT Recommendations**

The Market Oversight Division of the PUCT investigated the 2003 cold weather event and issued a number of recommendations.[226] Notable among these are the following:

- Stricter enforcement of Resource Plan accuracy.
- Improved weather and electric demand forecasting.
- Consider providing financial incentives for fuel oil inventories to be maintained for use by dual fueled units.
- Curtailment prioritization – development of a joint curtailment methodology for natural gas and electricity production.
- ERCOT should communicate with both QSEs and Transmission / Distribution Service Providers in the future when the power system is under stress.

**Consequences**

Following the 2003 generating unit outages, ERCOT revised its Protocols to establish Resource Plan performance metrics. These were put in place in 2004. The February 2003 event ultimately became an impetus for the establishing of Emergency Interruptible Load Service in ERCOT.

## 1989 Event

Beginning on Thursday, December 21, 1989, an arctic air mass descended on Texas for three days, delivering some of the coldest temperatures ever recorded in the state over a one hundred year period. Temperatures bottomed out at 7 degrees in Houston, -1 in Dallas, and -7 in Abilene. As a result of the cold weather, the demand on the ERCOT power system peaked at 38,300 MW, an 11 percent increase over the previous winter's peak and 18 percent above the projected peak for the winter of 1989-1990. This load level was equivalent to 93 percent of the summer peak demand.[227]

---

[226] Julie Gauldin, Richard Greffe, David Hurlbut & Danielle Jaussaud, Pub. Util. Comm'n of Tex., Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003, 29 (May 19, 2003), *available at* http://puc.state.tx.us/industry/electric/reports/ERCOT_annual_reports/special/weather_event.pdf (PUCT 2003 Report).

[227] Elec. Reliability Council of Texas, *ERCOT Emergency Operation: December 21-23, 1989* (Undated), at 5 (ERCOT Emergency Operation).

The high demand, combined with weather-related forced outages of generating units and the curtailment of natural gas fuel supplies, resulted in the need for ERCOT to shed firm load system-wide for the first time in its history or the history of its predecessor.[228] Although there were two subsequent years in which ERCOT shed load during hot weather spells,[229] the 1989 event remained the only cold weather-related load shed event until February 2011.[230]

The 1989 event predated deregulation of the electric utility business in Texas, which began in 2002. Utility companies were therefore still vertically integrated and owned and operated generation, transmission, and distribution in their franchise service territories.

## System Events

On Wednesday, December 20, 1989, a severe cold weather alert was declared for north Texas, effective the following morning; by 6:00 PM on Thursday, all of ERCOT's territory had been placed under severe alert. The temperature was 21 degrees in Dallas and 41 in Houston at that time. Gas curtailments were experienced starting on December 21, and continued for several days thereafter. These resulted in a considerable number of generators switching to or increasing their mix of fuel oil.

On Friday, December 22, ERCOT was unable to maintain minimum required operating reserve levels, due to record-high loads and a large number of generating units being forced offline. The frequency dropped below 59.95 Hz at 8:30 AM, and ERCOT ordered the start up of all available units. Those local control centers experiencing generation deficiencies also shed interruptible loads and minimized their own internal loads such as mining operations and station

[228] ERCOT's predecessor was Texas Interconnected Systems, formed in 1941. *Id*. at 1.

[229] In May 2003, the loss of two nuclear-powered generating units tripped automatic UFLS relays, resulting in the shedding of 1549 MW of firm load; service was restored within three hours and 30 minutes. In April 2006, an early season heat wave and the loss of four generating units caused ERCOT to shed 1000 MW of firm load via rolling blackouts; service was restored within one hour and 45 minutes.

[230] For the Houston area, which was the hardest hit in Texas, it was the first shedding of firm load in the history of the Houston Lighting and Power Company, dating back to the energizing of its first lighting load in 1882. *See* Bill Beck, At Your Service: An Illustrated History of Houston Lighting & Power Company (Houston Lighting & Power Company, 1st ed.1990) at 409; *see also* A Brief history of CenterPoint Energy, 1880-1889, CenterPoint Energy, http://www.centerpointenergy.com/about/companyoverview/companyhistory/timeline/23b55aef7af66210VgnVCM10000026a10d0aRCRD/ (last visited Aug. 3, 2011.

lighting. Utilities made public appeals for customers to voluntarily reduce consumption.

At 10:00 AM on December 22, ERCOT's load peaked at 38,300 MW. At this point, the online generating capacity was 39,800 MW, or 1500 MW greater than the load. Within two hours, decreasing load and the restoration of some generating units that had been forced offline earlier succeeded in bringing reserves back up to acceptable levels. Thus, the record-setting peak load period was met without the need to shed firm load.

However, temperatures continued to drop overnight Friday into Saturday, December 23, when they reached minimums of -7, -1, and 7 degrees in Abilene, Dallas, and Houston, respectively, with wind chill factors down to -35 degrees.

Up until midnight Friday night, approximately 3000 MW of generation was offline due to weather-related problems. The system also suffered 1500 MW of capacity reduction on account of units switching from natural gas to fuel oil. Between midnight and 7:00 AM on the following morning, an additional 4700 MW of generation was forced offline due to weather-related problems. It was also difficult getting power from outside ERCOT. West Texas Utilities offered 220 MW of emergency power to Houston Lighting and Power Company (HL&P), to be delivered over the North Tie, but then had to withdraw the offer due to unspecified technical problems.

By 5:36 AM on Saturday, December 23, the frequency had again dropped below 59.95 Hz, and over the course of the next hour and a half it hovered between 59.79 and 59.92 Hz, indicating the system was in difficulty. Interruptible loads were shed during the early morning hours. At 7:49 AM, ERCOT directed the utilities that were generation deficient to shed firm load.

HL&P had already begun shedding firm load, and increased its load shed to 1000 MW. Lower Colorado River Authority and the City Public Service of San Antonio shed 60 and 150 MW of firm load, respectively.

This firm load shedding, combined with some internal and external power transfers, succeeded in restoring the frequency to 60 Hz, re-stabilizing the system. Around 10:20 AM, however, seven generating units producing a combined 1275 MW were all forced offline nearly simultaneously, causing the frequency to plummet to 59.65 Hz. ERCOT was then forced to invoke system-wide load shedding, beginning with 500 MW, allocated among the utilities. Within ten minutes, the frequency had recovered and the system was stable once again.

As the midday Saturday load declined (typical for a weekend midday), much of the firm load that had been shed was able to be restored within only 30 minutes. The load shed directive was terminated slightly more than two hours later, when reserves increased to acceptable levels.

Accounts vary regarding the amount of total firm load that was shed. The PUCT reported a total load shed of 1710 MW.[231]

**Generation Outages, Derates and Failures to Start**

The following table presents a summary of the causes of the outages, derates, and failures to start experienced in ERCOT during the 1989 cold weather event.

| Number of Units | Capacity | Cause |
|---|---|---|
| 34 | 11,623 MW | Frozen Instrumentation |
| 6 | 1385 MW | Paralyzed or Dead Fish Clogging Water Intakes |
| 9 | 1051 MW | Other, Cold Weather-related |
| 7 | 1246 MW | Non-weather-related |
| **56** | **15,305 MW** | **Subtotal** |
| Not Available | 1500 MW | Gas curtailment impact (oil burning derate) |
| **56+** | **16,805 MW** | **Total** |

[231] *See* Pub. Util. Comm'n of Tex., Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989 (Nov. 1990), at 14 (PUCT 1989 Report); ERCOT Emergency Operation at 6.

.

Virtually all types of generating units encountered problems, whether viewed from the perspective of fuel type or unit type, suggesting that the problems could not be attributed to a particular fuel or unit design. The breakdown is as follows:

- Sorted by **Fuel Type:**
  - Coal: 8 units; 4669 MW
  - Natural Gas: 29 units; 3881 MW
  - Distillate Oil: 1 unit; 257 MW
  - Dual Fuel – Gas & Oil: 15 units; 4418 MW
  - Dual Fuel – Coal & Gas: 1 unit; 670 MW
  - Nuclear: 1 unit; 1250 MW *
  - Petroleum Coke: 1 unit; 160 MW

    *This unit was forced off line the previous weekend due to the failure of an expansion joint in a steam condenser. An attempt was made to start it up during the December 21-23 cold spell, but that failed due to equipment freeze-ups.

- Sorted by **Unit Type:**
  - Conventional Steam Turbine Generators: 32 units; 13,298 MW
  - Simple Cycle Gas Turbines: 7 units; 235 MW
  - Combined Cycle Units: 17 units; 1772 MW

**PUCT Recommendations**

The PUCT staff investigated the cold weather event of 1989 and issued a report the following year that evaluated the causes of the generator outages and made recommendations. Because the circumstances of the event, and the causes of the outages, are so similar to those of the 2011 event, it is worth reproducing those recommendations verbatim:[232]

- All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.

- All utilities should implement procedures requiring a timely annual (each Fall) review of unit equipment and procedures to ensure readiness for cold weather operations.

[232] PUCT 1989 Report at 7.

- All utilities should ensure that procedures are implemented to correct defective freeze protection equipment prior to the onset of cold weather.

- All utilities should maintain insulation integrity and heat tracing systems in proper working order. Generating unit control systems and equipment essential to cold weather operations should be included in a correctly managed preventive maintenance program.

- Additional training programs for plant personnel on the emergency cold weather procedures, including periodic drills, should be implemented by each responsible utility.

- PUC Engineering Staff should modify procedures for power plant CCN [Certificates of Convenience and Necessity] reviews to include a specific review for plant reliability under adverse weather conditions. Of special interest would be the selection of proper design temperature ranges for the power plant site.

The PUCT identified inoperative or inadequate heat tracing systems and inadequate insulation on instrumentation sensing lines as the most common technical equipment problems encountered during the freeze. (These problems also featured prominently in the failure of many generators during the February 2011 event.) Many of the PUCT's recommendations involve weatherization improvements it advised the generators to make, including ensuring the working operation of freeze protection equipment, insulation, and heat tracing systems; instituting preventative maintenance for cold weather equipment; and implementing adequate training for extreme conditions.

The report concluded that "the near complete loss of the ERCOT grid brings an awareness that, even in Texas, plant operators must prepare for cold weather emergencies...this awareness of and attention to cold weather problems must be continued."[233]

**<u>Comparison of 1989 and 2011 Events</u>**

A summary of the statistics for the 1989 event and the 2011 event show how similar they were. Weather conditions and system events for each year are set forth below.

---

[233] *Id*.

**Comparison Table: Basic Information**

| | December 21-23, 1989 | February 1-2, 2011 |
|---|---|---|
| Min. Temps & Wind Chills in Dallas Area | Temperature: -1 degrees F<br>Wind Chill: -12 degrees F | Temperature: 13 degrees F<br>Wind Chill: -6 degrees F |
| Peak System Load | 38,300 MW | 56,334 MW |
| Net Generating Capacity Reduction | 11,809 MW<br>31% of peak load | 14,702 MW<br>26% of peak load |
| Gross Generating Capacity Reduction | 56+ units<br>16,805 MW | 193 units<br>29,729 MW |
| Firm Load Shed | 1710 MW<br>4.5% of peak load | 4900 MW<br>8.7% of peak load |
| Overall Duration of Firm Load Shedding | 5 hours, 47 minutes | 7 hours, 24 minutes |

The following table compares the causes of the outages, derates, and failures to start for each year.

**Comparison Table: Generator Problems**

| | December 21-23, 1989 | February 1-2, 2011 |
|---|---|---|
| Frozen Instrumentation | 34 units<br>11,623 MW | 61 units<br>13,924 MW |
| Fish Clogging Water Intakes | 6 units<br>1385 MW | None reported |
| Other Cold Weather-related | 9 units<br>1051 MW | 54 units<br>6365 MW |
| Non-weather-related | 7 units<br>1246 MW | 63 units<br>7905 MW |
| Gas Curtailment Impact | No. of units not specified<br>1500 MW | 15 units<br>1534 MW |
| **Weather-related % of Gross Capacity Reduction in MW** | **84 % *** | **68 % *** |
| **Frozen Instr. % of Gross Capacity Reduction in MW** | **69 %** | **47 %** |

* Does not count gas curtailments as weather-related.

Despite the recommendations issued by the PUCT in its report on the 1989 event, the majority of the problems generators experienced in 2011 resulted from failures of the very same type of equipment that failed in the earlier event. And in many cases, these failures were experienced by the same generators. Of the over 56 units and 16,805 MW of generating capacity that became unavailable during the December 1989 event, 43 units (representing 13,606 MW of capacity) are still in service in 2011. And 26 of those units, representing 5654 MW of capacity, experienced problems again during the February 2011 cold weather event.

The failures of these repeating units alone eroded a large share of ERCOT's reserve margin going into the morning of February 2, 2011, putting the entire system in jeopardy. Weighing the shedding of 4000 MW of firm load in February 2011 against the 5654 MW of generation capacity that experienced problems in both the December 1989 and February 2011 events, it can be argued that had three-quarters of that capacity not failed again in 2011, the February 2011 blackouts would not have happened. [234]

In its 1989 report, the PUCT commented that "whether the corrective actions being implemented [by the generators in the wake of the event] are sufficient to prevent future freeze-off related power plant failures, only direct experience with another deep freeze will ascertain."[235] Texas has now had that second event, and the answer is clearly that the corrective actions were not adequate, or were not maintained. Generators were not required to institute cold weather preparedness, and efforts in that regard lapsed with the passage of time. It is also possible that new ownership or new plant personnel lacked the historical perspective to make these efforts a priority, at least in the absence of externally imposed requirements.

The task force considered whether cost alone could have been the driving factor in the failure to maintain adequate winterization, and believes it to be unlikely. Based on current industry data, the task force estimates that for conventional gas-fired units and combined cycle units, the capital cost of upgrading basic equipment such as insulation and heat tracing could range from $50,000 to $500,000, depending on the age and condition of the materials, the original design temperature of the unit, and any change in the design temperature.[236] (However, if significant plant components needed to be upgraded

[234] The number of units that tripped, had derates, or failed to start was much larger in 2011 than in 1989. This is primarily a matter of scale. The number of generating units in ERCOT increased from 323 in 1989 to 550 in 2011. However, the increase in the number of units does not correlate exactly with the increase in generating capacity from 54,000 MW to 84,400 MW (using full wind power nameplate capacity, i.e., not adjusted) because of the large increase in combined cycle natural-gas fired plants since 1989 and the introduction of wind power. Combined cycle plants have multiple, and smaller, generating units than conventional steam-turbine plants. Wind power installations vary widely in size from tens of megawatts to hundreds of megawatts, adding greatly to the unit count, but less so to the actual capacity. With so many more, and smaller, units on line in 2011, it is not surprising that the number of trips, derates, and failures to start were greater than in 1989.

[235] PUCT 1989 Report at 6.

[236] *See* Black and Veatch Corp., *Cold Weather Protection Assessment for El Paso Electric Company (Rev. 1),* at 6-4 and 6-7. In the event an independent engineering analysis is commissioned, and based on current industry estimates, the costs for such an analysis for a gas-fired unit could range from $25,000 to $150,000, depending on the type of unit.

or replaced, the cost could be significantly higher. For instance, if cooling towers had freezing problems, the addition of a cooling tower bypass or variable speed tower fan motor might be needed; such costs could range from $150,000 to $500,000.[237])

Texas has recently enacted legislation to deal with the problem of inadequate winterization by generators. A bill was introduced in the Texas legislature following the February 2011 blackouts, with provisions directing the PUCT to prepare a weather emergency preparedness report, to review the emergency operations plans on file, and to recommend improvements to the plans to ensure electric service reliability. In introducing the bill, State Senator Glenn Hegar stated: "What I don't want, is another storm and another report someone puts on the shelf for 21 years and nobody looks at."[238]

After a Senate Committee hearing, the bill was amended and unanimously adopted by the Texas Senate.[239] The House unanimously passed the bill on May 23, and the bill was signed into law by Governor Richard Perry on June 17, 2011.

## B. <u>Natural Gas</u>

Gas production suffered declines in each of the six prior years identified by the task force as having had severe cold weather, and in 1989 and 2003, the declines led to gas curtailments that caused outages or derates to a number of gas-fired electric generators. While some winterization has been put in place by producers and processing plants, production declines occur with each successive severe cold weather event, including the event of February 2011. It may well be that producers have limited market incentives to pay for more elaborate winterization, as they will likely lose less money from short periods of non-production than they would expend on preventing freeze-offs at each of the many wells a producer typically owns.

---

[237] *Id.*

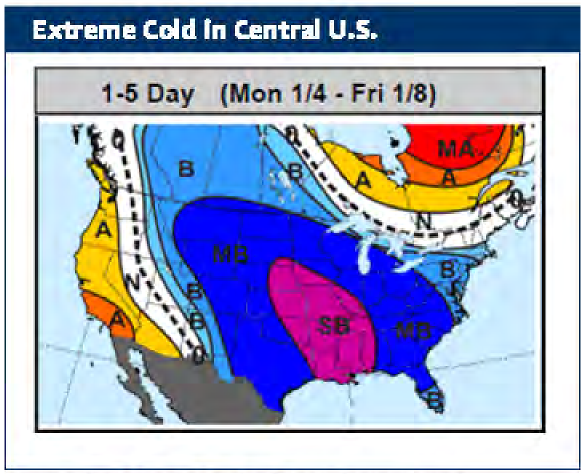
[238] Eric Dexheimer, *February Power Blackouts Across Texas echoed 1989 Failures, State Report Shows,* Austin American-Statesman, Apr. 10, 2011, http://www.statesman.com/news/local/ february-power-blackouts-across-texas-echoed-1989-failures-1390558.html?viewAsSinglePage=true.

[239] SB 1133, 82 Leg., Reg. Sess. (TX 2011) *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133E.pdf#navpanes=0._ The bill would also allow the PUCT to require entities to update their emergency operations plans and to adopt rules relating to implementation of the bill.

Gas production declines in these prior extreme cold weather years are presented below, beginning with the most recent.

**January 2010**

In 2010, an ongoing cold spell led to wellhead and gathering line freeze-offs in the Rockies, San Juan and other southwestern producing basins. About 0.5 Bcfd[240] was lost in the Rockies and another 1.0 Bcfd was lost from the Southwest and shale basins. From January 21 through January 28, Northern Natural Gas and Southwest Gas issued low line pack alerts. High temperatures in every city in the area were above freezing during the month, and low temperatures fell only to the low 20s in a few cities on a few days.




Source: MDA EarthSat, 15-day Report, January 1, 2010

[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.]

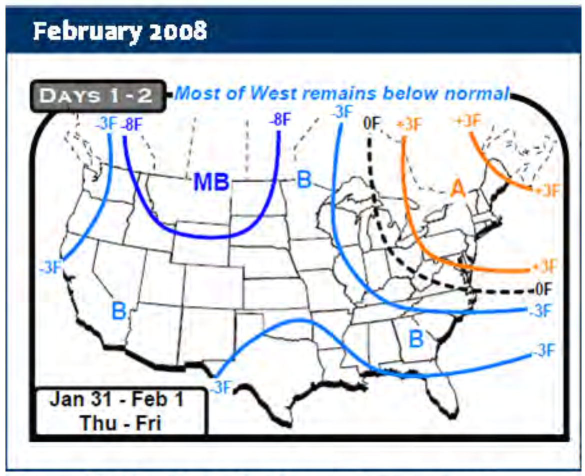
**February 2008**

There was widespread cold weather during late January and early February 2008 in the Rockies, Midwest, and Northeast. El Paso, Southwest Gas, Mississippi River Transmission (MRT), Natural Gas Pipeline Company of America (NGPL), ANR, Northern Natural Gas, and Kern River issued low line pack warnings, and receipts at the Opal[241] processing plant in Wyoming fell due to

[240] Production data in this section is drawn from Bentek, Supply and Demand Daily report.

[241] The Opal processing plant is a major source of output for Rockies production. Major interstate pipelines transport output from that plant to regional markets and markets in the East, the Pacific Northwest, California and the desert Southwest.

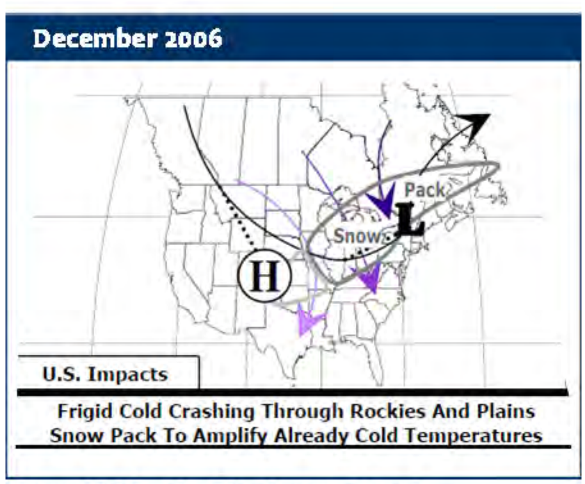
wellhead and gathering line freeze-offs in the region. Rockies production was off between 0.5 and 1.0 Bcfd over a 10-day period. Southwest regional production also fell by about 0.5 Bcfd during that time.




Source: MDA EarthSat, 1-5 Day Outlook, January 31, 2008

## December 2006

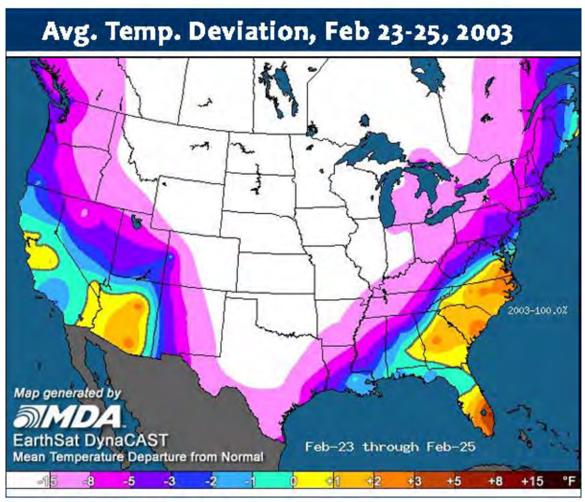
During the first few days of December 2006, unseasonably cold air accompanied by a good deal of snow covered much of the Rockies, the Great Plains and the Midwest. The Midwest and Chicago took the brunt of the frigid temperatures. Lows were in the single digits with a wind chill of -12 degrees. For two days, wellhead freeze-offs caused midcontinent production to fall almost 1 Bcfd, while Rockies and Texas/Louisiana production each were off about 0.5 Bcfd. Temperatures in Midland and El Paso dipped into the low teens for a short time. The short cold snap set off a flurry of operational warnings and alerts; El Paso issued a system operating condition flow order, and Southwest Gas, MRT, NGPL, Kern River, and Transwestern issued low line pack warnings.




Source: MDA EarthSat, Friday December 1, 2006.

## February 2003

Overall, the winter of 2002/2003 was the third coldest of the most recent 11 winter periods. The winter began with record inventories (at that time) of gas in underground storage. But by April, over 2.5 Tcf (trillion cubic feet) was withdrawn, also a record at the time. Regional and national natural gas storage inventories were at record lows when compared to many metrics. During the period from February 23 through February 25, a shot of very cold air swept out of the Rockies and through the Midwest. It brought wind chills of -50° to portions of Wyoming and Colorado and lows below zero in Chicago. Gathering system and wellhead freeze-offs were reported in the Permian Basin and the midcontinent and Rockies regions, and NGPL issued an operational flow order. Midland and Dallas temperatures fell below freezing, although only for a short time. El Paso and Transwestern did issue low line pack alerts that were quickly lifted. As noted earlier, in ERCOT there were gas curtailments to electric generators, estimated by ERCOT to have resulted in a loss of 5500 MW of capacity.




Source: MDA EarthSat

In a May 19, 2003 report on the 2003 cold weather event, the PUCT observed that the gas supply shortages experienced by electric generators in Texas were due in part to an unusually steep decline in storage volumes in the months preceding the event. Those depleted storage reserves during a time of increased demand made it difficult for generators to obtain adequate gas supply, although only one supplier, the TXU Lone Star Pipeline (now Atmos Pipeline-Texas), actually curtailed industrial customers. The PUCT also noted that newly independent power producers, unlike the old vertically integrated utilities, tended not to have their own storage facilities, a factor that contributed to the supply shortage.[242]

[242] PUCT 2003 Report at 12-16.

The 2003 PUCT report recommended that the PUCT and the TRC collaborate on developing a joint curtailment methodology for natural gas and electricity.[243] According to industry observers at the time, the recommendation was aimed at coordinating electrical generation needs with gas supply, to ensure that supply was being used where it was most needed during shortages. However, the agencies reportedly were unable to develop a policy and the project died.[244]

**December 1989**

December 1989 was described at the time by the National Weather Service as the coldest December ever recorded for the combined northeast, central, and southeast regions of the United States. The freeze of December 21 through December 25 caused severe problems for Texas electric utilities, as described earlier in the discussion on electric prior cold weather events. Record and near record low temperatures occurred across the state. For Dallas, it was the coldest and second coldest days in the last 38 years; for Midland, the third and fifth coldest days; for San Antonio, the first and fourth. Houston and Brownsville each had two days among the top five coldest. Wind chill factors in Houston fell to -5 degrees, and in Dallas and Midland, to -12 degrees and -14 degrees, respectively.

While the gas supply situation was more precarious in the Northeast, the Gulf Coast supply regions, Texas and the Southwest were not without their problems. United States productive capacity had not been tested by a prolonged cold snap for more than a decade. Major processing plants[245], refineries and petrochemical plants in the Gulf Coast region shut down. Supply problems occurred in the Gulf of Mexico, Kansas, Texas, Oklahoma, Arkansas, and Louisiana. High winds prevented crews from reaching offshore production platforms that froze off. A major gathering operation in Oklahoma saw 40 percent of its supply frozen off. Producer respondents to a 1991 AGA study said that 10 percent of their production was affected by the cold temperatures.[246]

Most major interstate pipelines accessing Gulf supply experienced some kind of problem. Texas Eastern Transmission Corporation (TETCO) suspended all interruptible transportation deliveries and reduced firm deliveries by 0.5

[243] *Id.* at 16.

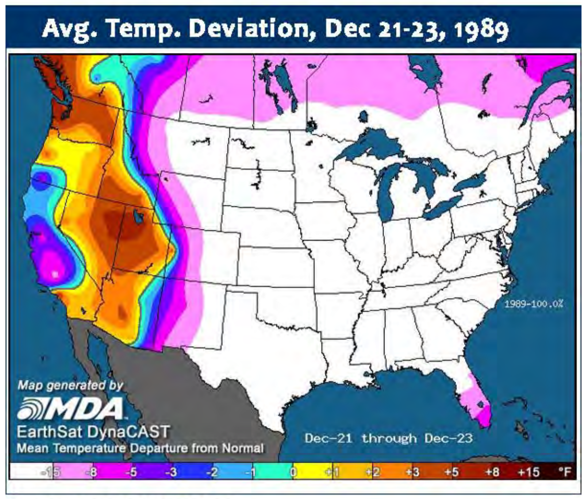
[244] Drawn from materials submitted to the task force by a pipeline company.

[245] Conoco Inc. lost its 1 Bcfd Grand Chenier processing plant in coastal Louisiana due to gas supply and plant operational problems.

[246] Foster Natural Gas Report No. 1845 (Oct. 3, 1991) at 20.

Bcfd.[247] Trunkline and NGPL also suspended interruptible transportation services. Transco curtailed firm service between 22 percent and 50 percent.[248]

In ERCOT there were gas curtailments to electric generators, tabulated earlier in the section on prior electric cold weather events.




Source: MDA EarthSat

## December 1983

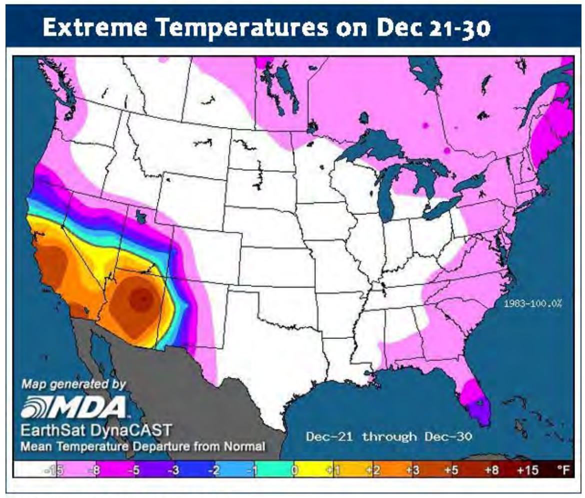
At the end of December 1983, a nine-day stretch of cold weather in Texas resulted in a 3 Bcfd shortfall in supply. Demand was met by massive withdrawals from storage and fuel switching by generators. Refinery operable capacity fell over 72 percent during the week, due to gas supply curtailments. The TRC said that if schools and factories had not been closed for the Christmas holiday, deliveries to high priority customers would have been curtailed. Producers behind Valero Energy reported well freeze-offs, accounting for a 43 percent drop in supply.[249]

---

[247] TETCO reported a field supply shortfall of 1 Bcfd from its normal of 1.9 Bcfd.

[248] See Rick Hagar, Winter Hits U.S. Industry, Strains Gas Supply, OIL & GAS J., Jan. 1, 1990, at 28; see also Rick Hager, U.S. Gas Industry Ponders Lessons Learned from Severe Winter, OIL & GAS J., Mar. 5, 1990, at 17.

[249] See Rick Hagar, TRC Chairman Downgrades Size of Gas Surplus in U.S., OIL & GAS J., Feb. 27, 1984, at 47.




Source: MDA EarthSat

An examination of these prior years reveals that production declines are common during cold weather events. However, only in limited circumstances did they lead to curtailment of natural gas customers, including curtailment of gas-fired electric generators.

The production declines raise the question as to why producers did not improve their winterization preparations to withstand these not uncommon cold snaps. The reason most likely comes to one of cost (as well as to the lack of regulation requiring it). A study performed for the task force by the Gas Technology Institute[250] has estimated that capital costs for winterization could vary from as little as $2,800 to more than $30,000 per well, depending on the degree of cold weather protection required and other variable factors such as gas flow rates, pressures, existing winterization, and the like. In addition to these capital costs, the cost of maintenance and operational supplies such as methanol (antifreeze) could add up to several thousand dollars per year for each well. (These costs include costs associated with protecting field processing, such as separating water from the gas, as well as the flow lines to the separating facilities.)[251] Since it is not uncommon for the larger producers to have hundreds of wells in a given basin, these costs would quickly mount up. Such costs need to be accounted for in some fashion if mandatory weatherization were to be considered by regulatory or legislative bodies (as would the costs that would be incurred by electric generators to meet comparable requirements.)

[250] This report is included as an appendix, entitled "GTI: Impact of Cold Weather on Gas Production."

[251] Kent F. Perry, Gas Technology Institute, *Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During Early February, 2011* (June 2011) at 33.

Producers suggest that even improved winterization of the wells would not prevent a significant portion of production declines, since other problems, such as icy roads that prohibit hauling off water (which, if not done, shuts down the well), are also commonly encountered.

**This page intentionally left blank.**

# VIII. Electric and Natural Gas Interdependencies

The February 2011 cold weather event highlights the interdependency of electricity and natural gas, an interdependency that has grown in recent years. Natural gas has become an increasingly popular fuel choice for electric generators. Concurrently, compressors used in the production and transportation of natural gas have come to rely increasingly on electricity for their power source, rather than natural gas.

The reason for the increased popularity of gas-fired electric generation is one of economics. Natural gas prices have fallen due to increased gas production, beginning in 2008 when producers developed the technology to drill the Barnett Shale. Just prior to 2008, average daily marketed production was about 55.5 Bcf per day. Spot prices at the Henry Hub during 2007 averaged almost $7.00 per MMBtu. Shale production accounted for perhaps five percent of total United States production, and offshore production comprised approximately 15 percent.

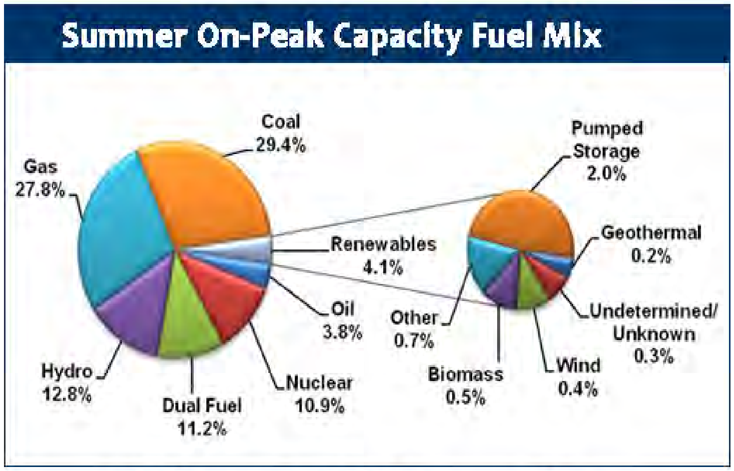
But by the end of 2008, average daily production had grown to over 59.3 Bcf per day. In the ensuing years, producers applied the lessons learned in the Barnett Shale to other basins, most notably the Fayetteville, Haynesville and Marcellus Shales, with notable results. Thus far in 2011, gas production is averaging almost 62.8 Bcf per day (and recently topped 64 Bcf per day), while average daily spot prices at the Henry Hub have fallen to $4.27 per MMBtu. Offshore production in 2010 accounted for only 10 percent of total United States production, and analysts estimate that shale production alone now accounts for 25 percent of total production.

At the same time, gathering companies, as well as pipelines and LDCs located in urban areas, have increasingly turned to electric-powered compressors. Gathering companies prefer electric-powered compressors because they can fit in smaller spaces than gas-fired compressors, and the companies do not need as much compressive power as the large pipelines. For pipelines and LDCs in urban areas, environmental restrictions relating to noise and air quality, as well as the ready availability of electricity, tip the scales in favor of electricity over natural gas. The large pipelines favor gas-fired compressors, because the gas is readily available to them and they have large horsepower demands.

The following chart depicts the mix of generation available for United States electricity needs in the summer of 2010, by fuel type.[252] It shows that 27.8

[252] NERC 2010 Summer Reliability Assessment (May 2010) at 10, http://www.nerc.com/files/2010%20Summer%20Reliability%20Assessment.pdf.

percent of all generation uses gas as the fuel source, and an additional 11.2 percent is dual-fueled (mostly gas and diesel oil).




Source: NERC's Summer Reliability Assessment, May 2010

The Southwest relies heavily on gas-fired generation to meet its peak capacity needs. In ERCOT, approximately 57 percent of the available on-peak summer and winter capability is from gas-fired generation (with 40 percent solely gas-fired and 17 percent having dual-fuel capability with gas as the primary fuel).[253] In the SPP region, 50 percent of the summer and winter on-peak capability is from gas-fired generation, and in WECC, 41 percent.

In New Mexico, gas-fired generating units consume approximately 70,102 MMcf annually, representing approximately one percent of total national consumption of gas used in the utility sector.[254] In Texas, gas-fired generating units consume approximately 1,387,421 MMcf of natural gas annually, representing approximately 20.2 percent of total national consumption of gas used in the utility sector.[255] And in Arizona, gas-fired generating units consume approximately 261,904 MMcf of natural gas annually, representing approximately 3.8 percent of total national consumption of gas used in the utility sector.[256]

[253] Based on data provided by ERCOT.

[254] EIA, Natural Gas Annual 2009, at 128-129 (Table 58), http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html.

[255] *Id*. at 152-153 (Table 70).

[256] *Id.* at 70-71 (Table 29).

## Interdependency Effects During the February Event

The task force examined data from numerous electric and gas entities to gauge the severity that shortfalls in one commodity had on the other during the February event. Materials received from natural gas producers indicate that the rolling blackouts (or customer curtailments) in ERCOT were a significant cause, from 29 to 27 percent respectively, of production shortfalls in the Permian and Fort Worth Basins. For pipelines and LDCs, however, the effects of the rolling blackouts were negligible.[257]

Gas shortfalls caused problems for some generators in Texas, although not nearly to the extent as did direct weather-related causes such as equipment failure from below-freezing temperatures. In ERCOT, as detailed in the section of this report entitled "Causes of the Outages and Supply Disruptions," the outages and derates from inadequate gas supply during the cold weather event totaled 1282 MW, compared to a peak net capacity reduction of 14,702 MW. While gas supply to SRP and EPE was compromised due to problems at the Chevron Keystone Storage Facility, EPE's generating units failed for other reasons, and SRP was able to obtain gas from other sources. However, during the 2003 cold weather event, there were significant gas curtailments to electric generators in Texas, which affected generating capacity. Gas curtailments also caused a loss of generating capacity in 1989, although to a lesser extent.

The task force was cognizant of the possibility that gas shortages may have been a less significant factor only because so many generators were forced offline for other reasons, and thus unable to take the gas (as was the case with EPE). The task force attempted to answer the question of whether there would have been adequate gas supplies to ERCOT had its failed gas-fired generators been able to take the gas. To do so, the task force tallied and compared the MWs forced offline, the amount of gas demand the generators would have imposed on suppliers had they been capable of running, and the capacity of the gas supply system at the time.

The task force determined that 5256 MW of generation in ERCOT could have imposed demands on the gas supply system had the generating units not experienced trips, derates, or failures to start. This number represents the total 5556 MW of the 55 gas-fired generating units in ERCOT, reduced by 300 MW for those generating units connected to a single pipeline that had pressure or gas

[257] An exception for LDCs supplying gas is the surge effect experienced when electricity is restored after an outage, which places instant and simultaneous demand on gas equipment and systems. This effect is described in the section of this report entitled "The Event: Outages and Curtailments."

quality problems (making it unlikely the generating units could have received gas even if they had had no operational difficulties). Each unit was assumed to have a 9,000 Btu/kWh heat rate. In the aggregate, these units would have added a maximum additional gas demand of approximately 1.1 Bcf per day.

Adding this additional hypothetical demand to the actual peak demand of 12.5 Bcf per day[258] would have imposed total demand on the system of 13.6 Bcf. Supply in January was running at 17.7 Bcf per day; these volumes declined during the first week of February. On February 2, the worst day from the standpoint of ERCOT, supply declined to 16.35 Bcf per day. On February 4, when production volumes hit their lowest point for the week, supply declined to 14.08 Bcf per day.

A comparison of these supply and demand numbers shows that total demand (actual demand plus hypothetical demand) would still have been below the available supply during the February cold weather event, particularly so on February 2, the day rolling blackouts were implemented. The task force's analysis therefore indicates there would have been adequate gas to supply the generators in ERCOT that failed for other reasons.[259] This conclusion was confirmed by knowledgeable industry observers, who were of the opinion that the Texas supply of gas would have been adequate had the generators not experienced weatherization problems.

## Fuel Switching

A not insignificant amount of gas-fired generation in the Southwest has fuel switching capability. In ERCOT, 16 percent of total generation can fuel switch; in SPP, it is seven percent. Within WECC, of those generating units that are directly connected to El Paso, Northern Natural Gas, or ONEOK WesTex, 38 have fuel switching capability.

Fuel switching enables a simple or combined cycle generating turbine to alternate between fuel sources, typically natural gas and some type of fuel oil.

---

[258] The actual demand listed is a worst case scenario, because the calculation was derived by adding together the peak demand of each of the three major pipelines in Texas serving gas-fired generating units. A more realistic number would probably be demand of approximately 12 Bcf per day or less.

[259] The excess gas was sold out of state, but had the generators in ERCOT been able to use it, they could have gotten it. Since gas prices rose modestly in the region during the event, the shippers would very likely have redirected the gas to Texas to take advantage of the higher prices, had the generators been able to accept it. This would be true whether or not the contracts were interruptible, since a shipper could adjust its purchases and sales to take advantage of the pricing differential.

Fuel switching can be as simple as a control room operator pushing a button which automatically switches to oil, or as complicated as having to remove gas injectors and install oil injectors in every position around the boiler, a process that can take days rather than minutes.

It is common for units that switch to an alternate fuel type to experience a capacity derate, since normally each unit is designed to most efficiently burn a particular fuel.

The choice to perform fuel switching is primarily based on three factors: 1) cost, 2) environmental restrictions, and 3) the availability of natural gas. Running the generating unit on alternate fuels, such as fuel oil, may cost up to twice as much on a MW basis.[260] And environmental and air quality control restrictions, which vary by state, may limit the number of hours per year a generator is allowed to run on fuel oil.

Fuel switching capability was a more desirable option in the past, when the relative prices of gas and oil fluctuated, making one or the other more economical at any given time. Given the decline in natural gas prices, this option has become less valuable.

During the February event, 20 generating units in ERCOT attempted to switch fuels, with 15 managing it successfully.[261] (This echoed ERCOT's experience during the 2003 cold weather event, when a number of units that attempted to switch fuels were unable to do so, and those that did switch experienced derates of capacity.[262]) SRP has nine units capable of switching, and EPE has three units capable of switching. None was asked to switch during the event, as the units either failed for other reasons or were able to obtain adequate gas supply. In SPP, of the three representative entities the task force examined, eight generating units have fuel switching capabilities; four attempted to switch during the event and ultimately succeeded, although half had initial difficulties.

---

[260] Based on information supplied to the task force by an LDC.

[261] A majority of the units that attempted to switch fuels but were unable to do so experienced a mechanical failure of some sort in the switching equipment, which could have been due to the cold temperatures, inadequate maintenance, lack of regular testing, or the infrequent use of the alternate fuel in normal operations.

[262] PUCT 2003 Report at 17. The PUCT recommended that providing financial incentives for fuel oil inventories, to be maintained for use by dual-fueled generating units, should be considered.

Fuel switching raises a number of questions, such as: whether generators that have the capability to switch fuels should be required to maintain their alternate fuel equipment and stockpile an adequate supply of the alternate fuel, whether subsidies or incentives should be instituted to compensate for such requirements or to add fuel switching capabilities to those units that do not currently have it, and whether units that can switch fuels should be paid to do so in order to preserve gas supplies for residential consumers. These are issues that can be most fruitfully addressed in forums involving representatives of both the electric and natural gas industries operating in the region, as well as the regulatory bodies overseeing them.

## Communications

In 2004, NERC released a report entitled "Gas/Electricity Interdependencies and Recommendations," which summarized the findings of its Gas/Electricity Interdependency Task Force (GEITF). The GEITF held a series of meetings with representatives of both the electric and gas industries and prepared a list of recommendations for NERC's consideration. The GEITF reported that a recurring theme expressed by gas industry participants was concern about communications between pipeline operators and entities other than the pipeline's contractual customers. While the pipelines communicate with the LDCs serving a generator or with the generator itself, they do not communicate with a regional reliability coordinator, apparently due to confidentiality restrictions. The GEITF recommended that NERC, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

Communication failures between gas and electric entities did not seem to play a role during the February 2011 event (although there were complaints of communication issues between shippers and pipelines). Nonetheless, the electric and gas industries might consider revisiting the GEITF recommendations to see if procedures should be developed for communications between pipelines and reliability coordinators.[263]

[263] NERC plans to conduct an electric/gas interdependency study in 2011 to reevaluate the GEITF recommendations. The study will analyze whether procedures should be developed for communications between the electric and gas industries.

# IX. Key Findings and Recommendations

The facts that came to light in the course of the joint inquiry conducted by the staffs of FERC and NERC, as well as the conclusions drawn from them, have been presented throughout the body of this report. Because the matters examined are complex and detailed, this section presents in summary form the task force's key findings. It also presents recommendations that the task force believes, if implemented, could significantly contribute to preventing a recurrence of the rolling blackouts and natural gas curtailments experienced in the Southwest during the February 2011 cold weather event.

## A. The Electric Industry

### Key Findings -- Electric

- During the February event, temperatures were considerably lower (15 degrees plus) than average winter temperatures, and represented the longest sustained cold spell in 25 years. Steady winds also accelerated equipment heat loss. However, such a cold spell was not unprecedented. The Southwest also experienced temperatures considerably below average, accompanied by generation outages, in December 1989. Less extreme cold weather events occurred in 2003 and 2010. Many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment.

- While load forecasts fell short of actual load, the forecasts were not a factor in the loss of load. ERCOT manually increased its February 1 and February 2 forecasts by 4000 MW to factor in wind chill, and had established sufficient reserves to accommodate both forecasted load and the actual load that transpired. The reason blackouts had to be initiated was that over 29,000 MW of generation that was committed in the day-ahead market or held in reserve either tripped, was derated, or failed to start. This was the largest loss of generation in ERCOT's history, including during the prior cold weather load shed event in December 1989 and the two hot weather load shed events in 2003 and 2006. While units of all types (except nuclear generating units) tripped, derated, or failed to start in 2011, in ERCOT, gas combined cycle units had the highest percentage of failures, compared to their percentage of the total fuel mix.

- ERCOT and the generators within ERCOT could better coordinate generator scheduled outages, both in terms of the total amount of scheduled outages at a given time and their location. A substantial amount of generation (11,566 MW) was on scheduled outage going into the cold weather event. ERCOT's current Protocols provide that requests for scheduled outages submitted earlier than eight days before the outage is to begin are automatically approved, unless they would violate a Reliability Standard.

- ERCOT's fast action in initiating rolling blackouts prevented more widespread and less controlled ERCOT-wide blackouts. Had ERCOT not initiated manual load shedding, its under-frequency load shedding relays would have instantaneously dropped approximately 2600 MW (five percent of system load), a loss that could have created further system disturbances and resulting generation outages. Load shedding by the transmission and distribution operators in ERCOT's footprint was generally carried out in a timely and effective manner.

- Transmission operators and distribution providers generally did not identify natural gas facilities such as gathering facilities, processing plants or compressor stations as critical and essential loads.

- Balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when temperatures dropped.

- The lack of any state, regional or Reliability Standards that directly require generators to perform winterization left winter-readiness dependent on plant or corporate choices. While Reliability Standard EOP-001 R.4 and R.5 refer to winterization as a consideration in emergency plans, these requirements apply only to balancing authorities, transmission owners, and transmission operators.

- Generators were generally reactive as opposed to being proactive in their approach to winterization and preparedness. The single largest problem during the cold weather event was the freezing of instrumentation and equipment. Many generators failed to adequately prepare for winter, including the following: failed or inadequate heat traces, missing or inadequate wind breaks, inadequate insulation and lagging (metal covering for insulation), failure to have or to maintain heating elements and heat lamps in instrument cabinets, failure to train operators and maintenance personnel on winter preparations, lack of fuel switching training and drills, and failure to ensure adequate fuel.

- Gas curtailment and gas pressure issues did not contribute significantly to the amount of unavailable generating capacity in ERCOT during the event. The outages, derates, and failures to start from inadequate fuel supply totaled 1282 MW from February 1 through February 5, as compared to an overall peak net generating capacity reduction of 14,702 MW.

**Recommendations -- Electric**

***PLANNING AND RESERVES***

**1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generation Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer peak season.**

The large number of generating units that failed to start, tripped offline or had to be derated during the February event demonstrates that the generators did not adequately anticipate the full impact of the extended cold weather and high winds. While plant personnel and system operators, in the main, performed admirably during the event, more thorough preparation for cold weather could have prevented many of the weather-related outages.

Capacity margins going into the winter of 2010/2011, for both ERCOT and the southwest regions of WECC, were adequate on paper. (ERCOT reported a 57 percent margin above forecasted winter peak demand, and the southwest regions of WECC projected a 105.7 percent margin.) But those margins did not take into account whether many of the units counted would be capable of running during the severe cold weather that materialized in February.

While the probability of a winter event in the predominantly summer peaking Southwest appears to be low, shedding load in the winter places lives and property at risk. The task force recommends that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season.

**2. Planning authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon.**

Both ERCOT and the Southwest regions of WECC undertake planning studies to ensure that sufficient reserves are available to meet seasonal peak loads. However, the forecasted peak demand in the winter assessments for 2010/2011 was not as high as that actually experienced in early February.

Planners should undertake a sensitivity study, using the 2011 actual conditions as a possible extreme scenario, that reflects expected limits on available generation. These limits would include those due to planned outages, limited operations during periods of extreme cold weather, ambient temperature operating limitations, and any likely loss of fuel sources.

This sensitivity study should be used by operational planners to identify various system stress points, and by Reliability Coordinators, Balancing Authorities, and Transmission Operators to improve and refine strategies to preserve the reliability of the bulk power system during an extended cold weather event. These strategies should include procedures relating to utilization of generators with fuel switching capabilities and implementing early start-ups for generators with long start-up times.

**3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies**.

This recommendation is designed to ensure that Balancing Authorities take into account transmission constraints, other demands on reserve sharing resources, the possibility that more than one reserve sharing group member might experience simultaneous emergencies, and other factors that might affect the availability or deliverability of reserves. ERCOT is currently considering a similar recommendation, which was presented to its Board of Directors in March, 2011.

**4. ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage, consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria.**

ERCOT's Protocols provide that it may not forbid an outage request submitted more than eight days prior to the scheduled outage, unless the outage would keep ERCOT from meeting applicable Reliability Standards or Protocol requirements. The Protocols further limit review of outage requests made earlier than eight days before the outage to the following three things: load forecast, other known outages of both generation and transmission, and the results of a contingency analysis to indicate whether the outages would cause overloads or voltage problems.

The task force recommends that ERCOT consider lengthening the period for which ERCOT may deny an outage request, assuming the conditions for doing so are met. (ERCOT is presently considering a Protocol revision to give itself the authority to deny an outage request that is not scheduled more than 90 days prior to the outage date, a revision which the task force supports.) In addition, ERCOT should consider giving itself the authority to cancel previously approved outages in cases of approaching extreme weather conditions, even up to the time of the event itself. In making this evaluation, ERCOT should take into account the costs that would be imposed on the generator as well as the practical difficulties of returning it to service if plant components are disassembled, as well as the generator's need to perform maintenance at some point while also avoiding the high demand summer season.

In addition to the criteria for outage evaluation currently provided in the Protocols, the task force recommends that ERCOT take into consideration the potential loss of units based on weather conditions beyond their design limits, and the effects likely to result from the totality of scheduled and proposed outages.

In furtherance of these criteria, ERCOT should:

- Have available to it the design temperatures of all generation resources.
- Take into consideration as an extreme weather event approaches which plants will not be available based on their design temperature limits.
- Consider increasing reserve levels during extreme weather events.
- Commit, for purposes of serving load and being counted as reserves, only those plants whose temperature design limits fall within the forecasted temperature range.
- Determine, prior to approving an outage, if the combination of previously approved scheduled outages with the proposed scheduled outages might cause reliability problems.

**5. ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to utilize pre-operational warming prior to anticipated severe cold weather, and (iii) allow**

**it to verify with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.**

ERCOT data on forced outages during the 50 coldest days between 2005-2011 show a correlation between low temperatures and forced outages. This was demonstrated not only by the February 2011 event but also by the 1989 event; in both cases, extremely low temperatures led to the loss of large amounts of generation and the implementation of rolling blackouts.

Increasing the amount of responsive reserves going into a cold weather event would compensate for the probability that a number of generating units might fail, and would provide better response to system instability in the event of such losses.

Additionally, pre-operational warming would help prevent freezing and identify other operational problems. Running a unit prior to the start of extreme cold weather would utilize the unit's own radiant heat to help prevent freezing. And starting it up would permit correction of any problems that otherwise would not be noticed until the unit was called upon for performance.

While pre-operational warming has considerable value, issues of whether or how generators are to be compensated for taking such actions at ERCOT's direction would need to be addressed.

***COORDINATION WITH GENERATOR OWNERS/OPERATORS***

**6. Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.**

Sixteen percent of ERCOT's generation capacity is listed as having fuel switching capabilities. During the February cold weather event, a quarter of the 20 units that attempted to switch fuel were unsuccessful. If a unit represents itself as having fuel switching capability, verification of the adequacy of its capability would provide useful information to the Balancing Authority or Transmission Operator as to the availability of that unit in the event of natural gas curtailments.

Fuel switching verification might consist of the following:

- Documented time required to switch equipment,
- Documented unit capacity while on alternate fuel,
- Operator training and experience,

- Fuel switching equipment problems, and
- Boiler and combustion control adjustments needed to operate on alternate fuel.

**7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions.**

The task force determined that a combination of scheduled and forced outages of ERCOT's black start units would have put ERCOT's ability to restore the system in jeopardy, had an uncontrolled blackout not been averted by the implementation of load shedding. Balancing Authorities and Transmission Operators should take steps to ensure the availability and reliability of their black start units during adverse weather and emergency conditions, particularly to prevent a gap in this function before 2013, when the provisions of Reliability Standard EOP-005-2 on System Restoration from Blackstart Resources becomes mandatory. These steps should ideally include auditing Generator Owner/Operators, random testing of black start units during temperature extremes (both hot and cold), determining the ambient operating temperature limitations of the black start units, evaluating the effects of extreme temperatures on implementation of the entity's black start plan; and ensuring that operators are trained to start the black start units during extreme weather conditions. ERCOT is presently considering Protocol revisions that would provide for unannounced testing of black start units and "claw back" payments for black start units that fail testing or fail to perform.

**8. Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.**

In order to ascertain actual capabilities during extreme weather conditions, Balancing Authorities and Reliability Coordinators should require Generator Owner/Operators to provide accurate ambient temperature design operating limits for each generating unit that is included in its portfolio (including the accelerated cooling effect of wind), and update them as necessary. These limits should take into account all temperature-affected generator, turbine, and boiler equipment, and associated ancillary equipment and controls.

The Balancing Authorities should take steps to verify that Generator Owner/Operators comply with this requirement, and should prepare for the winter season by developing a catalog of individual generating unit temperature limitations. These should be used to determine if forecasted temperatures place a particular generating unit in a high risk category.

Lastly, Balancing Authorities and Reliability Coordinators should consider the feasibility of counting on a generating unit whose rating falls below forecasted weather conditions, and should consider whether to take into account weather-related design specifications in ranking units in the supply stack during critical weather events.

**9. Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.**

Balancing Authorities are permitted to request a forecast of real output capability under Reliability Standard TOP-002-02 R15. Doing so would allow operators to make proactive decisions prior to the onset of cold weather, including but not limited to:

- Requesting cancellation of planned outages,
- Directing advanced fuel switching,
- Directing startup of units with startup times greater than one day,
- Requesting startup of seasonally mothballed units, and
- Making advance requests for conservation.

In the case of ERCOT, which does not own the generators in its footprint, consideration needs to be given to ensuring that there is an adequate cost recovery mechanism in place for reliability measures taken by the generators at ERCOT's direction.

**10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages.**

Some generators experienced derates during the event due to emission limitations. The Texas Commission on Environmental Quality (TCEQ) exercised enforcement discretion with respect to its emission restrictions during the event; however, this action, which was taken after the TCEQ received requests during the event itself, did not come in time to prevent all the emissions-related derates that occurred on February 2. It is recommended that ERCOT work out procedures in advance with the TCEQ for the exercise of its enforcement discretion in the case of severe weather events, and have an internal procedure in place that delegates specific ERCOT personnel as responsible for contacting the TCEQ and other environmental regulatory bodies during the early stages of an event, in order to inform them of the significance of the situation.

***WINTERIZATION***

**11. States in the Southwest should examine whether Generator/Operators ought to be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate.**

The task force determined during its inquiry that certain generators were better prepared than others to respond to the February cold weather event. In many cases the entities that performed well had emergency operations or winterization plans in place to provide direction to employees on how to keep their units operating. Although the implementation of a winterization plan cannot guarantee that a unit will not succumb to cold weather conditions, it can reduce the likelihood of unit trips, derates and failed starts.

The state of Texas has provided a starting point for such legislation with SB 1133, which was signed into law on June 17, 2011. This statute incorporates two important components: (1) mandatory reporting of emergency operations procedures, and (2) independent review by the PUCT.

In addition to the matters covered in the Texas statute, the task force recommends that planning take into account not only forecasts but also historical weather patterns, so that the required procedures accommodate unusually severe events. Statutes should ideally direct utility commissions to develop best winterization practices for its state, and make winterization plans mandatory. Lastly, it is recommended that legislatures consider granting utility commissions the authority to impose penalties for non-compliance, as well as to require senior management to acknowledgement that they have reviewed the winterization plans for their generating unit, that the plans are an accurate representation of the winterization work completed, and that they are appropriate for the unit in light of seasonal weather conditions.

NERC staff has concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability. Accordingly, NERC intends to submit a Standard Authorization Request, the first step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations.

***Plant Design***

**12. Consideration should be given to designing all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed.**

The ideal time to prepare a generating unit to withstand cold temperatures is in the design stage. For that reason, the low temperatures and wind chills that can occur during the occasional severe storm should be incorporated in the design process.

**13. The temperature design parameters of existing generating units should be assessed.**

The task force found that for existing generating units, it is often not known with any specificity at what temperature the unit will be able to operate, or to what temperature heat tracing and insulation can prevent the water or moisture in its critical components from freezing. For that reason, Generator Owner/Operators should conduct engineering analyses to ascertain each unit's operating parameters, and then take appropriate steps to ensure that each unit will be able to achieve the optimum level of performance of which it is capable.

The task force recommends the following:

- Each Generator Owner/Operator should obtain or perform a comprehensive engineering analysis to identify potential freezing problems or other cold weather operational issues. The analysis should identify components/systems that have the potential to: initiate an automatic unit trip, prevent successful unit start-up, initiate automatic unit runback schemes and/or cause partial outages, adversely affect environmental controls that could cause full or partial outages, adversely affect the delivery of fuel to the units, or cause other operational problems such as slowed valve/damper operation.

- If a Generator Owner/Operator does not have accurate information about the ambient temperature to which an existing unit was designed, or if extensive modifications have been made since the unit was designed (including changes to plant site), it should obtain an engineering analysis regarding the lowest ambient temperatures at which the unit can reliably operate (including wind chill considerations).

- Each Generator Owner/Operator should ensure that its heat tracing, insulation, lagging and wind breaks are designed to maintain water temperature ( in those lines with standing water) at or above 40 degrees when ambient temperature, taking into account the accelerated heat loss due to wind, falls below freezing.

- Each Generator Owner/Operator should determine the duration that it can maintain water, air, or fluid systems above freezing when offline, and have contingency plans for periods of freezing temperatures exceeding this duration.

***Maintenance/inspections generally***

**14. Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis.**

The task force found a number of inadequacies in generating units' preparations for winter performance. These included a lack of accountability and senior management review, lack of an adequate inspection and maintenance program, and failure to perform engineering analyses to determine the correct capability needed for their protection equipment.

The task force recommends the following:

- Each Generator Owner/Operator's senior management should establish policies that make winter preparation a priority each fall, establish personnel accountability and audit procedures, and reinforce the policies annually.

- Each Generator Owner/Operator should develop a winter preventative maintenance program for its freeze protection elements, which should specify inspection and testing intervals both before and during the winter. At the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance, in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season.

- Each Generator Owner/Operator should prioritize repairs identified by the inspection and testing program, so that repairs necessary for the proper functioning of freeze protection systems will be completed before the following winter.

- Each Generator Owner/Operator should use the recommended comprehensive engineering analysis, combined with previous lessons learned, to prepare and update a winter preparation checklist. Generator Owner/Operators should update checklists annually, using the previous winter's lessons learned and industry best practices.

***Specific Freeze Protection Maintenance Items***

The task force found that many generating units tripped, were derated, or failed to start as a result of problems associated with a failure to install and maintain adequate freeze protection systems and equipment. Based on these findings, on an examination of freeze protection systems of many of the affected generating units, and in some cases on standards issued by the Institute of Electrical and Electronics Engineers, the task force has prepared a number of recommendations designed to prevent a repeat of the spotty generator performance experienced during the February cold weather event. Of course, specific actions should conform to best industry practices at the time improvements are made, as well as to the requirements of any mandatory winterization standards imposed by regulatory or legislative bodies.

*Heat tracing*

**15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.**

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the power supply to all heat trace circuits, including all breakers and fuses.

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the continuity of all heat trace circuits, check the integrity of all connections in the heat trace circuits, and ensure that all insulation on heat traces is intact. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could cause grounds.

- Each Generator Owner/Operator should, before each winter begins, inspect, test, and maintain all heat trace controls or monitoring devices for proper operation, including but not limited to thermostats, local and remote alarms, lights, and monitoring cabinet heaters.

- Each Generator Owner/Operator should, before each winter begins, test the amperage and voltage for its heat tracing circuits and calculate whether the circuits are producing the output specified in the design criteria, and maintain or repair the circuits as needed.

- Each Generator Owner/Operator should be aware of the intended useful life of its heat tracing equipment and should plan for its replacement in accordance with the manufacturer's recommendations.

*Thermal Insulation*

**16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.**

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins, inspect all accessible thermal insulation and verify that there are no cuts, tears, or holes in the insulation, or evidence of degradation.

- Each Generator Owner/Operator should require visual inspection of thermal insulation for damage after repairs or maintenance have been conducted in the vicinity of the insulation.

- Each Generator Owner/Operator should ensure that valves and connections are insulated to the same temperature specifications as the piping connected to it.

- Each Generator Owner/Operator should be aware of the intended useful life of the insulation of water lines and should plan for its replacement in accordance with the manufacturer's recommendations.

*Use of Wind breaks/enclosures*

**17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed.**

Specifically, the task force recommends:

- A separate engineering assessment should be performed for each generating unit to determine the proper placement of temporary and/or permanent wind breaks or enclosures to protect and prevent freezing of critical and vulnerable elements during extreme weather.

- Temporary wind breaks should be designed to withstand high winds, and should be fabricated and installed before extreme weather begins.

- Generator Owner/Operators should take into account the fact that sustained winds and/or low temperatures can result in heat loss and freezing even in enclosed or semi-enclosed areas.

*Training*

**18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.**

Operator training should include awareness of the capabilities and limitations of the freeze protection monitoring system, proper methods to check insulation integrity and the reliability and output of heat tracing, and prioritization of repair orders when problems are discovered.

*Other Generator Owner/Operator Actions*

**19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner.**

Specifically, the task force recommends:

- Each Generator Owner/Operator should maintain a sufficient inventory of supplies at each generating unit necessary for extreme weather preparations and operations.

- Each Generator Owner/Operator should place thermometers in rooms containing equipment sensitive to cold and in freeze protection enclosures to ensure that temperature is being maintained above freezing and to determine the need for additional heaters or other freeze protection devices.

- During extreme cold weather events, each Generator Owner/Operator should schedule additional personnel for around-the-clock coverage.

- Each Generator Owner/Operator should evaluate whether it has sufficient electrical circuits and capacity to operate portable heaters, and perform preventive maintenance on all portable heaters prior to cold weather.

- Each Generator Owner/Operator should drain any non-critical service water lines in anticipation of severe cold weather.

*Transmission Facilities*

**20. Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions.**

Transmission Operators reported several incidents of unplanned outages during the February 2011 event as a result of circuit breaker trips, transformer trips, and other transmission line issues. Although these outages did not generally contribute materially to any transmission limitations, some transmission breaker outages did lead to the loss of generating units. Many breaker trips were the result of low air in the breaker, low sulfur hexa-fluoride ($SF_6$) gas pressure, failed or inadequate heaters, bad contacts, and gas leaks.

Specifically, the task force recommends:

- Transmission Owner/Operators should ensure that the $SF_6$ gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold, and also perform annual maintenance that tests $SF_6$ breaker heaters and supporting circuitry to assure that they are functional.

- Transmission Owner/Operators should maintain the operation of power transformers in cold temperatures by checking heaters in the control cabinets, verifying that main tank oil levels are appropriate for the actual oil temperature, checking bushing oil levels, and checking the nitrogen pressure if necessary.

- Transmission Owner/Operators should determine the ambient temperature to which their equipment, including fire protection systems, is protected (taking into account the accelerated cooling effect of wind), and ensure that temperature requirements are met during operations.

*COMMUNICATIONS*

**21. Balancing Authorities should improve communications during extreme cold weather events with Transmission Owner/Operators, Distribution Providers, and other market participants.**

During the February event, ERCOT communicated with Transmission Owners and Transmission Service Providers (an ERCOT-specific term) concerning the initiation of load shedding and the subsequent restoration of service. These communications appear to have been made in accordance with applicable ERCOT Operating Guidelines and Reliability Standards. However, ERCOT and several of its Transmission Service Providers that were responsible for curtailing firm load suggested areas for improvement in communications.

Transmission Service Providers are dependent on ERCOT for much of their information on ERCOT-wide system conditions, as they do not have information regarding generator trips beyond those on their own systems, and can only track ERCOT-wide system status by monitoring ERCOT's posted Physical Response Capability levels or monitoring frequency levels. Some of these Transmission Service Providers suggested that ERCOT should have communicated concerns about deteriorating conditions much earlier than it did.

A task force appointed by ERCOT's Board of Directors to look into the February 2 rolling blackouts concluded that there was a need for earlier dissemination of operational information to Transmission Service Providers and Distribution Service Providers (an ERCOT-specific term) during the period leading up to a possible emergency, a conclusion with which this task force agrees.

**22. ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service.**

Some ERCOT Transmission Service Providers expressed concern that they have virtually no information regarding loads on their own systems that may be deployed by ERCOT as Load Resources or Emergency Interruptible Load Service resources. These loads contract directly with ERCOT, and the Transmission Service Provider does not receive information about their status. When these loads are shed by ERCOT without prior notification to the Transmission Service Providers and Distribution Service Providers, they have the potential to cause localized imbalances in line flows, voltages, and other system parameters that may be problematic.

The task force suggests that ERCOT share information about the status of these loads with Transmission Service Providers on a daily basis, and study the effects of the loss of large blocks of these loads on the transmission grid.

**23. WECC should review its Reliability Coordinator procedures for providing notice to Transmission Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency), and consider whether modification of those procedures is needed to expedite the notice process.**

The Task Force observed a lag in communicating a declared system emergency in WECC. In one instance, a Reliability Coordinator did not issue an EEA 3 declaration until seven minutes after the decision had been made to do so; the delayed declaration appeared to have been the first official notice by the Reliability Coordinator to other WECC entities of the seriousness of the generation failures on the system of the Balancing Authority in question.

**24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.**

The task force's review of incidents during the event, as well as of operating procedures and protocols in place at the time, indicated that critical employees such as operators had numerous responsibilities that, while manageable in non-emergency situations, could prove impossible to meet during the often-compressed time frame of an emergency situation. In at least one instance, overloading a single on-call operations representative appears to have led to a delay in making emergency power purchases.

### *LOAD SHEDDING*

**25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.**

Keeping gas production facilities in service is critical to maintaining an adequate supply of natural gas, particularly in the Southwest where there is a relatively small amount of underground gas storage. And keeping electric-powered compressors running can be important in maintaining adequate pressure in gas transmission lines.

The task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.

**26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills**.

The task force found that at least one Transmission Operator in WECC experienced a minor delay in initiating its load shedding sequence, due to problems notifying the concerned Distribution Provider. Another Transmission Operator experienced delay in executing its load shedding because the individual operators had never shed load before and had not had recent drills. These incidents underscore the necessity of adequate training in load shedding procedures.

## B. The Natural Gas Industry

### Key Findings -- Natural Gas

- Extreme low temperatures and winter storm conditions resulted in widespread wellhead, gathering system, and processing plant freeze-offs and hampered repair and restoration efforts, reducing the flow of gas in production basins in Texas and New Mexico by between 4 Bcf and 5 Bcf per day, or approximately 20 percent, a much greater extent than has occurred in the past.

- The prolonged cold caused production shortfalls in the San Juan and Permian Basins, the main supply areas for the LDCs that eventually curtailed service to customers in New Mexico, Arizona, and Texas.

- Wellhead freeze-offs normally occur several times a winter in the San Juan Basin but are not common in the Permian Basin, which is the supply source that LDCs in the Southwest region typically rely upon when cold weather threatens production in the San Juan Basin.

- Electrical outages contributed to the cold weather problems faced by gas producers, processors, and storage facilities in the Permian and Fort Worth Basins, with producers being more significantly affected by the blackouts; however, based on information obtained from a sampling of producers and processing plants in the region, the task force concluded that the effect of electric blackouts on supply shortages was less important than the effect of freezing temperatures.

- Although producers in the New Mexico and Texas production areas implemented some winterization measures such as methanol injection, production was nevertheless severely affected by the unusually cold weather and icy road conditions, which prevented crews from responding to wells and equipment that were shut in.

- The extreme cold weather also created an unprecedented demand for gas, which further strained the ability of the LDCs and pipelines to maintain sufficient operating pressure.

- The combination of dramatically reduced supply and unprecedented high demand was the cause of most of the gas outages and shortages that occurred in the region.

- Low delivery pressures from the El Paso Natural Gas interstate pipeline, caused by supply shortages, contributed to gas outages in Arizona and southern New Mexico.

- Some local distribution systems were unable to deliver the unprecedented volume of gas demanded by residential customers.

- No evidence was found that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages.

- The pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls.

- Additional gas storage capacity in Arizona and New Mexico could have prevented many of the outages that occurred by making additional supply available during the periods of peak demand. Natural gas storage is a key component of the natural gas grid that helps maintain reliability of gas supplies during periods of high demand. Storage can help LDCs maintain adequate supply during periods of heavy demand by supplementing pipeline capacity, and can serve as backup supply in case of interruptions in wellhead production. Additional gas storage capacity in the downstream market areas closer to demand centers in Arizona and New Mexico could have prevented most of the outages that occurred by making additional supply available in a more timely manner during peak demand periods.

## Recommendations – Natural Gas

**1. Lawmakers in Texas and New Mexico, working with their state regulators and all sectors of the natural gas industry, should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.**

The Texas and New Mexico production basins experienced unusually sharp declines due to the prolonged freezing weather of early February 2011. Although these areas typically experience occasional freeze-offs during periods of sub-freezing weather, and although natural gas producers and processors in those regions employ some winterization techniques, to a significant degree those measures were inadequate to meet consumer demand during this event. Production difficulties were compounded by icy road conditions, which disrupted routine maintenance and delayed repairs.

Some industry representatives stated that producers and processors already have strong economic incentives to keep gas flowing at all times, and that increased winterization would not have prevented many of the shortfalls that occurred in the Southwest production basins in early February 2011. Others stated that the levels of winterization typically employed in these areas are designed to deal with less severe, more typical winter weather conditions, and that additional winterization could protect the system from the effects of unusually harsh weather. Many expressed the view that along with increased reliance upon natural gas for energy, steps should be taken to improve the reliability of gas supply during extreme cold weather events.

Whether the adoption of uniform winterization standards for natural gas facilities is the right way to meet the goal of increased reliability is a complex question. Among the issues that need to be resolved are the following:

- Determining the costs of increased winterization and balancing those costs against the need for increased reliability,
- Determining who should ultimately bear the costs of additional winterization, and whether ratemakers would be willing to pass the costs of increased reliability along to consumers,
- Determining whether it is practical to design for very low temperatures, which may not recur for years or even decades,

- Ensuring that standards are uniformly applied, and determining whether state commissions would have adequate resources or authority to promulgate and enforce those standards, and
- Identifying possible incentives for industry that could improve the reliability of winter supply without government regulation.

Because the Commission does not have jurisdictional authority over this sector of the natural gas industry for these purposes, we recommend that state lawmakers and regulators in Texas and New Mexico investigate whether minimum standards for the winterization of gas production and processing facilities should be adopted, by way of legislation, regulation, or the adoption of voluntary industry practices, and whether such standards would be likely to effectively and reliably improve supply during extreme weather events.

**2. The gas and electric sectors should work with state regulatory authorities to determine whether critical natural gas facilities can be exempted from rolling blackouts.**

The natural gas industry depends in many instances on electric utilities for the power that helps move gas from the production fields to end users. Electric-powered instrumentation, compression, pumps, and processing equipment are essential links in that process, and in some instances, even the brief, temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service for long periods of time, especially where weather conditions delay access to those facilities. The resulting gas outages can contribute to electricity shortages by cutting off or reducing fuel supply to gas-fired generating plants.

Gas producers, processors, pipelines, storage providers, and LDCs should identify portions of their systems that are essential to the ongoing delivery of significant volumes of gas, and which are dependent upon purchased power to function reliably under emergency conditions. State regulatory authorities should work with the gas industry and electric transmission operators, balancing authorities and reliability coordinators to determine whether such facilities can be shielded from the effects of future rolling blackouts.

**3. State utility commissions should work with LDCs to ensure that voluntary curtailment plans can reduce demand on the system as quickly and efficiently as possible when gas supplies are disrupted.**

One tool available to LDCs faced with supply disruptions during periods of high consumer demand is the implementation of voluntary curtailment plans, which seek reductions or curtailment from large commercial users. State regulators, who review and approve the voluntary curtailment plans of LDCs, should assess whether they are designed and implemented in a way that maximizes their potential effect in emergency situations.

Voluntary curtailment plans should include multiple points of contact for large customers and up to date, 24-hour contact information. Where appropriate, the plans should provide for pre-event planning, training, and customer education. Large customers should be contacted prior to emergencies and efforts should be made to explain the circumstances under which reductions or curtailments would be sought and to obtain advance commitments for possible reductions, giving LDCs a clearer idea of the amount of demand that can be reduced in an emergency. While voluntary curtailment does nothing to increase supply, in light of the importance of reducing demand when distribution systems are near collapse, regulators and the LDCs should ensure that planning for voluntary curtailments is as thorough and well-thought out as possible.

**4. State utility commissions should work with balancing authorities, electrical generators, and LDCs to determine whether and under what circumstances residential gas customers should receive priority over electrical generating plants during a gas supply emergency.**

Gas-fired generation provides much needed electrical power during a weather emergency, but also consumes large amounts of natural gas. Although restoring residential electricity service after a rolling blackout is a fairly simple process, restoring gas service after an outage is both labor-intensive and time-consuming.

State utility commissions should work with LDCs to identify situations where consumption by gas-fired generators could contribute to residential gas customer outages, and should consult with those generators and the relevant Balancing Authority to determine whether alternative power suppliers or fuel supplies could be used in emergency situations. The state commissions should also evaluate the relative importance, for human needs customers, of gas-fired generation and residential use, and should assess the relative impacts of curtailing generating plants versus gas supply to residences.

**5. State utility commissions and LDCs should review the events of early February 2011 and determine whether distribution systems can be improved to increase flows during periods of high demand.**

In some instances during the winter storm event, LDC distribution systems were unable to flow scheduled volumes, suggesting that downstream parties may not have had sufficient capacity or facilities to handle historically high demand.

Accordingly, state commissions and distribution companies should determine whether system enhancements can be made to improve volume handling capacity, such as additional distribution valving, looping, more compression, or reconfigured compression. Although such system improvements would probably not compensate for the level of supply shortfalls that occurred in early February 2011, they might allow LDCs to take higher volumes for longer periods of time.

**6. State utility commissions should work with LDCs to determine whether the LDC distribution systems can be improved so that curtailments can be implemented, when necessary, in a way that improves the speed and efficiency of the restoration process.**

The events of early February 2011 demonstrated that once operational pressures and line pack begin to fall beyond normal tolerances, little time may be available to evaluate, locate, and shut off portions of the pipeline systems of the LDCs to avoid system collapse. Regulators should work with LDCs, as part of the annual system review process, to determine whether the systems under their regulatory authority should be further sectionalized to provide more options when involuntary curtailments are necessary.

**This page intentionally left blank.**

# ATTACHMENTS

## Acronyms

## Glossary

## <u>Appendices</u>

**Task Force Members**

**Legislative and Regulatory Responses by the States**

**Categories of NERC Registered Entities**

**Electricity: How it is Generated and Distributed**

**Power Plant Design for Ambient Weather Conditions**

**Impact of Wind Chill**

**Winterization for Generators**

**Natural Gas: Production and Distribution**

**Natural Gas Storage**

**Natural Gas Transportation Contracting Practices**

**GTI: Impact of Cold Weather on Gas Production**

This page intentionally left blank.

## Acronyms

| | |
|---|---|
| AC | Alternating Current |
| ACE | Area Control Error |
| ANR | ANR Pipeline Company |
| Bcf | Billion Cubic Feet |
| Btu | British Thermal Unit |
| CFE | Comisión Federal de Electricidad |
| CNG | Compressed Natural Gas |
| COP | Current Operating Plan |
| DC | Direct Current |
| DC Tie | Direct Current Tie |
| EEA | Energy Emergency Alert |
| EILS | Emergency Interruptible Load Service |
| EPE | El Paso Electric Company |
| ERCOT | Electric Reliability Council of Texas |
| ERO | Electric Reliability Organization |
| FERC | Federal Energy Regulatory Commission |
| Hz | Hertz |
| IMM | Independent Market Monitor |
| ISO | Independent System Operator |
| LDC | Local Distribution Company |
| LNG | Liquefied Natural Gas |
| LRGV | Lower Rio Grande Valley |
| Mcf | Thousand Cubic Feet |
| MMcf | Million Cubic Feet |
| MW | Megawatt |
| MWh | Megawatt Hour |
| NGL | Natural Gas Liquids |
| NMGC | New Mexico Gas Company |
| NERC | North American Electric Reliability Corporation |
| OCN | Operating Condition Notice |
| OFO | Operational Flow Order |
| PNM | Public Service Company of New Mexico |

## Acronyms

PRC Physical Response Capability

PUCT Public Utilities Commission of Texas

QSE Qualified Scheduling Entity

RMR Reliability Must Run

SRP Salt River Project Agricultural Improvement and Power District

SRSG Southwest Reserve Sharing Group

RTO Regional Transmission Organization

RUC Reliability Unit Commitment

SCADA Supervisory Control and Data Acquisition

SPP Southwest Power Pool

SRSG Southwest Reserve Sharing Group

TRE Texas Reliability Entity, Inc.

TRC Texas Railroad Commission

UFLS Under-Frequency Load Shedding

WECC Western Electricity Coordinating Council

# Glossary

**Active Power** - Also known as real power, this is the rate at which work is performed or at which energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW) when referring to electricity. In the field of electric power, the terms "active power" or "real power" are often used in place of the term "power" alone to differentiate it from reactive power. (See Reactive Power)

**Allocation of Capacity** - A process by which capacity available in a pipeline is distributed to parties in the event requests for volume (*i.e.*, nominations) are in excess of the available space. Typically the allocation is based on service type, contract type and a company's tariff provisions.

**Alternating Current (AC)** - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

**Ambient Conditions** - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

**Ancillary Services** - The services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. These include, but are not limited to, voltage support, regulation, reserves, and black start capability.

**Aquifer Storage** - The storage of gas underground in porous and permeable rock stratum, the pore space of which was originally filled with water and in which the stored gas is confined by suitable structure, permeability barriers, and hydrostatic water pressure.

**Area Control Error (ACE)** - The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, plus the instantaneous difference between the interconnection's actual frequency and scheduled frequency and a correction for meter error.

**Asynchronous** - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

# Glossary

**Auto-Transformer** - A power transformer with a single coil for each electrical phase, as opposed to a conventional transformer, which has two coils per phase. In an auto-transformer, the entire coil acts as the primary winding while a portion of the same coil acts as the secondary winding.

**Automatic Generation Control (AGC)** - A feature of a power system's centralized control system that automatically adjusts generation in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus its Frequency Bias.

**Balancing (Natural Gas)** - Equalizing a shipper's receipts and deliveries of gas on a transportation pipeline. Balancing may be accomplished daily, monthly or seasonally, with penalties generally assessed for excessive imbalances.

**Balancing Authority (BA)** - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports interconnection frequency in real time.

**Base Load (Natural Gas)** - A given volume of gas used by a LDC or other large user, remaining fairly constant over a period of time. Base load does not vary with heating degree-days.

**Baseload Generating Units** - Electric generating units which produce energy at a constant rate, usually at a low cost relative to other generating units available to the system. Baseload units are used to meet some or all of a given region's continuous energy demand on a seasonal or daily basis, including at minimum load levels, and tend to operate non-stop except for maintenance or forced outages.

**Base Load Storage (Natural Gas)** - Storage facilities capable of holding enough natural gas to satisfy long term seasonal demand requirements.

**Blade** - The component of a steam turbine that is acted upon by the flow of steam. Blades in steam turbines are also referred to as "buckets." Similarly, in gas, or combustion turbines, the blades are the components acted upon by the flow of the high pressure, high temperature gases produced in the combustor. In both steam turbines and combustion turbines, the blades are arranged in multiple stages of varying diameter, with many blades per stage. Modern wind turbines, in contrast, typically utilize only three long blades. The purpose of the blades is to extract energy from the motion of the propelling fluid (steam, combustion gases, or air) and convert it into rotational form by direct coupling to a common spinning shaft which is in turn used to drive a generator.

**Boiler** - The component of a steam power plant in which water is heated and converted into steam.

**British Thermal Unit (BTU)** - the measurement of heat released by burning any material. The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density.

**Bulk Electric System** - The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not considered to be part of the bulk electric system.

**Capacitor Bank** - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

**Capacity Market** - A market where Load Serving Entities purchase generating capacity (including adequate reserves) to cover their peak loads.

**Capacity Release (Natural Gas)** - A mechanism by which holders of firm interstate transportation capacity can relinquish their rights to utilize the firm capacity to other parties that are interested in obtaining the right to use that capacity for a specific price, for a given period of time and under a specifically identified set of conditions. The firm transportation rights may include transmission capacity and/or storage capacity.

**Capacity-Short Charge** - In ERCOT, a monetary charge to Qualified Scheduling Entities (QSEs) who cannot meet their resource commitments when a Reliability Unit Commitment (RUC) study (conducted periodically) determines there is insufficient generation to meet projected demand, and the costs associated with bringing the needed additional generation on-line cannot be fully recovered using energy revenue. The capacity-short charge is the mechanism for covering those costs. This is done on the basis of settlement intervals.

**Centrifugal Compressor Unit(s)** -Compressors that produce pressure by centrifugal force from rotation of a compressor wheel that translates kinetic energy into pressure energy of the gas. Centrifugal compressors are commonly used in gas transmission systems due to their flexibility.

**Charge** - In physics, charge, also known as electric charge, electrical charge, or electrostatic charge is a characteristic of an object that expresses the extent to which it has more or fewer electrons than protons. A single electron carries an elementary charge of negative polarity, whereas a single proton carries the same, except of positive polarity. The unit of electrical charge is the coulomb (symbolized C) where 1 C is equal to $6.24 \times 10^{18}$ elementary charges. It is not unusual for real-world objects to hold charges of many coulombs. When two objects having electric charges are brought into proximity with each other, an electrostatic force is manifested between them – attractive if the charges are of opposite polarity and repulsive if the charges are of the same polarity.

**Circuit Breaker** - In electrical power systems, circuit breakers are used to disconnect and reconnect transmission lines, transformers, generators, and other facilities from the power system or from each other. Circuit breakers trip to interrupt the flow of current when faults develop, de-energizing the faulted facility and isolating it from the system. They are also used to switch facilities in or out of service.

**Citygate** - The point at which a Local Distribution Company receives natural gas from an interstate or intrastate pipeline.

**Cold Load Pickup** - Phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: 1) inrush current which reestablishes the magnetic fields in motors and transformers and the necessary temperatures in heating coils and incandescent lamp filaments and 2) loss of load diversity due to cyclic loads which normally cycle randomly with respect to one another, such as refrigerator compressors, all restarting at the same time. The inrush current may last up to several seconds while the loss of load diversity may persist for many minutes.

**Combined Cycle Unit** - This type of electric generating unit consists of one or more gas turbines, also referred to as combustion turbines, equipped with heat recovery steam generators to capture heat from their exhaust. Steam produced in the heat recovery steam generators then drives a steam turbine generator to produce additional electric power. A typical arrangement consists of two natural gas-fired combustion turbines combined with a single steam turbine, each driving its own electrical generator, for a total of three generators. The heat recovery aspect of combined cycle units increases the overall efficiency of electric power production.

## Glossary

**Comisión Federal de Electricidad (CFE)** - A Mexican governmental entity that generates, transmits, distributes and sells electricity to more than 34.2 million customers, representing more than 100 million people annually. CFE interconnects to ERCOT via two high voltage DC (HVDC) ties and to WECC via AC transmission lines at the California border just south of San Diego.

**Compressor or Compressor Units** - Mechanical equipment that adds pressure to the natural gas stream to enable the flow of natural gas through a pipeline system.

**Compressor Station** - A permanent facility that houses compression equipment that supplies pressure to move natural gas through pipelines.

**Condensate and Water Return Lines** - Plumbing in a generating station that captures condensate and used water for recycling or re-use.

**Condenser** - In a steam turbine generating station, the condenser is a type of heat exchanger that cools the steam exiting the turbine to the point where it condenses into water, thereby recovering the high quality feed water for reuse. The cooling is accomplished using separate cooling water. Surface condensers use a shell and tube assembly wherein the cooling water is circulated in the tubes, and the steam and condensate are contained in the tank-like housing, or shell, that surrounds and encloses the tubes.

**Conductor** - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

**Contingency** - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

**Contingency Reserve Level** - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. The Contingency Reserve Level is that level of reserves required for the reliable operation of an interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

**Contract Pressure (Natural Gas) -** The maximum or minimum required operating pressure at a natural gas receipt or delivery point, as specified in the agreement between a pipeline and its customer.

**Control Area -** An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: 1) match, at all times, the power output of the generators within the electric power system(s) with the load in the electric power system(s); 2) maintain scheduled interchange with other Control Areas; 3) maintain the frequency of the electric power system(s); and 4) provide sufficient generating capacity to maintain operating reserves, all within reasonable limits in accordance with Good Utility Practice.

**Controllable Load Resources (CLR) -** In ERCOT, CLRs are a type of load resource capable of controllably reducing or increasing consumption under dispatch control (similar to automatic generation control or AGC) and able to immediately respond proportionally to frequency changes (similar to generator governor action) to provide the following ancillary services: Up and Down Regulation (URS & DRS), Responsive Reserve (RRS), and Non-Spinning Reserve (NSRS).

**Cooling Tower** - A structure and associated equipment intended to facilitate the evaporative cooling of water by contact with air. In steam turbine generating stations, cooling water is routed through the cooling tower for cooling after having absorbed heat in the condenser.

**Cooling Water** - In steam turbine generating stations, water that is used in the condenser to extract heat from steam exiting the turbine for the purpose of condensing that steam back to feed water. The feed water is then cycled back through the boiler to make steam again. The cooling water is generally taken from a nearby lake (often man-made for this purpose) or river and is distinctly separate from the feed water that is used to make steam and which must be specially treated to prevent corrosion. Electric generating stations use wholly separate cooling water systems to extract heat from the large copper conductors comprising the generator stator windings.

**Cooling Water Intakes -** The point at which industrial plants, including power plants, bring cooling water into their system from lakes, rivers, or other sources.

Broadly, the total physical structure and any associated constructed waterways used to withdraw cooling water.

**Current (Electric)** - The rate of flow of electrons in an electrical conductor. The symbol for current is “I” and the unit is the ampere, or amp, where one amp is defined as one coulomb of charge per second.

**Current Operating Plan (COP)** - In ERCOT, a plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the resources that it represents for each hour in the next seven operating days, including resource operational data, resource status, and ancillary service schedule.

**Curtailment (Electric)** - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

**Curtailment (Natural Gas)** - A method to balance a utility's natural gas requirements with its natural gas supply. Customers are typically ranked by priority in the utility’s curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and the customer's priority.

**Day-Ahead Market** - A daily, co-optimized market in the 24 hour period before the start of the next operating day for ancillary service capacity, certain congestion revenue rights, and forward financial energy transactions.

**Day-Ahead RUC (DRUC)** - In ERCOT, a Reliability Unit Commitment (RUC) process performed for the next operating day.

**Decommitment Payment -** In ERCOT, a payment made to a resource committed by the Reliability Unit Commitment (RUC) process if the directive to use that resource is cancelled prior to its scheduled start time.

**Demand (Electric)** - The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. The term “demand” is often used interchangeably with the term “load” with respect to electric power systems.

**Depleted Oil and/or Gas Fields** - Naturally occurring reservoirs that once held deposits of oil and gas, consisting of porous and permeable underground formations confined by impermeable rock or water barriers. The working gas requirement for this type of storage reservoir is generally about 50% of the total reservoir capacity. Gas is typically withdrawn in the winter season and injected in the summer.

**Derate (Electric Generator)** - A reduction in a generating unit's net dependable capacity.

**Direct Current (DC)** - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

**Direct Current (DC) Tie** - In electric power systems, the term "DC Tie" or, more correctly, "HVDC Tie" referring to high voltage DC, is used to describe a transmission-level facility that interconnects between two portions of a power system, two different power systems, or two different electric power interconnections. The DC Tie consists of: (1) a converter station to convert three phase AC power to DC; (2) a DC connection to a second converter station; and (3) a second converter station that reconverts the DC power back to three-phase AC. The DC connection between the two converter stations (step 2 above) may be either a long HVDC transmission line or, in the case of "back-to-back" converters at the same location, a simple set of bus bars. The power flow in DC ties is not free-flowing as it is in AC lines, but rather is controlled precisely by control systems on the converters. Unlike AC lines, DC ties can interconnect between asynchronous interconnections such as ERCOT, the Eastern Interconnection, and the Western Interconnection because concerns about frequency, phase angle, and voltage differences are rendered immaterial by the AC-to-DC-to-AC conversion process.

**Distribution (Electric)** - The function of distributing electric energy to retail customers, and all associated physical means of serving that function, including substations, low voltage distribution lines, transformers, etc.

**Distribution Provider** - As defined by NERC, a Registered Entity that provides and operates the "wires", *i.e.*, distribution lines, transformers, and associated facilities, between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider.

**Distribution Service Provider** - As defined by ERCOT, an entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

**Electrical Energy** - Electric power generated, transmitted, distributed, and consumed over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).

**Electric Reliability Council of Texas, Inc. (ERCOT)** - ERCOT is an Independent System Operator (ISO) that manages the flow of electric power to 23 million customers in Texas representing 85 percent of the state's electric load and 75 percent of its land area. ERCOT is registered with NERC to serve the following roles: Balancing Authority, Interchange Authority, Planning Authority, Reliability Coordinator, Resource Planner, and Transmission Service Provider. It is also jointly registered with other entities as a Transmission Operator.

**Electric Reliability Organization (ERO)** - The Energy Policy Act of 2005 required the creation of an independent Electric Reliability Organization (ERO) to be certified by FERC and tasked with developing and enforcing mandatory reliability standards applying to the bulk power system. (*See* Energy Policy Act of 2005, Pub. L. No. 109-58, section 102.)

**Electromagnetic Induction** - The creation of a voltage in a conductor due to a relative movement between the conductor and a magnetic field. Electromagnetic induction is the basic principle of operation of generators.

**Emergency Interruptible Load Service (EILS)** - In ERCOT, EILS is an emergency load reduction service designed to decrease the likelihood of the need for firm load shedding. It is provided by qualified loads that make themselves available for interruption in an electric grid emergency. Customers meeting EILS criteria may bid to provide the service through their Qualified Scheduling Entities (QSEs). EILS is called upon during an Energy Emergency Alert (EEA) Level 2B to assist in maintaining or restoring system frequency. EILS is not an Ancillary Service.

**Energy** - See Electrical Energy.

**Energy Emergency Alert (EEA)** - NERC Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's Reliability Coordinator, and are categorized by level of severity, *i.e.*, EEA1, 2, or 3, with level 3 being the most severe. ERCOT defines EEA as an orderly, predetermined procedure for maximizing use of available resources and, only if necessary, curtailing load during an emergency condition while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT system.

**Energy Imbalance Service (EIS)** - EIS is provided when a difference occurs between the scheduled and the actual delivery of energy to/from the transmission system over a single hour. The market participant must purchase this service from the transmission provider or make comparable alternate arrangements with another market participant who will purchase this service from the transmission provider.

**Energy-only Market (Electric)** - A market for electric energy that pays resources only for delivered energy and ancillary services, and does not pay for installed capacity (ICAP).

**Energy-only Resource Adequacy Mechanism** - A mechanism that allows real-time energy prices to rise in times of scarcity in order to provide incentives for investment in peaking as well as base-load generation.

**E-Tag** - Electronic Tagging, or e-Tag, is used to schedule an interchange transaction in a wholesale electricity markets. NERC and/or Regional Entities (such as WECC) collect all e-Tag data in near real-time to assist Reliability Coordinators in identifying transactions to be curtailed to relieve overload when transmission constraints occur. NERC defines an interchange transaction as “an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority area boundaries.”

**Export** - In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

**Firm Service (Natural Gas)** - Transportation service on a firm basis means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service.

**Flow Line** - Flow lines carry the fluids or natural gas from the wellhead to and in-between individual vessels in separation, treating, heating, dehydrating, compression, pumping or other processing equipment generally located at or near the well site.

**Force Majeure** - A superior force, “act of God” or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

**Forced Outage** - The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. This can be done automatically, as in the case of tripping, manually, as in the case of forced shutdowns, or by withholding a generating unit, transmission line, or other equipment from returning to service due to unresolved problems.

**Frequency** - The rate, in terms of time, at which a periodic pattern repeats itself. In electric power systems, frequency is measured in cycles per second, or Hertz (Hz). The symbol is “F”. The nominal, or base, frequency for power systems in North America is 60 Hz.

**Frequency Bias** - A weighting factor applied to the difference between the Interconnection’s actual frequency and scheduled frequency during the calculation of a Balancing Authority’s Area Control Error (ACE). The weighting factor determines how strongly a Balancing Authority will respond to deviations from the scheduled frequency. Larger Balancing Authorities will usually have a larger Frequency Bias.

**Frequency Deviation** - Broadly, a change in the frequency of an electrical interconnection. More typically, sudden changes that result in the frequency of the interconnection going outside the normal bounds of 59.95 Hz to 60.05 Hz due to the unexpected loss of a significant amount of generation or load.

**Generation** - The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

**Generator** - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

**Generator Operator** - An entity that operates a generating unit or a fleet of generating units and performs the functions of supplying energy and interconnected operations services to a power system.

**Generator Owner** - An entity that owns and maintains a generating unit or a fleet of generating units.

**Generator Runback** - The intentional rapid reduction of the output level of an electric generating unit or an entire generating station, either manually or automatically via plant controls, due to any of a variety of problems in the plant that limit the plant's capacity to generate power, or problems on the transmission system external to the plant which limit the capability of the system to accept the plant's power output.

**Good Utility Practice** - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric power industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Grid** - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

**Heat Tracing** - The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

**Hertz** - The unit of frequency equal to one cycle per second.

**Hockey Stick Bidding** - A pricing strategy during a supply shortage whereby a trader offers to sell a small quantity of energy at a price well above marginal cost, in order to manipulate prices upward.

**Hourly RUC (HRUC)** - In ERCOT, any Reliability Unit Commitment (RUC) executed after the Day-Ahead RUC (DRUC).

**Human Needs Customers** - Customers such as residential users, hospitals, and nursing homes, who use natural gas for essential human needs.

**Hydrate Crystals** - Crystals of hydrates formed under certain pressure and temperature conditions by hydrates and water present in natural gas. Hydrate crystals can form when the temperature is above the melting temperature of ice and can block natural gas wells, gathering systems, and pipelines.

**Import Limit** - The maximum level of electric power that can flow into a power system or portion of a power system over a transmission path or paths without violating facility thermal ratings, voltage ratings, transient stability limits, or voltage stability limits either in real-time or post contingency, *i.e.*, after the loss of a generator, transmission line, or other facility.

**Independent System Operator (ISO)** - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis. ISOs in the U.S. include the California ISO, ISO New England, the New York ISO, PJM, the Midwest ISO, and ERCOT. These ISOs dispatch generation in their respective geographic territories.

**Induction Machine** - A rotating electromagnetic machine using alternating current that may be a generator or a motor. When a generator, the induction machine's rotor is driven at a speed greater than synchronous speed. When a motor, the induction machine's rotor is driven at a speed less than synchronous speed. Induction generators are rarely used for large scale power generation. Induction motors, on the other hand, are the most common type of AC motor. Induction machines absorb reactive power and cannot be used to produce reactive power (as a synchronous machine can).

**Insulator** - A material with a high resistance to the flow of electric current. More broadly, mechanical supports and spacers constructed of insulating materials. Electrically speaking, an insulator is the opposite of a conductor.

**Interchange** - Electrical energy transfers that cross Balancing Authority boundaries.

**Interconnection** - In North America, any one of the four major electric system networks – Eastern, Western, Quebec, and ERCOT. These operate asynchronously with respect to one another.

**Interruptible Service** - Service on an interruptible basis means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service and receives a lower priority than such other classes of service.

**Interruptible Responsive Reserve -** In ERCOT, Interruptible Responsive Reserve is provided by load resources that are automatically interrupted when system frequency decreases to 59.7 Hz. The total amount of Interruptible Responsive Reserve procured for a given hour is limited to one half of the Responsive Reserve Service required for that hour.

## Glossary

**Inverter** - A converter designed and operated to convert DC power to AC power. In power systems, inverter generally refers to high voltage DC (HVDC) converters.

**Island (Electrical)** - An electrically isolated portion of an interconnection.. The frequency in an electrical island must be maintained by balancing generation and load in order to sustain operation. Islands are frequently formed after major disturbances wherein multiple transmission lines trip, or during restoration following a major disturbance.

**Joule-Thomson Effect** - The cooling that occurs when a compressed gas is allowed to expand in such a way that no external work is done. The effect is approximately 7 degrees Fahrenheit per 100 psi for natural gas.

**Lateral Line** - A pipe in a gas distribution or transmission system that branches away from the central and primary part of the system.

**Line Pack** - Natural gas occupying all pressurized sections of the pipeline network. Introduction of new gas at a receipt point "packs" or adds pressure to the line. Removal of gas at a delivery point lowers the pressure (unpacks the line).

**Line Trip** - This refers to the automatic disconnection of a transmission line by its circuit breakers. Line trips are initiated by protective relays and are designed to protect the power system when a short circuit, or fault, occurs on a line by isolating the faulted line from the system.

**Liquefied Natural Gas (LNG)** - Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

**Long Haul Pipeline** - A transportation pipeline that transports natural gasa significant distance (hundreds of mile or more) from the production area.

**Load** - See Demand (Electric).

**Load Acting as Resource (LaaR) -** This term, discontinued by ERCOT when they transitioned from a Zonal Market to a Nodal Market on December 1, 2010, was replaced by the term Load Resource (see below).

**Load Resource** - In ERCOT, Load Resources provide ancillary services for either Responsive Reserve Service (RRS) or Non-Spinning Reserve Service (NSRS). There are two types of Load Resources – Controllable Load Resources (CLRs) and Non-Controllable Load Resources (NCLRs). "Controllable" refers to the capability to control the load remotely from the ERCOT control center rather than solely at the end-use customer location (or by its Qualified Scheduling Entity (QSE)).

**Load Service Entity** - An entity that secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

**Load Shedding** - The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence. (See Rolling Blackouts.)

**Local Distribution Companies (LDC)** - Any firm, other than a natural gas pipeline, engaged in the transportation or local distribution of natural gas and its sale to customers that consume the gas.

**Magnetic Field** - The invisible lines of force between the north and south poles of a magnet. A magnetic field is created when electric current flows through a conductor.

**Make-Whole Charge** - In ERCOT, a charge made to a Qualified Shedding Entity (QSE) for a resource to recapture all or part of the revenues received by a QSE that exceed the Make-Whole Payment for a resource (see below).

**Make-Whole Payment** - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource to reimburse it for allowable startup and minimum energy costs of a resource not recovered in energy revenue when a resource is committed by the Day-Ahead Market (DAM) or by a Reliability Unit Commitment (RUC).

**Maximum Allowable Operating Pressure** - The maximum operating pressure at which a pipeline system may be operated safely.

**Mercaptans** - A group of strong-smelling chemical compounds added to natural or LP gases as a safety measure, to warn of leaks.

**Metering (Electric)** - A meter is a device for measuring and displaying an electrical quantity. For example, meters are used to measure power flows, voltage, current, frequency, etc. The term "metering" generally refers to a group of meters associated with a given facility, and the information from those meters transmitted to and displayed in a control room or control center.

**Methanol** - A light volatile flammable poisonous liquid alcohol used especially as a solvent, antifreeze, or denaturant for ethyl alcohol, and in the synthesis of other chemicals.

**Nomination** - A request for a physical quantity of natural gas under a specific purchase, sales or transportation agreement, or for all contracts at a specific point. A nomination will continue for specified number of days or until superseded by another service request for the same contract.

**North American Energy Standards Board** - A non-profit, private standards development organization established in January 2002 to develop voluntary standards and model business practices designed to promote more competitive and efficient natural gas and electric service.

**Nodal Market (Electric)** - Prices are assessed at points (*i.e.*, nodes) where electricity enters or leaves the grid. Transmission lines throughout the grid may be subject to congestion rents, which means generators may receive different prices based on how they contribute to or relieve congestion on the grid. ERCOT transitioned from a zonal to a nodal market on December 1, 2010. Their nodal market calculates transmission costs from the point of generation from roughly 4,000 delivery points. Nodal pricing is intended to provide a more detailed and accurate picture of transmission and generation than zonal pricing. ERCOT's nodal system reduces the time interval for which the market-clearing price is calculated to five minutes (from fifteen minutes in their former zonal market).

**Non-Controllable Load Resources (NCLRs)** - In ERCOT, these represent loads that provide selected Ancillary Services, but that do not have the capability of being switched or controlled directly from the EROCT control center. (Compare Controllable Load Resources)

**Non-Spinning Reserve Service** - In ERCOT, this refers to generation resources capable of being ramped to a specified output level within thirty minutes or load resources that are capable of being interrupted within thirty minutes. The generation resources must be capable of running at a specified output level for at least one hour, and the load resources must similarly be capable of remaining out of service for at least one hour.

**Operating Condition Notice (OCN) -** In ERCOT, this is the first of four possible levels of communication issued (by ERCOT) in anticipation of a possible emergency condition**.**

**Operating Reserve -** That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

**Operational Balancing Agreement -** A contract that specifies the procedures that will be used between two interconnected natural gas pipelines in order to manage variances or imbalances at major interconnect points.

**Operational Flow Order (OFO) -** A notice to natural gas pipeline users designed to protect the operational integrity of the pipeline. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage.

**Outage -** The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

**Peak Load -** As defined by NERC, the highest hourly integrated Net Energy For Load (generation plus imports minus exports) within a Balancing Authority area occurring within a given period (*e.g.*, day, month, season, or year), or the highest instantaneous demand within the Balancing Authority area.

**Peak Load Storage (Natural Gas) -** Storage that provides high-deliverability of gas supplies to the market over short periods of time.

**Peaking Unit or Peaking Power Plant -** Peaking plants operate primarily during times when load or demand increases rapidly to a maximum level and remains there for only a short time, *e.g.*, on hot summer afternoons when air conditioning causes electricity usage to reach its highest level in the daily cycle. Peaking plants are often powered by natural gas, but they can also be powered by water at hydroelectric dams or by fuel oil. These plants can be brought online and taken offline quickly, in response to changing demand.

**Phase (Electrical) -** In AC power systems, power is generated, transmitted, and distributed using three virtually identical sets of (1) coil windings in generators and transformers, (2) conductors in overhead and underground transmission and distribution lines and busses, (3) electrical poles and contacts in circuit breakers and switches and (4) other power equipment such as capacitor banks, reactors, etc., known as phases, and often identified by the letters A, B, and C. The three individual phase windings of a typical generator stator are arranged so that they're evenly spread out around the circular / cylindrical design/construction, each oriented one third of a turn apart (120 degrees) from the other two. As the rotor spins, its magnetic field sweeps through each of these windings sequentially as it completes a single rotation. The voltage, current, and power associated with each phase are therefore separated in time from the other two phases by virtue of this sequence. This method is much more efficient than a single phase approach not only for generating power, but also for its transmission and distribution.

**Physical Responsive Capability (PRC) -** In ERCOT, this is defined as the total amount of system wide On-Line capability that has a high probability of being able to quickly respond to system disturbances. It can be made up of generation and load resources.

**Pigging -** The practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of natural gas in the pipeline.

**Planning Reserve Margin -** Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand through the planning horizon, which can range from the upcoming season to a ten-year period. It is calculated as the difference between resources and peak demand, divided by peak demand to arrive at a percentage figure.

**Poles -** The opposite ends of a magnet where the field is most concentrated, designated as the north and south poles. In a synchronous generator, the magnetic poles are established by DC current passing through the field winding on the rotor which is essentially the coil of an electromagnet. Separately, in AC electrical equipment, particularly in switches and circuit breakers, poles refer to the contact assemblies associated with a particular phase. For example, it is common to refer to pole A, B, or C of a three phase disconnect switch. (See Phase)

**Potomac Economics, Ltd**. **-** The Independent Market Monitor (IMM) for ERCOT.

**Power** - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts ( 1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

**Power System** - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

**Processing Plant** - A surface installation designed to separate and recover natural gas liquids such as propane, butane, ethane, or natural gasoline from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods, and to control the quality of natural gas marketed or returned to oil or gas reservoirs for pressure maintenance, re-pressuring, or cycling.

**Production Separator** - An item of production equipment used to separate liquid components of the well stream from gaseous elements.

**Qualified Scheduling Entity (QSE)** - In ERCOT, a Market Participant that is qualified for communication with ERCOT for Resource Entities and Load Serving Entities (LSEs) and for settling payments and charges with ERCOT. QSEs submit schedules on behalf of Resource Entities or LSEs such as retail electric providers (REPs). QSEs must submit daily schedules for their bilateral transactions with total generation and demand and bid curves for zonal balancing up and balancing down energy. The schedules for generation and demand are required to be balanced so that supply equals demand. QSEs also bid for ancillary services.

**Ramp or Ramp Rate (for Interchange Schedules)** - The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.

**Ramp or Ramp Rate (for Generator Output)** - The rate, expressed in megawatts per minute, that a generator changes its output, or is expected to change its output.

**Rating** - The operational limits of a transmission system element under a set of specified conditions. In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

**Reactive Power** - The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar), and is also known as "imaginary power."

**Reciprocating Compressor Unit(s)** - Also known as "positive displacement" compressors, reciprocating compressors operate by trapping a certain volume of natural gas within the compressor and reducing the volume. The high-pressure gas is then released through the discharge valve into the pipeline. Piston-operated reciprocating compressors fall within the category of positive displacement compressors. These compressors have a fixed volume and are able to produce high compression ratios.

**Rectifier** - A converter designed and operated to convert AC power to DC power. Electrically speaking, rectifiers are the opposite of inverters. High voltage DC (HVDC) converter stations contain large numbers of high power rectifiers.

**Regional Entity** - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk power system reliability.

**Regional Transmission Organization (RTO) -** A voluntary organization of electric transmission owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

**Regulation** - The ability to maintain a quantity within acceptable limits. For example, frequency regulation is the control or regulation of the system frequency to within a tight bandwidth around 60 Hz. Voltage regulation is the control of a voltage level within a set bandwidth. In power systems operations, regulation often refers broadly to changing the output level of selected generators to match changes in system load.

**Regulator, Pressure** - A device that maintains the pressure in a fluid flow line, less than its inlet pressure within a constant band of pressures, regardless of the rate of flow in the line or the change in upstream pressure.

**Relay Misoperation** - Any unintentional operation of a protective relay when no fault or other abnormal condition has occurred.

**Reliability Must Run (RMR) Unit** - A unit that must run for operational or reliability reasons, regardless of economic considerations. ERCOT specifies that an RMR unit would not otherwise be operated unless it is necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria where market solutions do not exist.

**Reliability Unit Commitment (RUC)** - In ERCOT, a process to ensure that adequate resource capacity and ancillary service capacity are committed in the proper locations to serve the forecasted load. ERCOT conducts at least one Day-Ahead RUC (DRUC) and at least one Hourly RUC (HRUC) before each hour of the operating day, but additional RUCs are conducted when needed to evaluate and resolve reliability issues.

**Reserve Sharing Group** - A group whose members consist of two or more balancing authorities that collectively maintain, allocate, and supply operating reserves required for each balancing authority's use in recovering from contingencies within the group.

**Resource Entity (RE)** - In ERCOT, Resource Entities either own or control a generation resource or behave as a load resource that can comply with ERCOT instructions to reduce electricity usage or provide an ancillary service. Each RE must also be represented by a Qualified Scheduling Entity (QSE), which establishes a control interface with ERCOT.

**Responsive Reserve Services (RRS)** - As defined by ERCOT, an ancillary service that provides operating reserves that is intended to: (1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT transmission grid using primary frequency response and interruptible load, (2) help restore frequency to its scheduled value to return the system to normal, (3) provide energy or continued load interruption during the implementation of an Energy Emergency Alert (EEA), and (4) provide backup regulation. RRS can be provided by generation or by load resources having Interruptible Responsive Reserve capability.

**Restoration** - The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

**Reticulated Pipelines** - Natural gas pipelines with highly networked, web-like transmission lines, with many possible transportation paths for natural gas supplies to reach the desired marketplace.

**Rolling Blackouts** - Also known as rotating outages, these are controlled, temporary interruptions of service to customers, most commonly initiated by switching off selected distribution circuits intended to reduce load during times of capacity shortfalls due to significant forced outages of generation and/or transmission facilities. The service interruptions are transferred from one group (or block) of customers to another over time so that no one group bears the entire burden of the necessary reduction in load.

**Rotor** - The rotating component of a generator attached to the spinning shaft of the generator. In the large synchronous generators that are predominant in electric power systems, the rotor winding acts as an electromagnet that produces the magnetic field used to induce voltage in the stator windings.

**RUC Clawback Charge** - In ERCOT, money returned by a Qualified Scheduling Entity (QSE) to ERCOT for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are lower than those allowed by the prevailing RUC guaranteed payment.

**RUC Make-Whole Payment** - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are less than revenues received.

**Salt Cavern** - An underground natural gas storage cavern which has been developed in a salt dome by the solution mining process.

**Scarcity Pricing Mechanism** - A pricing mechanism based on the idea that under scarcity conditions, generating units will receive higher compensation for producing electricity. The additional revenue is intended to provide an incentive for investment in new generation facilities, and to promote overall system reliability. Under this mechanism, when available supply falls below a predetermined threshold, the price of additional power rises significantly.

**Scheduled Frequency** - For power systems in North America, the scheduled frequency is normally 60.00 Hz. During periods of time error correction, which may last several hours, the scheduled frequency in a given interconnection is set to 59.98 Hz to slow down clocks that use synchronous motors when they are running fast, and to 60.02 Hz to speed them up when they are running slow The fact that the clocks are running fast or slow is an indication that system frequency averaged slightly higher or lower than 60.00 Hz over a long duration, signaling the need for a correction.

**Sine Wave** - The graphical representation of a mathematical function that describes the smooth, symmetrical, and periodic variation of a quantity that oscillates in magnitude or amplitude. In AC electric power systems, the voltage and current are characterized by sine waves having a frequency of 60 Hz. These waveforms, starting from a zero baseline, traverse a path that increases to a crest (positive maximum), then falls back to zero, continues downward to a trough (equal but opposite to the crest, *i.e.*, in the negative direction), and back to zero in one-sixtieth of a second.

**Sluicing/Service Water Systems** - A system used to remove bottom ash from many coal-fired boilers.

**Southwest Power Pool (SPP)** - A Regional Transmission Organization serving members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas (non-ERCOT). SPP is connected to and is part of the Eastern Interconnection.

**Southwest Reserve Sharing Group (SRSG)** - A pool of electric load-serving entities in Arizona, New Mexico, Nevada, southern California, and El Paso, Texas that have entered into an agreement to share contingency reserves. SRSG is a NERC Registered Entity that administers certain requirements on behalf of its members related to disturbance control and emergency operations. SRSG is connected to and is part of the Western Interconnection.

**Spinning Reserve** - Unloaded generation capacity that is synchronized and available to serve additional demand.

**Stability** - The ability of an electric power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. Instances of instability are serious because they have the potential to cause widespread outages in the power system, and possibly even in the entire interconnection.

**Static VAR Converter / Compensator (SVC)** - A combination of shunt reactors and shunt capacitors whose switching is precisely controlled by power electronics to automatically manage reactive power injections and withdrawals from the power system to help maintain proper transmission voltage.

**Stator** - The stationary component of a motor or generator surrounding but not making physical contact with the spinning rotor in the typical cylindrical design/construction.

**Substation** - A site that houses circuit breakers, disconnect switches, transformers, reactors, capacitors, and other equipment serving as an electrical hub in the power system, especially at interfaces between different voltage levels. The prefix "sub" distinguishes substations from generating stations. A central control house is often provided to house control and protective equipment.

**Supervisory Control and Data Acquisition Systems (SCADA)** - A system of remote control and telemetry used to monitor and control a power system or a natural gas transportation or distribution system.

**Synchronize** - The process of bringing two electrical systems together by closing a circuit breaker at an interface point when the voltages and frequencies are properly aligned. Also, when generators are brought on-line, they are said to be synchronized to the system.

**Synchronous** - To be in-step with a reference. The rotor of a synchronous machine, be it a motor or a generator, spins in unison with the power system in terms of frequency (see Synchronous Speed, below).

**Synchronous Speed** - The speed at which the rotor of a synchronous generator must rotate in order to stay in synchronism with the rotating magnetic field of the system. The synchronous speed is determined by the frequency of the power system and the number of magnetic poles in the rotor. For example, the synchronous speed of a two pole steam-turbine generator in a 60 Hz system is 3600 revolutions per minute (rpm), while the synchronous speed of a 24 pole hydro generator is only one-twelfth of that, or 300 rpm.

**System (Electric Power)** - A combination of generation, transmission, and distribution facilities, equipment, and components.

**System Operator** - An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

**System Operating Limit (SOL)** - The value of any of a number of electrical quantities such as real power flow (in MW), total power flow (real plus reactive) (in MVA), voltage (in kV), current (in amperes) or frequency (in Hz) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure that established reliability criteria are satisfied.

**Telemetry** - Equipment for measuring a quantity (amperes, volts, MW, etc.) and transmitting the result via a telecommunication system to a remote location for indication and/or recording.

**Texas Reliability Entity (TRE)** - Texas Reliability Entity, Inc. is authorized by NERC to develop, monitor, assess, and enforce compliance with NERC Reliability Standards within the geographic boundaries of the ERCOT region. In addition, TRE has been authorized by the Public Utility Commission of Texas (PUCT) and is permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides. TRE is independent of all users, owners, and operators of the bulk power system.

**Thermal Insulation** - Any material which slows down or retards the flow or transfer of heat.

**Transformer** - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

**Transient Flow or Unsteady State Flow** - The process which involves changes within the control volume with time.

**Transmission** - An interconnected group of lines and associated equipment operated at high voltage levels in the range of 100 kV to 765 kV in North America for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

**Transmission Operator** - The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

**Transmission Owner** - The entity that owns and maintains transmission facilities, including, but not limited to, overhead and underground transmission lines, substations, transformers, circuit breakers, capacitor banks and busses.

**Transmission Service Provider (TSP)** - As defined by NERC, an entity that administers the transmission tariff and provides transmission service to transmission customers under applicable service agreements. ERCOT specifies that TSPs own or operate transmission facilities.

**Treatment Plant -** A plant designed primarily to remove undesirable impurities from natural gas to render the gas marketable. Examples of these impurities are water, water vapor, sulfur compounds, carbon dioxide, nitrogen and helium.

**Turbine** - A rotating mechanical device driven by the force of a working fluid. The working fluid is typically steam, water, combustion gases or, in the case of wind turbines, air.

**Under Frequency Load Shedding (UFLS)** - The automatic disconnection or tripping of customer load based on a decline in system frequency. The set points are predetermined. For example, a utility may trip 5% of their connected load if frequency falls below 59.3 Hz, an additional 10% if it falls below 58.9 Hz, and a final 10% if it falls below 58.5 Hz. The purpose of UFLS is to arrest the frequency decline accompanying major system disturbances generally involving the sudden loss of large amounts of generation or multiple transmission line tripping that results in the formation of an electrical island in which the remaining generation is inadequate to supply the load, thereby forestalling a complete system collapse.

**Under Voltage Load Shedding (UVLS)** - The tripping of customer load based on a decline in system voltage. For example, a utility may trip 5% of their connected load if voltage falls below 92% of nominal and an additional 10% of their load if voltage falls below 90% of nominal. The purpose of UVLS is typically to avoid a voltage collapse, but it can also be used to avoid overloading transmission facilities during contingency conditions when other transmission facilities trip or are forced out of service.

**Unit Commitment** - The process of selecting which generating units will be placed on line to serve the load and reserve requirements.

**Verbal Dispatch Instruction** - In ERCOT, a dispatch instruction issued by operators in the control center to a generating unit or units, load resource, or their Qualified Scheduling Entities (QSEs) orally over the telephone, as opposed to one issued in writing or issued automatically by a control system and delivered electronically via telecommunications.

**Vertically Integrated Utility** - An electric utility company or a federal, state, or municipal agency that owns and operates all aspects of the power system in its franchise service territory, *i.e.*, generation, transmission, and distribution. The ownership of certain facilities may be shared or held wholly by others, but the vertically integrated utility still controls the power system in the territory.

**Voltage** - The force characteristic of a separation of charge that causes electric current to flow. The symbol is "V" and units are volts or kilovolts (kV).

**Well Freeze-offs** - Natural gas flow blockages resulting from water vapor freezing or the formation of crystal hydrates in the gas stream.

**Wellhead** - The assembly of fittings, valves, and controls located at the surface and connected to the flow lines, tubing, and casing of the well so as to control the flow from the reservoir.

**Wellhead Choke** - Points at the wellhead where flow and pressure are primarily controlled.

**Western Electricity Coordinating Council** - The Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

**Wheeling (Natural Gas)** - The transportation of customer-owned gas by a transmission company for the customer at a pre-determined cost to the customer.

**Windbreaks** - Temporary or permanent structures intended to obstruct, or serve as a barrier against, the wind for the comfort and safety of people and/or the protection of property or equipment.

**Wind Chill Factor** - The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people to feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

**Zonal Market -** A market for electric energy divided into regional pricing zones. Generators within a zone receive the same price for the power they provide, and transmission lines crossing zonal boundaries are assessed additional costs due to market congestion when the power flowing through them reaches operational constraints.

# Appendix: Task Force Members

**FERC Staff**

**Office of Administrative Litigation**
James Ballard
Pamela Swinson-Okhomina

**Office of Electric Reliability**
David Cole
Justin Cunningham
Kent Davis
Kenneth Githens
Donald Hargrove
Nick Henery
Loye Hull
Raymond Orocco-John
Monica Taba
Daniel Taft
Richard Waggel

**Office of Energy Market Regulation**
Adam Bednarczyk
Julie Graf
James Sarikas
John Yakobitis

**Office of Energy Policy & Innovation**
Pamela Silberstein

**Office of Energy Projects**
Joseph Caramanica
Michael McGehee

**Office of Enforcement**
Ahuva Battams
Todd Brecher
Gregory Campbell
Gloria Cloteykine
Catherine Collins
Neil Dyson
Christopher Ellsworth
Sidney Gerson
Robert Hartwell
Kenneth Kohut
Kathryn Kuhlen
Gary Mahrenholz
James Meade
Cristina Melendez
Roger Morie
Michelle Norman
Thomas Pinkston
Heather Polzin
Eric Primosch
Charles Reusch
Janette Richardson
Timothy Shear
Gabriel Sterling III
Paul Varnado
Lee Ann Watson
Young Yoo

**Office of External Affairs**
Judy Eastwood
Mark Hershfield
Sandra Waldstein

**Office of the General Counsel**
Julie Greenisen
Renee Wright

**NERC Staff**

Eric Allen
Bob Cummings
G. Michael Curley
Tom Galloway
Robert Kenyon
Mark Lauby
Steve Masse
Earl Shockley
Jule Tate

**This page intentionally left blank.**

## Appendix: Legislative and Regulatory Responses by the States

The natural gas and electricity shortages that occurred in the Southwest in early February 2011 seriously affected three states: Arizona, New Mexico and Texas.[1] Each state took different regulatory and legislative actions in response to the events. As part of its inquiry, the task force contacted state regulators and followed subsequent legislative and regulatory developments. The following section describes the actions taken by each state.

### Arizona

In Arizona, approximately 19,000 customers in the Tucson and Sierra Vista areas lost gas service on February 3, 2011. Most of those customers had their service restored within four days.[2] The Arizona Corporation Commission (ACC), which among other things, regulates public utilities in the state, took the lead in reviewing the circumstances surrounding the gas outages.[3] One commissioner met with Southwest Gas Corporation representatives on February 3,[4] and another sent data requests to four impacted pipelines on February 16, 2011.[5]

On March 2, 2011 the ACC held an open meeting on the Southern Arizona gas outages, with witnesses from Southwest Gas Corporation and El Paso Natural Gas Company testifying. At the hearing, representatives from both companies stated that cold weather was the primary reason for the outage, as demand far outweighed supply during the record-low cold temperatures.

---

[1] The task force contacted regulatory staff with the Public Service Commission of Nevada and the California Public Utilities Commission, who informed us that they did not experience a substantial, direct impact from the February 2011 gas supply shortages, and that no related inquiries or proceedings were underway in their states.

[2] *See* Alex Dalenberg, *ACC Meeting will Delve into SW Gas Outage, Arizona Daily Star* (Feb. 13, 2011).

[3] The Arizona legislature did not hold hearings or take any legislative actions in response to the outages.

[4] *See* Letter from Commissioner Barbara Burns to the Chairman and Commissioners of the Arizona Corporation Commission, Docket No. G-00000C-11-0081 (Feb. 11, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123284.pdf (last visited Aug. 5, 2011).

[5] *See* Letter from ACC Commissioner Sandra Kennedy to Southwest Gas Corporation; El Paso Natural Gas Company; UNS Gas, Inc.; and Transwestern Pipeline Company, LLC, Docket No. G-00000C-11-0081 (Feb. 7, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123172.pdf (last visited Aug. 5, 2011).

The ACC held two follow up meetings, on April 6, 2011 and April 7, 2011, to gather information from customers affected by the outages.[6] No further action has taken place in the ACC proceeding.

**New Mexico**

More than 30,000 customers lost gas service in New Mexico on February 2 and 3, 2011, some for as long as a week. Shortly thereafter, a New Mexico State Senator asked the state's Attorney General to look into the causes of the outages,[7] and the legislature announced that it would hold hearings. On February 11, 2011, a hearing was held before the full New Mexico Senate, which heard testimony from some of the individuals who lost gas service and from representatives of New Mexico Gas Company (NMGC), El Paso Natural Gas Company, and the New Mexico Public Regulation Commission (PRC).

On February 14, 2011, the New Mexico Senate directed the PRC to convene a task force to investigate how and why New Mexico consumers lost natural gas service and to make recommendations on how to prevent such loss of service in the future.[8]

On March 16, 2011, Governor Susana Martinez signed a bill[9] into law that created a state task force to investigate the causes of the outages and to make recommendations on how to prevent similar outages in the future.[10] As of the date of this report, the report from the Natural Gas Emergency Investigation Legislative Task Force is pending.

---

[6] *See Tucson Residents Tell Commissioners About Freezing Nights and No Natural Gas Service, Associated Press*, (Apr. 8, 2011).

[7] *See State Senator Carlos Cisneros, Senator Calls on AG to Immediately Investigate Gas Outage* (Feb. 8, 2011), *available at* http://www.democracyfornewmexico.com/democracy_for_new_mexico/2011/02/sen-carlos-cisneros-requests-immediate-investigation-into-gas-outage-by-ag.html (last visited Aug. 5, 2011).

[8] SM 30 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/SM030.pdf (last visited Aug. 5, 2011).

[9] HB 452 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/HB0452.pdf (last visited Aug. 5, 2011).

[10] *See* House Executive Message No. 2 (Mar. 16, 2011) *available at* http://www.governor.state.nm.us/uploads/FileLinks/7bbb779a53dd4071933247333d38f22c/House%20Executive%20Message%202.pdf (last visited Aug. 5, 2011).

The United States Senate Committee on Energy and Natural Resources held a field hearing in New Mexico on February 21, 2011 to receive testimony regarding the natural gas service disruptions in New Mexico and the reliability of regional energy infrastructure.[11] The Committee heard testimony from three different panels, and sent follow up questions to the Federal Energy Regulatory Commission.

The PRC opened its investigation into the outages on February 11, 2011.[12] In its order opening the inquiry, the PRC directed NMGC, Public Service Company of New Mexico, El Paso Electric Company, and Southwestern Public Service Company to provide testimony responding to specific questions within 30 days of the order.[13]

At the same time, the PRC also initiated a non-docketed proceeding entitled the NMPRC Informal Task Force Investigation into Severe Weather Cascading Events. The Informal Task Force, which included representatives of several New Mexico utilities,[14] PRC staff, the state Attorney General's Office, several municipalities, and the general public, was charged with developing a summary of the weather event, identifying the causes, determining how to mitigate the impact of future events, and reviewing the policies and rules of the PRC and other New Mexico agencies.[15]

On May 3, 4, and 5, 2011, the PRC held hearings on the outages, hearing testimony from gas company representatives and other parties, including

[11] *See* Recent Natural Gas Service Disruptions in New Mexico and Reliability of Regional Energy Infrastructure before the Senate Energy and Natural Resources Committee, 112th Congress (Feb. 21, 2011) *available at* http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=169bb12f-e360-3d3f-378c-4a762ddf0b56 (last visited Aug. 5, 2011).

[12] *See* Press Release, Public Regulation Commission, NMPRC initiates investigation into Natural Gas Delivery Failure (Feb. 10, 2011), *available at* http://www.nmprc.state.nm.us/news/pdf/2011-02-10-gasinvestigation.pdf (last visited Aug. 5, 2011).

[13] In the Matter of an Investigation into New Mexico Gas Company's Curtailments of Gas Deliveries to New Mexico Consumers, Order Initiating Investigation and Setting Hearing, New Mexico Public Regulation Commission, Case No. 11-00039-UT (Feb. 15, 2011), *available at* http://164.64.85.108/infodocs/ 2011/2/PRS20156381DOC.PDF (last visited Aug. 5, 2011).

[14] The utilities are Public Service Company of New Mexico, Southwestern Public Service Company, El Paso Electric Company, NMGC, Zia Natural Gas Company, and Raton Natural Gas Company.

[15] February 2011 Severe Cold Weather Investigations & Status, Presentation before the Natural Gas Emergency Investigation Legislative Task Force (July 25, 2011) at pp. 1-2.

representatives of the affected municipalities. Since then, the parties have submitted additional written testimony and briefs to the PRC. As of the date of this report, the PRC's investigation is still pending.

**Texas**

With several million consumers affected by electrical blackouts, the State of Texas was severely impacted by the extreme weather events of early February. Two regulatory agencies in Texas have jurisdiction over the industries in question – the Public Utilities Commission of Texas (PUCT) (which has primary jurisdiction over the electrical power industry) and the Texas Railroad Commission (TRC), whose jurisdiction includes the natural gas industry.

The PUCT reacted at once to the electric outages, asking the state's independent energy market monitor on February 4, 2011 to investigate whether power generators, pipeline companies or others broke market rules.[16]

The PUCT also directed the Texas Reliability Entity, Inc. (TRE) to investigate the Electric Reliability Council of Texas (ERCOT) Energy Emergency Alert Level 3 that occurred on February 2, 2011. At the same time, the PUCT asked El Paso Electric Company to investigate and report back on the weather-related issues surrounding this event.

On February 8, 2011, the TRC held the first state hearing on the outages. One of the witnesses, the TRE, addressed the impact of the rolling blackouts on natural gas service.[17]

On February 15, 2011, the Texas Senate's Committee on Natural Resources and Committee on Business and Commerce jointly convened a hearing to discuss the causes of the rolling blackouts.[18] The hearing included testimony from the PUCT, the TRC, the Texas Commission on Environmental Quality, ERCOT, and the Office of Public Utility Counsel. The House Committee on State Affairs also held a hearing on the causes of the rolling blackouts on February 17, 2011.

---

[16] *See* Rebecca Smith, *Texas to Probe Rolling Blackouts, Wall Street Journal* (Feb. 7, 2011).

[17] *See* Press Release: Railroad Commission Emergency posted item to be discussed at 1:30 P.M today, Texas Railroad Commission (Feb. 8, 2011), *available at* http://www.rrc.state.tx.us/pressreleases/2011/020811.php (last visited Aug. 5, 2011).

[18] *See* Chris Tomlinson, *Texas Senate Investigates Power Outages, The Associated Press* (Feb. 16, 2011).

Prompted by the hearings, the legislature enacted a bill to address the perceived causes of the rolling blackout.[19] On June 17, 2011, that bill was signed into law.[20]

The law directs the PUCT to prepare a "weather emergency preparedness report on power generation weatherization preparedness." [21] Under the law, the PUCT must review the emergency operations plans it currently has on file,[22] determine the Texas electricity grid's ability to operate continuously during extreme weather events in the upcoming year, consider the upcoming year's forecasted weather patterns, and recommend improvements to emergency operations plans to ensure electric service reliability.[23] In addition, the law permits the PUCT to require entities to update their emergency operations plan when it does not contain information sufficient to determine whether that entity can perform during adverse weather. The law also permits the PUCT to adopt rules implementing the legislation.[24]

On April 21, 2011, the Independent Market Monitor reported that "there was no evidence of market manipulation or market power abuse" within the ERCOT region.[25] The Independent Market Monitor similarly determined "that the ERCOT real-time and day-ahead wholesale markets operated efficiently and the outcomes are consistent with the ERCOT energy-only wholesale market design."[26]

[19] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[20] Another bill was introduced which would have required the PUCT to develop a process for obtaining emergency reserve power generation capacity, but it was not considered during the legislative session. HB 1986, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/ HB01986I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[21] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[22] P.U.C. Subst. R. 25.53(c)(2) (TX, 2011).

[23] S.B. 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[24] *Id.*

[25] Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011, Potomac Economics LTD. (April 21, 2011), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf at 2 (last visited Aug. 5, 2011).

[26] *Id.*

On May 13, 2011, the TRE issued a report on whether ERCOT Protocols and Operating Guides were followed during the period leading up to the Energy Emergency Alert event.[27] The TRE concluded that event "was caused by either insufficient or ineffective preparation of generating facilities for prolonged freezing weather."[28] The report went on to find that "ERCOT Market Participants committed potential violations of the ERCOT Protocols and Operating Guides in connection with the event."[29] The TRE will conduct additional investigations as necessary and forward information to the PUCT for further action, as appropriate.[30]

Also, on May 13, 2011, PUCT staff issued a report on El Paso Electric Company's activities during the weather event.[31] PUCT staff did not identify any violations of the Public Utility Regulatory Act or the PUCT's Substantive Rules.[32] The report, however, did conclude that "designed cold weather tolerances of El Paso Electric Company's current generation equipment and/or weatherization preparation were inadequate to prevent failures in the conditions during the event timeframe."[33]

[27] Protocol and Operating Guide Compliance Report of the ERCOT Emergency Alert (EEA) Level 3 on February 2, 2011, Texas Reliability Entity, Inc. (May 13, 2011), *available at* http://www.puc.state.tx.us/files/TX_RE_EEA_Protocol_Comp_Report.pdf (last visited Aug. 5, 2011).

[28] *Id.* at 1.

[29] *Id*.

[30] *Id.*

[31] Report on El Paso Electric Company Weather-Related Issues in February 2011, Staff of the Public Utilities Commission of Texas (May 2011), *available at* http://www.puc.state.tx.us/files/EPE_Report_05-13-11.pdf (last visited Aug. 5, 2011).

[32] *Id.* at 4.

[33] *Id.* at 1.

# Appendix: Categories of NERC Registered Entities

All entities that fall within one or more of the following categories must register with NERC. Many entities carry out multiple roles and therefore have multiple registrations.

| Function Type | Acronym | Definition/Discussion |
|---|---|---|
| Balancing Authority | BA | The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within BA area, and supports interconnection frequency in real-time. |
| Distribution Provider | DP | Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the distribution function at any voltage. |
| Generator Operator | GOP | The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services. |
| Generator Owner | GO | Entity that owns and maintains generating units. |
| Interchange Authority | IA | The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes. |
| Load-Serving Entity | LSE | Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers. |
| Planning Authority | PA | The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. |

# Appendix: Categories of NERC Registered Entities

| | | |
|---|---|---|
| Purchasing-Selling Entity | PSE | The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities. |
| Reliability Coordinator | RC | The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. |
| Reserve Sharing Group | RSG | A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG. |
| Resource Planner | RP | The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area. |

# Appendix: Categories of NERC Registered Entities

| | | |
|---|---|---|
| Transmission Owner | TO | The entity that owns and maintains transmission facilities. |
| Transmission Operator | TOP | The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities. |
| Transmission Planner | TP | The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area. |
| Transmission Service Provider | TSP | The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements. |

This page intentionally left blank.

# Appendix: Electricity - How It Is Generated and Distributed

Electricity is one of the most widely used forms of energy in the industrialized world. According to the U.S Energy Information Administration, in 2009 the U.S. electric utility net generation was 2,372,776 gigawatt hours. Table 1 shows the share of net electricity generation by energy source in the United States.

| Energy Source | Net Generation (%) |
|---|---|
| Coal | 44.5 |
| Nuclear | 20.2 |
| Natural Gas | 23.3 |
| Hydro | 6.8 |
| Oil (Petroleum) and other | 1.6 |
| Renewables | 3.6 |

Table 1: Share of net electricity generation in 2009 in the U.S. (Source: U.S. Energy Information Administration)

Electric power is produced at generating stations and transmitted via transformers, transmission lines, switching devices and protection and control equipment for delivery to end users. The electric power system as shown in figure 1 is an integrated system made up of generation, transmission and distribution subsystems.

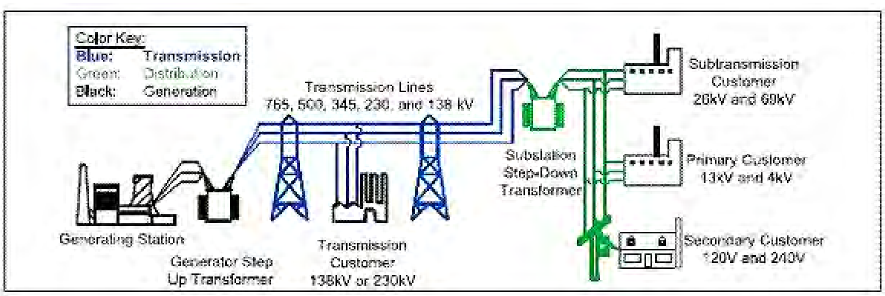



Figure 1 – Basic structure of the electric system (NERC)

## Generation

Generating plants produce electricity by burning fuels such as oil, coal, natural gas, or lignite to create steam that drives a turbine, which in turn drives a turbine generator shaft. In a coal-fired plant (figure 2), coal is ground by pulverizers into fine powder, mixed with pre-heated air and injected into a combustor, where it is ignited. The hot combustion gas rises through the boiler and heats water that enters the steam generator. The partially vaporized water enters the steam drum, where steam is separated from the water. The remaining water cycles through the boiler again, and through tubes lining the furnace walls. The steam is passed through another section of the boiler known as the superheater, where the temperatures are increased to well above boiling.

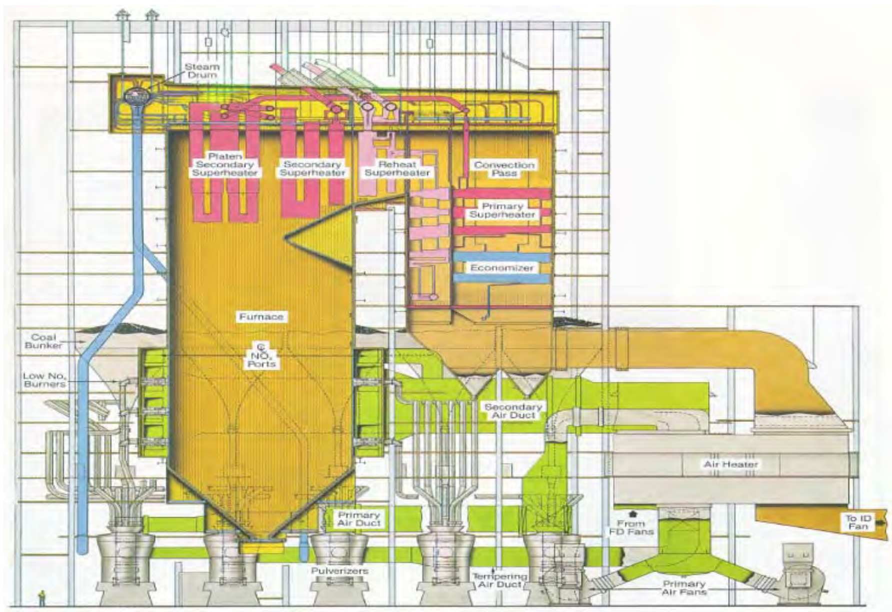



Figure 2 – Typical drum-type coal/lignite boiler plant
(PJM Generation Basics)

The superheated steam, now at very high pressure, passes through a high pressure turbine (shown in figure 3), causing the turbine to spin and turning the shaft of an electrical generator. After passing through the high pressure turbine, the steam is piped back to the boiler to be reheated, then enters an intermediate pressure turbine and low pressure turbine before it passes through a condenser, where the steam is converted back to water, which is usually cycled back to the steam generator for reuse. The mechanical energy generated by the spinning generator shaft is converted to electrical energy for delivery to the electric power system.

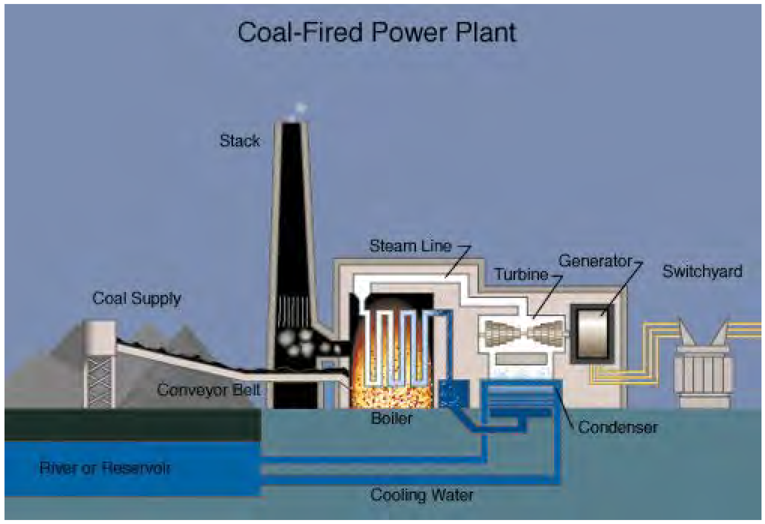


Figure 3: Typical coal burning generating plant with cooling tower (Department of Energy)

In nuclear generating stations, steam is also used to drive a turbine. However, the energy required to produce the steam is derived from nuclear fission, typically fueled by uranium.

Wind turbines use blades to collect the energy of the wind. As wind blows, it flows over the blades, causing them to turn. The blades are connected to a gear box with a drive shaft that turns an electric generator to produce electricity.

In hydroelectric plants, the gravitational force of water flowing downhill drives the turbine generator shaft (as shown in figure 4). The mechanical energy of the spinning shaft is then converted to electrical energy.

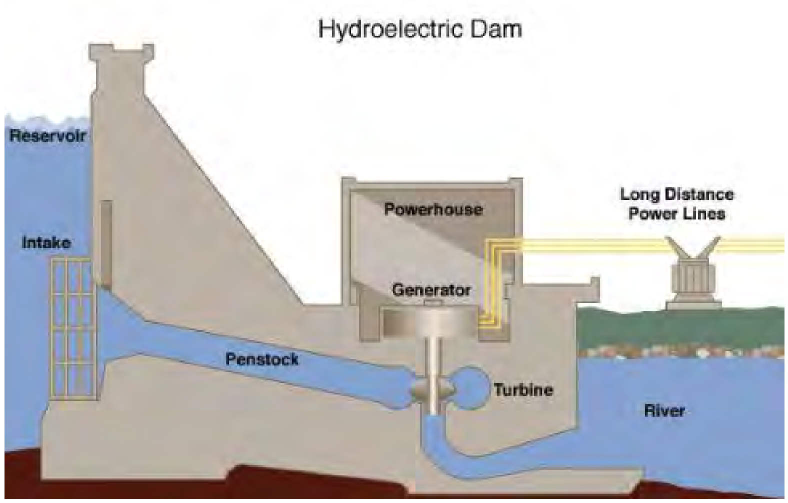



Figure 4: Typical hydroelectric generator
(Energy Information Administration)

Electric energy can also be produced by simple cycle or combined cycle combustion turbines or internal combustion engines, which usually burn natural gas or fuel oil. The combustion turbine drives an electric generator to produce electricity. One advantage of combustion turbines is that they can be started quickly, making them suitable for emergencies and during peak periods, when demand for electricity is at its highest.

A combined cycle combustion turbine is shown in figure 5. Note: a simple cycle combustion turbine plant does not include a heat recovery steam generator (HRSG), steam turbine, and a second generator as depicted in figure 5.

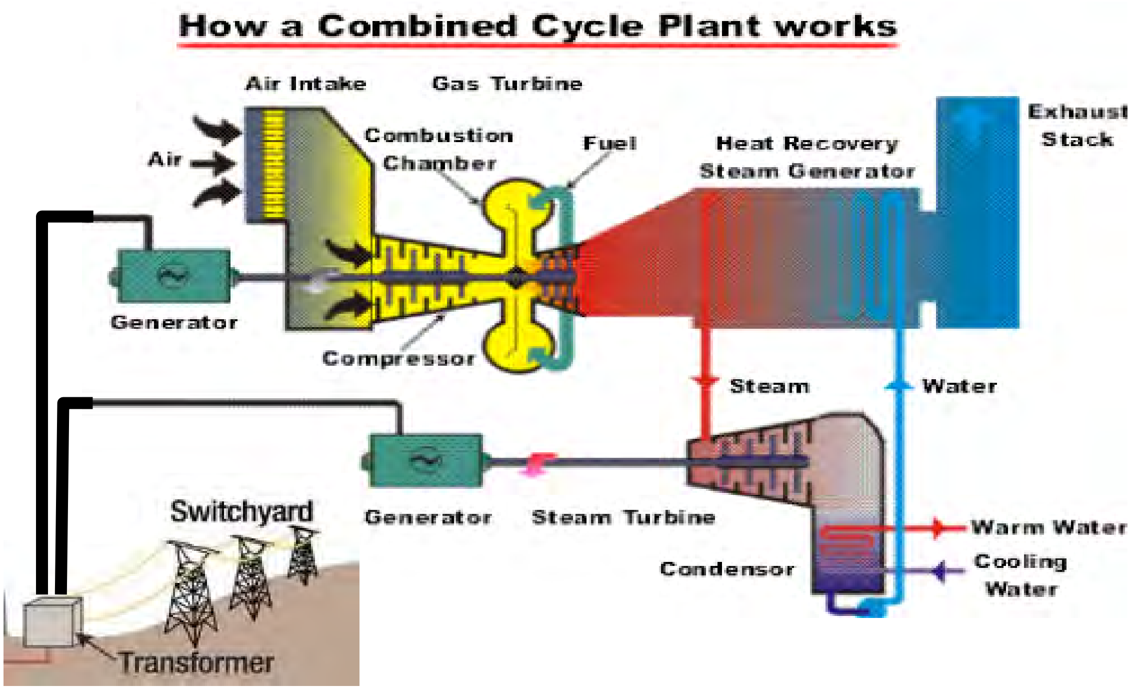



Figure 5: Combined cycle turbine generator with steam generator and HRSG (Washington State University)

**Conversion of Mechanical Energy to Electrical Energy**

A generator works on the principle of electromagnetic induction, discovered by scientist Michael Faraday between 1831 and 1832. Faraday discovered that the flow of electric charges could be induced in a coil of wire by passing a magnet through the coil. This movement creates a voltage difference between the two ends of the wire or electrical conductor, which in turn causes the electric charges to flow, thus generating electric current.

Every modern generator consists of two main components: the rotor (the moving part) and the stator (the stationary part). In an AC generator, the rotor spins inside the stator. A mechanical device is used to spin or turn the rotor. With every rotation, the changing magnetic field creates a current in the stator windings. A generator does not actually make electrical energy. Instead, it uses mechanical energy supplied to it to cause the movement of electric charges present in the wire of the stator windings, thereby generating an electric current that is supplied to the grid. A generator is akin to a water pump, which causes the flow of water but does not actually create the water flowing through it.

Most large power generators are three-phase generators and have three windings (A, B and C phases), one winding for each phase. In a three-phase generator, a rotor rotates at the center of the three windings creating the changing magnetic field. Each one of the winding sets produces a voltage. Each phase voltage has a 120º phase angle separation from the other two phase voltages as shown in figure 6. The waveform of the induced voltages is a sine wave (also shown in figure 6) in which each phase voltage periodically reverses direction. The current produced from this generator is known as alternating current (AC).

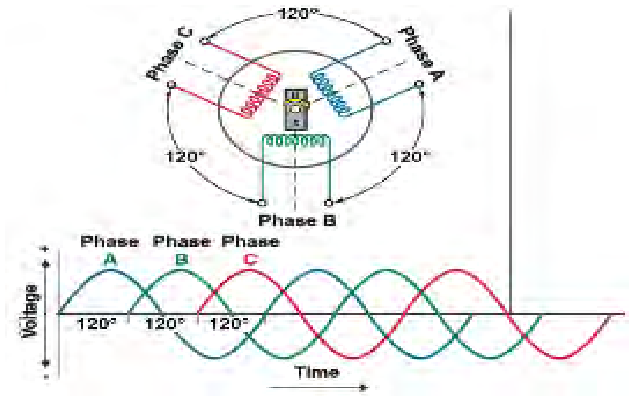



Figure 6: Three-phase generator diagram & waveform
(Electric Power Research Institute)


Figure 7: Three-phase power generator
(Electric Power Research Institute)

There are two general types of AC generator: synchronous and asynchronous. The terms synchronous and asynchronous refer to the relationship between the generator rotor's speed of rotation and the power system speed. Power system speed (or synchronous speed) is the speed of rotation of the AC electrical system to which the generator is connected. When a generator is connected to the power system, the rotating magnetic field of the generator is synchronized with the rotating magnetic field that already exists in the three-phase system. An AC generator can be designed to rotate in-step, or in synchronism, with the power system's rotating field. This type of AC generator is called a synchronous machine. Most utility power generators and most large motors are synchronous machines.

An AC generator's rotor can also be designed to rotate slower or faster than synchronous speed. This type of machine is called an asynchronous machine. Most small AC motors are asynchronous machines. Induction machines – alternating current machines in which power is supplied to the rotor by means of electromagnetic induction – are the most common type of asynchronous machines. Most wind turbines use induction generators.

Synchronous machines are the most common type of generator used for large-scale power production, and can be used to produce both active[1] and reactive power[2]. This is in contrast to conventional induction machines, which cannot produce reactive power, only active power. The latest design for wind turbine generators, however, includes sophisticated power electronic interfaces and controls that allow these units to inject or absorb reactive power from the grid, as well as providing frequency response, inertial response, etc.

**Transmission**

Electricity from generators is stepped up to higher voltages by means of a generator step-up transformer for transportation in bulk over transmission lines. Operating the transmission lines at high voltage (100,000 to 765,000 volts) reduces electricity losses from conductor heating and allows power to be transported economically over long distances. The higher the voltage, the lower the current flow needed to transmit the same amount of power. Since losses are related to high current flow, lowering the current lowers the losses. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power grid. Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics, along paths of least resistance. When power arrives near a load center, it is stepped down to lower voltages by means of step-down transformers, usually located at substations throughout the system. These substations contain other equipment such as communication, control, protection

---

[1] Active Power is the useful or working energy supplied by a power source. It is used to perform work such as lighting a room or heating a building or turning a motor shaft.

[2] Reactive Power is used to support the magnetic and electric fields necessary to operate power system equipment. Reactive power is never consumed by the power system and is stored in the electrical and magnetic fields that exist in the system.

and metering equipment. The Bulk Power System (BPS) is predominantly an AC system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another.

Three-phase AC power is normally transmitted by overhead AC circuits, which consist of aluminum conductors with a reinforcing steel core suspended from metal towers by porcelain insulators, as shown in figure 8. Underground transmission circuits can also be used, but are used less frequently than overhead circuits due to the costs involved, as well as the associated reduction in current carrying capacity. Transmission cables installed underground must be insulated, increasing cost and limiting the current carrying capability of the system.

High Voltage Direct Current (HVDC) systems are usually employed for special purposes, including the transmission of large blocks of power from remote sources to load centers or interconnection to systems that operate at different frequencies. A DC transmission system consists of a two conductor line connecting two AC systems. A rectifier at one end of the line converts the AC voltage to a constant DC value and an inverter at the other end reconverts the DC into AC.

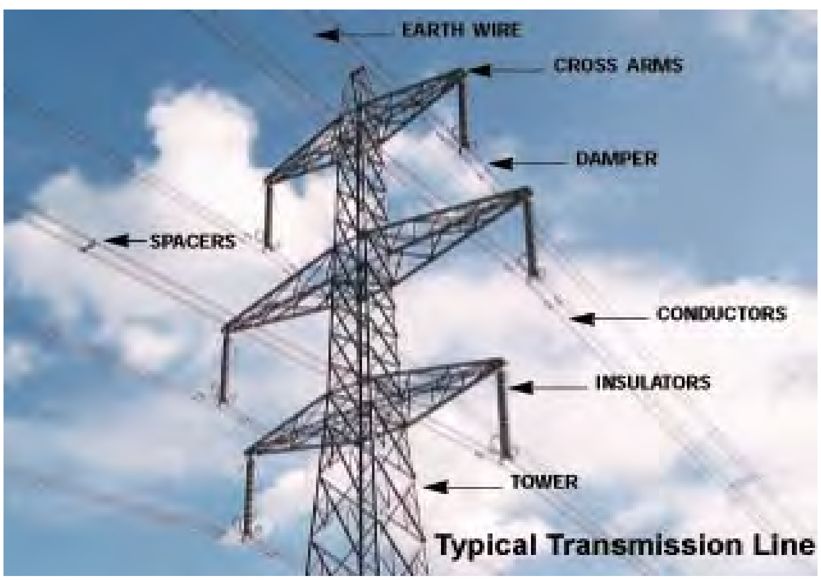



Figure 8: Transmission tower (National Grid)

While the power system is commonly referred to as “the grid,” there are actually three distinct power grids or interconnections in the United States. Figure 9 shows the various interconnections. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a small part of Mexico near the California border. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small DC ties. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads. The frequency at which the various interconnects were designed to operate is 60 Hz.

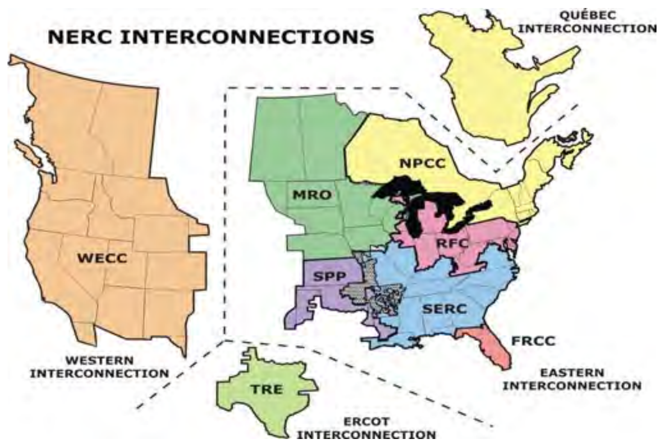



Figure 9: North American interconnections (NERC)

*System Frequency*

If the total demand from customers is not in balance with the available generation, the electrical frequency of an entire interconnection will deviate from 60 Hz. The target frequency is referred to as the scheduled frequency. When the actual frequency deviates from the scheduled frequency, a frequency deviation has occurred. For example, if the scheduled frequency is 60 Hz but the actual frequency is 59.95 Hz then a -0.05 Hz frequency deviation has occurred. When the supply of generation to the transmission system is inadequate, the frequency falls below 60 Hz. When too much generation is supplied to the transmission system, the frequency rises above 60 Hz. Individual power systems within an interconnection work together to maintain the frequency within a narrow band around the 60 Hz nominal frequency.

Under normal conditions, the power system frequency in a large interconnection (such as the Eastern Interconnection) varies approximately ±0.03 Hz from the scheduled value. If the scheduled frequency is 60 Hz, the normal range is 59.97 to 60.03. These variations are normal and constantly occur due to the varying nature of the interconnection's load. However, large downward, or negative, frequency deviations can trigger automatic load shedding schemes in most areas, designed to reestablish the necessary balance between generation and load. Depending on the region, automatic under-frequency load shedding usually begins when the frequency declines to levels of 59.3 to 59.7 Hz. Distribution loads are typically shed in various size blocks before generating units start to trip.

*System Voltage*

The maintenance of voltage within a narrow range is critical to utility customers. Transmission voltage fluctuations of more than ten percent can affect the overall stability of the transmission system. Entities that experience sustained voltage fluctuations equal to or greater than ten percent must file a report with NERC.[3] Capacitor banks, Static VAR Compensators, load tap changing transformers, phase shifters, and voltage regulators are used to control system voltage. Low voltage conditions are usually caused by the loss of critical transmission or generation facilities and may result in the overload of adjacent circuits, which could require bringing power in over tie lines.

*Load Balancing*

An electric power system must have enough generating capacity to supply expected peak load demand plus a reserve margin to accommodate forced outages of generating units. Operating reserves also are necessary to regulate and respond to unanticipated events such as load forecast errors.

Large frequency deviations from the scheduled value occur when there is a significant mismatch between total load demand and total generation. The frequency rise or decay will in most cases be halted by the action of the speed governors on generators which respond to frequency changes and automatically adjust generation to meet demand. Governor action is supplemented by the Automatic Generation Control (AGC) system which over a period of several minutes brings the frequency and interchange (energy transfers that cross Balancing Authority boundaries) back to schedule.

AGC can be a very effective tool during system restoration. The primary function of AGC is to make continuous and automatic adjustments to the output of selected generators in a way that meets load demand and the established interchange schedule at the desired operating frequency. AGC software is normally designed to control a defined portion (within the Balancing Authority boundaries) of the interconnected system. To accomplish the AGC control function, control parameters are continuously monitored. The control parameters

[3] Reliability Standard EOP-004-1 (Disturbance Reporting).

consist of an actual frequency reading and all tie-line MW flows to neighboring Balancing Authority areas. These control parameters are selected and normally fixed for the portion of the system being controlled. A key assumption to the typical AGC control strategy is that the power system is operating in an interconnected mode.

**Distribution**

Some larger industrial and commercial customers take service at intermediate voltage levels (4,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts. Residential customers receive power via overhead or pad mounted transformers supplied by distribution feeders from substations. The transformers step down the voltage from a typical voltage of 13,000 volts to 120/240 volts. The lines carrying the power to a business or residence usually terminate at an electric meter owned and maintained by the distribution company. The meter records the energy consumed by the end user and is read periodically by the distribution company to monitor energy usage and for billing purposes.

**This page intentionally left blank.**

# Appendix: Power Plant Design for Ambient Weather Conditions

Geographic location and the corresponding ambient weather conditions, including expected temperatures and wind speed, have a direct impact on the preferred design for generating facilities. In the northern regions of the United States, most generating plants (especially steam-cycle plants) are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiated from boilers, other generation equipment, and supplemental heaters can generally maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling purposes during the hot weather months.

Enclosed coal fired power plant in the northeastern United States (Allegheny Energy)[1]

In the southern and other warm weather regions of the U.S., generating plants are designed and constructed without enclosed building structures, with the boilers, turbine/generators, and other ancillary systems exposed to the weather, in order to avoid excessive heat build up. For the colder months, when temperatures may fall below freezing, generation owners and operators undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, temporary heating, and temporary wind breaks (to prevent heat loss from normal operations and from supplemental heating sources).

[1] *Available at* http://www.industcards.com/st-coal-usa-wv.htm (last visited Aug. 10, 2011).

Non-enclosed coal fired power plant in the southern United States (Luminant)[2]

**Common Freezing Problems**

Some power plant components and systems are susceptible to freezing. Any power station system that uses water, air (which can contain moisture), or rotating machinery (which uses lubricating oil) can develop operational problems or trip off-line as a result of sub-freezing temperatures, unless adequate cold weather protection is in place.

- Instrumentation - Instrumentation provides operational data necessary for process monitoring and control systems. Freezing often may occur not in the instrumentation itself, but in the sensing lines that run from piping, pressure vessels, and tanks that contain water or steam. The sensing lines are filled with a static water column that, if frozen, will send incorrect data, possibly resulting in unit trips, load rejection, unit runback schemes, or incorrect operator actions. Critical instrumentation sensing lines that are susceptible to freezing include lines used to monitor boiler steam drum water level, deaerator pressure, feedwater heater water levels, and various critical cooling water flows (generator, turbine oil cooling, etc.).

- Feedwater systems - The condensate and boiler feedwater systems for steam-cycle generation units utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are all susceptible to freezing. This is especially true of generation units that are not in operation at the onset of freezing temperatures, due to static water in the feedwater systems. In addition, the reverse osmosis

[2] *Available at* http://www.powermag.com/environmental/Luminants-Oak-Grove-Power-Plant-Earns-POWER-s-Highest-Honor_2877_p2.html (last visited Aug. 10, 2011).

equipment, demineralizers, filters, and storage tanks often found in condensate make-up water systems are susceptible to freezing.

**Cooling Water Systems**

- Cooling Water Intakes - Steam cycle power plants require large quantities of cooling water, often supplied by rivers or lakes. Water drawn from a river or lake is filtered through trash racks and circulating water screens to remove tree branches, debris, and fish. When temperatures drop below freezing, ice can clog racks and screens, limiting the flow of cooling water. Water intakes can also become clogged by fish kills during extreme cold weather, as happened in Texas in 1989.

- Cooling Towers - Cooling towers lower the temperature of water used in the cooling process so that it can be reused (reducing the amount of water taken from lakes and rivers) or discharged at lower temperatures. Cooling towers use mechanically induced draft or natural draft designs. Mechanical cooling towers (box) have fans mounted on the top to draw air through the water as it falls over trays to remove the heat gained in the steam condenser. Natural draft cooling towers are of the familiar, hyperbolic design that can be seen at many large coal and nuclear power plants. During extended periods of freezing temperatures, ice can accumulate on the trays in the towers and affect operations or damage the unit.

- Equipment Cooling Water - Various equipment and systems in power plants require cooling water to stay operational. These include turbine lubricating oil coolers, generator/hydrogen coolers, pump and fan bearings, and air compressors. Freezing of the piping, valves, and instrumentation sensing lines in these systems can cause derates or outages.

- Sluicing/Service Water Systems - Sluicing water is used to remove bottom ash from coal-fired boilers. Icing problems in the bottom ash removal system can interfere with ash removal and may lead to derates or outages. Service water is used for various wash down systems and fire protection systems. Loss of service water due to freezing should not affect unit capacity, but could affect equipment protection systems.

- Wastewater Systems - Various power plant systems that use water can create waste streams that must be treated for contaminants before re-use or discharge. Those systems include boiler blowdown, cooling tower blowdown, various cooling systems, bottom ash sluicing water, and service water systems.

Freezing of valves and piping on these systems can result in the accumulation of wastewater, which could affect other systems.

**Emission Reduction Systems**

- Sulfur Dioxide Removal Systems - Among the methods available to reduce and remove sulfur dioxide from emission flue gas on coal plants, the predominant technology has been use of wet lime or limestone scrubbers. Lime or limestone contains calcium oxide, which when mixed (slaked) with water forms calcium hydroxide. Calcium hydroxide is sprayed through the flue gas to produce a chemical reaction to form calcium sulfite or sulfate (gypsum). As the waste product is processed, it contains less and less water, which is then reused in the scrubber. The scrubbing and waste processes require many runs of piping and instrument/control locations, many of which are susceptible to freezing. Freezing problems on piping runs or sensing lines could cause scrubber chemistry problems, tank overflows, etc., which could lead to derates or unit shutdowns if the plant is unable to stay within permitted emission limits.

- Nitrogen Oxides Reduction Systems - As with sulfur dioxide systems, numerous technologies are available to reduce nitrogen oxides in fossil fuel plants. Many of these technologies use water in the emissions reduction process. These systems are susceptible to freezing that can lead to failure in the emissions reduction process, resulting in derates or unit shutdowns.

**Control Air Systems, Control Drives, Valve Actuators, Valves**

- Freezing in Control Air Systems - Air is compressed and used to operate pneumatic control valves, boiler damper control drives, and various other pneumatic controls in the plant. Moisture in the air can condense and accumulate in lines, air receivers, and component control mechanisms. If moisture is not removed (through use of air dryers and air receiver blow-downs), these pneumatic controls can freeze and cause equipment controls to malfunction or fail, which can in turn cause a unit shutdown or limit the unit's output.

- Sluggish Valve Operation - When exposed to severe cold weather, the operation of valves and control valves can become sluggish. This can lead to instability in boiler or turbine controls and ultimately lead to a unit trip.

- Lubricating Oil - Various types and grades of lubricating oil and grease are used in power plants on rotating machinery and other moving parts. As the temperature decreases, the lubricating properties and viscosity of these oils change, possibly affecting operation of the equipment.

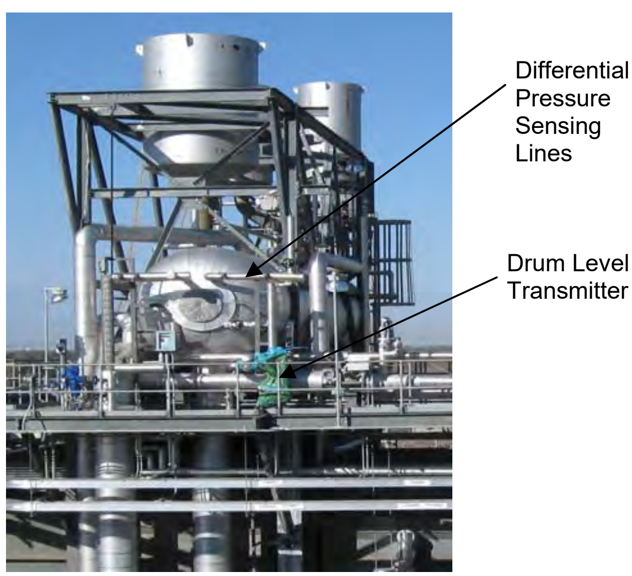
**Fuel**

- Coal - Severe cold weather can limit or prevent the transfer of coal into a plant. Coal in Texas (lignite) typically contains between 30 and 40% moisture. When temperatures are low enough to freeze moisture in the coal, the coal may slide on conveyor belts or block belt transfer points, chutes, and crushers, limiting supply.

- Natural Gas Supply - Freezing weather can cause gas valves to malfunction, adversely affecting gas supply to the units.

- Fuel Oil - During cold and freezing weather, fuel oil supplies in storage can gel without the appropriate additives. Gelled fuel oil can affect pump and burner performance, which in turn affects the unit's output. Some types of fuel oil must be heated before they can be used in cold weather.

**Steam Drum Level Measurements**




One of the most critical measurements made on a drum type steam boiler is the water level in the main drum. Too high a water level can result in water being injected into the boiler tubes or steam turbine, damaging the boiler tube or turbine blade. Too low a water level or no water can result in overheating the drum or boiler tubes, leading to drum or boiler tube damage.

The steam drum in a southern plant can be located outside, near or at the top of the boiler. During the February 2011 cold weather event many of the plants had problems with freezing in the drum level water level regulating system.

A typical drum level measurement system works by maintaining the differential pressure between the steam side and water side of the drum to a constant value. The drum level transmitter monitors and regulates this differential pressure by controlling the amount of water being added or removed from the drum. On a normal drum, the water level is controlled to approximately plus or minus 2 inches of the desired level.

# Appendix: Impact of Wind Chill

## Wind Chill Factor

The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

The polar explorer and geographer Paul Siple first used the term "wind chill" in 1939. During the second expedition of Admiral Richard Byrd, Siple and his partner Charles Passel conducted experiments at Little America, Antarctica, to determine the time required to freeze water in plastic vials exposed outside in the wind. They developed a formula for relating heat loss to wind speed and air temperature, expressed in units of atmospheric cooling-watts per square meter. Later, the formula was modified to allow computation of a wind chill equivalent temperature.

Wind Chill Temperature is only defined for ambient temperatures at or below 50 degrees Fahrenheit and wind speeds above 3 mph. Bright sunshine may increase the wind chill temperature by 10 to 18 degrees.

## Wind Chill Effect on Inanimate Objects

The Wind Chill Factor, per se, applies only to human beings and animals. The only effect wind chill has on inanimate objects, such as car radiators and water pipes, is to more quickly cool objects to the current air temperature. Objects will not cool below the actual air temperature. For example, when the temperature outside is -5 degrees and the Wind Chill Temperature is -31 degrees, a car's radiator will not get any colder than -5 degrees. Similarly, if the ambient temperature is above freezing, stationary water in piping exposed to the wind will not freeze, no matter how strongly the wind may blow.

# Appendix: Impact of Wind Chill

## Wind Chill Effect on Industrial Plants

Industrial plants, including electric generating stations, can nevertheless be affected by the accelerated rate of heat loss, or cooling, caused by air movement. During the hot summer months, this cooling effect can help prevent temperatures from exceeding equipment operating limits. For this reason, many plants in warmer climates are of an open-air design, without walls or enclosures. In the winter, however, the enhanced cooling from the unimpeded flow of air can cause freezing problems.

On cold days when the outside temperature drops below freezing, sustained high winds can quickly and continuously remove the heat radiating from boiler walls, steam drums, steam lines, and other equipment in an electric generating station, causing ambient temperatures to drop below freezing in spite of the heat being produced by the facility. If stationary water lines, such as those used for differential pressure measurement, are exposed to the wind under those conditions, they can freeze if they lack adequate freeze protection such as heat tracing and insulation. Wind screens and enclosures can slow the rate of heat loss caused by high winds, while at the same time acting to contain heat supplied by supplemental space heaters at critical locations.

## Wind Chill Effect on Electric Demand or Load

The accelerated cooling effect of the wind affects buildings and homes throughout the community, and can significantly increase demand for electric power. In particular, buildings that are not well insulated, with frequently opened doors or drafty windows, can experience higher rates of heat loss on windy days, increasing the demand for heating energy.

During the February 2011 weather event, ERCOT engineers and operators concluded, based on archived historical data, that the forecasted wind speeds would significantly increase the load on the system. They therefore increased the conventional load forecast by 4000 MW to account for the added load created by high winds combined, with low temperatures.

# Appendix: Winterization for Generators

Extreme cold weather can cause generators to fail for many reasons, including the failure or absence of heat tracing on key components, missing or inadequate wind breaks, inadequate insulation, lack of supplemental heating devices, human error, or inadequate training, maintenance, or preparation. As discussed below, effective winterization programs incorporate both physical components and operational processes to protect generating plants from freezing weather.

**Physical Components of Winterization**

Physical freeze protection is accomplished by three primary components:

- Heat tracing – the application of a heat source to pipes, lines, and other equipment that must be kept above freezing;
- Thermal insulation – the application of insulation material to inhibit the dissipation of heat from a surface; and
- Windbreaks – temporary or permanent structures erected to protect components from wind.

Generators use other temporary measures to prevent freezing in plants, including installing space heaters, draining non-essential water lines, and placing small heat lamps in cabinets.

*<u>Heat Tracing</u>*

*Types of Heat Tracing Cable*

Electric heat tracing involves the application of heat to the outside of pipes or other lines to maintain proper operating temperature. A heat tracing system is typically made up of the following: (i) heat tracing cable wound around the pipe; (ii) a thermostat that measures ambient air temperature; (iii) thermal insulation; and (iv) a power source. The failure of any of these components can result in frozen instrumentation.

There are five main types of heat trace cable. “Self-regulating” cable automatically increases power to produce additional heat as the temperature falls. It can be used on metal or plastic components for freeze protection, temperature maintenance, and foundation heating, and is typically found on sensing lines and other ancillary components. However, it cannot be used on surfaces that have high surface temperatures.

“Power-limiting” heat tracing is similar to self-regulating heat tracing in that it increases power and heat as temperatures drop, and decreases power as temperatures rise. It is specifically designed to produce high temperatures and to be used on high surface temperature fixtures.

“Parallel constant watt” heat tracing cable consists of a continuous series of short, independent heating circuits that maintain a consistent output of heat for up to several hundred feet. One benefit of this type of cable is that if one of the independent circuits fails, the rest of the cable will continue to operate. However, the length of the cable is limited, based upon the distance between the circuits, making it impractical for certain situations.

A “series constant watt” heat tracing cable is designed specifically for components that need longer circuit length. These cables are made of high-resistance wire that is powered at a particular voltage to generate heat. However, a break anywhere along the cable will result in failure of the entire heat tracing installation.

Another common type is “mineral insulated” heat tracing cable, which is typically used to maintain high temperatures, or in locations where it will be exposed to high temperatures. Mineral insulated cable is also used to provide heat over long distances, and is often used to protect high temperature steam lines.

*Power Supply*

Each heat tracing cable must be connected to a power source. In a typical installation, several cables covering one component of a generating unit will be connected to a freeze protection electric panel that contains circuit breakers or fuses for the various circuits. Depending on the size and layout of the generating unit, it may have dozens of freeze protection panels. These panels are often equipped with visual displays that indicate when the system is energized and when the heat tracing is activated. Images 1 and 2 are examples of the inside and outside of a new freeze protection panel.

**Figure 1: Freeze Protection Panel Interior**

**Figure 2: Freeze Protection Panel Exterior**

As can be seen in the example above, lights on the front of the panel indicate the status of the freeze protection system. Such indicator lights must be regularly monitored and tested by plant employees, since control room personnel are not always able to monitor panels remotely.

The failure of a freeze protection panel during cold weather can cause heat trace cables connected to that panel to fail. Failure to properly maintain or inspect the panel can cause corroded connections to go unnoticed and go unrepaired, possibly resulting in a short circuit that shuts off power to other panels.

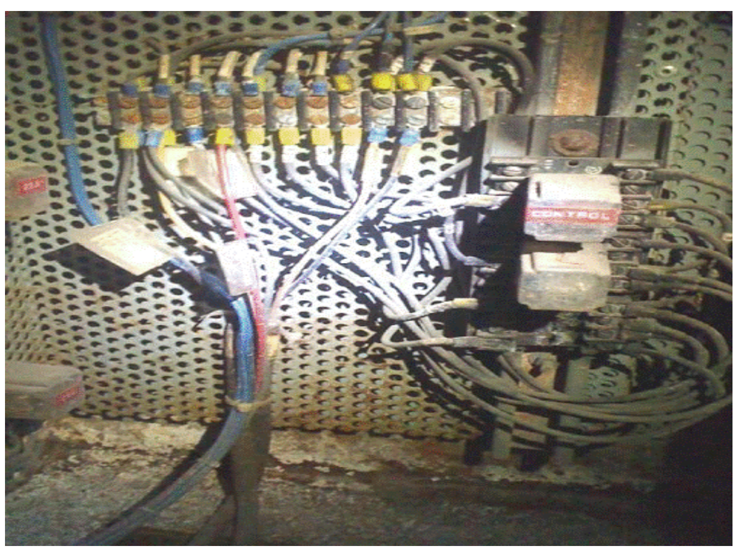



**Figure 3: Corroded Freeze Protection Panel**

*Thermostats*

Although the panel is always energized, heat tracing cables are turned on only when low temperatures call for freeze protection. Power to the cable is supplied either by a contactor (wherein two metal plates, usually separated, are pressed together to power the cables), or by a solid state controller. In most cases the system is turned on by a thermostat located at the panel. In some cases plants initiate freeze protection procedures at certain specific temperatures, and in some instances, the heat tracing must be turned on manually by plant personnel.

*Thermal Insulation*

A layer of thermal insulation is placed on top of the heat tracing that is installed on a pipe. This insulation is similar to home insulation, but is composed of different materials. A weatherproof skin is typically applied as an external layer to protect the insulation and heat trace from damage.

**Figure 4: Insulated Piping with Heat Tracing**

Thermal insulation plays a significant role in freeze protection, particularly in windy conditions, by preventing rapid heat loss. However, even small gaps in insulation have been known to result in frozen lines.

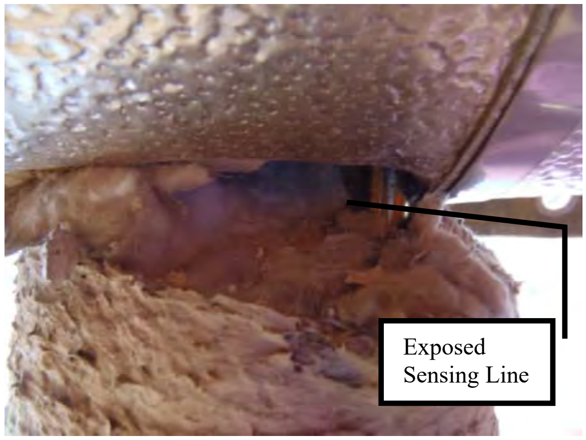



**Figure 5: Gap in Insulation**

In addition to the pipe itself, valves, flanges, traps and fittings should be insulated to the extent possible. Non-insulated valves, like those pictured below, can cause pipe to freeze if enough surface area is exposed to freezing wind conditions.

**Figure 6: Exposed valves emerge from thermal insulation and are not heat traced**

*<u>Windbreaks</u>*

The third major component to winterization is windbreaks. Windbreaks are temporary or permanent structures used to prevent wind from blowing directly over exposed components and dissipating heat at an increased rate.

**Figure 7: Temporary windbreak created with scaffolding and tarpaulin**

*Other Winterization Efforts*

In addition to the three major winterization techniques, generating stations sometimes use other freeze protection measures. These include keeping water flowing to reduce freezing, draining liquids from valves, purging drained lines of water with compressed air, and installing space heaters in enclosed areas to raise ambient air temperatures.

## Winterization Processes

Although designing freeze protection systems for exposed areas is critical to cold weather operation, preparation for freezing conditions is equally important. In order to achieve good freeze protection, a generator must know what areas are likely to freeze, and must take steps to ensure that appropriate procedures are put in place. The following paragraphs describe some of the steps that can be taken to prepare for winter, and discuss how the proper use of checklists can help plant managers implement effective winterization measures.

*Winter Preparation*

Preparation for winter weather should begin well before its arrival, and many generator operators in Texas and the Southwest start their winterization programs in the fall of each year. These procedures include verifying that installed heat tracing is working, components are properly insulated, space heaters are operational, fuel switching can be initiated, and instrument systems are free of moisture. Many generators also verify that their inventory of freeze protection equipment – such as heat lamps, heat guns, propane torches, tarps, de-icing material, fuel, insulation, sand, and extension cords – is adequate for the upcoming season. Timeliness is an important aspect of pre-winter preparation – it should begin early in the season so that there is time to make necessary repairs before cold weather hits.

In addition to pre-season preparation, generating stations typically have a set of procedures that are initiated whenever a winter storm is expected. Much of the work that is done before a storm arrives is similar to pre-season preparation. However, the pre-storm procedures may include calling in additional operators and maintenance personnel, moving motor vehicles into garages, draining non-essential water lines, and moving portable heaters into position.

As winter weather sets in, generating stations may adjust their operations to protect against freezing conditions. Such changes may include switching instrument air to nitrogen backup, warming up standby boilers every two hours, opening bypass valves on steam traps, and rotating pumps every two hours.

A critical component of winterization plans is the opportunity for post-winter critiques and reports on lessons learned. Applying lessons learned is sometimes done informally but some generators go further, requiring plant managers to conduct post-winter meetings to identify necessary improvements and to file written reports on the plant's performance during the winter season.

*Checklists*

In order to ensure that all of the plant-specific tasks are properly completed, many generator operators create checklists for plant personnel to follow. Although the form of such checklists may vary depending on the size of the plant and the types and locations of the generating units, effective checklists tend to have certain characteristics.

Good checklists are sufficiently detailed to allow plant operators and maintenance personnel to adequately prepare for and deal with cold weather events. For example, a checklist may specify who is responsible for assigning personnel to freeze protection duty, or may identify specific tasks triggered by different freeze alert levels.

A checklist can be broken down not only by task, but also by area and by individual components or areas to be checked. For example, the checklist can specify which particular lines should be drained and which vents should be closed.

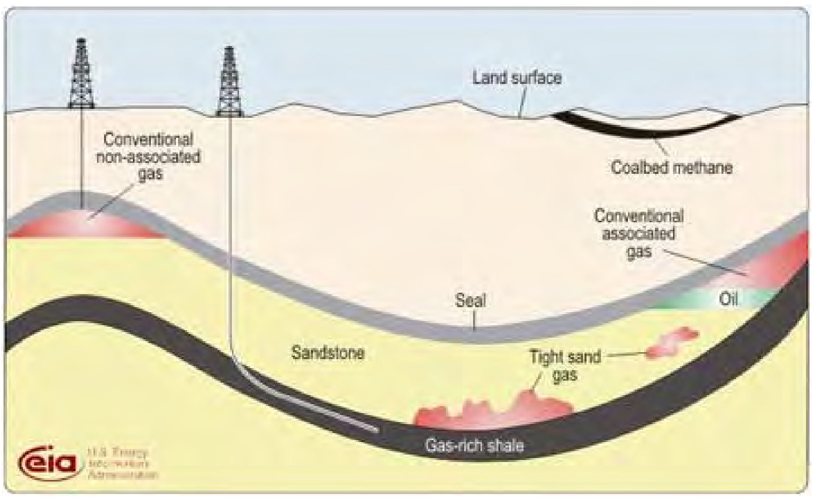
A list that is lacking in detail and that only includes general tasks such as turning off vent fans or checking boiler and duct air heater enclosures will not be effective. Plant employees might understand which components should be included in such general references, but non-specific descriptions are inadequate to ensure that all systems are identified and checked.

Checklists can also offer generating stations the ability to audit their performance in implementing winterization. A common feature of effective checklists is a requirement that employees initial and date the checklist for each task completed. Not only does this provide confirmation that the tasks were completed, but it also holds operators and maintenance staff accountable for their performance.

# Appendix: Natural Gas – Production and Distribution

## What Is Natural Gas?

Natural gas is a highly compressible, naturally occurring mixture of hydrocarbons, principally containing methane, that migrate upward through geological formations until the migration is halted by a physical barrier that allows the natural gas to accumulate in the small pore spaces within a geological formation, or reservoir. The physical barrier is a non-permeable formation that is known as a reservoir seal or caprock. The type of formation where the natural gas can accumulate, which can include sandstone, coal as well as shale, depends upon the location of deposition of the original organic material and the geologic formations that lie above. To access the natural gas that has accumulated within the reservoir, drilling companies will drill down to the formation using drilling rigs that punch into the formation using drill bits and long string pipes to bring the natural gas to the surface at the well site.

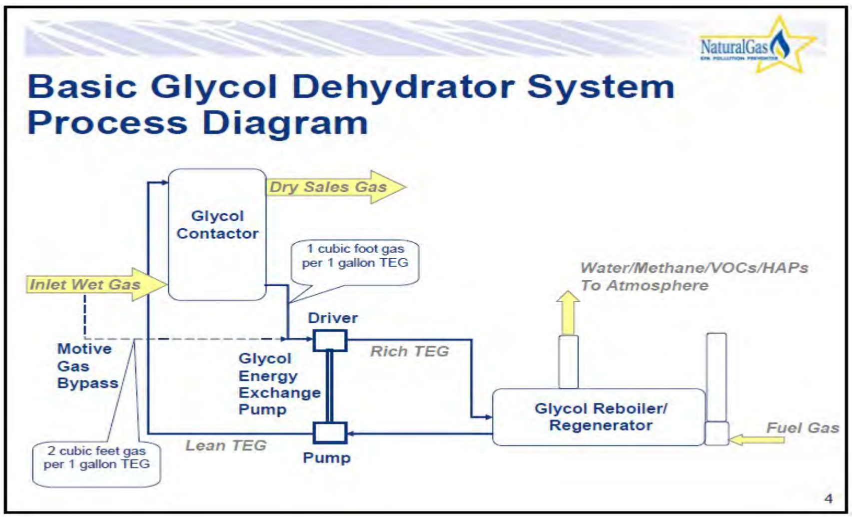



(Energy Information Administration)

While in the ground, the natural gas is under high pressure. When these formations are produced, the natural differential in pressure, between the high pressure in the formation and lower pressure at ground level, can provide the driving force to move the gas to the surface. The company in charge of producing the natural gas, by allowing the natural gas to flow from the subsurface formation up to the surface, will drill several wells to maximize its ability to produce the natural gas while maintaining the integrity of the reservoir within the geological formation to ensure a long and active production life.

As part of the natural gas stream that reaches the surface and is produced from the wellhead, there are many other gas constituents other than methane. Heavier hydrocarbons, such as ethane, propane, butane, and pentane plus, are also produced along with the methane-rich gas stream. After production, these heavy hydrocarbons or natural gas liquids (NGLs) can be removed through processing and sold separately from the natural gas. Other gases, such as hydrogen, carbon dioxide, nitrogen, oxygen, sulfur, and hydrogen sulfide, are also produced, and most of the gases will be removed from the natural gas stream through the use of treating plants. Unlike NGLs, some of these gases are undesired impurities with little or no commercial value.

Another common byproduct of natural gas production is water. Just as natural gas can migrate through geologic formations and into reservoirs, water and crude oil can follow the same process. Water that accompanies natural gas is removed through the use of dehydration facilities located at or near the wellhead.[1] The water is then commonly injected back into the outer limits of the reservoir's geological formation to help produce additional natural gas from the reservoir by displacing the natural gas from the pore spaces within the geologic formation and push the natural gas toward the producing wells. Unless water is removed from the gas stream, it can freeze in the pipeline and stop the flow of gas from the wellhead.



(Environmental Protection Agency)

Over time, multiple wells are drilled into the formation in order to maximize production of natural gas in the reservoir. After each well is tested and examined by the production company, the wells are connected through a series of pipelines increasing in diameter as more gas is gathered and transported through the gathering pipeline.

[1] The dehydration of natural gas usually involves one of two processes – absorption or adsorption. Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface. The absorption process requires a chemical with an affinity for water, such as glycol, which is the most commonly used dehydration agent. After absorbing the water, the glycol falls out of solution to the bottom of the tank where the water-rich glycol is removed. The adsorption process is a physical-chemical process in which the gas is concentrated on a surface of a solid or liquid to remove the impurities. Natural Gas Supply Association, Processing Natural Gas, *available at* http://www.naturalgas.org/ naturalgas/processing_ng.asp (last visited Aug. 5, 2011); Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 262 (Elsevier 2006).

Depending upon the impurities in the natural gas stream, the pipeline will funnel the natural gas stream to processing and treatment plants. The treatment plants are used to remove impurities and other objectionable material usually before the natural gas stream is transported to the processing facilities.

The natural gas stream often contains other contaminants that must be removed before the natural gas stream is delivered to downstream pipelines. Some of these contaminants are hydrogen sulfide, carbon dioxide and other sulfur-based impurities, which are sometime referred to as "acid gas."[2] When hydrogen sulfide combines with water in the natural gas stream, sulfuric acid forms. Similarly, carbon dioxide that combines with oxygen forms carbonic acid. These acid gases can cause damage which, if left unchecked, could lead to pipeline failure.[3]

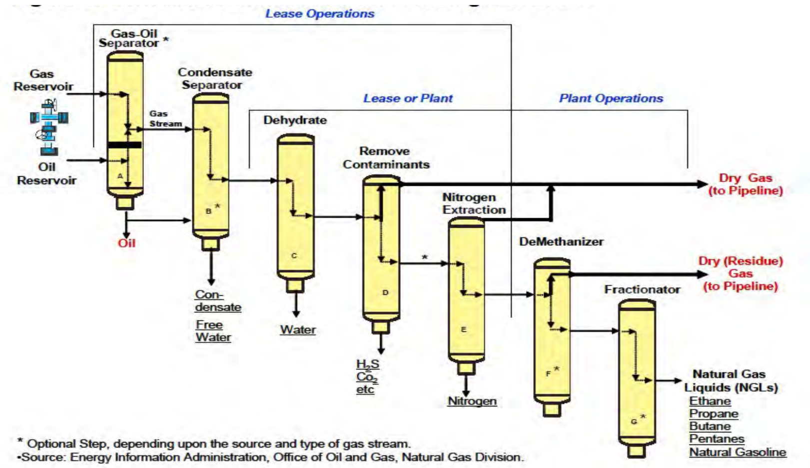
The processing plants typically remove NGLs through a refrigeration process that involves a form of rapid cooling of the natural gas stream. Two types of this cooling process are mechanical refrigeration, as used in lean oil absorption, and turbo-expander or cryogenic process. The technology used will depend upon the age of the processing facilities as well as the desired result. Mechanical refrigeration is a process whereby the natural gas stream is chilled by a vapor compression refrigeration process, similar to the process used by a refrigerator or an air conditioner, but producing much colder temperatures. This is coupled with the use of glycol as an absorption fluid that combines with the NGLs and falls out of the gas stream. In the cryogenic process, the high pressure natural gas stream is rapidly expanded by decreasing the pressure. This process causes the gas stream to cool rapidly (Joule-Thomson Effect)[4] to temperatures that will cause the NGLs to move from a gaseous phase to a liquid phase. The NGLs fall out of the gas stream and are collected for sale and additional processing. The residual gas, from which the NGLs have been removed, is transferred to a downstream pipeline for transmission to end users. Both of the above processes are effective means for recovering NGLs and for reducing the possibility that NGLs will condense and fall out of the gas stream as liquids that could cause damage to downstream equipment.

---

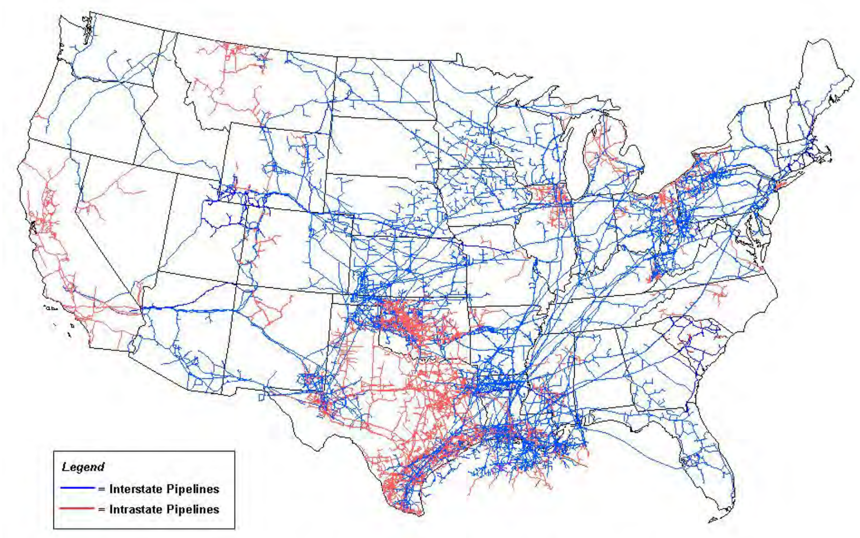
[2] Natural gas containing hydrogen sulfide is considered "sour" gas while natural gas without hydrogen sulfide is considered "sweet" gas. *Id*. at 261.

[3] Frøydis Eldevik, *Safe Pipeline Trasmission of CO2,* Pipeline & Gas J., April 2011, Vol. 238 No.4, p. 3, *available at* http://www.pipelineandgasjournal.com/safe-pipeline-transmission-co2?page=3 (last visited Aug. 5, 2011).

[4] Joule-Thomson Effect is the change in temperature or cooling effect resulting from the rapid expansion of pressurized natural gas through a valve.




After treating and processing, the natural gas can be transported to market centers by the intrastate and interstate pipeline system. This network is made up of more than 210 pipeline systems with over 305,000 miles of varying diameter pipeline, 1,400 compressor stations, and 400 underground storage facilities, all connecting the various natural gas production areas, both onshore and offshore, to multiple markets throughout the United States.[5]




Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

**Types of pipeline systems**

The interstate pipelines can divided into two types of systems – long-haul and reticulated. Long-haul pipelines receive natural gas supplies from producers and

[5] U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas*, *available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

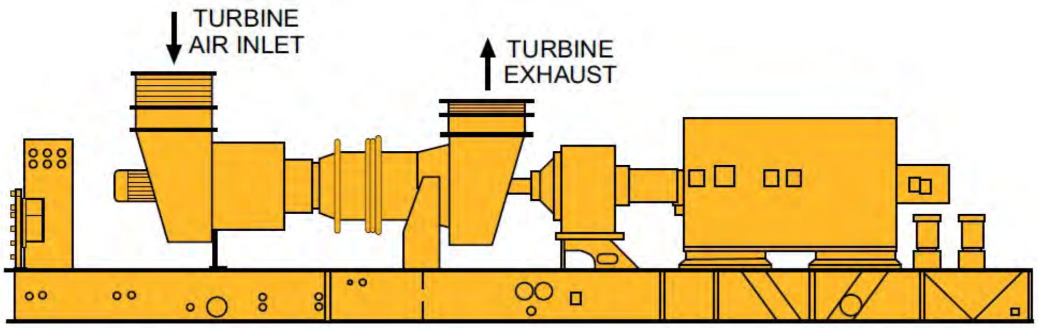
processors and transport it across hundreds of miles to market areas outside the production areas. Reticulated pipelines resemble a spider web that overlays both the supply areas and the market areas, and typically have multiple lines that can change direction of gas flow through the system, depending upon market needs.

**Pipeline Design**

A natural gas pipeline system can be as simple as a single diameter pipe receiving gas from one source and transporting it to a single delivery point, or as complex as a network of multiple diameter pipes covering hundreds of miles with compressor stations, storage facilities, and numerous receipt and delivery points. In order to move natural gas supplies from the supply areas to the market areas, a pipeline must be designed to transport the required volume of gas supplies, while maintaining system pressures along the length of the pipeline necessary to serve its shippers.

The design of all pipeline systems starts with the same basic idea, the need to transport a specific volume of natural gas from at least one supply source to a specific destination while maintaining contractual delivery pressure obligations. Due to frictional loss resulting from the gas flow, the pressure of the gas stream will decrease. Compressor stations are designed to re-pressurize the gas stream in order to overcome the pressure losses associated with movement of gas in a pipeline. Compressor stations are above-ground facilities where the pipeline connects with large individual compressor units through various smaller pipelines or "yard piping" as well as meter and regulation equipment. Compressors are mechanical devices that increase the pressure of the gas stream. After the gas stream has been re-pressurized, the gas re-enters the pipeline for further transmission to downstream markets. Compression facilities are needed along the length of the pipeline, and are typically placed at 40 to 60 mile intervals.

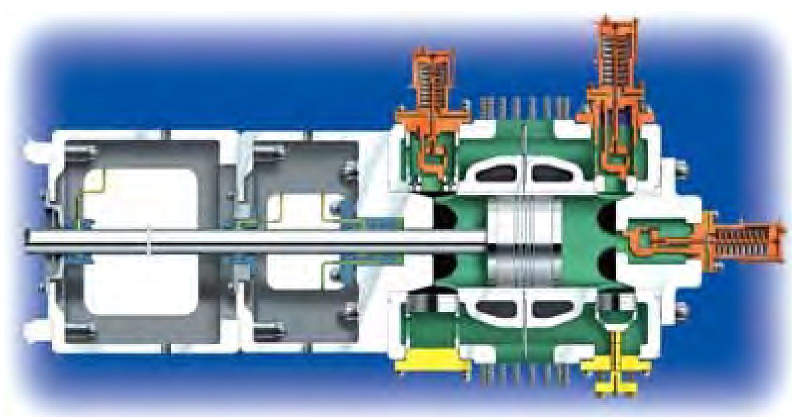
Compressors are split into two basic parts, the compressor and the driver, or motor. The motor, which can be fueled by electricity or gas-fired, powers the compressor unit that compresses the gas. The two types of compressors that are most commonly used by the interstate natural gas companies are centrifugal and physical displacement or reciprocating compressors. Centrifugal units are turbines that spin at high rates of speed to compress and accelerate the gas stream. These compressors are used to accommodate high flow rates at high pressures. Most interstate pipeline systems use centrifugal compressor units on their mainlines. The following is an illustration of a centrifugal compressor and gas-fired motor.




(Solar Turbines Incorporated (a Caterpillar Company))

The gas stream enters the inlet or suction side of the compressor unit, where it is forced through the rotating turbines at high speed and exits the compressor at the discharge side, moving back into the transmission pipeline. With gas-fired compressor motors, a small amount of natural gas is funneled from the gas stream at the suction side to provide fuel for the motor.

Reciprocating units increase the pressure of the gas stream by compressing or reducing the volume of the gas through the use of pistons within a cylinder similar to the pistons in a car engine. These compressors can be found on interstate pipelines' mainline systems, which need to compress gas volumes with greater pressure differentials. Storage facilities also utilize reciprocating compressors to inject gas supplies received from pipeline systems at pressures ranging from 500-1,000 psig, into storage caverns at pressures that can exceed 2,000 psig. Just like the motors used by gas-fired centrifugal compressors, a small amount of natural gas is taken from the gas stream to provide fuel.



Reciprocating Compressor Cylinder Assembly (machinerylubrication.com)[6]

[6] "Reciprocating Compressor Basics," *available at* http://www.machinerylubrication.com/Read/775/reciprocating-compressor (last visited Aug. 5, 2011).

**Line pack**

Line pack is the volume of gas in the pipeline at a given point in time. Pipeline operators use line pack to maintain system operating pressures while accommodating the system's highly variable load requirements.

Most gas supplies enter a pipeline system at a relatively even hourly rate, or about 1/24th of the total amount of gas per hour (4.17 percent per hour) for the entire day, also known as "steady-state" conditions.[7] On the demand side, deliveries rarely leave the system at an even hourly rate. Deliveries are not constant primarily due to variations in demand caused by inlet and outlet flow changes, non-performance of receipt or delivery points, scheduled or unscheduled maintenance, and compressor startups and shutdowns.[8] Flow conditions that vary over time are known as transient flow conditions. Depending upon the flexibility provided by the interstate pipeline within its tariff or contract with the customer, the hour rates for gas delivery could be 5 percent and even up to 8 percent per hour. These hour rates are equivalent to a 20 hour to a 12.5 hour day, or simply stated, the customer can take the entire scheduled and confirmed quantity of gas for the entire 24-hour gas day in as little as 20 to 12.5 hours. Managing these transient loads could not be done without actively managing system line pack.

In order to prepare for the upcoming gas day, the pipeline operator will increase system pressures by increasing the use of available compression horsepower at compressor stations strategically located along the pipeline system. The increase in pressure will allow the pipeline operator to "pack" the pipes with additional gas from other portions of the pipeline system located closer to the supply points. Further, depending upon demand forecasts for the upcoming gas day, customers will often increase their receipts in order to ensure that they will be able to meet their load requirements. Unlike electricity, which is added to the transmission lines instantaneously, natural gas must be physically moved through the pipeline from the supply areas to the market areas for delivery. Depending upon the length of the pipeline system, this physical transportation of gas from the supplier to the end user can take days. Most interstate pipeline systems move gas at speeds between 20 and 30 mph. If the pipeline has its origin in the Gulf of Mexico and the destination is the New York City market area, 1,500 miles away, the gas will need roughly two days to travel that distance

---

[7] Steady-state flow conditions exist when the gas volumes both received into and delivered out of the pipeline system are equal at every moment in time while the pipeline is operating at a constant pressure and temperature. For example, a pipeline is said to operate under steady-state conditions when 1/24th of the gas volumes are entering the system every hour while simultaneously 1/24th of the gas volumes are leaving the pipeline system every hour. Gas volumes going into the system must equal the gas volumes leaving the system to be considered steady-state conditions.

[8] Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 414 (Elsevier 2006).

at 30 mph. This is why it is critical for pipeline systems to receive gas supplies nominated, scheduled and confirmed in order to replace the system line pack in a timely manner.

**Maximum Allowable Operating Pressure**

The Maximum Allowable Operating Pressure (MAOP) is one of the many design assumptions that will limit either a pipeline's design capacity or peak day capacity. The MAOP, which represents the maximum pressure at which a pipeline may operate its system,[9] is an operational or safety-based constraint that protects the integrity of the pipeline system while defining an upper capacity limit. As such, the MAOP will act as a physical constraint[10] that the pipeline companies' system design engineers must address with each pipeline expansion project before the Commission.

When a pipeline company files an application to add a new service or to expand its existing facilities, it will look to the Commission's regulations (18 C.F.R. § 157.14(a)(7)-(9)(vi)) for guidance. Under these regulations, the pipeline company is required to provide to the Commission flow diagrams reflecting "Daily Design Capacity" and "Maximum Capabilities" for both its existing and proposed facilities. Currently, most of the interstate pipeline companies justify the need for facility augmentation through the use of a steady-state model of their respective systems while operating under design peak day flow conditions. These models are designed to meet the pipeline's firm contractual obligations while maintaining: (1) the volumetric requirements of its existing firm shippers; (2) the minimum contractual delivery pressure obligations; (3) controlling pressures located at critical points on their system; and (4) the full utilization of the existing available capacity through the use of all available compression horsepower along the path of the new service.

Implicit in the pipeline companies' design process is the need to maintain actual operating pressures at or below the MAOP in order to maximize throughput levels on their respective systems. From the design perspective, this is a relatively simple task. In most cases the pipeline's design capacity is based upon maximum utilization of compression facilities while transporting gas volumes between primary contractual

[9] In its November 14, 2002 comments in Docket No. PL02-9-000, the Office of Pipeline Safety (OPS) stated that the purpose of setting regulatory standards for determining pipeline MAOP is to "prevent pipeline failure that could result from excess operating pressure, startup and shutdown." OPS defines MAOP as the maximum pressure at which a pipeline or pipeline segment may operate. The Office of Pipeline Safety, Comments in Response to Open Forum at the Natural Gas Markets Conference Oct. 25, 2002, Docket No. PL02-9-000 at 4 (filed 11/14/2002); s*ee also* 49 C.F.R. § 192.3.

[10] Physical constraint, or pipeline bottleneck, is a point on a system where the existing facilities are inadequate to accommodate 100 percent of the flowing capacity of the upstream pipeline facilities.

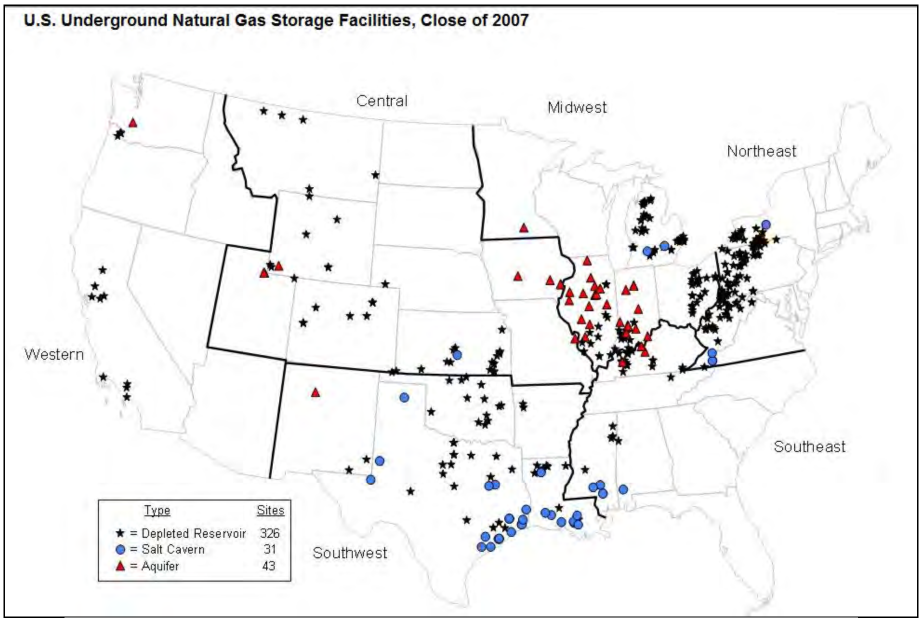
receipt and delivery points. Under these specific design assumptions, maintaining operating pressures at or approaching the MAOP will ensure that existing shippers will receive their gas requirements.[11] However, as previously discussed, the changing load requirements and the capacity release market could potentially reduce the pipeline's ability to maintain optimum operating pressures to meet new demands on its system if the new loads are not proximate to the traditional markets. The potential impact of new markets could reduce the operational flexibility of the pipeline by reducing the operating pressure. If the pipeline cannot maintain historical operating pressures that are necessary to meet the requirements of its shippers, the throughput capacity of the pipeline will be reduced.

[11] Scheduled and unscheduled maintenance is not incorporated into the pipeline's design capacity. As a result, required maintenance will reduce the pipeline's ability maximize throughput capacity and could prevent the pipeline from meeting its firm contractual requirements.

**This page intentionally left blank.**

# Appendix: Natural Gas Storage

Natural gas, like many other sources of energy, can be stored during periods of low use and called upon during periods of greatest demand. There are over 400 underground storage facilities, eight LNG import facilities and over 100 LNG peaking facilities located throughout the U.S.[1]




Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

## Base load vs. Peak load Storage Facilities

Storage facilities are designed to meet either base load or peak load requirements. Base load storage is designed to meet seasonal demand that exceeds the average deliverability of the pipeline system. Base load storage facilities have sufficient capacity to meet the long-term seasonal demand requirements for the pipeline's market areas. Historically, these storage facilities were used by the pipeline's customers to inject natural gas supplies into the storage facility during periods of low system use, such as the non-heating season (when gas prices are low), which typically runs from April 1 through October 31. These gas volumes were then withdrawn to meet base load requirements during the heating season, which usually runs from November 1 through March 31.[2]

[1] United States Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas*, *available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/ analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

[2] This trend has changed in the last decade as newer and more efficient natural gas-fired electric generation facilities have replaced higher emission oil-burning facilities. As a result, more natural gas is needed during the spring and summer months to meet increased electrical demand for the summer cooling season. Now, instead of having one peak season, market areas served by some pipelines may have two peak periods, during both the summer and winter months.

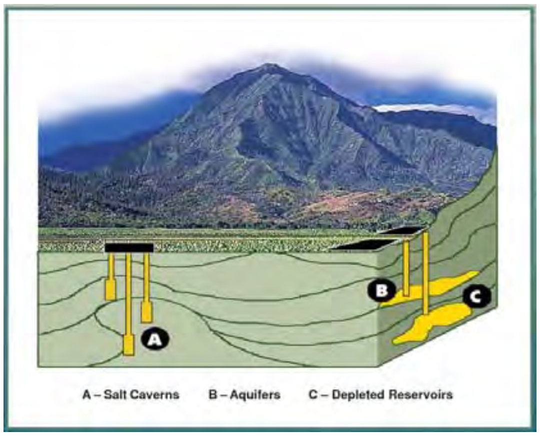
Base load storage facilities are usually large depleted oil or gas reservoirs that have relatively low withdrawal rates. They can provide a steady flow of natural gas and typically have turnover rates of once a year due in part to the length of time necessary to replenish the gas supplies. Depleted gas reservoirs are the most common type of base load storage facilities.

Peak load storage facilities, on the other hand, are designed to operate at high rates of withdrawal. These facilities are used to meet peak load requirements that can call for large amounts of gas over short periods of time. Peak load facilities are much smaller than base load facilities but can be quickly replenished – in some cases within days or weeks.

**Different Types of Underground Storage Facilities**

Three types of reservoirs or geological formations are used as underground storage facilities – aquifers, depleted reservoirs, and salt caverns. All of these formations must be developed or reworked in order to create the space necessary to provide the storage service. Natural gas is injected slowly into the formation through the use of compression facilities in order to build up the reservoir pressure necessary to allow the natural gas to flow freely from the storage facility directly into the downstream pipeline systems. Toward the end of the withdrawal season, when the prevailing reservoir pressures fall below the operating pressures of downstream pipeline systems, compression equipment that was used to inject gas volumes into storage is used to re-pressurize the gas stream so that gas from storage can be moved downstream into the pipeline systems.

Not all of the natural gas in storage facilities can be withdrawn. In order to maintain the integrity of the formation and to prevent migration of water into the reservoir, some natural gas must be left in the reservoir. This is typically called "base gas" or "cushion gas." Similar to line pack in a natural gas pipeline, base gas is the volume of gas left in the reservoir to provide the pressure needed to extract the remaining gas. The gas that is withdrawn from the storage field is referred to as "working gas." The amount of working gas within the reservoir represents the storage capacity of the facility.




Types of Underground Natural Gas Storage Facilities (FERC)

**Depleted Reservoirs**

Depleted gas reservoirs are the most commonly used formations for storage reservoirs. These formations are formerly producing gas reservoirs that have had all of the economically recoverable natural gas extracted, and which can be readily converted from production to storage. However, to maximize the usefulness of the facility, the reservoir should be located near a market area (for base load or peaking facilities) or a supply area, (to supplement supply when production is interrupted). The reservoir also must be located near a mainline pipeline facility. Most depleted gas reservoirs are located in production areas, leaving aquifers and salt caverns as the only option for storage development in other areas.

**Aquifers**

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. A porous rock formation has small spaces between the grains of rock where natural gas, oil and water can be found. A permeable formation is one where liquid can flow through small channels that connect the small pore spaces within the formation. Aquifers are the least desirable and most expensive types of natural gas storage facilities for the following reasons:

- The geological formations are not as well known as depleted reservoirs, which are explored during the development and production process. Accordingly, there is a significant cost associated with developing and studying the geological characteristics of an aquifer in order to determine its suitability as a storage reservoir.

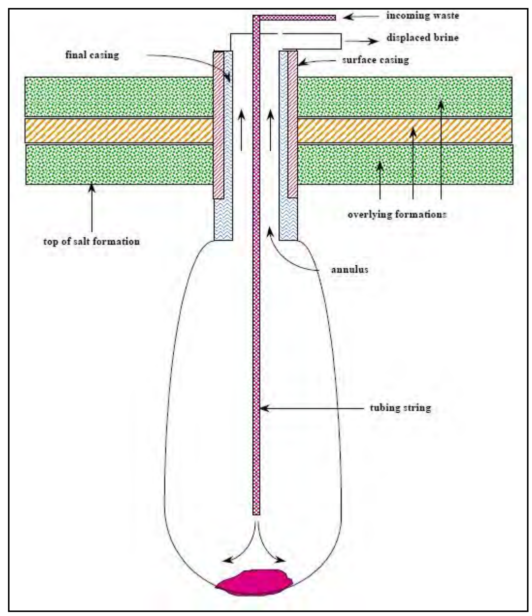
- Aquifers do not have in place the facilities and equipment associated with a producing gas reservoir, such as extraction equipment, pipelines, dehydration facilities, and compressors. Aquifers may also produce large volumes of water as natural gas is withdrawn from storage, increasing costs.

- Development of an aquifer as a gas storage facility can take twice as long as development of a depleted reservoir facility.

**Salt Caverns**

A salt formation is a naturally occurring deposit of salt that may exist in two forms: salt domes and salt beds. Salt domes are formations that have migrated through sedimentary geological formations to form large domes of salt. These domes can be a mile wide and 30,000 feet thick. Salt domes most often used as salt caverns are generally found about 6,000 feet beneath the surface. Salt beds are not as thick or as deep – these formations are usually less than 1,000 feet thick and are less stable than salt domes, but both formations are well suited to natural gas storage.

Salt Cavern Underground NG
Storage Reservoir
(Energy Information Administration)

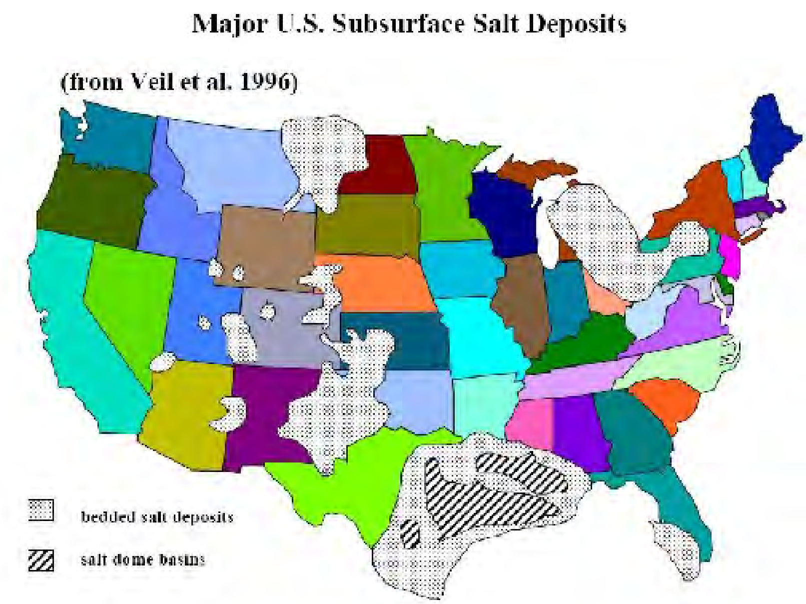



Salt Cavern Leaching
(Oregon National Laboratory)

Salt caverns are developed by drilling into the salt formation and circulating large amounts of water under high pressure to dissolve and extract the salt, leaving a large void. This process is known as "salt cavern leaching."[3] Once created, the salt cavern offers an underground vessel-like structure that can provide very high rates of delivery.

[3] Salt Cavern Storage, *What is Salt Cavern Storage? available at* http://www.saltcavernstorage.com/what-is-salt-cavern-storage.html (last visited July 20, 2011).

Salt caverns provide another operational benefit, in that they can operate with less base gas than depleted reservoirs and aquifers.




(Oregon National Laboratory)

Because salt cavern storage reservoirs are typically much smaller than depleted gas reservoirs, they cannot hold the volumes necessary to meet base load storage requirements. However, because the deliverability of the salt caverns is typically much higher, gas stored in these facilities can be more quickly withdrawn and replenished than gas stored in any other type of facility.

**LNG and LNG Peak Shaving Facilities**

Liquefied natural gas (LNG) is natural gas that is stored and transported in liquid form at -260 degrees Fahrenheit. In liquefied form, the gas volume is reduced by a factor of 610. This reduction in volume makes the transportation and storage of liquefied natural gas more practical.

In order to introduce LNG into the pipeline system, the LNG must be warmed and re-gasified. This is done at specially built re-gasifier terminals attached directly to the interstate pipeline grid or to LDC distribution systems.

LNG can also be produced on a much smaller scale at liquefaction facilities, which receive natural gas directly from the pipeline system, convert it to liquid form, and store it in above ground facilities until needed to meet peak load requirements. These facilities are referred to as “peak shaving” plants.

LNG Peak shaving plant (Energy Information Administration)

# Appendix: Natural Gas Transportation Contracting Practices

Interstate natural gas pipeline rates for transportation of natural gas may be based on distance transmitted (zone matrix) or on a "postage-stamp" basis, where all consumers pay the same rate regardless of distance transmitted. Natural gas pipelines' tariffs may contain rates based on a function of the volume reserved for a particular buyer (a set capacity charge) and a variable based on the pipeline volume actually consumed by the buyer (a commodity charge). Gas is sold by unit of energy, not by volume. Prices are usually stated in price per unit of energy, such as dollars per million British thermal units (Btu), rather than price per unit volume, such as dollars per thousand cubic feet (Mcf). Interstate natural gas transportation tariffs are often priced per thermal unit or energy unit, not on a volumetric basis.

The wholesale market is composed of both the natural gas commodity market and the transportation market. Since 1984, when FERC Order No. 436 was issued, large numbers of industrial customers, electric generators, and end use customers have been buying gas from parties other than the pipelines or LDCs. After the issuance of FERC Order No. 636 in 1992, the industry witnessed a dramatic growth in the use of marketers to provide gas, arrange transportation, or provide both services to LDCs, industrials, retail users, and electric generators.

Gas customers use marketers in a variety of ways. LDCs, which hold firm transportation rights on a single pipeline, can use the marketer to obtain and deliver gas to an interconnect point on that pipeline, and the LDC can use its firm transportation service to deliver that gas to its citygate delivery point. Other customers, such as industrials, may employ a marketer to acquire gas and interstate transportation service to deliver the gas to the industrial's citygate delivery point. Increasingly, marketers are offering additional services to customers such as asset management services, where the marketer manages capacity for LDCs, as well as providing price hedging, financing, and risk management services.

The transportation market also has developed to provide shippers with alternative means of acquiring capacity. Shippers can choose either short or long-term services from the pipeline or can acquire capacity from other shippers through the capacity release mechanism.

The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires capacity on interconnecting pipelines and schedules gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points not on a single pipeline company's system.

## Nominations, Confirmations, and Scheduling

The North American Energy Standards Board (NAESB) is an independent, industry-supported entity whose primary purpose is to set business standards across the industry. The Commission's standards relating to nominating, confirming, and scheduling gas across the interstate pipeline system were developed by industry representatives in conjunction with NAESB. The nomination, confirmation, and scheduling processes control the movement of gas across the interstate pipeline system.

*Nominations*

A nomination is a request for service under any transportation agreement by a gas purchaser (referred to as the shipper) to transport gas from a specified receipt point to a specified delivery point over a specific time period. In short, a nomination is the request for space in a pipeline to ship gas. Pipelines use the nomination process to coordinate and reconcile gas from different shippers on their pipelines.

A shipper purchases capacity on a pipeline by entering into a service agreement with that pipeline. For example, a shipper may have a firm transportation agreement with Pipeline A for 100,000 dekatherms (DTH) per day of service. Since the agreement is firm in nature, as opposed to interruptible, the shipper pays for that full capacity whether it uses it or not, and has priority for that capacity on the pipeline.

On a given day, the shipper may not need the full 100,000 DTH of capacity, but might need, for instance, 75,000 DTH to meet its needs. The shipper will thus nominate 75,000 DTH for that day, and the pipeline can then schedule the unused 25,000 DTH of available pipeline capacity to another shipper as interruptible transportation.

The industry-standard gas day begins each day at 9:00 AM central time, and runs for 24 hours. In order to standardize nominations across the interstate pipeline system, FERC has implemented four time cycles where shippers may nominate gas (or change their nominations) over the course of each gas day. These nomination cycles follow the NAESB standards. While this is the minimum number of nomination cycles that a pipeline must have in its tariff, some pipelines offer more nomination options.

The first of the four standard nomination times is the "timely nomination cycle." Under the timely nomination cycle, shippers must make their nominations by 11:30 AM the day before the gas is to flow. The pipeline will acknowledge receipt of the nomination by 11:45 AM and will issue its final confirmations by 3:30 PM and post scheduled quantities by 4:30 PM. Gas under the timely nomination cycle will flow at 9:00 AM the following morning, which is the beginning of the gas day.

The second nomination cycle – which also occurs prior to gas flow – is the "evening nomination cycle." Shippers must make their nominations for this cycle by 6:00 PM the day before gas flows, and the pipeline will acknowledge receipt of the nomination by 6:15 PM, issuing its final confirmations by 9:00 PM and posting scheduled quantities by 10:00 PM. Gas under the evening nomination cycle will flow at 9:00 AM the following morning. During the evening nomination cycle, the firm shipper can adjust his nomination to his full contractual capacity for the next day, taking precedence over, or "bumping," an interruptible shipper's nomination.

The two remaining cycles are known as intra-day nomination cycles, since they occur while gas is flowing during the same gas day. Under the intraday 1 nomination cycle, shippers must make their nominations by 10:00 AM on the gas day. The pipeline will acknowledge receipt by 10:15 AM, issue its final confirmations by 1:00 PM, and post scheduled quantities by 2:00 PM. Gas under the intraday 1 nomination cycle will flow at 5:00 PM on that gas day. The same bumping procedures apply to the intraday 1 nomination cycle. The intraday 1 nomination cycle is the first opportunity for shippers to adjust their gas flows during the gas day.

For the intraday 2 nomination cycle, shippers must make their nominations by 5:00 PM, and the pipeline will acknowledge receipt of the nomination by 5:15 PM, issue its final confirmations by 8:00 PM, and post scheduled quantities by 9:00 PM. Gas nominated under the intraday 2 nomination cycle flows at 9:00 PM on the same gas day.

Bumping rights do not apply to the intraday 2 nomination cycle. FERC implemented this no-bumping rule for the intraday 2 nomination cycle because shippers bumped this late in the gas day would be unlikely to be able to arrange alternative transportation.

*Confirmations*

Once a nomination is received by the pipeline or the party providing the requested service, the nomination must be confirmed. The confirmation process verifies that (a) the shipper agrees to supply the nominated quantity to the pipeline for transportation, and (b) the pipeline agrees to transport the nominated quantity, based on the availability of capacity. The confirmation process provides a degree of assurance to the parties that gas will be delivered, and is also important for record keeping purposes.

*Scheduling*

For each nomination cycle, once the shippers nominate gas on a particular pipeline, it is the pipeline's responsibility to schedule the gas. Scheduling refers to the process by which nominations are consolidated by receipt point and by contract, and verified by upstream and downstream parties. If there is enough capacity to accommodate all nominations, then all nominated quantities will be scheduled. If the nominated capacity exceeds the available capacity on a pipeline, quantities will be allocated according to what is referred to as scheduling priorities. Shippers with a higher priority service will receive their capacity before shippers with a lower priority service.

Scheduling priorities for each pipeline are set forth in that pipeline's tariff. Although scheduling priority specifics may differ from pipeline to pipeline, all follow a general priority model. In general, primary firm shippers are given highest priority. Firm shippers are shippers that have entered into firm transportation agreements with pipelines. Firm shippers reserve a volume of capacity on a pipeline and pay for that capacity whether they use it or not. Each transportation agreement specifies a primary receipt and delivery point for service under the agreement. In some cases, the agreements may set forth multiple primary receipt and delivery points that can be used. When the shippers take service under the primary receipt and delivery points set forth in the agreement, they are considered primary firm shippers, and receive the highest priority of service.

In general, secondary firm shippers are given the second highest service priority. Under FERC policy, shippers may use receipt and/or delivery points for service other than the primary points set forth in their agreements, but only if capacity is available at those points. These alternate points are referred to as secondary points. In general, when a firm shipper takes service under secondary receipt and/or delivery points, that shipper no longer has the highest priority of service, but rather the second highest service priority. These secondary firm shippers get their gas scheduled after the primary firm shippers.

Interruptible shippers are generally given the third highest priority service. Interruptible service is service that is not guaranteed. Whereas firm shippers pay for the capacity whether they use it or not (and are given highest priority on that capacity), interruptible shippers only pay for transportation capacity when it is used.

Pipelines implement various methods for allocating interruptible capacity. One method is to schedule interruptible nominations *pro rata*, whereby all shippers with interruptible capacity have a proportional share of their capacity scheduled. Another method is based on economic ranking, where shippers who pay more for their interruptible capacity receive priority over shippers who pay less. A particular pipeline's practices for scheduling interruptible capacity will be set forth in the priority provisions of its tariff.

**Nominations and Scheduling on Intrastate Natural Gas Pipelines**

The NAESB standards do not apply to intrastate pipelines, which follow their own scheduling practices. Only thirteen percent of the member companies of the Texas Pipeline Association that responded to an informal poll reported that they accept electronic nominations, and none indicated that they follow the NAESB standards.

In Texas, intrastate pipelines schedule gas transportation five days a week, with no weekend scheduling. Some intrastate pipelines do not schedule volumes at particular delivery points on their systems, but instead accept nominations from customers, typically LDCs, that can have hundreds of delivery points. These customers do not schedule volumes at a particular point, but submit a nomination that covers all of their points, with the right to obtain delivery at any of them.

The Commission requires major non-interstate pipelines to post scheduled volumes no later than 10:00 PM central time the day before gas is to flow. This deadline occurs after interstate natural gas pipelines are required to post their evening cycle schedule confirmations by receipt and delivery point.

**Imbalances**

A point imbalance is the difference between the volume of gas that is scheduled to flow at a receipt or delivery point, and the volume of gas that actually flows through the point (typically determined by meters). A transportation imbalance is the difference between net receipts under a specific agreement (total receipts minus any fuel receipts), and total deliveries made under a specific agreement. When an imbalance occurs on a pipeline system, the pipeline must resolve that imbalance to keep all parties whole. There is no single method pipelines use to handle system imbalances. Instead, each pipeline resolves imbalances in accordance with the imbalance provisions set forth in its FERC NGA Gas Tariff.

**Operational Balancing Agreements**

An operational balancing agreement (OBA) is a contract between two physically interconnected parties specifying the procedures to be used in processing imbalances or differences in hourly flows between the parties. An OBA ensures that a shipper, once it has properly nominated and had its gas confirmed, will not be subjected to imbalance penalties resulting from the transfer of gas between the pipelines. In Order No. 587-G, the Commission adopted a requirement that each interstate pipeline enter into an Operational Balancing Agreement at all points of interconnection between its system and the system of another interstate or intrastate pipeline. That requirement is codified in section 284.12(b)(2)(i) of the Commission's regulations.

# *Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During early February, 2011*

## Winterization Document

**Prepared for Federal Energy Regulatory Commission**

**Prepared by Gas Technology Institute**
**Kent F. Perry**

**July, 2011**

## Table of Contents Page

## Figures Page

## Tables Page

## Introduction

Colder-than-normal weather during the first week in February led to the biggest non-hurricane natural gas supply disruption in the United States since at least 2005.

Due to a combination of well freeze-offs (gas flow blockages resulting from water vapor freezing in the gas stream) and other temperature-related well failures, processing plant shutdowns, electric power outages, and pipeline operational issues, estimated daily natural gas production fell from about 62 billion cubic feet per day (Bcfd) to less than 57 Bcfd, a decrease of 8%. (Ref. 1)

The cold weather likely impacted thousands of natural gas wells in Texas and Louisiana, home to one-third of U.S. gas production. Because it rarely freezes in these southern U.S. latitudes gas wells aren't built to withstand the phenomenon called "well head freeze off." That's when the small amount of water produced alongside the natural gas crystallizes inside pipelines, completely blocking off the flow and shutting down the well.

In particular, along with the cold weather came severe icing conditions.  Icy roads inhibited the movement of water hauling trucks in particular and the ability to access wellheads.  The result was that fail safe switches on water and condensate storage tanks at wellheads and at compressor stations were activated.  The fail safe switches are designed to shut down operations to prevent spills. (Ref. 2)

This report focuses on gas well winterization technology that is deployed in colder climates and discusses to what degree they might be applied to the impacted production areas (Texas and New Mexico) addressed with this study.

## The Phenomena of Wellhead Freezing and Cold Weather Impact on Gas Production Operations

Freezing is a potential and serious problem starting at the production wellhead through the last point in the customer delivery system.  The occurrence of freezing is continuously reduced each step of the way, but care must be taken at each and every step to assure smooth operational conditions and satisfied consumers at the end of the line.  Freezing not only affects the wellhead and gas pipeline but is also a significant contributor to measurement errors, instrumentation upsets or failures and other regulation equipment that can be found at compressor stations, gas processing plants, regulator stations and other critical points of operation.  (Ref. 3)

Many criteria can have an impact on the freezing issue including:

- Gas quality and composition
- Wellhead and wellbore design and configuration
- Piping designs, regulation or restriction points

- Instrument take-off points
- Other

Three areas will be reviewed as to the potential for freezing due to cold weather conditions:

1. The reservoir, wellbore and wellhead environment.
2. The gas well production facilities located at or near the wellhead.
3. The gas gathering system including compressor stations and gas processing plants.

## Potential for Freezing - Within the Reservoir, Wellbore and Wellhead

Natural gas resides in geologic formations for time periods of millions of years (geologic time). Over this extended time period the gas becomes saturated with water. The volume of water that natural gas can carry as water vapor is a function of pressure, temperature and gas composition. Figure 1 is a schematic of a gas reservoir (Barnett shale in this example), its gas quality, reservoir conditions and gas flow pathway from the reservoir to the surface. The gas flows from the reservoir through perforations in the pipe (casing) and then up through the production tubing, through the wellhead and then to production facilities.

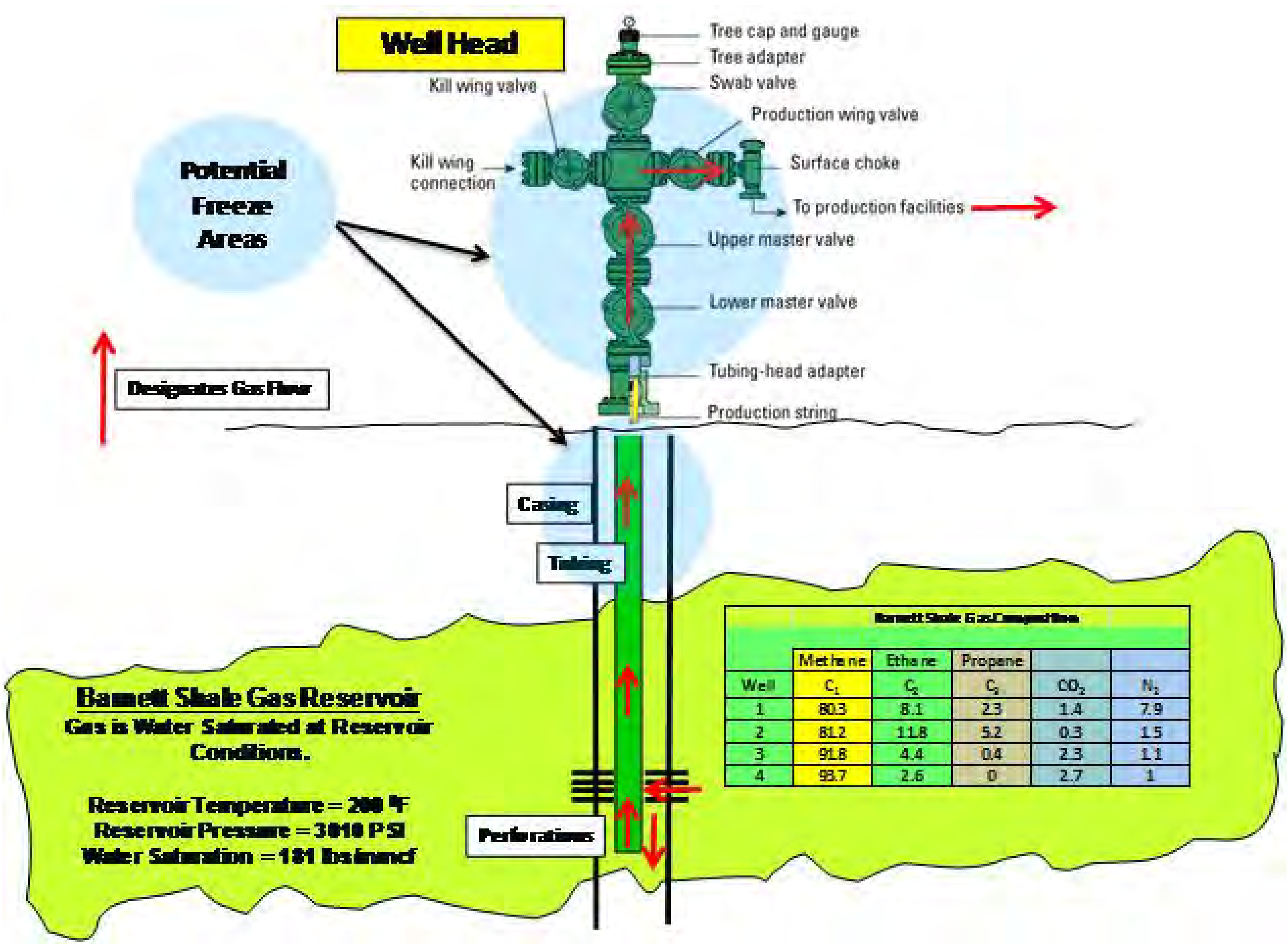



**Figure 1 – Schematic of Gas Reservoir (Barnett Shale as example), wellbore and wellhead flow paths to Production Facilities, (Ref. 4&5)** (**Figure from GTI)**

Under the Barnett example reservoir conditions the gas can hold as much as 181 lbs of water per mmcf of natural gas. For production operations, 7 lbs of gas per mmcf is considered to be dry gas, or at least dry enough for safe and efficient transportation of the gas without undo problems due to water fallout or freezing. Many natural gas compositions include not just methane $CH_4$ but also heavier hydrocarbons such as ethane and propane. In the Barnett example, the composition of well #2 contains over 11% ethane and 5% propane. The existence of these heavier hydrocarbons can facilitate the formation of hydrates (a combination of hydrocarbons and water that form ice under conditions well above freezing). Hydrates are discussed in more detail later but for this discussion can be thought of as ice capable of reduction or complete blockage of gas flow. (Ref. 4 &5)

As the gas flows up the production tubing and nears the surface it experiences a drop in pressure and can also be cooled by gas expansion (Joule Thompson effect) and exposure to cold ambient temperatures at the surface. The Joule-Thomson rule of temperature effect as a result of pressure reduction is such that temperature will decrease approximately 7 degrees Fahrenheit for every 100 psi pressure reduction. As an example, if you can have gas flowing at 60 degrees Fahrenheit and 700 psi and you may have no evidence of freezing. If you pass through a flow choke and cut the pressure to 225 psi, the flowing temperature at the point of regulation will drop 33 degrees to approximately 27 degrees Fahrenheit. If the gas stream is saturated with water vapor and condensate, you will quickly experience freezing. The gas stream is the same, but conditions have changed and icing problems can impact your operations. (Ref. 3 &4)

The presence of ice or hydrates can not only shut off the pipeline, but can also alter measurement. If ice forms on the rim of the orifice plate, the flow measurement will be in error as a result of the reduced orifice diameter. If ice forms in the instrumentation supply lines, controllers will cease to function causing a loss of control of the system. Ice can block off sensing ports and other vital instrument readings. Once the ice begins to thaw, problems are still going to be present. On the initial start-up of a new or cold well, probes, intrusive instruments and orifice plates should have been removed from the pipeline. Large balls of ice traveling down the pipeline can do physical damage to the pipeline itself and to any object protruding into the pipeline such as sample probes, temperature probes, meters, orifice plates and similar intrusive devices. After the flowing stream has stabilized and temperature conditions are above the hydrate point, these items can be safely re-installed. (Ref. 3 &4)

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in Table 1. See also Figure 1.

**Table 1 – Points of Freezing Potential in the Reservoir, Wellbore and Wellhead (Ref.4)**

| Point of Freezing Potential | Cause of Freezing | Solution |
|---|---|---|
| | | |
| Near Surface Wellbore | As the natural gas travels from the reservoir to the surface, cooling can occur due to gas expansion and exposure to colder temperatures near the surface. | Methanol is injected into the flow stream at the wellhead. The flow of methanol is down the wellbore annulus and then is carried up the gas flow stream through the wellhead preventing freezing. |
| Wellhead including Wellhead Valves | At the wellhead a change in flow path size can change causing an increase in velocity and cooling. Well head also exposed to surface weather conditions. | Solution is as above, methanol injection. In some cases the wellhead can be completely enclosed in a small building or "hut", insulated and heated, but methanol is the most practiced solution. |
| Wellhead Chokes | Wellhead chokes are points at the wellhead where flow and pressure is primarily controlled. Significant pressure | As above with methanol application. Also, wellhead design should consider choke points and avoid wherever |

| | | |
|---|---|---|
| | drop often occurs and expansion cooling can be severe. This cooling combined with cold ambient temperatures can cause significant freezing issues. | possible. |

## Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead

The basic flow of natural gas from a wellhead through the processing equipment and to the gas sales distribution system is illustrated in Figure 2. Note that this is described as a typical configuration keeping in mind that variations to equipment placement and metering occur dependent upon the number of wells, their proximity to each other, well ownership and other factors.

Referencing Figure 2, when gas leaves the wellhead it sometimes flows through a line heater which will warm the gas, any gas condensate and water within the flow stream, mitigating freezing and facilitating the separation of these three phases. (Line heaters are not always deployed in warmer production climates unless large flow volumes requiring pre-heating before separation of phases are experienced). The flow stream next enters the production separator (sometimes described as a heater treater) where gravity, heat and flow through mesh material separate the gas condensate from gas and from water. The condensate and water flow to storage tanks through liquid meters in some cases, or alternatively volumes are measured directly within the storage tank. These liquids are marketed by truck or pipeline in the case of condensate and the water sent to disposal facilities by truck or pipeline dependent on volumes and distances.

The gas flow stream exits the top of the production separator and flows to the dehydration unit. It is noted that the gas, while free of liquid phase water and condensate at this stage, is still saturated with liquid vapors notably water. Gas flows into a dehydration unit for removal of water or dehydration of the gas, drying it to normally 7 lbs/mmcf or less allowing for transport without freezing and water fallout issues. The normal dehydration process utilizes glycol which absorbs the water from the gas leaving the hydrocarbons within the flow stream. The glycol when saturated with water is sent to a glycol reboiler that through application of heat boils off the water. The dry gas is now metered and flows to the gas gathering system. (Ref. 4&6)

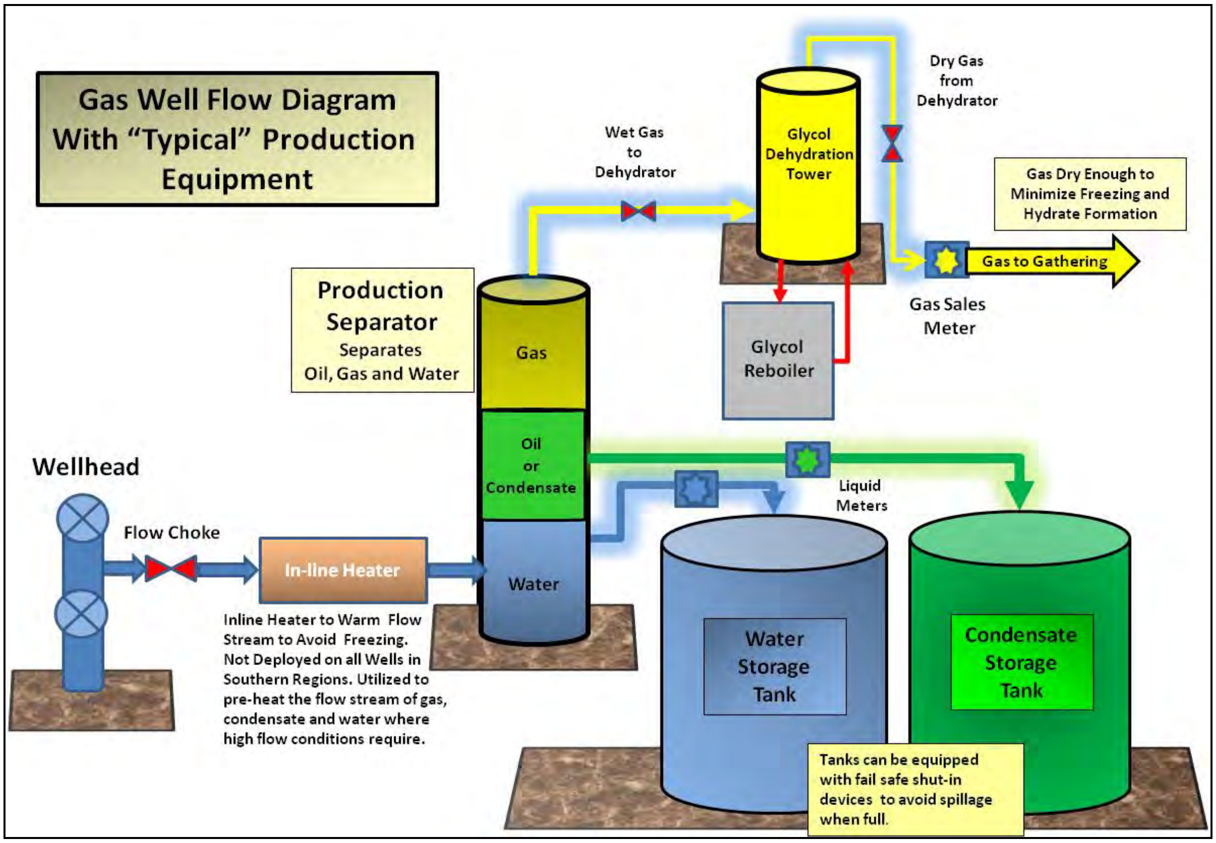



**Figure 2 – Gas Well Producing Location with Typical Equipment for Gas Production Operations – Does not Include Gas Processing or Compressor Station. Production Equipment is Equipped with Fail Safe Devices to Shut-in Production to Avoid Spillage and Equipment Damage - (Ref. 4&6). (Figure from GTI)**

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in the following Table 2. See also Figure 2.

**Table 2– Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead. (Ref. 3, 4&6)**

| | Cause of Freezing | Solution Utilized in Colder Gas Production Regions |
|---|---|---|
| | | |
| Flow lines from wellhead to line heater. If no line heater (common in warmer regions) | Exposure to low surface temperatures, gas has cooled due to expansion, gas contains water and heavier hydrocarbons which are prone to freezing or hydrate development. | Methanol injection, line heating, maintaining level flow lines to avoid liquid build-up, and limit choking points. Additional protection is usually required including insulating |

| | | |
|---|---|---|
| then flow line to separator. | | flow lines, wrapping with heat tape or glycol tubing under the insulation. |
| Production Separator | The production separator has equipment and instrumentation that can be impacted by cold weather. Gas, water and condensate flow throughout the unit. It is exposed to surface temperatures. | The unit is sometimes placed in a heated housing unit or hut. Alternatively, a cold weather version needs to be utilized. The cold weather unit is designed such that all piping and potential freeze instruments are internalized to the unit or insulated. |
| Gas Flow lines to Dehydration Facilities | If exposed these lines, which are still carrying water saturated gas and other hydrocarbons are prone to freezing and hydrate formation. This can take place in a particularly exposed portion of the line or at a bend or reduction in line size. | Sometimes these lines can be buried if it is some distance to the dehydration facility. This alone may not be adequate and insulation and heating may be required. A methanol injection point can be designed into the flow scheme if a particular area becomes a problem. |
| Flow Line to Sales Meter and Meter | The gas flowing to the sales meter has now been dried and is much less prone to freezing. The gas however can still be comprised of ethane and higher hydrocarbons as well as $CO_2$ or $N_2$ or other constituents. Depending on conditions of T & P Hydrates can still form despite dry (water content) gas. | Hydrate control can be achieved through application of heat, housing the meter and protecting from weather, methanol injection and other techniques described for managing wet gas freezing. |
| Condensate and Water Lines and Storage Tanks. | The lines to the storage tanks are at low pressures and the water is usually brine so freezing and hydrates are not as much of an issue. Depending on fluids and climate however some freezing can occur. If this takes place in the flow lines it can disrupt the separator causing production shut-in. | These lines can be insulated or in severe conditions heated with electric tape or glycol tubing. The tanks themselves do not normally present a problem. |

## Potential for Freezing - Gas Gathering System Including Compressor Stations and Gas Processing Plants.

After natural gas leaves the wellhead and wellhead production site it continues flow downstream through the natural gas system (Figure 3). Along the way, gas compression is required to maintain pressure and gas processing is applied to further dry the gas and remove heavy hydrocarbon components. Each is discussed further in this section.

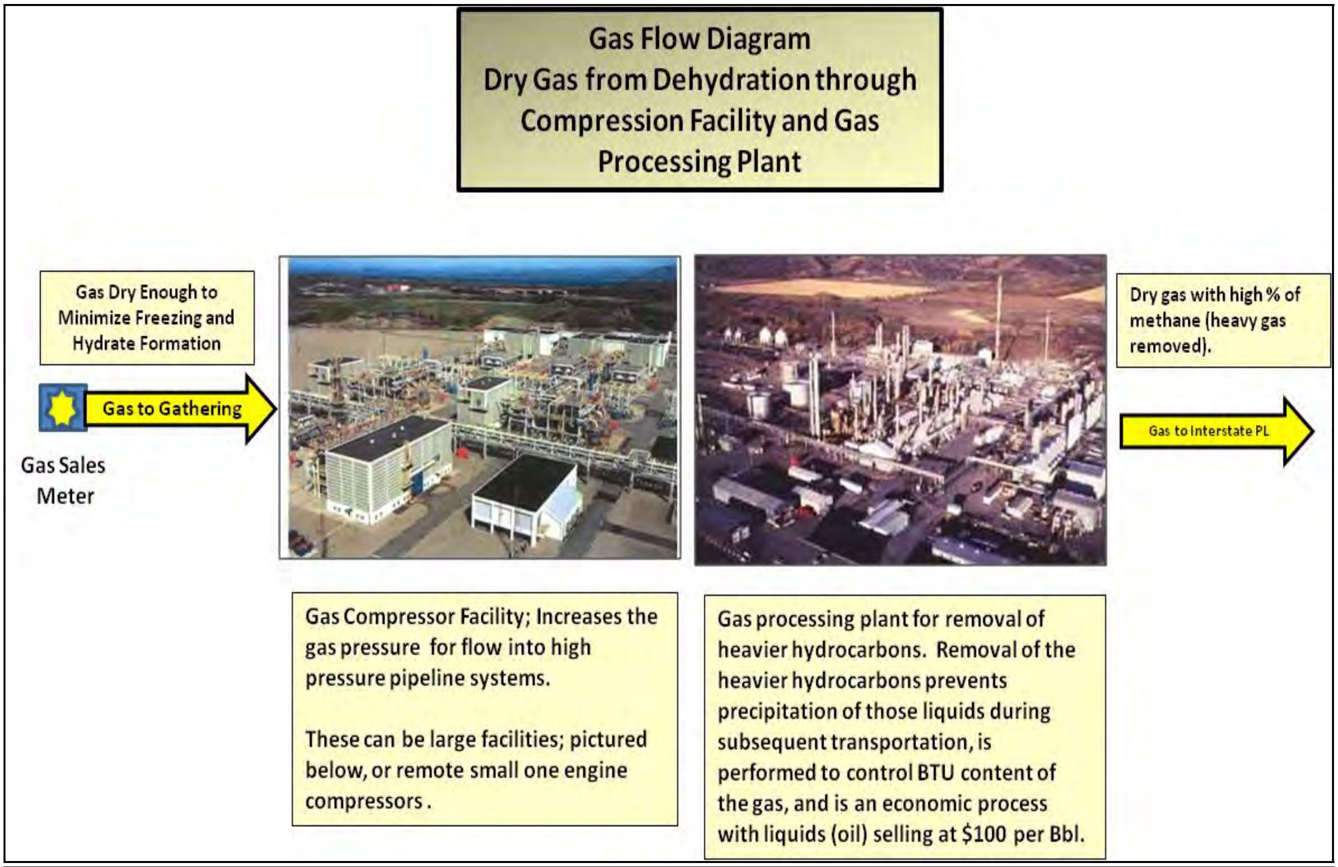



**Figure 3 – Gas Flow Diagram – Dry Gas from Dehydration Facilities through Gas Compression and Gas Processing Plant.** (**Figure from GTI and ABB Oil and Gas and Duke Energy Canada)**

**Compression** - After the natural gas stream leaves the dehydration facility it will at times flow through a compression facility or single compressor. The purpose of this is to boost the pressure of the gas such that it is able to flow into a sales line that is at higher pressure. The natural gas industry utilizes a large number and wide variety of compressors. Overall greater than 45,000 compressors are in place in the United States (Figure 4) (Ref. 7).

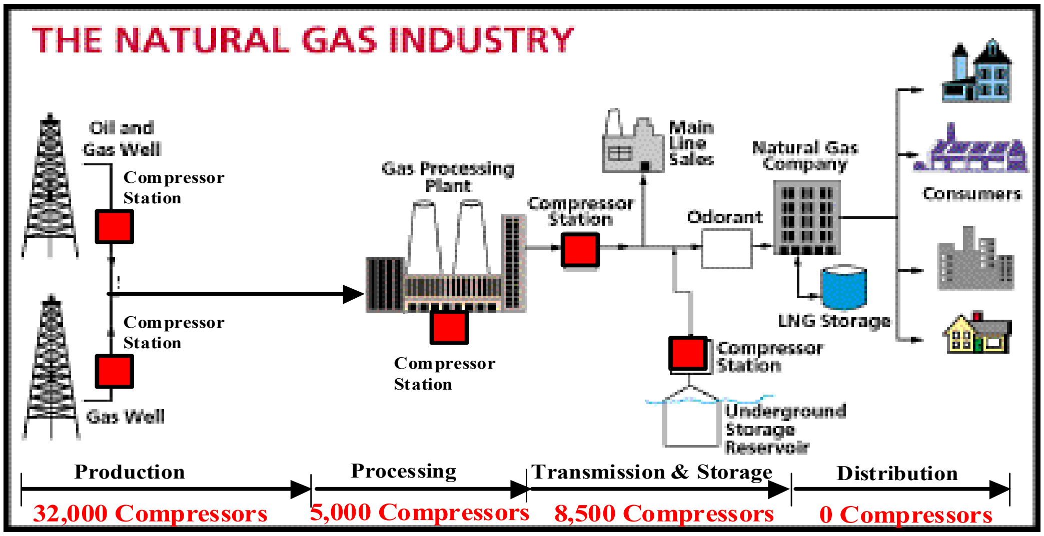



**Figure 4 – Natural Gas Compressors in the U.S. Natural Gas System (Ref. 9) (Diagram from Wikimedia Commons)**

Compression facilities range from small single compressors to large facilities handling large volumes of gas at aggregation points. The compression facilities within a producing gas field will change with time due to several factors:

- The drilling of new wells over time introduces increased gas volumes in a gas producing region.
- Existing wells will decline in gas production volumes over time reducing gas volumes.
- Gas flowing from the wellhead is initially at high pressure but then declines as gas is produced. This decline can be very rapid for the newer gas shale wells being developed, requiring compression facilities to be installed at appropriate points to keep wells flowing.
- The older well flow rates (at low pressure) will be reduced by the high pressure new wells in the absence of compression facilities. It is under these circumstances that new and sometimes remotely located compressors are installed.

The overall effect of these changing conditions is that compressors may need to installed, removed or resized based on the many factors impacting their size and number requirements.

The impact of cold weather on compressor stations can vary. Compressors stations all have safe guard instrumentation that senses temperature, pressures and flow rates. If pressure, as an example, gets too high or too low, the compressor will shut itself down to prevent expensive damage. These instrumentation processes can be impacted by cold weather. In colder climates, compressors can be housed to protect against any severe weather conditions (Figure 5). The majority of these compressors are fueled by natural gas as it is readily available due to it being the medium being compressed and transported. (Ref. 4, 7, 8)

Compressor stations take low pressure gas and increase the pressure significantly which is accompanied with temperature increases of the gas flow stream. Changes in pressure and temperature will cause additional liquids to drop out of the gas stream. The temperature and pressure conditions can vary considerably at these facilities. Some of the variables and conditions involved include:

- Pressure changes can occur; pressures can be dropped to manage the inlet pressure conditions to the compressor. High pressure and low pressure wells may be feeding the inlet side of the compressor. These well pressures are brought into balance at the inlet section of the compressor by dropping some well pressures to balance with the low pressure wells.
- The drop in pressure can cause gas cooling (Joule Thompson effect).
- Increasing pressure through the compression facility can cause gas heating.
- Temperatures and pressures are monitored throughout the compressor system and automatic shut down devices will be activated if they deviate from a defined range (too high or too low).
- Many of these changes can cause liquids (water and condensate) to condense from the gas stream and need to be removed and stored in nearby storage tanks.
- The storage tanks must be emptied on a regular schedule or fail safe shut-in devices will activate.

In urban areas (Dallas Ft. Worth as an example) electric compression is sometimes required due to noise limitations or emissions constraints. These facilities in particular are subject to any reduction in electric power due to weather or other conditions. There are some electric compression facilities in the Ft. Worth area but not in large enough numbers to have significant impact on gas production. (Ref. 4, 7, 8, 9)

**Figure 5 - Fully enclosed, insulated and heated compressor; for cold weather environments. The unit offers metering, separation, and compression, all on one skid. (Photo Wikimedia Commons)**

Larger compressor facilities are located at gas aggregation points where larger volumes of gas are compressed to higher pressures. These can be complex facilities with extensive piping, metering, and instrumentation. Cold weather can impact these facilities similar to smaller, more remote facilities. The incentive to weatherize however is greater at these locations due to the size and gas flow rates they address. There is an economic incentive as well as a reliability of service incentive to maintain flow at these aggregation points. The technology is readily available for winterization of these facilities and is commonly applied in colder regions of the country. As with the wellhead and production sites, the weatherization approach is a combination of heating important components via electric supply or warmed liquid flow (glycol), insulation of components, housing critical portions of the facility, injection of anti-freeze type chemicals (methanol), drying of the gas flow components, drying instrumentation gas via desiccants or other drying medium, or a combination of these techniques. (Ref. 4, 6)

Gas processing plants function to remove heavier hydrocarbons from the gas stream. These include ethane, propane, butane and others. There are three factors that drive the gas processing business:

1. The need to control gas heating value (BTU). Gas going into most end use functions (residential, commercial) requires gas within a certain BTU range which is often a narrow window around 1000 BTU/Ft$^3$ of gas.
2. For gas to be transported long distances through interstate pipeline systems it needs to be relatively free of heavier hydrocarbons. The heavier constituents will eventually precipitate during the pressure ups and downs encountered during long distance transportation. They then form liquids inside of the pipeline causing an unwanted pressure drop, freezing (through hydrate formation) or other interference.
3. With high oil prices, liquids are more valuable than natural gas. Therefore an economic incentive exists to remove the heavier hydrocarbons and sell into the liquids market as opposed to keeping them in the gas phase and selling based on BTU value alone.

These plants can be very complex (Figure 6) with extensive piping, processing units, regulators, instrumentation and other components. Many of these components can be impacted by weather conditions and to assure ongoing processing plant operation must be protected against weather. (Ref. 4, 10)

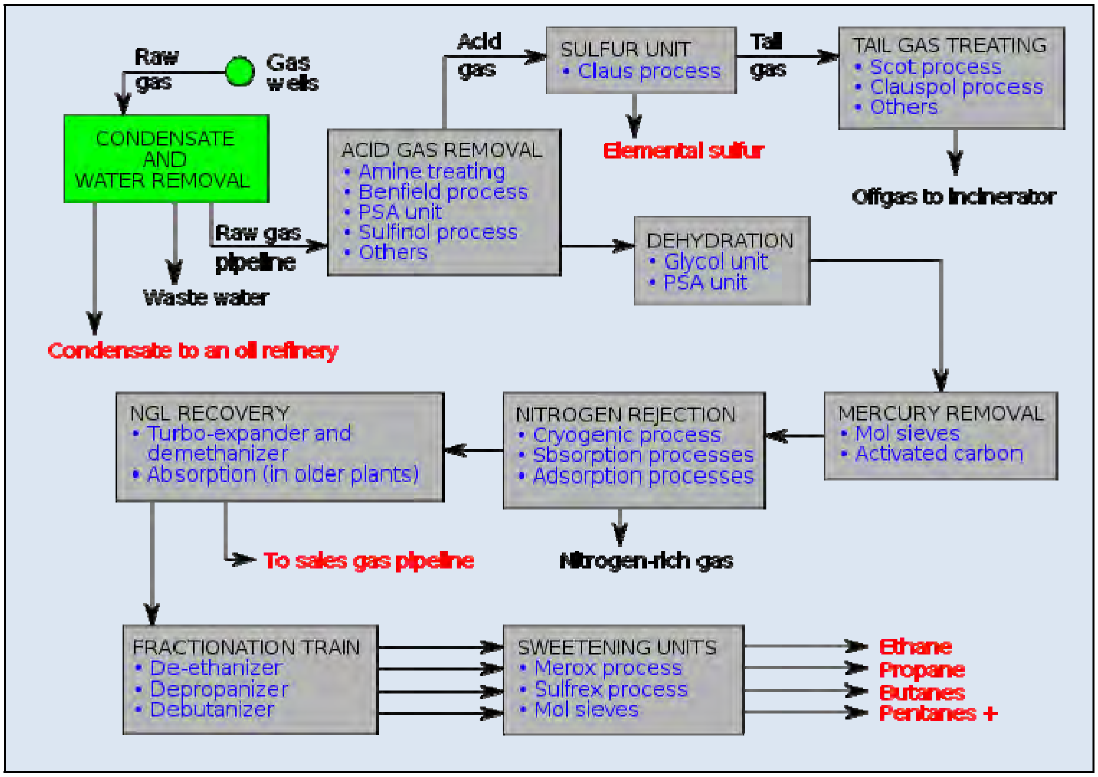



**Figure 6 – Flowchart for a Gas Processing Facility – Illustrates the Complexity of the Process and the many Steps that can be Required. Levels of Complexity vary from Plant to Plant based on Need. (From ABB Oil and Gas).**

Gas processing plants operate in cold weather climates along with other gas production facilities and as such, winterization equipment and processes are well known. It is a matter of frequency of events (cold weather) and the amount of time the facility is impacted, vs. the cost and time to winterize. Some processing plants have adequate piping and flow schematics to bypass some processes that might be impacted by cold weather. (Ref. 10)

## Prevention of Wellbore, Wellhead and Production Facilities from Freezing – General Discussion and Description

There are several options for the prevention of freezing problems. Many of these are practiced on a regular basis in the colder regions of the country, to a lesser extent in the Mid-Continent region of the United State and not at all (in many cases) in Southern regions of the country. In order to correct freezing problems that occur under differing operational conditions, solutions must be designed for the particular needs of the location where the problem exists. Protection against freezing requires deployment of one or more mitigation techniques. Each of these techniques requires and investment in capital and operating expenses. The application of these techniques is usually determined by the need or frequency of use along with the consequences (loss of production for a certain time period) of not utilizing.

In Southern regions of the United States, cold weather can be infrequent and when it does occur, can be limited in duration. A consequence is that the investment in freeze protection equipment and operations can be limited. The consequence to the producing life of a well can be minimal compared to the investment for cold weather operations in that lost production occurs for several days from a well with 20-30 years of operation life. On the other hand, if the level of impact is similar to the events of early February, 2011 and occurs on a more frequent basis, there can be a detrimental impact to the overall natural gas industry, as lack of reliability and accountability can result in loss of market. (Ref. 4)

Described below in general order of frequency of use are several techniques that can be applied to prevent freezing in gas operations:

1. **Methanol Injection to Prevent Freezing** - Methanol (an anti-freeze type solution) injection is a very common practice for freeze protection of wellbores and pipelines where wet gas flow occurs. Injection down the annulus of a wellbore by chemical injection pumps is utilized in production facilities in cold climates and in many gas storage operations where reliable, high flow rates in cold weather is required. The same technique can be practiced within a pipeline system and production facilities. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. The amounts of methanol required can be calculated by using available tables for specific applications.

   A small volume methanol tower can also be fabricated allowing small volumes of gas to pass through the methanol for treatment. Because of the sensitive nature of many pneumatic controllers, this method is occasionally used to prevent freeze-ups in these devices and to prevent liquid migration into small orifices and passages. An additional filter is often used to ensure that the methanol is not carried over into the instrumentation. (Ref. 4, 11)

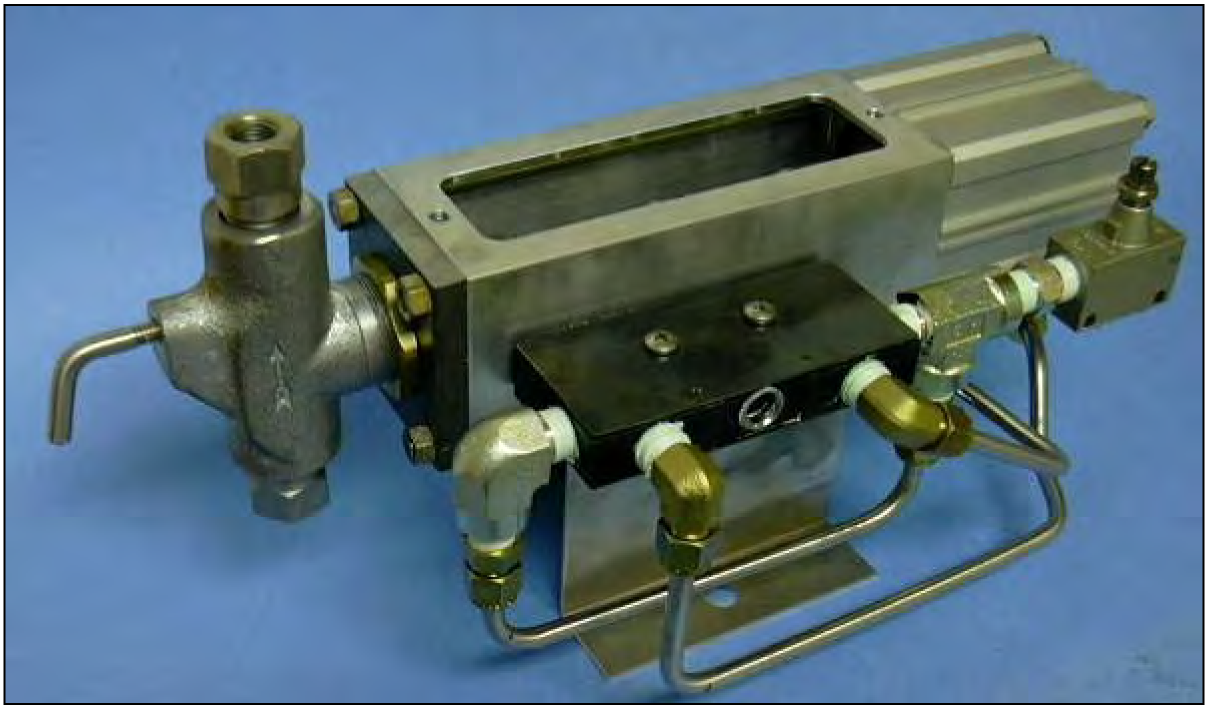


**Figure 7 – Methanol Injection Pump Utilized to Inject Methanol into a Wellhead and/or Flow line to Prevent Freezing and Hydrate Buildup. Usually Located in Protected Housing on the Gas Well Location. (Ref. 11) (Photo Source ZKO Oilfield Industries; PTAC.org)**

2. **Buildings or "Huts" to Enclose Production Equipment and other Weather Sensitive Equipment**
   Buildings are often constructed to house weather sensitive equipment in cold weather. This can be the preferred method for protecting production equipment and is widely applied in colder climates. The housing can be heated by catalytic heaters and can be insulated as needed for the extremes of weather conditions anticipated.

   Figure 8 is a typical setup for a Midwest Gas Storage Field (Manlove Gas Storage Field near Champaign, IL). The green fiberglass housing structure protects metering and other production equipment from freezing. Heating devices of various types can be utilized within the structure. Methanol chemical injection pumps are housed within the structure. During gas withdrawal operations (winter conditions) methanol is injected into the wellbore to prevent freezing. The wellhead itself is not enclosed. The wellhead is left open to allow for workover rigs to access the wellbore for any type of downhole maintenance required. Also, the heating of the wellhead may not preclude the formation of gas hydrates down in the wellbore some distance. This requires methanol injection as described in #1 above (Ref. 4, 12)

**Figure 8 - Fiberglass Housing Surrounding Production Equipment at Gas Storage Field in Midwest United States (Ref. 12) (Photo credit Wikimedia Commons)**

3. **Water Removal from the Gas Stream by Glycol Dehydration.** Gas dehydration is practiced on all natural gas flow systems to enable flow of gas without problems of hydrate formation, freezing, water drop out, corrosion and other issues. One of the most common methods of dehydration for large volumes of gas is glycol absorption. Gas passes through the glycol inside a vessel called a contactor (See Figure 2). The object is to remove the water to a point where the water vapor dew point of the gas will not be attained at the highest pressure and lowest temperature of the pipeline system. The glycol absorbs water and is then treated by circulating the glycol to a regenerator and distilling the water out of the glycol. The reconditioned glycol is returned to the contractor and the procedure is repeated. This process can reduce the water dew point to 60-70 degrees Fahrenheit. Colder climates frequently dictate a dehydration system in a natural gas system, but even warmer climates may require central dehydration due to pressure, temperature and gas composition. A producer can basically look at three dehydration options.
   a. Partial dehydration at the well head and later additional steps to meet contract specifications.
   b. Chemical injection at the well head with later dehydration at the central delivery point.
   c. Full and complete dehydration at each and every well head.

The glycol dehydration system is a low cost system with continuous operation and minimal pressure loss across the unit, thus making it a preferred approach in several areas of operation. The drawbacks can be glycol carry-over during surges, contamination by solid particles and inefficiency during fluctuating flow rates. (Ref. 4, 13)

4. **Heat Application for freeze protection** - Heat is a logical solution to freezing problems. It is also a costly approach to the problem for several reasons. Obviously, if the gas is never allowed to reach freezing temperatures, ice cannot form and will not be present. The water will likely not be removed, which remains an issue for operations and contracts, but the freezing is eliminated. The problems with heat are that it is expensive equipment to install, it requires additional fuel (energy and revenue) to produce the heat, and the heat will not remain effective as it travels down the pipeline and away from the heat source. Heat is also a potential hazard as it can provide an ignition point for the gas. Safety and special emphasis on proper application is a must when using a heat source. The most common application of heat for freeze protection is in a specific and direct situation, as in the case of a regulator valve body. The pressure drop at the regulator is the only problem point and therefore, can be the only specific location where freeze protection is required. There are multiple ways to apply heat from heating blankets, to catalytic heaters, to fuel line heaters, or in some cases, steam systems where they are properly designed, installed and maintained. Heat systems can be very effective for a localized freezing problem.  Heat application coupled with insulation is a common technique for protecting flow lines in northern climates. (Figure 11).  (Ref. 3)

**Figure 9 – Gas Wellhead with Insulation on Flow line to Protect Freezing.  (Photo Courtesy of ABB Oil and Gas)**

5. **Combination of Techniques are Often Utilized –** A combination of winterization techniques are often required to fully protect a gas well production facility. Figure 10 illustrates a typical installation for a cold climate.

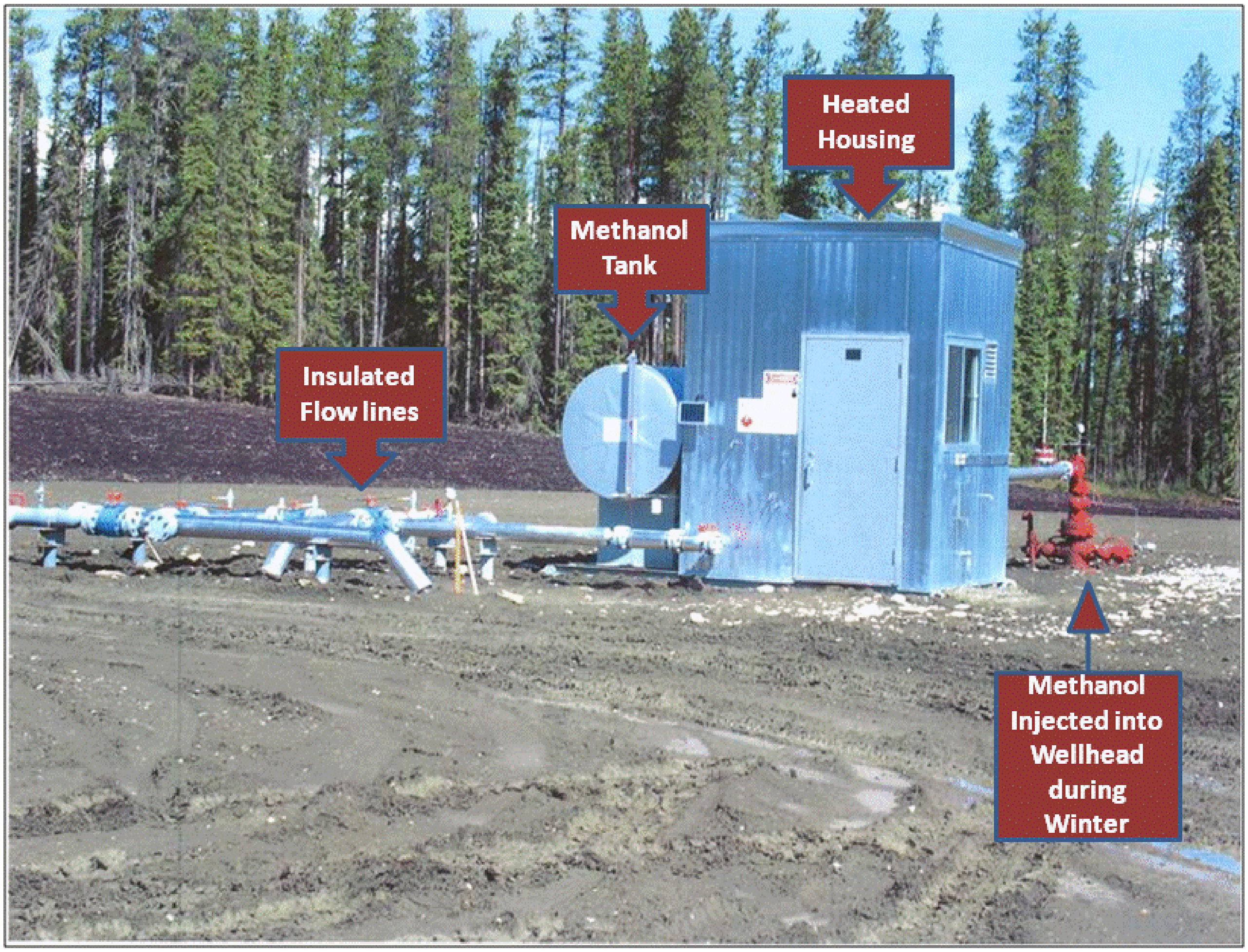



**Figure 10 – Gas Production Wellhead and Production Equipment in Northern Region of United States Winterized for Cold Weather Operations. (Photo Source ZKO Oilfield Industries; PTAC.org and modified by GTI)**

Referencing Figure 10, the following equipment and steps are practiced for flow assurance in cold weather climates:

- Flow lines are insulated.
- All wellheads are set up to inject Methanol which is done throughout the cold months.
- Assurance that flow lines are level, avoiding low spots where water can accumulate.
- Utilization of gas fired line heaters ahead of the production separators to keep all fluids warm enough to avoid freezing prior to separation of gas, gas condensate and water phases (See Figure 6).

- All flow lines beyond the production separator are insulated and heat traced. This is accomplished by electrical heat tape when electricity is available. Where there is no electric service, glycol tubes for circulating glycol are utilized to maintain flowing temperatures.
- Minimizing flow chokes is also practiced wherever feasible. Flow chokes are notorious Joule Thompson freeze points.
- Fiberglass huts over the wellheads are sometimes considered but difficult to accommodate due to impediments to accessing the wellbore for work-over and other considerations. (Ref. 3, 4, 6, 11)

6. **Pipeline Pigging** - Pigging in the maintenance of gas pipelines refers to the practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of the gas in the pipeline (Figure 11).

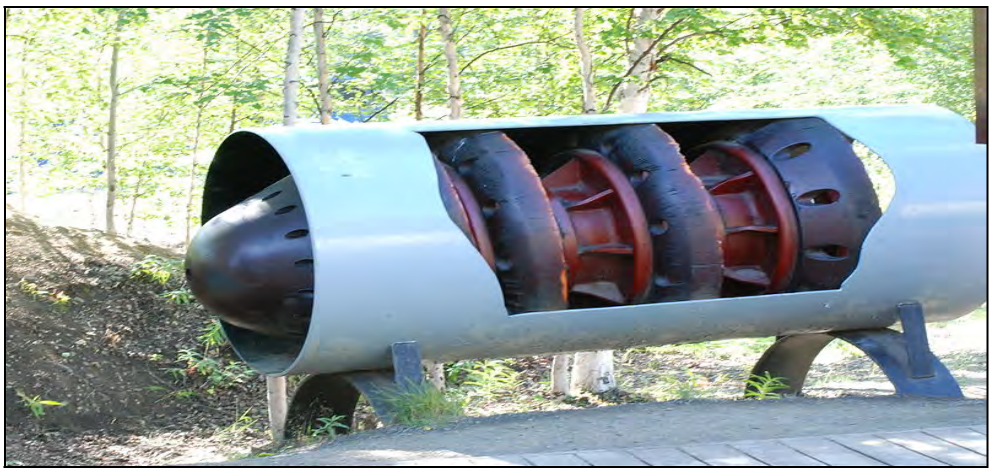


**Figure 11 – Pipeline Pig Inside of Cut out Section of Pipeline (Photo Credit Wikimedia Commons).**

These operations include but are not limited to cleaning and inspecting of the pipeline. This is accomplished by inserting the pig into a 'pig launcher. The launcher / launching station is then closed and the pressure of the product in the pipeline is used to push it along down the pipe until it reaches the receiving trap - the 'pig catcher' (Figure 12). (Ref. 14)

**Figure 12 – Pipeline Pig Launch and Receiving Station (Photo credit Wikimedia Commons).**

If the pipeline contains butterfly valves or other restrictions in line diameter the pipeline cannot be pigged. Pigging has been used for many years to clean larger diameter pipelines in the oil industry. Today, however, the use of smaller diameter pigging systems is now increasing in many areas to maintain pipeline flow integrity.

Pigs are also used in gas pipelines where they are used to clean the pipes, but also there are "smart pigs" used to measure pipe properties such as pipe thickness and corrosion. They usually do not interrupt production, though some natural gas can be lost when the pig is extracted. Most of the pigging operations are deployed in the gas gathering, transmission and distribution portions of the gas system as opposed to the wellhead production areas where pipeline configurations and sizes do not allow for pigging operations.

Pigging operations are conducted on a year around basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased due to additional liquids fallout and due to increased flow rates during cold weather. (Ref. 14)

7. **Practical Piping and Equipment Construction Considerations for Freeze Protection** - During the design phase of the piping and the instrumentation system, certain steps can be taken to reduce the negative effects of freezing problems. Piping configurations that would allow for liquid accumulation should be avoided if at all possible. Drainage should slope towards drain fittings located at low spots. Where possible, use ball valves and large diameter tubing for instrument feed lines and sensing lines. Avoid restrictions where flow will occur. Limit choking points. Tubing runs should slope back toward the pipeline and you should have a leak free

instrument system. Liquids, if they are present, will be drawn towards the leak. If you avoid creating traps and liquid drop out areas, your freezing problems will be minimized. (Ref. 3, 4).

8. **Other Water Removal Techniques for Cold Weather Protection, Especially for Instrumentation**
    a. **Solid Absorption -** A very efficient method of water removal is the dry bed or molecular sieve method. The gas is passed through large towers of solid particles and the molecular sieve absorbs the water very aggressively. Very dry gas over a wide range of flow rates can be attained by this method. Eventually, the sieve becomes saturated and must be regenerated. The stream must be switched to a second tower and hot gas is introduced to the original unit to evaporate the water and dry the sieve. Cool gas is then used to cool the desiccant and the tower is ready for re-use. This cycle is repeated until the desiccant has degenerated and is no longer effective. While this method produces very dry gas and has several positive operating characteristics, it is more costly than typical glycol systems and more complex to operate. If the gas contains heavier hydrocarbons they can sometimes interfere with the sieves.
    b. **Drip pots, coalescers and automatic liquid dumps can reduce freezing problems on instrumentation** - Occasional slugs of liquid can damage or even "shut in" many instrument supply systems. Where this slug potential exists or in cases where liquid is a severe problem in the gas supply used for instrumentation, drip pots and coalescers can effectively knockout or reduce the water and condensate in a small volume instrument supply system. If the problem is excessive, an automatic liquid dump designed for instrumentation can be extremely helpful. Whereas the drip pot requires routine manual draining, the automatic liquid dump will act as a drip pot collection vessel with a coalescer and as a result of an internal float assembly and pivot valve, will automatically release the collected liquid to a lower pressure point.
    c. **Instrument filters designed for freeze protection to control equipment** - Many instrument controllers and other sensitive measurement equipment powered by instrument gas supply need the highest level of clean and dry instrument supply that is attainable. In some cases a good linear polyethylene filter can provide adequate protection. But the most common solution for instrument supply gas is the filter dryer. These units are designed for high pressure applications with removable media cartridges. While various types of media are available from molecular sieve to special H2S removal media, most are equipped with a combination desiccant and charcoal filter cartridge. Coupled with providing extremely dry and fresh gas, the ancillary filtration elements in the cartridge provide for 2-4 micron protection as well. (Ref. 3, 4).

Natural gas systems, from mainstream pipeline flow to low pressure instrumentation, are subject to freezing conditions. Figure 10 is contrasted with Figure 13 where a non winterized location is illustrated.

Through careful planning and evaluation of a specific application, proper selection of available options, and a good routine maintenance program, this industry wide concern can be controlled and minimized. The cost of dealing with the aftermath can be more expensive than the preventative action that could have been taken.

**Figure 13 - Typical wellhead in Warm Climate. (GTI)** No methanol or other injection equipment for freeze mitigation. Flow line is elevated without insulation of other protection from cold weather. Tank battery and other production equipment are not protected from cold weather. (Ref. 4)

## Alternatives to Cold Weather Control Techniques

Emissions of natural gas and other greenhouse gases are under increasing scrutiny as the concern about global warming continues to grow. Natural gas can be emitted to the atmosphere in many locations along the gas system. The gas industry has taken steps to mitigate these releases and continues to do so. Gas dehydration facilities are one step in the process where some gas is emitted. The dehydration step is required to remove water vapor from the gas stream to allow for safe and efficient transportation of the gas, and in particular to avoid gas line freeze-up when weather conditions turn cold.

One alternative to gas dehydration is the continuous injection of methanol into the system from the wellhead to a point of aggregation of the gas where it can be dried to pipeline specifications. This practice would eliminate the need for many individual dehydration facilities and thus the gas emissions. This is relevant when discussing flow assurance under cold weather conditions as well. The injection of methanol could have the additional impact of avoiding freezing conditions within the gas flow system. This mechanism is practiced in the offshore environment where long pipelines transport oil, gas and water to onshore facilities for processing. Application of this technique onshore however, is often hampered by the many different mineral owners involved with each well. Each mineral owner has a royalty interest in the well allowing him a percentage of the revenue generated. This requires that a gas sales meter be installed to measure his appropriate share prior to mixing the flow volume with another well. Accurate gas measurement requires dry, liquid free gas leading to dehydration facilities at most wells. In the offshore environment there is only one royalty owner, the Federal Government. (Ref. 4, 11)

## Discussion of Gas Hydrates Formation

Gas hydrate formation, also known as freezing, is a potentially serious problem in natural gas flow lines starting at the production well all the way through to the customer delivery system. The effective inhibition of hydrate formation, especially during cold weather, is essential for producers and transmission companies if they are to maintain a continuous supply of natural gas. Methods to control freezing range from removing water from the gas stream to lowering the water's dew point by injection of chemicals such as methanol.

Natural gas hydrates are ice-like substances that form through entrapment of hydrocarbon molecules inside the lattice of ice crystals. Hydrate crystals are formed under certain pressure and temperature conditions where the temperature may be above the melting temperature of ice. Many types of hydrates can form based on the presence of various gases. These include methane, ethane and propane hydrates, carbon dioxide and nitrogen hydrates and others.

Hydrates are very complex systems and their formation and dissolution remain a topic of ongoing research. They are known to exist in nature and form frequently within natural gas flow systems from the wellbore through the distribution systems for natural gas. They have been known to plug pipelines in the Gulf of Mexico for thousands of feet shutting in flow from multiple production platforms and significantly interrupting gas supply. In the Gulf of Mexico, where flow lines lay on the ocean floor in deep, cold water, and where the flow through the pipelines includes oil, gas and water prior to separation at onshore facilities; hydrate formation is a threat throughout the year. The solution to this problem is simply to inject methanol and other chemicals that inhibit hydrate development. This is performed as an ongoing operation and continues to be practiced. Research continues to better understand and control the formation of hydrates under these conditions, but today the application of methanol is the only effective solution. (Ref 4, 16)

**Figure 14 – Hydrate Photos – Inset is the Water- Methane Hydrate Structure (Ref. 16, 17) (Photo Credits National Energy Technology Center (DOE) and Wikimedia Commons)**

Figure 14 is comprised of two hydrate photos, one illustrating the melting of hydrates with the associated release of methane which has been ignited. It is through this phenomenon that the term "burning ice" is often used when describing hydrates. The smaller inset figure illustrates the hydrate cage formed by water and methane.

Methane hydrate, much like ice, is a material very much tied to its environment—it requires very specific conditions to form and be stable. Remove it from those conditions, and it will quickly dissociate into water and methane gas. A key area of basic hydrate research is the precise description of these conditions so that the potential for occurrence of hydrates in various localities can be adequately predicted and the response of that hydrate to intentional, unintentional, and/or natural changes in conditions can be assessed.

Figure 15 illustrates the combination of temperatures and pressures (the phase boundary) that describes hydrate formation conditions. When conditions move to the left across the boundary, hydrate formation will occur. Moving to the right across the boundary results in the dissociation (akin to melting) of the hydrate structure and the release of free water and methane.

In general, a combination of low temperature and high pressure is needed to support methane hydrate formation. Note that depending on the ambient pressure, methane hydrate can form at temperatures well above the freezing temperature for water; for example at 2500 psi pressure, the ice-like methane hydrate will form at 65 $^{o}$ F.

Heavier hydrocarbon gases and other gases such as carbon dioxide can form hydrates at higher temperatures and lower pressures than methane. Hydrates may form in wet natural gas streams containing high percentages ethane, propane, $CO_2$ and $H_2S$ where no methane hydrate is formed.

Referring to Figure 15, note that the phase line for $CO_2$ and ethane are to the warm side of the methane phase boundary indicating that under a given pressure $CO_2$ and ethane hydrates form at higher temperatures. (Ref 4, 16, 17)

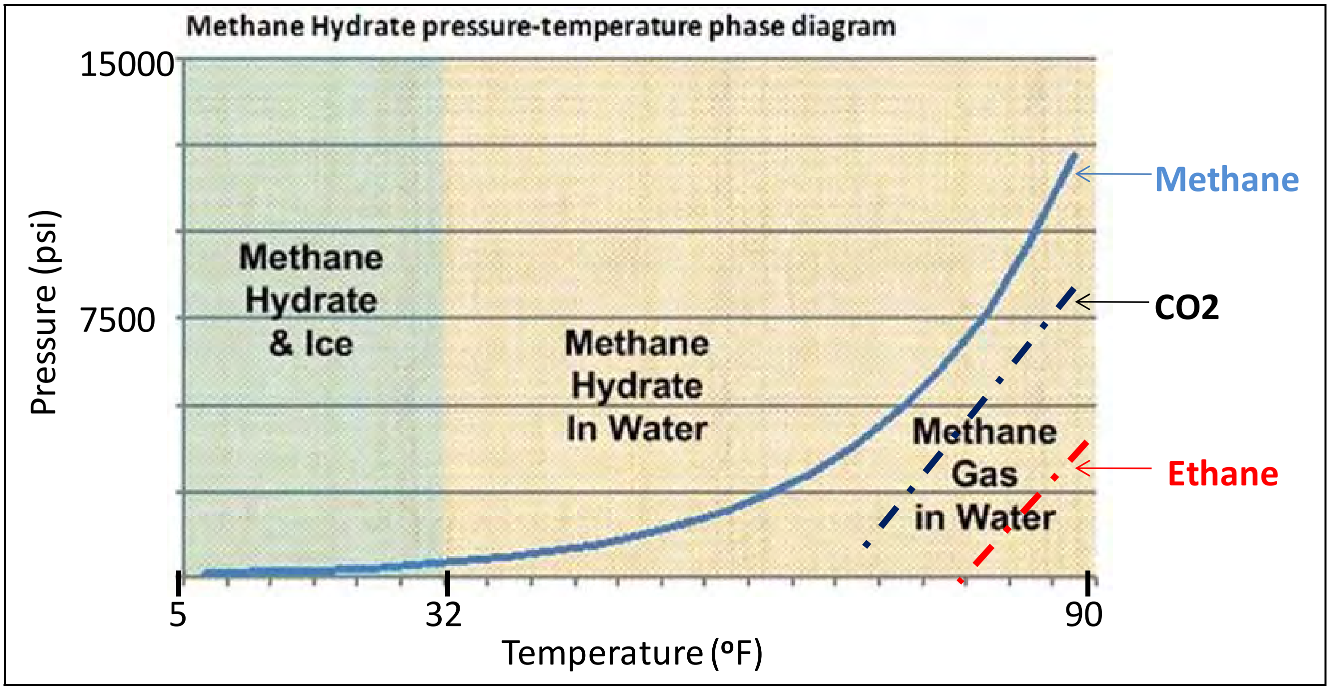



**Figure 15 - Methane Hydrate Phase Diagram (Diagram Modified from Physical Chemical Characteristics of Natural Gas Hydrate).**

The control of hydrates as previously discussed is accomplished in the same manner as for the control of icing conditions; application of heat, drying of the gas or chemical injection. With hydrates however it must be noted that they can form in somewhat dry gas especially if heavier hydrocarbons are present.

## Gas Quality Considerations and Gas Processing

New technology has enabled the development of many new and significant shale gas plays in the United States including the Barnett, Marcellus, Eagle Ford, Fayetteville and others. The quality of the gas from these shale resources is different in each area requiring different approaches to production and gas processing. The volume of ethane, propane, carbon dioxide, nitrogen and other constituents vary considerably from play to play and can vary considerably within a single shale area such as the Barnett.

The gas processing industry has scrambled to keep up with the growth of the Barnett shale. Gas production has increased to 4 Bcf/day from near zero in 1999. Major gas processing plants have been constructed by Devon, Quicksilver, Enbridge and others. Most of the plants include compression, $CO_2$ treating with amine units, Cryogenic separation and fractionation. The process gas moves east toward Carthage, Texas where it can reach the Midwest markets via various hubs or it moves Southeast via the Transco or Florida gas pipeline. The gas processing plant typically process large volumes of gas. Within the Barnett region, plant capacities can range from 35 mmcf/day increasing to 1.0 bcf/day. Given the size of these plants, the volume of gas processed, the investment and sophisticated processes and equipment they are likely better able to withstand weather changes and disruptions due to rapid declines in temperature. When they do occur the problems can be identified and resolved. Unlike individual well locations the scale of these operations can justify winterization equipment and processes even for infrequent events. (Ref. 4, 5)

**Table 3 – Barnett Shale Gas Compositions (Ref. 5) *Oil and Gas Journal*, March 9, 2009, Compositional Variety Complicates Processing Plans for U.S. Gas Shales.**

| | | Barnett Shale Gas Composition | | | |
|---|---|---|---|---|---|
| | Methane | Ethane | Propane | | |
| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
| 1 | 80.3 | 8.1 | 2.3 | 1.4 | 7.9 |
| 2 | 81.2 | 11.8 | 5.2 | 0.3 | 1.5 |
| 3 | 91.8 | 4.4 | 0.4 | 2.3 | 1.1 |
| 4 | 93.7 | 2.6 | 0 | 2.7 | 1 |

Table 3 illustrates the gas composition from 4 wells from the Barnett shale producing area. As can be seen the compositions vary considerably. These changes and levels of gas constituents across the Barnett region have the following impact on gas production with respect to cold weather:

- The presence of the heavier hydrocarbons establishes a higher probability of hydrate formation even after the gas stream has been dried to 7 lbs/mmcf.

- There is the potential for liquids fallout with the heavier gases that may be accelerated during cold weather. This condensation may occur without hydrate formation.
- The heavier liquids provide an economic incentive along with high oil prices to establish gas processing plants to remove liquids.
- The presence of $CO_2$ and $N_2$ require that these waste gases be removed or blended with other gases to bring their percentage levels down to pipeline specifications.

In general the variation in gas composition adds complexity as compared to a dry gas producing region. The complexity consists of additional gas handling, processing, transportation, blending, metering and other operations that potentially can be impacted by cold weather. The exposure of this additional equipment to weather can impact the reliability of gas flow under conditions not normal for an area. (Ref. 4)

On the other hand, independent of the heavier hydrocarbons, gas shale production has all of the issues associated with water production and methane hydrate formation. There is the possibility that these conditions alone are enough to cause disruption during cold weather spells and as such the presence of heavier hydrocarbons may have limited additional impact. (Ref. 4)

What needs to be determined is the impact of cold weather on gas processing plants which are established solely for heavy gas removal. They being located at aggregation points can disrupt large volumes of gas flow when problems occur. Alternatively they are large complex facilities, located in a contained area (as compared to wellheads spread across many miles) which combines to provide both the incentive and opportunity for cold weather control technology.

## Discussion of Cost Implications to Winterize Gas Wells – Per Well Cost and Per Field Cost

Recent technology development has enabled the recovery of gas from shale formations around the U.S. and now around the world. Unlike offshore platforms or large flow volume conventional gas wells, many wells are required to recover gas from low permeability gas fields. Gas well spacing requirements can reach down to one well per 10 or 20 acres in some cases. In the Barnett area typical spacing is one well per 40 acres and over time greater than 14,000 gas wells have been drilled over a 12 county area (Figure 10). This development took place in stages over a 10 year period as a better understanding of the full potential developed.

Another factor regarding gas fields with a large number of wells is the time required to respond to an event that impacts every wellhead. Within the time frame of the recent cold weather event it would have been impossible to attend to each of 14,000 wellheads, most at a different location to alleviate freezing and/or other cold weather issues. (Ref 4, 18)

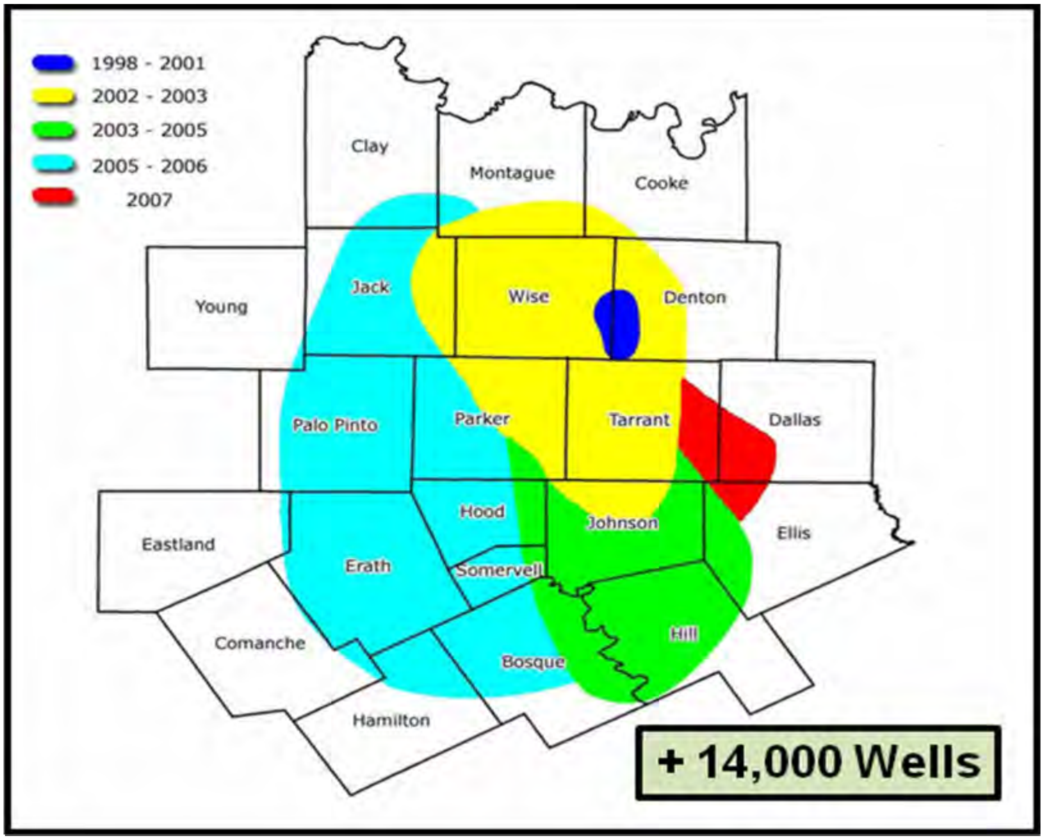



**Figure 16 – Barnett Shale Gas Development Area near Dallas, TX, (Ref. 18) (Figure Courtesy Perryman Group – HART Unconventional Gas Conference).**

The implications for cold weather flow assurance is that unlike the ability to winterize a large volume of gas flow at a single well location with a single investment, unconventional gas development requires winterization of many locations at practically the same capital expense.

Winterization of a gas well requires both capital expenditures and annual operating expense. Table 6 identifies the cost per well of these items.

In Northern regions of the country this equipment is normally part of the original well design and installed as a matter of necessity along with all other production equipment. On wells that can cost well in excess of $1 million each, these costs are not as significant as when compared to a retrofit after the well has been placed on production. This investment needs to be weighed against the impact and ramifications of the reduction in gas flow, power reductions and outages during this time period. (Ref 4, 19, 20)

Winterization cost of a wellhead or associated production equipment can varying considerably based on the size of facilities to be winterized, location, weather conditions, gas quality and other criteria.

Some approaches can be relatively simple with other facilities requiring more elaborate winterization equipment. Several scenarios based on conditions are described below with discussion of cost.

- **Case 1 - Cost Analysis for Simple Methanol Injection Pump and Hookup**

In some areas, possibly in many locations in the warmer climate production areas in Texas and New Mexico, a simple installation of a methanol injection system to be utilized during cold weather spells may be effective. Unlike northern climates where severe cold is experienced throughout the extended winter, the warmer production regions may not require significant equipment installation. If problem areas or key producing facilities are identified they may be protected with a simple investment.

A methanol injection and solar powered pump system can be installed for a capital cost of approximately $2,800 per installation. The systems are designed to reduce maintenance and operation expenses. Methanol costs are $12.00 per mmcf of gas throughput based on a treating ratio of 3 gallons of methanol per mmcf at a cost of $4.00 per gallon. Based on a well producing 1 mmcf per day of gas, methanol costs would equal $12 per day. On an annualized basis assuming methanol injection for 5 months the methanol cost equals $1800. Labor is estimated at $1000 per month or $5000 total. (Ref. 15)

Capital Cost = $2800 per installation.
Operating Cost for 5 months cold weather = $6800.

- **Case 2 - Cost Analysis for Building to Enclose Production Equipment**

In some cold weather climates the most efficient approach to winterization is to house the susceptible equipment in a small building or hut. This can sometimes save on more expensive approaches while at the same time protecting all equipment from year around weather conditions. These buildings can be heated with specialized heating equipment or in many cases can be warmed simply from the heat given off by the production equipment itself (assumes a heated production unit is within the building). In cold weather climates the design and construction of the production equipment includes the insulated housing, all of which is skid mounted for portability. When managed in this fashion the additional cost for winterization can be negligible compared to total well cost. Building cost can vary according to size requirements. This may be an option for critical equipment in the Texas, New Mexico producing regions.

Building cost = $2500 to $10,000

- **<u>Case -3 - Cost Analysis for Equipment to Winterize Gas Wellhead in Very Cold Climate e.g., Canada (See Figure 10).</u>**

In very cold production areas such as Canada, several winterization techniques need to be applied including methanol injection, line insulation, a small hut to protect chemical injection pumps small heaters, and methanol storage. The total cost of this installation is estimated at $34,425 per installation (see itemization below). (Ref. Table 10) Operating cost for a 5 month period is estimated at $6800 the same as Case 1.

**Table 4 – Winterization Equipment Cost for a Gas Well Located in a Cold Climate**

| Equipment | | Description | | Cost |
|---|---|---|---|---|
| | | | | |
| Winterized Production Unit - Net Cost for Winterization | | Production unit winterized by internal piping and insulation. | | $23,000 |
| Timberline solar powered methanol pump w/solar panels | | | | $2,800 |
| Chemical Pump to Supply Chemical Inhibitors | | Chemical Inhibitor Pump for Corrosion Protection | | $1,350 |
| Vent Gas Bottle to Supply Heater | | System to Collect Vent Gas from Injection Pumps to Supply Heaters | | $675 |
| Methanol Tank | | Stores Methanol | | $1,000 |
| Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft | | Methanol Transfer | | $500 |
| Flow Line Insulation - $3/Ft - 100 Ft | | Insulate Flow Line | | $300 |
| Flow Line Heat Tape - $4/Ft - 100 Ft | | Provide Heat to Flow Line | | $400 |
| Fiberglass Hut for Enlcosing Production Equipment | | Weather Protection | | $1,500 |
| Catalytic Heater for Location Housing | | Heating for Hut | | $500 |
| Installation Cost - 2 men for 3 days at $50 per hour. | | Labor | | $2,400 |
| **Total Capital Cost per Well** | | | | **$34,425** |

- **<u>Case 4 - Cost Analysis for Equipment to Winterize Gas Wellhead Equipment Including Gas Production Unit</u>**

In areas where a gas production unit is required to remove liquids (water or condensate or both) from the production stream a gas separator must be installed. The cost of a separator can vary based on size which is dependent on the total flow volume to be handled by the separator. In warm weather climates the piping and instrumentation for the separator is installed externally to the unit as freezing is not an issue. For cold weather climates all of the piping needs to be internalized where heat from the production unit itself, in addition to insulation where required will prevent freezing. The additional design requirements, locating of piping and instrumentation in a confined space can add as much as $23,000 to the cost of a production unit. (Ref. 20) A less expensive option in some cases can be as described in Case 2 where all of the production equipment is housed in a small building or hut. These insulated buildings often require no additional heat beyond what is supplied by the heating unit in the production separator itself. (Ref 21)

- **Case 5 – Installation of Additional Storage Capacity at Critical Facilities**

During the recent cold weather spell in Texas and New Mexico many wells and compressor facilities were shut-in by automatic fail safe shut down devices that were triggered by tanks filling up with liquids. The fail safe shut-in devices protect against tank overflow and spillage. For critical facilities such as central compressor stations, gas processing plants or important well tank batteries, additional storage could be installed to allow for operations during bad weather conditions. Additional tanks are relatively inexpensive when compared to the impact of significant gas flow reductions.

**Total Cost Discussion**

The cost estimates for winterization can vary considerably based on the type of facility, the number of installations being considered, the degree of cold weather protection that is required, gas flow rates, pressures and other factors.

Simple weatherization such as for Case 1 above can be accomplished for an estimated $2800 capital cost and $6800 annual operating cost.

More comprehensive winter protection can increase the capital cost to over $11,000 per installation.

Winterization of production units, if required can add an additional $23,000 per installation depending on production unit size.

Overall, the cost of winterization, given the number of wells can be considerable. The simple table below illustrates cumulative capital cost with variable well counts and per well equipment costs.

**Table 5 – Cumulative Cost for Winterizing Gas Wells – Variable Well Counts and Individual Well Equipment Cost.**

| | | | Well Count | | |
|---|---|---|---|---|---|
| | **10,000** | **20,000** | **30,000** | **40,000** | **50,000** |
| **Cost per Well** | | | **Cumulative Cost** | | |
| **$2,500** | $25,000,000 | $50,000,000 | $75,000,000 | $100,000,000 | $125,000,000 |
| **$10,000** | $100,000,000 | $200,000,000 | $300,000,000 | $400,000,000 | $500,000,000 |
| **$20,000** | $200,000,000 | $400,000,000 | $600,000,000 | $800,000,000 | $1,000,000,000 |
| **$35,000** | $350,000,000 | $700,000,000 | $1,050,000,000 | $1,400,000,000 | $1,750,000,000 |

For 50,000 wells the total cost could vary from $125 million to $1.75 billion based on per well equipment needs. It may be that key compressor locations and gas processing facilities, if winterized or supplied with additional liquid storage tanks, could mitigate a significant percentage of the cold weather flow problem. The total number of these locations is likely to be much reduced from the number of wells noted in Table 5 above. If 1000 facilities of this type required a $10,000 investment each the total would equal $10 million, a much reduced number from those illustrated above.

Table 6 which follows itemizes capital cost and operating expenses for winterization of production facilities. The capital costs do not total within the spreadsheet as there is duplication of equipment in some cases.

**Table 6 – Itemization of Capital and Operating Expenses for a Typical Gas Well – (Note, the Capital Costs Items Listed in the Table are not Totaled as Locations will require a Subset of these Items).**

| Gas Well Winterization Expenses | | | |
|---|---|---|---|
| **Cold Weather Protection Equipment** | **Description** | **Cost Per Well - Excludes Duplicate Applications** | **Source** |
| **Capital Cost** | | | |
| Winterized Production Unit - Net Cost for Winterization | Production unit winterized by internal piping and insulation. | $23,000 | Sivals Engineering, Odessa, Tx., Ref 20 |
| Methanol Injection Pump | High Pressure Pump to Inject Methanol | $1,648 | ZKO Oilfield Industries, Ref. 11 |
| Timberline solar powered methanol pump w/solar panels | | $2,800 | Timberline Manufacturing, Ref. 22 |
| Chemical Pump to Supply Chemical Inhibitors | Chemical Inhibitor Pump for Corrosion Protection | $1,350 | ZKO Oilfield Industries Ref. 11 |
| Vent Gas Bottle to Supply Heater | System to Collect Vent Gas from Injection Pumps to Supply Heaters | $675 | ZKO Oilfield Industries Ref. 11 |
| Methanol Tank | Stores Methanol | $1,000 | estimate |
| Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft | Methanol Transfer | $500 | Drillspot .com |
| Flow Line Insulation - $3/Ft - 100 Ft | Insulate Flow Line | $300 | Drillspot .com |
| Flow Line Heat Tape - $4/Ft - 100 Ft | Provide Heat to Flow Line | $400 | Drillspot .com |
| Fiberglass Hut for Enlcosing Production Equipment | Weather Protection | $500 | JW Williams Co. Casper, Wyoming, Ref. 21 |
| Catalytic Heater for Location Housing | Heating for Hut | $500 | ZKO Oilfield Industries Ref. 11 |
| Installation Cost - 2 men for 3 days at $50 per hour. | Labor | $2,400 | JW Williams Co. Casper, Wyoming, Ref. 21 |
| **Operating Expense for Methanol Injection** | | | |
| Methanol costs are $4.00 per gallon. Assume 10 gallons per day for 5 months. Methanol cost = 5 months * 30 days/mo.*10 gal/day * $4/gallon = $6000 | Methanol Cost | $6,000 | Timberline Manufacturing, Ref. 22 |
| Maintenance - Per Month - $200 @ 5 months | | $1,000 | |
| Total - Cost per Year | | $7,000 | |

## References


1. Bentek Energy LLC - Deep Freeze Disrupts U.S. Gas, Power, Processing – February 8, 2011.
2. Gas Technology Institute (GTI) Personal Communications with Gas Producers in the Dallas Ft. Worth area.
3. Freeze Protection for Natural Gas Pipeline Systems and Measurement Instrumentation, David J. Fish, Senior Vice President, Welker Engineering Company, Sugar Land, TX
4. Gas Technology Institute – June, 2011 – Cold Weather Study and Impact on Gas Production.
5. *Oil and Gas Journal*, March 9, 2009, Compositional Variety Complicates Processing Plans for U.S. Gas Shales.
6. Shell Oil Company – Gas Flow Schematics for Typical Flowing Gas Wells.
7. NaturalGas.org http://naturalgas.org/naturalgas/transport.asp
8. Compressor Stations – The Heart of the Pipeline System – El Paso Pipeline Group.
9. www.wikipedia.org/wiki/Compressor_station.
10. Oil and Gas Production Handbook, ABB, Havard Devold
11. ZKO Oilfield Industries, Inc. and PTAC.org
12. Manlove Gas Storage Field, Midwest Gas Storage Section, Gas Technology Institute; http://en.wikipedia.org/wiki/File:Manlove_gas_storage_facility.jpg
13. http://www.engtechinc.com/downloads.php
14. www.en.wikipedia.org/wiki/Pigging
15. Replace Glycol Dehydration Units with Methanol Injection, EPA Star Program - PRO Fact Sheet No. 205
16. DOE – NETL website – www.netl.doe.gov – Hydrates Resources and Technology Program. http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/about-hydrates/about_hydrates.htm
17. http://en.wikipedia.org/wiki/Wik/hydrate
18. Barnett Map from Perryman Group, Hart DUG Conference, Ft. Worth, TX.
19. Optimizing methanol usage for Hydrate Inhibition in a Gas gathering System, Bryan Research Engineering, Annual GPA Convention, 2004
20. Sivalls Engineering, Midland-Odessa, Texas, www.sivalls.com , Kent Perry Personal Communications
21. JW Williams Inc., Casper, Wyoming – Kent Perry Personal Communications.
22. Managing Gas Well Freeze Protection, Timberline Manufacturing Company, Inc., www.tlinemfg.com

# Exhibit F

**Complaint of Michael Mabee Related to**
**Mandatory Reliability Standards**
**in the Texas Grid Collapse of 2021**

ELECTRIC DIVISION EVALUATION REPORT

# ELECTRIC UTILITY RESPONSE TO THE WINTER FREEZE OF DECEMBER 21 to DECEMBER 23, 1989

## An Evaluation of the Actions Taken by Texas Utilities to Correct Technical Plant Equipment Problems

November 1990

Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 400N
Austin, Texas 78757

**ELECTRIC DIVISION EVALUATION REPORT**

# ELECTRIC UTILITY RESPONSE TO THE WINTER FREEZE

# OF DECEMBER 21 to DECEMBER 23, 1989

## An Evaluation of the Actions Taken by Texas Utilities to Correct Technical Plant Equipment Problems

November 1990

Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 400N
Austin, Texas 78757

## TABLE OF CONTENTS



## ATTACHMENTS

**This report and the ideas expressed in this report do not necessarily represent a concensus of position of the Public Utility Commission of Texas or of its Staff members.**

Chester R. Oberg 11/15/90

Chester R. Oberg, Nuclear Projects

## Section I

## INTRODUCTION

Several major electric power generating utilities, within the State of Texas, were severely affected by the freezing weather conditions in December of 1989. In May of 1990 the utilities were requested to provide the PUC Staff information on the corrective actions taken by them to prevent recurrence of the technical problems experienced by plant equipment. A variety of corrective actions to the problems were reported by the utilities that were affected by the cold weather.

The intent of this Electric Division Evaluation Report is to compile the answers from the utilities and to assess the adequacy of the responses to the equipment problems. This report will not address changes to any PUC emergency notification measures nor will it consider ERCOT and utility emergency power curtailment procedures or steps that should be taken to manage consumer demand for electrical power prior to or during an extreme weather related emergency. These topics will be address elsewhere. This report is principally based on information provided by the utilities.

## Section II

## BACKGROUND

The winter freeze of December 21 through December 23, 1989, greatly strained the ability of the Texas electric utilities to provide reliable power to their customers. Record and near record low temperatures were felt throughout the state resulting in a significantly increased demand for electrical power. At the same time that demand was increasing, weather related equipment malfunctions were causing generating units to trip off the line. The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid.

It should be noted that other states also experienced similar power shortages resulting in rolling blackouts. The State of Florida experienced depressed temperatures that ranged from 20 degrees F to 30 degrees F below normal for that time of year. Most Florida utilities resorted to "rolling blackouts" to prevent the State grid from collapsing. The actual Florida peak demand during the rolling blackout period was 15,929 MW. This exceeded the projected demand by 18% and the Florida State 1988-1989 winter peak of 12,897 MW by 23.5%.

Most of the Texas electric generating utilities met the increased electric demands during this emergency with a minimum of service interruptions. Using emergency plan procedures, ERCOT, the Electric Reliability Council of Texas, was able to lessen the load of those utilities hit hardest by transferring power from utilities with a generating surplus to those lacking generation capacity.

Early on December 23rd, the loss of generating units and rising customer demands caused Houston Lighting and Power Company (HL&P), Lower Colorado River Authority (LCRA), and the City Public Service Board of San Antonio (CPSB) to use their remaining spinning reserves. Next these three utilities requested available spinning reserve power from other utilities in ERCOT to maintain the integrity of their control areas.

The ERCOT Emergency Electric Curtailment Plan calls for individual utilities having difficulties meeting their load to do all they can before other utilities are asked to shed load to preserve the entire electric system. As loads continued to increase on December 23rd, and with all available spinning reserves in ERCOT having been already utilized, individual utilities with generating deficits were required to start shedding load. Firm load was shed by HL&P from 6:53 to 10:58 a.m., by CPSB from 7:08 to 10:48 a.m., and by LCRA from 8:33 to 11:02 a.m.

System-wide, pre-allocated on a percentage basis, firm load shedding is the last step in the ERCOT emergency operating procedures and requires all utilities to reduce demand by interrupting customer service. When an additional set of generating units were lost around 10:15 a.m. because of the freeze-up of instrumentation, all ERCOT utilities were ordered to shed additional firm load between 10:21 and 10:31 a.m. on December 23rd to halt and reverse the collapse of the electric grid.

A detailed sequence of events is presented in Attachment No. 1. This attachment also contains graphs illustrating the ERCOT capacity vs. load demand and a partial representation of the resultant changes in the system frequency on December 23, 1989. Changes in demand load and temperature variation are also shown for one utility.

## SECTION III

## UTILITY RESPONSES

A questionnaire was sent to those ERCOT utilities affected by the severe December weather. In general, the questionnaire solicited the actions taken by the utilities to prevent recurrence of the equipment problems under similar conditions and the cost of those actions. The following specific questions were asked for each affected unit:

(1) Unit Name and Unit MW Capacity

(2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

(3) List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

(4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

(5) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

(6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

(7) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

The extreme weather pointed out several weak areas in power plant operations. Inoperative or inadequate heat tracing systems and inadequate insulation on instrumentation sensing lines seemed to be the most common technical equipment problem encountered during the freeze. Some plant operators battled this type of problem with hand held propane torches to keep pipes from freezing during the emergency. Other problems encountered ranged from fish plugging cooling water intake screens to frozen grease that prevented fuel valves from freely operating. The causes of unit failures are summarized in Attachment No. 2.

Utility detailed responses have been included in this report in Attachment No. 3. The responses of the utilities varied. One utility instituted a comprehensive engineering review of their power plants. Others merely corrected the specific equipment failures. In some cases there was a lack of maintenance evident, although it would be difficult to state that if the maintenance had been accomplished the unit would not have shut-down.

Cogeneration plants also experienced problems during the freezing weather. The problems of the cogenerators were similar in nature to those experienced by the larger generating power plants. A summary of cogeneration data is included in Attachment No. 4.

Some of the most prevalent post emergency actions taken by the utilities to prevent future power plant shutdowns caused by cold weather included:

1. Improving heat tracing and insulation coverage on power plant instrumentation,
2. Upgrading instrumentation air supplies by removing excessive moisture with desiccant instrument air dryers,
3. Purchasing fish nets to be placed in front of intake water screens if fish begin running,
4. Developing plant procedures calling for inspections of plant equipment prior to the cold weather season, and
5. Installing wind breaks and enclosures around certain equipment exposed to the weather.

One of the critical areas is that of the unit/plant design temperature range. In general, the utilities reported design temperatures were pushed to their lower limits. The following design temperatures apply to those plants that were reported to have failed during the freeze:

| Utility | Design Temperature Ranges(Pre-Dec. 1989) |
|---|---|
| CPL: | 10 degrees F with 30 MPH winds |

| Utility | Design Temperature Ranges(Pre-Dec. 1989) |
|---|---|
| HL&P | 10 to 105 degrees F, in general. STP was determined to be able to operate in a range of 3 to 105 degrees F. Limestone is protected to 5 degrees F with freeze protection equipment. |
| TUE | -10 degrees F with 35 MPH winds. |
| LCRA | 1 to 110 degrees F (No design temperatures were available for Sim Gideon 2.) |
| TMPA | 15 to 107 degrees F |

When power plant equipment is exposed to weather conditions beyond its design limits, subsequent failures can be expected. At that time only the dedication and adaptability of plant operations and maintenance personnel to rapidly changing conditions is able to mitigate plant problems.

The specific design temperature ranges of reported units is contained in Attachment No. 5, Plant Design Temperatures.

## SECTION IV

## COSTS OF CORRECTIVE ACTIONS

As part of Attachment No. 2, the costs of the corrective actions are listed for each plant with the dates that the corrective action was taken. The expenses listed vary considerably for each plant, from a high of $ 109,266 for a significant amount of heat tracing and insulation installation on a single unit to nominal, or essentially no cost for many of the other units. The no cost corrective actions usually involved routine maintenance tasks such as the resetting of instrumentation, sealing equipment to prevent water intrusion or the replacement of frozen valves.

The cost to "fix" the freezing weather plant problems is about $ 2,773,253. The costs have been divided approximately equal between O & M ($ 1,194,553), maintenance cost allocation, and capital expense ($ 1,578,700). The majority of the expenses being funded from maintenance cost allocations. Since the rules for determining a capital expense vary from utility to utility, it is difficult to draw any conclusions regarding this type of cost division.

It should be noted that the cost of "fixing" the generating units is not confined only to those units that were shutdown as a result of the cold weather. The utilities are also taking measures to ensure that those generating units that were not affected will be able to continue to operate in any future adverse weather conditions.

The costs of corrective action for cogeneration units was not included in the total costs given above or in Attachment No. 2. Only a portion of the cogenerators reported a cost to correct identified plant problems. Based on the reporting cogeneration units, their estimated corrective action costs are approximately $ 650,000.

## SECTION V

## EVALUATION OF UTILITY RESPONSES

Whether the corrective actions being implemented by the utilities are sufficient to prevent future freeze related power plant failures, only direct experience with another deep freeze will ascertain.

The design temperatures for all of the reported power plants have a range from -10 degrees F to +110 degrees F. Because of the size of Texas and its varying climates, it is not feasible for the PUC to entertain implementation of a single required design temperature range. It is clearly the responsibility of each utility to ensure that the proper temperature range is selected by the Design Engineer when a power plant is being designed and that it is constructed in accordance with that design. The selection of the proper temperature range is the essential ingredient that will determine the reliability of a power plant to respond correctly to adverse weather conditions. Where necessary the utilities should supplement instrumentation and control systems with supplemental heat tracing systems and other forms of protective devices.

After a power plant has been constructed, it is necessary to maintain the plant to keep it functioning in accordance with its design. Each unit's active and passive equipment must be maintained. Insulation must retain its integrity in order to be effective. Heat tracing systems must be checked for correct operation on a regular basis. Control air systems should be drained of excess moisture. Cold weather operating procedures need periodic review for changing circumstances, and plant personnel need training in order to maintain their operating proficiency. The results of improper maintenance and training will be seen in increased O & M expenses for the repair of failed equipment as well as loss of plant reliability.

The near complete loss of the ERCOT grid brings an awareness that, even in Texas, plant operators must prepare for cold weather emergencies. This awareness of and attention to cold weather problems must be continued.

A complete system blackout was prevented by timely implementation of the ERCOT emergency operating procedures and dedicated utility plant personnel working under adverse conditions to keep power plants generating.

## SECTION VI

## RECOMMENDATIONS

All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.

All utilities should implement procedures requiring a timely annual (each Fall) review of unit equipment and procedures to ensure readiness for cold weather operations.

All utilities should ensure that procedures are implemented to correct defective freeze protection equipment prior to the onset of cold weather.

All utilities should maintain insulation integrity and heat tracing systems in proper working order. Generating unit control systems and equipment essential to cold weather operations should be included in a correctly managed preventive maintenance program.

Additional training programs for plant personnel on the emergency cold weather procedures, including periodic drills, should be implemented by each responsible utility.

PUC Engineering Staff should modify procedures for power plant CCN reviews to include a specific review for plant reliability under adverse weather conditions. Of special interest would be the selection of proper design temperature ranges for the power plant site.

ATTACHMENT NO. 1

SEQUENCE OF MAJOR EVENTS DURING THE FREEZE

## ATTACHMENT No. 1

## SEQUENCE OF MAJOR EVENTS DURING THE FREEZE

**December 21,1989**

| | |
|---|---|
| 12:00 midnight | TMPP, TUE and WTU all curtailed by Lone Star Gas. |
| 4:00 AM | ERCOT's North Texas Security Center declares a Severe Cold Weather Alert for North Texas. |
| 12:00 noon | ERCOT's South Texas Security Center declares a Severe Cold Weather Alert for South Texas. |

**December 22,1989**

| | |
|---|---|
| 12:00 midnight | Some South Texas utilities curtailed of spot market supplies of gas. |
| 8:30 AM | ERCOT's operators observe system frequency drop to 59.95 hertz. |
| 8:40 AM | ERCOT requests utilities to implement 1st step of Emergency Electric Curtailment Plan (EECP 2.3.1.1) |
| 9:00 AM | ERCOT requests utilities to implement 2nd step of Emergency Electric Curtailment Plan (EECP 2.3.1.2). |
| 12:00 noon | EECP canceled in North Texas |
| 12:30 PM | EECP canceled in South Texas |

**December 23, 1989**

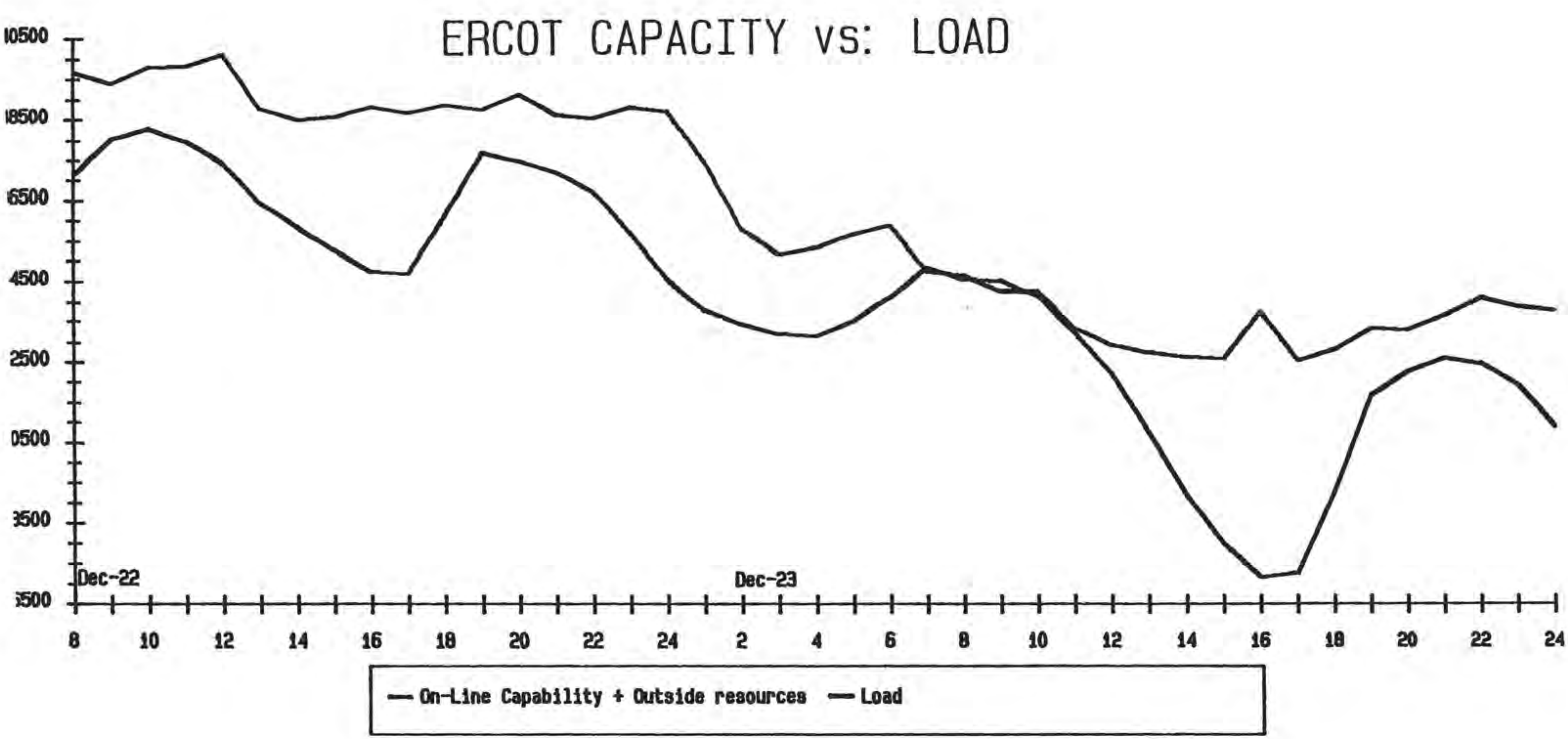
| | |
|---|---|
| 1:30 AM | WTU offers 220 MW of emergency power from Oklahoma DC tie. |
| 3:50 AM | HL&P takes 220 MW of emergency power from WTU. |
| 4:20 AM | WTU cancels emergency power from Oklahoma due to problems up there. |

**Attachment No. 1 Sequence of Major Events**

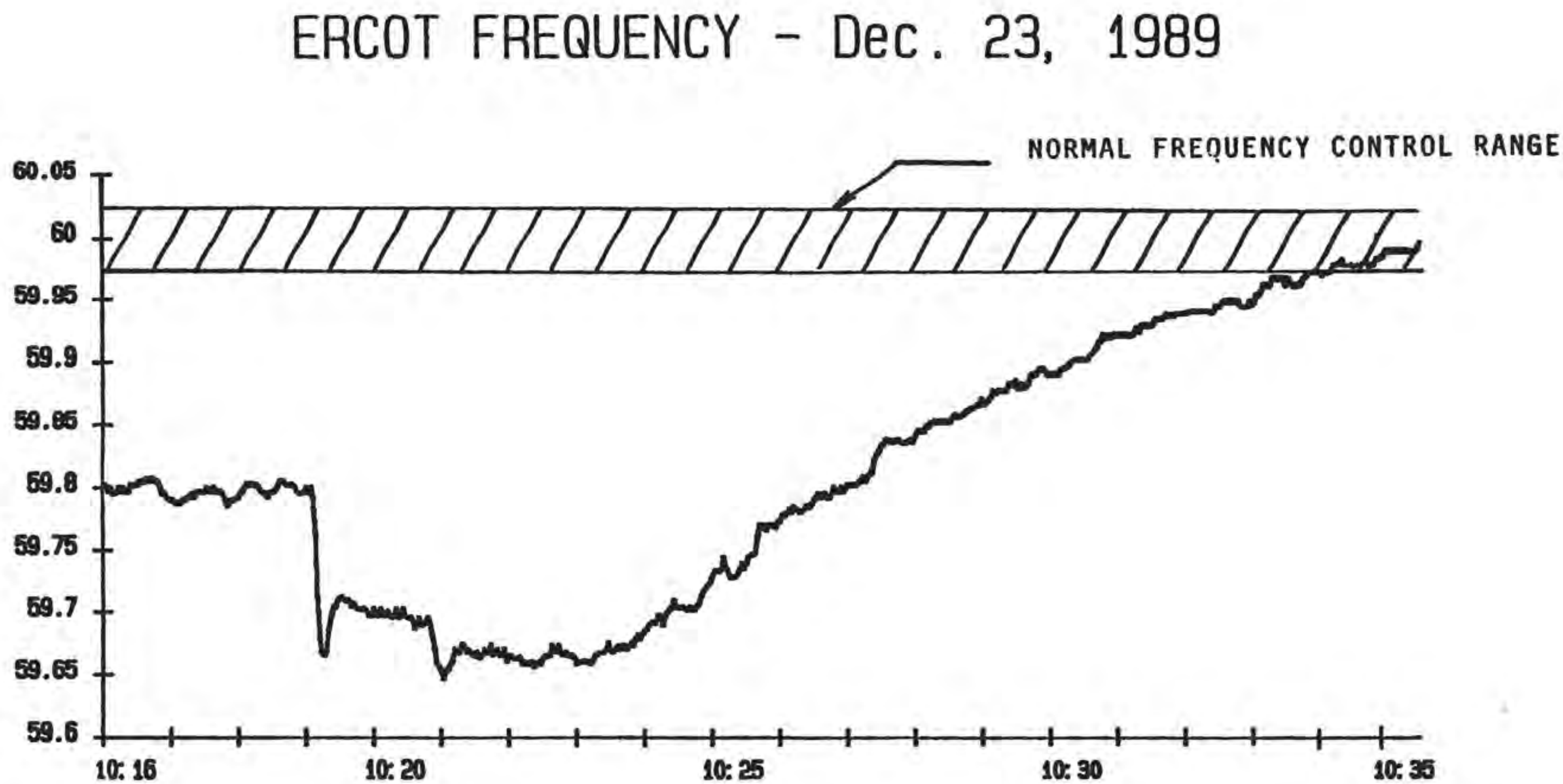
| | |
|---|---|
| 5:30 AM | ERCOT prepares to declare EECP again. System operators preparing for possibility of shedding firm load. |
| 5:36 AM | ERCOT system operators observe system frequency drop to 59.95 again. |
| 6:00 AM | CPSB, LCRA and HL&P unable to maintain spinning reserve obligation. |
| 6:04 AM | CPSB drops interruptible load. |
| 6:07 AM | Frequency drops to 59.85 recovers to 59.92. |
| 6:20 AM | TUE drops interruptible load. |
| 6:38 AM | Frequency drops to 59.90. |
| 6:40 AM | ERCOT declares EECP 2.3.1.2. |
| 6:43 AM | Frequency drops to 59.87. ERCOT requests utilities to implement EECP 2.3.1.3. |
| 6:53 AM | HL&P drops 300 MW of firm power. |
| 6:56 AM | Frequency drops to 59.79. |
| 6:59 AM | ERCOT requests utilities to implement EECP 2.4.1. CPL drops 85 MW of interruptible power transfers 11 MW to Mexico. |
| 7:08 AM | CPSB drops 150 MW of firm power. |
| 7:49 AM | ERCOT requests utilities implement EECP 2.4.2. |
| 8:20 AM | HL&P begins rolling blackouts of 1000 MW. |
| 8:33 AM | LCRA sheds 60 MW of firm load. |
| 9:45 AM | HL&P receive emergency power from TUE(200 MW) and TMPP(50 MW). CPSB receives emergency power from WTU(50 MW). |
| 10:20 AM | After recovery to 60.03, frequency drops back down to 59.65. ERCOT requests implementation of EECP 2.4.2.2 and 2.4.2.3. |
| 10:21 AM | All ERCOT utilities drop firm load. |

**Attachment No. 1 Sequence of Major Events**

| | |
|---|---|
| 10:31 AM | Frequency recovers to 60.05. ERCOT requests all utilities not in trouble to pick up firm load. All but HL&P, CPSB and LCRA comply. |
| 10:48 AM | CPSB begins picking up shed firm load. |
| 10:58 AM | HL&P begins picking up shed firm load. |
| 11:02 AM | LCRA begins picking up shed firm load. |
| 12:00 noon | ERCOT requests utilities back to EECP 2.3.1.2. |
| 12:40 AM | EECP canceled. |



ERCOT CAPACITY vs: LOAD
10500
8500
6500
4500
2500
0500
3500
5500
Dec-22
Dec-23
8
10
12
14
16
18
20
22
24
2
4
6
8
10
12
14
16
18
20
22
24
On-Line Capability + Outside resources
Load

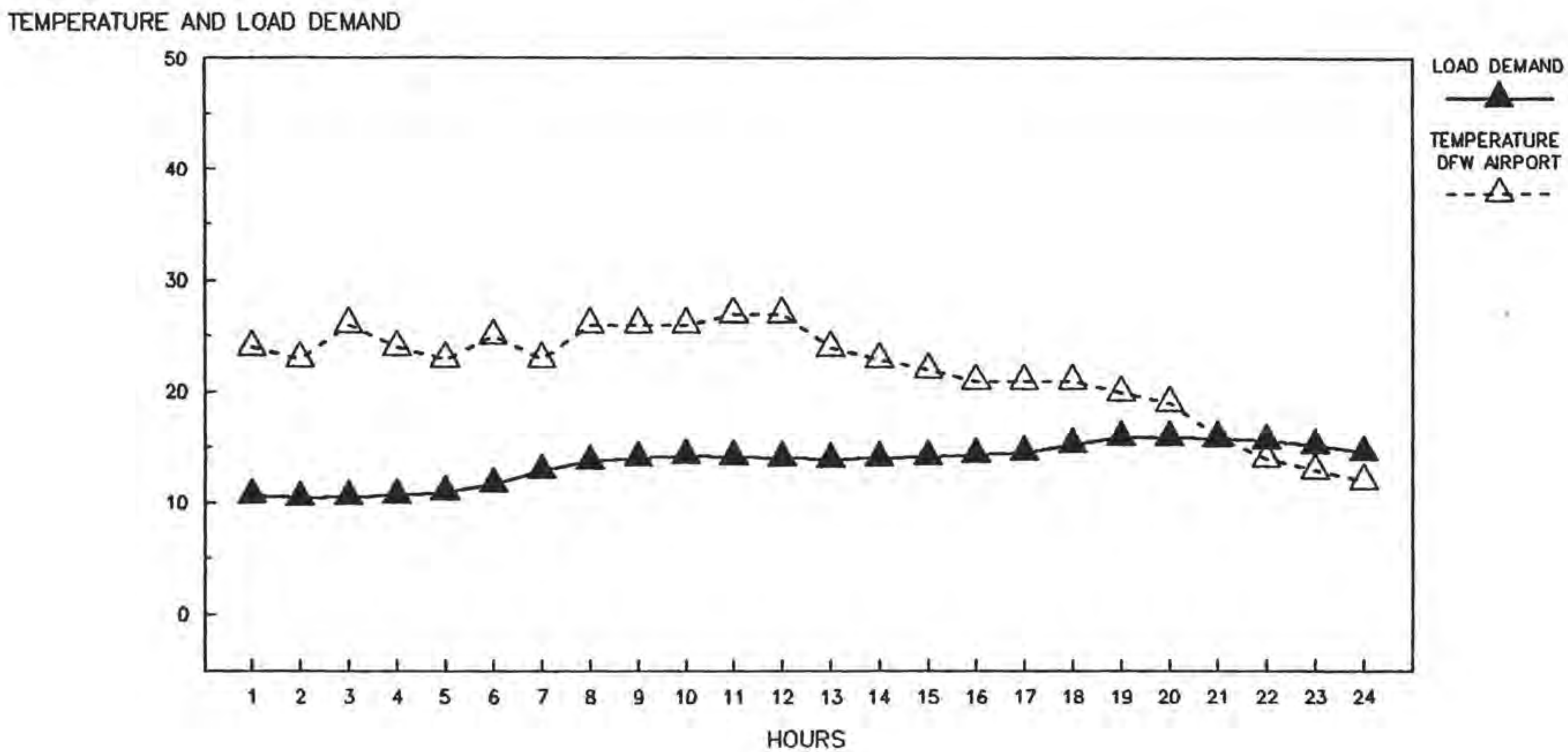


ERCOT FREQUENCY - Dec. 23, 1989
NORMAL FREQUENCY CONTROL RANGE
60.05
60
59.95
59.9
59.85
59.8
59.75
59.7
59.65
59.6
10:16
10:20
10:25
10:30
10:35

Temperature Variations December 1989
Texas Utilities Electric Company,
DFW Airport Temperatures

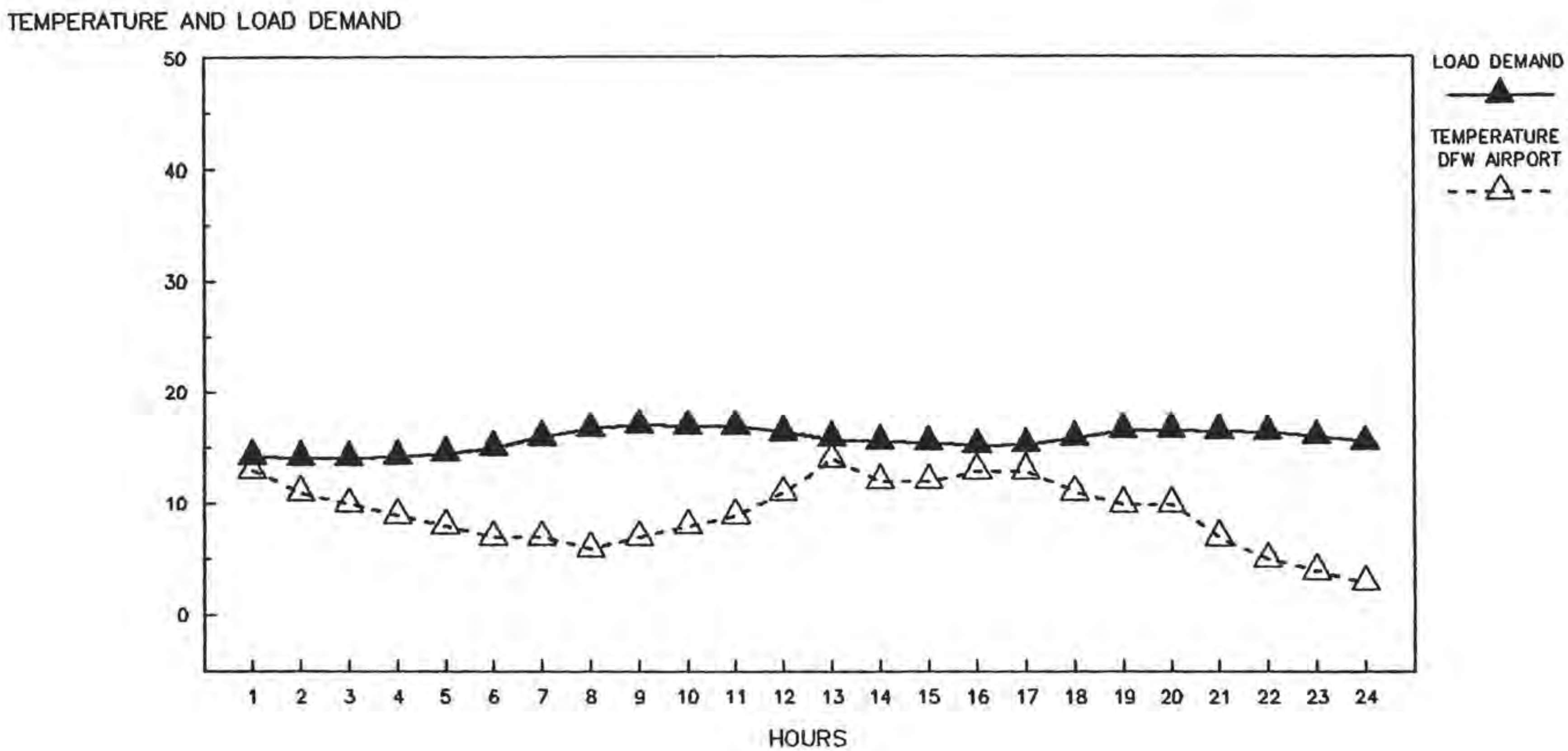
| Date | Hour | Load | Temp Fdeg | Date | Hour | Load | Temp Fdeg |
|---|---|---|---|---|---|---|---|
| 12/21/89 | 1 | 10658 | 24 | 12/23/90 | 1 | 15097 | 3 |
| | 2 | 10529 | 23 | | 2 | 14913 | 3 |
| | 3 | 10586 | 26 | | 3 | 14893 | 2 |
| | 4 | 10697 | 24 | | 4 | 14935 | 2 |
| | 5 | 11029 | 23 | | 5 | 15086 | 0 |
| | 6 | 11688 | 25 | | 6 | 15316 | 0 |
| | 7 | 12966 | 23 | | 7 | 15501 | -1 |
| | 8 | 13814 | 26 | | 8 | 15680 | 0 |
| | 9 | 14091 | 26 | | 9 | 15713 | 5 |
| | 10 | 14307 | 26 | | 10 | 15533 | 7 |
| | 11 | 14219 | 27 | | 11 | 14869 | 10 |
| | 12 | 14114 | 27 | | 12 | 14300 | 15 |
| | 13 | 14029 | 24 | | 13 | 13520 | 17 |
| | 14 | 14105 | 23 | | 14 | 12801 | 20 |
| | 15 | 14212 | 22 | | 15 | 12240 | 21 |
| | 16 | 14419 | 21 | | 16 | 11896 | 22 |
| | 17 | 14620 | 21 | | 17 | 11946 | 20 |
| | 18 | 15297 | 21 | | 18 | 12932 | 17 |
| | 19 | 15911 | 20 | | 19 | 13916 | 17 |
| | 20 | 15922 | 19 | | 20 | 14185 | 15 |
| | 21 | 15860 | 16 | | 21 | 14373 | 15 |
| | 22 | 15666 | 14 | | 22 | 14407 | 15 |
| | 23 | 15221 | 13 | | 23 | 14162 | 16 |
| | 24 | 14602 | 12 | | 24 | 13749 | 16 |
| 12/22/89 | 1 | 14271 | 13 | 12/24/89 | 1 | 13337 | 16 |
| | 2 | 14184 | 11 | | 2 | 13199 | 16 |
| | 3 | 14246 | 10 | | 3 | 13214 | 16 |
| | 4 | 14349 | 9 | | 4 | 13087 | 17 |
| | 5 | 14622 | 8 | | 5 | 12909 | 16 |
| | 6 | 15142 | 7 | | 6 | 13259 | 16 |
| | 7 | 16029 | 7 | | 7 | 13528 | 17 |
| | 8 | 16749 | 6 | | 8 | 13895 | 17 |
| | 9 | 17063 | 7 | | 9 | 14082 | 22 |
| | 10 | 16995 | 8 | | 10 | 13706 | 25 |
| | 11 | 16937 | 9 | | 11 | 12955 | 29 |
| | 12 | 16489 | 11 | | 12 | 12087 | 33 |
| | 13 | 15906 | 14 | | 13 | 11386 | 35 |
| | 14 | 15663 | 12 | | 14 | 10663 | 38 |
| | 15 | 15505 | 12 | | 15 | 10094 | 41 |
| | 16 | 15284 | 13 | | 16 | 9719 | 41 |
| | 17 | 15286 | 13 | | 17 | 9672 | 40 |
| | 18 | 15951 | 11 | | 18 | 10386 | 37 |
| | 19 | 16649 | 10 | | 19 | 11031 | 30 |
| | 20 | 16722 | 10 | | 20 | 11117 | 31 |
| | 21 | 16613 | 7 | | 21 | 11217 | 28 |
| | 22 | 16427 | 5 | | 22 | 11314 | 29 |
| | 23 | 16011 | 4 | | 23 | 11256 | 29 |
| | 24 | 15509 | 3 | | 24 | 10969 | 28 |

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 21, 1989



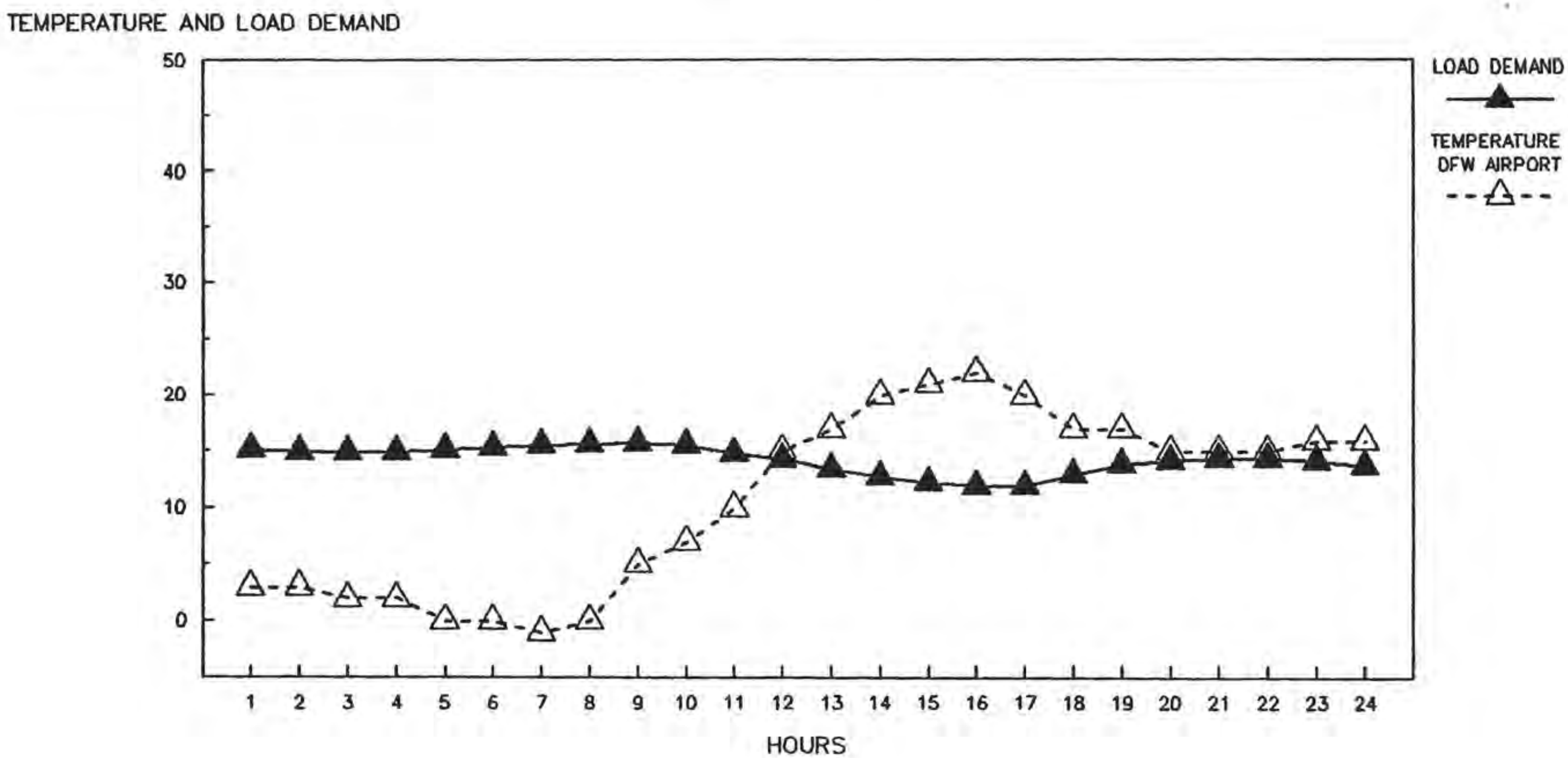

LOAD DEMAND IS x 1000.

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 22, 1989



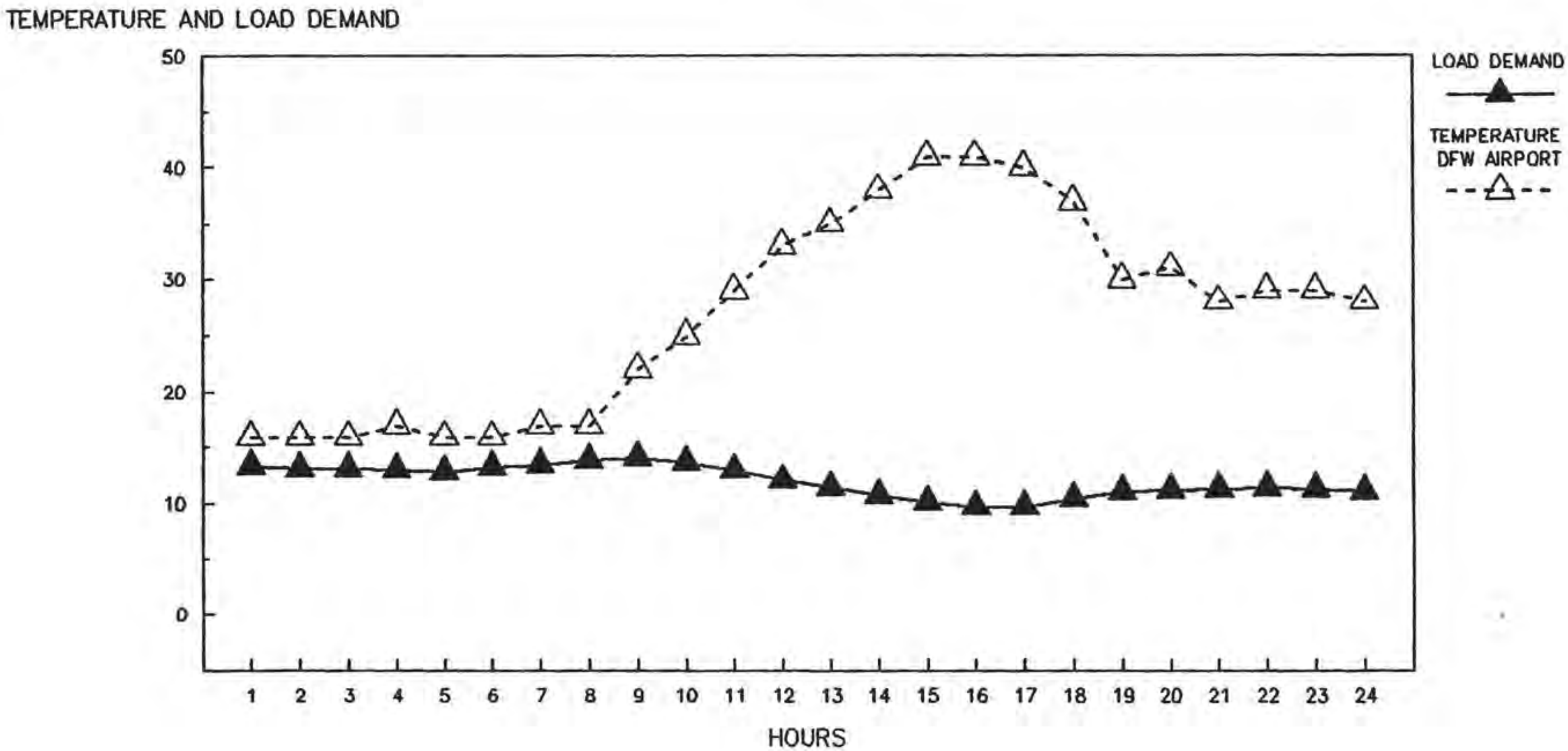

LOAD DEMAND IS x 1000.

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 23, 1989




LOAD DEMAND IS x 1000.

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 24, 1989




LOAD DEMAND IS x 1000.

ATTACHMENT NO. 2

CAUSES OF PLANT SHUTDOWNS
and
CORRECTIVE ACTION COSTS (SUMMARY)

**ATTACHMENT No. 2**

**CAUSES OF PLANT SHUTDOWNS AND CORRECTIVE ACTION COSTS (SUMMARY)**

| Unit Name | Cause | Date Compl. | Expenses O & M | Expenses Capital |
|---|---|---|---|---|
| | Central Power and Light (CPL) | | | |
| Barney Davis 1 | | | 3,500 | 50,000 |
| Barney Davis 2 | | | 3,500 | 50,000 |
| Caleto Creek 1 | | | 55,200 | 50,000 |
| E. S. Joslin 1* | Frozen instrumts | 11/90 | 92,500 | 50,000 |
| J. L. Bates 1 | | | 18,400 | 50,000 |
| J. L. Bates 2 | | | 1,500 | 50,000 |
| La Palma 6 | | | 32,200 | 50,000 |
| Laredo 1 | | | | 50,000 |
| Laredo 2 | | | 4,000 | 50,000 |
| Laredo 3 | | | 34,400 | 50,000 |
| Lon C. Hill 3* | Frozen instrumts | 12/90 | 65,600 | 50,000 |
| Lon C. Hill 4* | Boiler tube leak | 12/89 | 47,600 | 50,000 |
| Nueces Bay 6 * | Frozen instrumts | 11/90 | 37,600 | 50,000 |
| Nueces Bay 7 | | | 32,200 | 50,000 |
| Victoria 6 | | | 52,400 | 50,000 |
| Total CPL | | | $ 480,600 | $ 750,000 |
| Grand Total CPL | | | $ 1,230,600 | |

* Tripped off line during cold weather emergency

Preventive and corrective measures include the following:

Control Air Dryers (Capitalized)
DC Heater Enclosures (O & M )
Drum Enclosures (O & M )
Heat Tracing (O & M )
Drum Level Instrumentation (O & M )

**Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)**

Houston Lighting & Power Company (HL&P)

| Unit Name | Cause | Date Compl. | Expenses O & M | Expenses Capital |
|---|---|---|---|---|
| Cedar Bayou 1 | Frozen instrumts | 2/90 | $ 4,800 | 38,000 |
| Cedar Bayou 2 | | | | |
| Cedar Bayou 3 | Frozen instrumts | 10/90 | 10,000 | 90,000 |
| Greens Bayou 5 | Frozen instrumts | 9/90 | 15,800(4) | |
| Limestone 1 | Frozen instrumts | 9/90 | 57,700(2) | |
| Limestone 2 | Frozen instrumts | 9/90 | 57,300 | |
| P H Robinson 1 | Frozen instrumts | 10/90 | 38,800 | 38,000 |
| P H Robinson 2 | | | 38,800 | |
| P H Robinson 3 | | | | 38,000 |
| P H Robinson 4 | | | 1,100 | 48,000(3) |
| S R Bertron 1 | | 3/90 | 44,000 | 40,000 |
| S R Bertron 2 | | 9/90 | | 76,000 |
| S R Bertron 3 | Frozen instrumts | 10/90 | 3,700 | |
| S R Bertron 4 | Ice in boiler fan | 12/89 | | |
| South Texas 1 | Frozen instrumts | 10/90 | 20,000(1) | 140,700(5) |
| South Texas 2 | | 6/90 | 20,000 | 213,000(5) |
| T H Wharton 2 | Boiler motor failed | 1/90 | 51,509 | |
| T H Wharton 3 | Frozen instrumts | 10/90 | 65,140 | |
| T H Wharton 4 | Frozen instrumts | 5/90 | 109,266 | |
| T H Wharton GT21 | Frozen instrumts | 7/90 | 1,000 | |
| T H Wharton GT54 | Frozen fuel valve | 12/89 | | |
| W A Parish 1 | | 9/90 | 63,000(6) | |
| W A Parish 2 | | | | |
| W A Parish 3 | | | | |
| W A Parish 5 | Frozen instrumts | 7/90 | 74,918 | 57,000 |
| W A Parish 6 | | | | |
| W A Parish 7 | | | | |
| W A Parish 8 | Frozen instrumts | 8/90 | 2,500 | 50,000 |
| W A Parish GT21 | Batteries frozen | 5/90 | | |
| Webster GT | Frozen instrumts | 2/90 | | |
| **Total HL&P** | | | **$ 679,333** | **$ 828,700** |
| **Grand Total HL&P** | | | **$ 1,508,033** | |

**Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)**

Notes

(1) Additional Cost for seal water lines and instrumentation lines to be determined after engineering analysis.
(2) Maintenance costs for Bottom Ash Hopper and Sluice Gate Pistons included ($8,400).
(3) Costs for Aux Boiler Steam Drum End Enclosures.
(4) Costs for temporary burner deck enclosures not significant.
(5) Costs for additional freeze protection for auxiliary cooling surge tank and feedwater booster pumps.
(6) Cost for all Parish units combined.

Included in this list are anticipated cold weather modifications on various HL&P generating units that did not fail in service during the cold weather emergency (See Attachment B of HL&P letter dated June 15, 1990, that has been included in Attachment No. 4.)

**Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)**

**Texas Utilities Electric Company (TUE)**

| Unit Name | Cause | Date Compl. | Expenses O & M | Expenses Capital |
|---|---|---|---|---|
| Eagle Mountain 3 | Fish plugged intake | 1/90 | | |
| Handley 5 | Human error | 1/90 | | |
| Martin Lake 2 | Frozen instrumts | 1/90 | 2,000 | |
| Monticello 2 | Frozen instrumts | 1/90 | 2,000 | |
| Monticello 3 | Frozen instrumts | 1/90 | 2,700 | |
| Morgan Creek CT4 | Frozen fuel valve | 1/90 | | |
| Mountain Creek 2 | Fish plugged intake | 1/90 | | |
| Mountain Creek 7 | Instrument error | 1/90 | | |
| River Crest 1 | Fish plugged intake | 8/90 | 900 | |
| Stryker Creek 1 | Low gas pressure | 1/90 | | |
| Tradinghouse 1 | Frozen instrumts | 1/90 | 500 | |
| Valley 2 | Frozen instrumts | 1/90 | 300 | |
| Total TUE | | | $ 8,400 | |

**Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)**

Lower Colorado River Authority (LCRA)

| Unit Name | Cause | Date Compl. | Expenses O & M | Expenses Capital |
|---|---|---|---|---|
| Sim Gideon 2 | Frozen instrumts | 2/90 | 300 | |
| Sam K Seymour 3 | Frozen instrumts | 5/90 | 420 | |
| Total LCRA | | | $ 720 | |

Texas Municipal Power Agency (TMPA)

| Unit Name | Cause | Date Compl. | Expenses O & M | Expenses Capital |
|---|---|---|---|---|
| Gibbons Creek 1 | Frozen instrumts | 10/90 | 25,500 | |
| Total TMPA | | | $ 25,500 | |

| | | |
|---|---|---|
| GRAND TOTAL, ALL UTILITIES | $ 1,194,553 | $ 1,578,700 |
| Total | $ 2,773,253 | |

## ATTACHMENT NO. 3

## INDIVIDUAL UTILITY RESPONSES

================================================================

Utility Responses:

Brazos Electric Power Cooperative, Inc.
Central Power and Light Company
Houston Lighting and Power Company
Lower Colorado River Authority
Texas Municipal Power Agency
Texas Utilities Electric Company

================================================================

BRAZOS ELECTRIC COOPERATIVE

BRAZOS ELECTRIC POWER COOPERATIVE, INC.
2404 LaSalle Avenue • P.O. Box 2585
Waco, Texas 76702-2585
(817) 750-6500

June 11, 1990

Mr. Chester R. Oberg
Public Utility Commission of Texas
7800 Shoal Creek Boulevard Suite 400N
Austin, Texas 78757

Re: Cold Weather Operation
Your letter dated, May 10, 1990
PUC Project 9542

Dear Mr. Oberg:

Please recall that, with the exception of Miller 1 which was not designed for oil firing, all of our units were responsive and suffered no outages during the problem cold period.

The following actions have been taken on Miller 3 Unit:

The burner management system was tested making some minor fuel pressure trip adjustments.

Miller 1 unit was not equipped for oil firing because its gas fuel supply was very reliable, and Brazos builds its plants for the lowest first cost. We plan now to install the necessary equipment.

The following activity has been underway on Miller 1 Unit:

* Specifications have been prepared for the purchase of fuel oil pumps, and the purchasing process is now underway.

* Specifications are being prepared for the purchase of other associated equipment such as valves, strainers, etc.

* Specifications will be prepared for piping and installation labor.

* If new burner controls are needed we will attempt to delay this part of the project until they can be installed along with future replacement BTG controls.

It is hoped that this can be completed in December 1990.

We will make the usual preparations in November for cold weather operations. Such preparations include, but are not limited to, the following inspection and testing:

* Heating cable survey and inspection
* Equipment heaters
* Area Heating equipment
* Outdoor lube oil systems and oil inspection.
* Actual brief oil firing on at least one burner
* All fuel oil tanks full

Please call if we need to discuss this further.

Jack T. Ard

Jack T. Ard P.E.
Manager Power Production

Copy: J.D. Copeland

CENTRAL POWER AND LIGHT COMPANY / Home Office: P.O. Box 2121, Corpus Christi, Texas 78403 512-881-5300

cpl

October 8, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400n
Austin, Texas 78757

Subject: December 1989 Weather Problems

Dear Mr. Oberg

Central Power and Light had problems with its generating units just as many other utility company's did. The following information will address the seven question posed in your letter of May 10, 1990 concerning CPL generating units that were lost or unable to respond during the cold weather emergency of December 1989.

---

Question No. 1 - Unit name and unit MW capacity

Four (4) of CPL's generating units tripped off the line. The units and their capacity were as follows:

| Unit | Capacity | Unit Tripped Date | Unit Tripped Time |
|---|---|---|---|
| E S Joslin 1 | 257-NMW | 12-23-89 | 0150-Hrs |
| Nueces Bay 6 | 172-NMW | 12-23-89 | 0536-Hrs |
| Lon C. Hill 3 | 162-NMW | 12-23-89 | 0605-Hrs |
| Lon C. Hill 4 | 256-NMW | 12-23-89 | 0656-Hrs |

---

Question No.2 Unit general design temperature limitations (Maximum and minimum), in degrees F.

CPL's Generating Units are designed for a minimum ambient temperature of 10 degrees F with a wind velocity of 30-MPH. A specific maximum temperature is not specified as it is equipment dependant (eg. boiler tube metal may operate at temperatures as high as 1000 degrees F; furnace gas temperatures may be as high as 2300 degrees F). Other equipment such as electronic and digital control equipment may require a conditioned area where temperatures are controlled at or near 75 degrees F.

---

Question No. 3 - List of equipment(s) or plant systems that were adversely affected by the cold weather.

Question No. 4 - For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

The following equipment/plant systems were affected by the cold weather at the Power Stations noted above:

| Unit Name | No. | (3) Affected Equip. | (4) Failure Mode | (4) Failure Cause | (4) How did failure contribute to overall probs. |
|---|---|---|---|---|---|
| E S Joslin | 1 | Boiler | (A) | (C) | (E) |
| Nueces Bay | 6 | Boiler | (A) | (C) | (F) |
| Lon C Hill | 3 | Boiler | (A) | (C) | (F) |
| Lon C Hill | 4 | Boiler | (B) | (D) | (G) |

(A) Boiler Tripped as a result of low drum level
(B) Furnace over pressure protection tripped the boiler
(C) Frozen drum level sensing lines and instrumentation
(D) Boiler tube failure caused furnace over pressure
(E) The failure of the drum level instrumentation provided a false signal to the feed water control system which resulted in a reduction in feedwater to the boiler leading to a low water event in the boiler. The low water event caused the failure of several water wall tubes. The failed water wall tubes damaged the radiant section of the reheater. The unit was rendered unable to return to service until extensive NDT was performed and repairs were made.
(F) The units were tripped by the operator. The instrument problems were corrected and the units were returned to service
(G) A boiler tube leak caused the furnace over pressure. The tube leak was repaired and the unit returned to service.

---

Question No. 5 For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

In order to prevent recurrence of the system and equipment failure during future adverse weather conditions a complete post critique of power station operation was necessary. The Director of Generation Operation, Mr. Perry A. Beaty, appointed a taskforce to review the operation at each of CPL's Power Stations. The taskforce was charged with identifying all weather related problems and recommending action steps needed to prevent recurrence of weather related problems. The taskforce inspected records, logs, and interviewed the staff at each power station. The following actions were recommended:

(1) Engineering review of CPL's low temperature design requirements.
(2) The addition of desiccant type air dryers to the power station control air systems.
(3) Review power station heat tracing practices.
(4) Review power station boiler protection systems.
(5) Review power station boiler drum level instrumentation.
(6) Review boiler drum enclosures and D C heater instrumentation enclosures.

Stone and Webster Engineering was retained to perform the required design and specification for control air drying. Bath and Assoc. was retained to perform the required design review and specification for the drum enclosures and the DC heater enclosures.

---

Question No. 6 For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

See attached Tables 1, 2, 3, 4, & 5

---

Question No. 7 For each piece of equipment or system identified above report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

See attached Tables 1, 2, 3, 4, & 5

Thank you for your patience. If you have questions concerning the information provided please feel free to call us.

Very truly yours,

Ronald R. Earley
Manager Technical Services
Generation Operations Dept.

RRE:(rre10590)
Attachments
xc: Perry A. Beaty, Jr.
File:998-275.10.00-002

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO. 1 CONTROL AIR DRYERS

| POWER STATION | UNIT NO. | COMPLETION DATE PROJECTED | COMPLETION DATE ACTUAL | COST PROJECTED | COST ACTUAL | MAINT/ CAPITAL |
|---|---|---|---|---|---|---|
| NBPS | 6 | 11/15/91 | | $50,000.00 | | CAPITAL |
| Nueces Bay | 7 | 11/15/91 | | $50,000.00 | | CAPITAL |
| LAPPS La Palma | 6 | 11/15/92 | | $50,000.00 | | CAPITAL |
| LARPS | 1 | 11/15/92 | | $50,000.00 | | CAPITAL |
| Laredo | 2 | 11/15/92 | | $50,000.00 | | CAPITAL |
| | 3 | 11/15/92 | | $50,000.00 | | CAPITAL |
| LCHPS | 3 | 11/15/91 | | $50,000.00 | | CAPITAL |
| Lon C. Hill | 4 | 11/15/91 | | $50,000.00 | | CAPITAL |
| VICPS Victoria | 6 | 12/14/90 | | $50,000.00 | | CAPITAL |
| JLBPS | 1 | 11/15/92 | | $50,000.00 | | CAPITAL |
| J.L. Bate | 2 | 11/15/92 | | $50,000.00 | | CAPITAL |
| ESJPS E.S. Joslin | 1 | 12/14/90 | | $50,000.00 | | CAPITAL |
| BMDPS | 1 | 11/15/91 | | $50,000.00 | | CAPITAL |
| Barney Davis | 2 | 11/15/91 | | $50,000.00 | | CAPITAL |
| COCPS Coleto Creek | 1 | 12/14/90 | | $50,000.00 | | CAPITAL |
| | | | | $750,000.00 | | |

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.2 DC Htr ENCLOSURES

| POWER STATION | UNIT NO. | | COMPLETION DATE PROJECTED | COMPLETION DATE ACTUAL | COST PROJECTED | COST ACTUAL | MAINT/ CAPITAL |
|---|---|---|---|---|---|---|---|
| NBPS | 6 | 1 | 11/15/90 | | $7,500.00 | | MAINT |
| | 7 | 2 | 11/15/90 | | $1,500.00 | | MAINT |
| LAPPS | 6 | 3 | 11/01/90 | | $7,500.00 | | MAINT |
| LARPS | 1 | 4 | NONE REQUIRED | | | | |
| | 2 | 5 | NONE REQUIRED | | | | |
| | 3 | 6 | 12/15/90 | | $2,500.00 | | MAINT |
| LCHPS | 3 | 7 | 11/01/90 | | $5,000.00 | | MAINT |
| | 4 | 8 | 11/01/90 | | $5,000.00 | | MAINT |
| VICPS | 6 | 9 | 11/15/90 | | $7,500.00 | | MAINT |
| JLBPS | 1 | 10 | NONE REQUIRED | | | | |
| | 2 | 11 | NONE REQUIRED | | | | |
| ESJPS | 1 | 12 | 11/01/90 | | $7,500.00 | | MAINT |
| BMDPS | 1 | 13 | 11/01/90 | | $1,000.00 | | MAINT |
| | 2 | 14 | 11/01/90 | | $1,000.00 | | MAINT |
| COCPS | 1 | 15 | 11/15/90 | | $9,000.00 | | MAINT |
| | | | | | $55,000.00 | | |

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.5 DRUM LEVEL INSTRUMENT

| POWER STATION | UNIT NO. | COMPLETION DATE PROJECTED | COMPLETION DATE ACTUAL | COST PROJECTED | COST ACTUAL | MAINT/ CAPITAL |
|---|---|---|---|---|---|---|
| NBPS | 6 | 10/19/90 | | $19,900.00 | | MAINT |
| | 7 | 12/07/90 | | $19,900.00 | | MAINT |
| LAPPS | 6 | 11/23/90 | | $19,900.00 | | MAINT |
| LARPS | 1 | NONE REQUIRED | | | | |
| | 2 | NONE REQUIRED | | | | |
| | 3 | 11/30/90 | | $19,900.00 | | MAINT |
| LCHPS | 3 | 12/07/90 | | $19,900.00 | | MAINT |
| | 4 | 12/07/90 | | $19,900.00 | | MAINT |
| VICPS | 6 | 11/30/90 | | $19,900.00 | | MAINT |
| JLBPS | 1 | 12/14/90 | | $15,900.00 | | MAINT |
| | 2 | NONE REQUIRED | | | | |
| ESJPS | 1 | NONE REQUIRED | | | | |
| BMDPS | 1 | NONE REQUIRED | | | | |
| | 2 | NONE REQUIRED | | | | |
| COCPS | 1 | NONE REQUIRED | | | | |
| | | | | $155,200.00 | | |

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO. 4 HEAT TRACING

| POWER STATION | UNIT NO. | COMPLETION DATE PROJECTED | COMPLETION DATE ACTUAL | COST PROJECTED | COST ACTUAL | MAINT/ CAPITAL |
|---|---|---|---|---|---|---|
| NBPS | 6 | 11/15/90 | | $6,700.00 | | MAINT |
| | 7 | 11/15/90 | | $8,300.00 | | MAINT |
| LAPPS | 6 | 11/30/90 | | $3,000.00 | | MAINT |
| LARPS | 1 | NONE REQUIRED | | | | MAINT |
| | 2 | 12/01/90 | | $500.00 | | MAINT |
| | 3 | 11/30/90 | | $2,000.00 | | MAINT |
| LCHPS | 3 | 11/15/90 | | $37,200.00 | | MAINT |
| | 4 | 11/15/90 | | $7,700.00 | | MAINT |
| VICPS | 6 | 12/01/90 | | $20,000.00 | | MAINT |
| JLBPS | 1 | 12/14/90 | | $1,500.00 | | MAINT |
| | 2 | 12/14/90 | | $1,500.00 | | MAINT |
| ESJPS | 1 | 11/17/90 | | $70,000.00 | | MAINT |
| BMDPS | 1 | 11/30/90 | | $1,500.00 | | MAINT |
| | 2 | 11/30/90 | | $1,500.00 | | MAINT |
| COCPS | 1 | 12/01/90 | | $28,200.00 | | MAINT |
| | | | | $189,600.00 | | |

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.3 DRUM ENCLOSURERS

| POWER STATION | UNIT NO. | COMPLETION DATE PROJECTED | ACTUAL | COST PROJECTED | ACTUAL | MAINT/ CAPITAL |
|---|---|---|---|---|---|---|
| NBPS | 6 | 11/15/90 | | $3,500.00 | | MAINT |
| | 7 | 11/30/90 | | $2,500.00 | | MAINT |
| LAPPS | 6 | 11/01/90 | | $15,000.00 | | MAINT |
| LARPS | 1 | NONE REQUIRED | | | | |
| | 2 | 12/15/90 | | $3,500.00 | | MAINT |
| | 3 | 12/15/90 | | $10,000.00 | | MAINT |
| LCHPS | 3 | 11/01/90 | | $3,500.00 | | MAINT |
| | 4 | 11/01/90 | | $15,000.00 | | MAINT |
| VICPS | 6 | 11/15/90 | | $5,000.00 | | MAINT |
| JLBPS | 1 | 12/10/90 | | $1,000.00 | | MAINT |
| | 2 | NONE REQUIRED | | | | |
| ESJPS | 1 | 11/01/90 | | $15,000.00 | | MAINT |
| BMDPS | 1 | 11/01/90 | | $1,000.00 | | MAINT |
| | 2 | 11/01/90 | | $1,000.00 | | MAINT |
| COCPS | 1 | 11/15/90 | | $18,000.00 | | MAINT |
| | | | | $94,000.00 | | |

**The Light company**
Houston Lighting & Power

P.O. Box 1700 Houston, Texas 77251 (713) 228-9211

June 15, 1990

PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
JUN 15 1990
BY ______
ELECTRIC

Chester R. Oberg
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

Dear Mr. Oberg:

Your letter of May 10, 1990 requested that Houston Lighting & Power provide information regarding generating units which were lost or were otherwise unable to respond to the cold weather emergency which occurred throughout Texas in December of 1989.

Attachment A to this letter contains a response for each of the generating units which was adversely affected by the cold weather. General design temperature ranges are indicated for each unit. Plants built since the 1970's have included freeze protection design criteria which are indicated in Attachment A for Limestone and the South Texas Project. Although other plants do not have specific freeze protection design criteria established, freeze protection was provided in accordance with operating experience for Houston area plants. The following is offered to further supplement and clarify the information provided in Attachment A.

The Company is taking several administrative measures as a result of the experience gained during the 1989 cold weather emergency. The temperatures experienced were the coldest on record since the Company began building outside generating plants. The Company is re-evaluating its cold weather emergency procedures with regard to all of its plants to insure that they will operate at the weather extremes experienced in December of 1989. This response is consistent with the Company's commitment to the regular review of plans and procedures to insure that they remain current in light of experience. The Company is reviewing guidelines used by operators at the Company's generating plants when cold weather is imminent to insure that freeze protection measures are implemented. The guidelines are being revised to include improved freeze protection measures for equipment which experienced cold weather related problems during the 1989 cold weather emergency. Critical equipment lists are being reviewed and re-evaluated in light of the experience gained during the emergency. The Company is reviewing its cold weather emergency maintenance staffing levels and may increase crew size during such emergencies. Maintenance crews already provide twenty-four hour coverage during such emergencies. Maintenance crews monitor and activate freeze protection equipment and take necessary corrective action if and when problems arise.

The Company is taking corrective action with respect to equipment which failed and affected unit operation as a result of the 1989 cold weather emergency. Those actions are described in Attachment A. Each failure is being reviewed to determine the failure mode. If the failure resulted from an equipment malfunction, such as heat tracing circuit failure, maintenance is planned or has been undertaken to correct the situation. Most unit failures were of this type and resulted from frozen instrumentation sensing lines or transmitters. If the failure mode indicates the need for design modifications, an engineered modification is being developed. This engineering review has been extended to encompass similar units that did not experience failures during the 1989 cold weather emergency and engineering enhancements are being provided. Examples of modifications resulting from this review include drum-end enclosures to protect water-level sensing lines and moisture-removal devices for instrument air systems. Attachment B summarizes the modifications to generating units which did not experience failures in December 1989.

The Company is attempting to anticipate problems which it might experience in the event that even more extreme weather conditions occur and to take reasonable administrative and corrective actions to prepare for such conditions. The Company does not consider the administrative actions which it is implementing and the corrective steps which it is taking to necessarily be the ultimate answer to extreme cold weather conditions. The Company learns from each weather extreme how better to protect its generating equipment. The Company must emphasize, however, that it would not be prudent to plan for or implement steps which are beyond those needed given the historical weather patterns, including the occasional period of extreme cold weather, to which the Greater Houston area is subject. Generating plants in Amarillo, for example, are built with a level of freeze protection greater than would be reasonable or prudent in Houston.

Houston Lighting & Power Company



The Company has surveyed the larger cogenerators in its service area including those under firm contract. The responses received are included in Attachment C.

The Company hopes that the information provided in this response is useful to the Commission in its review of procedures established by the electric utilities of the state to deal with cold weather emergencies. Should you have any questions regarding this response, please contact the undersigned at (713) 220 5387.

Sincerely,

John C. Houston

John C. Houston
Manager, Regulatory Activities

JCH/MGB/bg
3861
Encl.

**ATTACHMENT A**

**Generating Plant Reports**
**December 21-24, 1989**

**Index**

The generating unit reports are formatted to respond to the following questions:

1. Unit Name and Unit MW Capacity

2. Unit general design temperature limitations (Maximum and Minimum), in degrees F.

3. List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

7. For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

1. W A Parish Unit 5 : 670 MW

2. Design Temperature Range : 10°F - 105°F

3. a. High Secondary Air Duct Pressure Switch
   b. Seal Water to Vacuum Pumps

4. a. Failure Mode - False indication of high secondary air duct pressure.

   Cause of Failure -Condensation collected in low point of sensing line; condensate froze, causing false indication of high duct pressure.

   Contribution to overall failure of unit - High secondary air duct pressure indication that lasts 2 minutes results in a main fuel trip.

   b. Failure Mode - Low condenser vacuum.

   Cause of Failure - Seal water to vacuum pump froze, during outage caused by High Secondary Air Duct Pressure indication. Vacuum pumps require seal water to operate.

   Contribution to overall failure of unit - Low condenser vacuum results in automatic trip of unit.

5. a. Pressure sensing line will be re-sloped, heat traced and insulated.

   b. Low-point drains will be installed to drain seal water line when unit is off-line during freezing conditions. Temporary windbreaks and heaters will be used to protect seal water line during operation in freezing weather.

6. a. Corrective action will be completed by 7/31/90.

   b. Corrective action will be completed by 7/31/90.

7. a. $3668 - Maintenance

   b. $1250 - Maintenance

1. W A Parish Unit 8 : 570 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Superheat and Reheat Spray Regulator Instrument Lines

   b. Boiler Water Circulating Pump Differential Pressure Transmitter

4. a. Failure Mode - Superheat and reheat spray valves failed to close.

   Cause of Failure - Moisture in instrument air lines to Superheat and Reheat Spray regulators froze, resulting in loss of control of regulators.

   Contribution to overall failure of unit - There was no overall failure of unit. Load was reduced to 416 MW to control Superheat and Reheat temperatures. Condition was cleared within three hours.

   b. Failure Mode - False indication of low Boiler Water Circulating Pump pressure differential.

   Cause of Failure - Transmitter sensing lines froze due to failure of freeze protection equipment.

   Contribution to overall failure of unit - There was no overall failure of unit. Unit was derated to 420 MW. Condition was cleared within 35 minutes.

5. a. Instrument air system will be modified to allow collected moisture to be drained.

   b. Heat tracing and insulation will be updated on BWCP pressure transmitter sensing lines.

6. a. Corrective action will be completed by 8/31/90.

   b. Corrective action was completed on 5/14/90.

7. a. $50,000 - Capital

   b. $2500 - Maintenance

1. W A Parish Gas Turbine Unit 21 : 13 MW

2. Design Temperature Range : 10°F to 105°F

3. Starting motor battery

4. Failure Mode - Battery was not able to start cranking motor.

   Cause of Failure - Battery was weakened by exposure to low temperature.

   Contribution to overall failure of unit - Gas turbine cannot be started without use of cranking motor.

5. Space heaters will be used in the gas turbine enclosure to maintain temperature of starting motor batteries.

6. Corrective action completed - 5/29/90

7. Negligible cost

1. Limestone Unit 1 : 780 MW

2. Design Temperature Range : 10°F to 110°F
   Freeze Protection : 5°F

3. Feedwater Flow Transmitter

4. Failure Mode - Loss of boiler feedwater flow

   Cause of Failure - Transmitter sensing lines froze, causing an incorrect control signal to slow boiler feed pumps to zero speed. This caused loss of feedwater flow.

   Contribution to overall failure of unit - Loss of feedwater flow resulted in a drop in drum water level. This ultimately caused a main fuel trip on boiler.

5. Heat Tracing and insulation on sensing lines will be upgraded.

6. Corrective action will be completed 9/15/90.

7. $300 - Maintenance

1. Limestone Unit 2 : 780 MW

2. Design Temperature Range : 10°F to 110°F
Freeze Protection : 5°F

3. a. Boiler Drum Level Instrumentation
   b. Boiler Water Circulating Pump Differential Pressure Transmitter
   c. Superheat Spray Flow Transmitter
   d. Ignitor Gas Valve Actuator
   e. Circulating Water Pump Seal Water Piping

4. a. <u>Failure Mode</u> - Drum water level sensing lines froze, resulting in incorrect signal on drum water level.

   <u>Cause of Failure</u> - Heat tracing and/or insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - Drum level indication out of limits caused Main Fuel trip.

   b. <u>Failure Mode</u> - BWCP sensing lines froze, causing false indication of low pressure differential.

   <u>Cause of Failure</u> - Heat tracing and insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - False indication of low BWCP flow initiated a Main Fuel Trip.

   c. <u>Failure Mode</u> - Sensing lines to Superheat Spray Flow transmitter froze, causing indication of low spray flow.

   <u>Cause of Failure</u> - Heat tracing and insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - This did not contribute to unit failure.

   d. <u>Failure Mode</u> - Ice on valve prevented valve operation.

   <u>Cause of Failure</u> - Moisture collected from prior washdown, froze.

   <u>Contribution to overall failure of unit</u> - Caused delay in unit restart following unit trip for other reasons.

(LEGS Unit 2 cont'd)

e. Failure Mode - Unprotected seal water piping froze and ruptured.

Cause of Failure - Isolation valves to circulating water pump leaked, making it impossible to drain the seal water piping while unit off line.

Contribution to overall failure of unit - This did not contribute to unit failure. Unit was off line for other reasons. Could have prevented unit restart.

5. a. Heat tracing and insulation on sensing lines will be upgraded. Also, Drum End Enclosures will be installed to protect from wind and rain.

   b. Heat tracing and insulation have been replaced.

   c. Heat tracing and insulation have been replaced.

   d. Ice was removed from valves. Administrative procedure was instituted to prevent recurrence.

   e. Seal water piping will be freeze protected.

6. a. Corrective action will be completed 9/15/90.
   b. Corrective action will be completed 9/15/90.
   c. Corrective action was completed 2/13/90.
   d. Corrective action was completed 1/2/90.
   e. Corrective action will be completed 9/15/90.

7. a. $50,400 - Maintenance
   b. $ 4,500 - Maintenance
   c. $ 500 - Maintenance
   d. $ 400 - Maintenance
   e. $ 1,500 - Maintenance

1. P H Robinson Unit 1 : 490 MW

2. Design Temperature Range : 10°F to 105°F

3. Boiler Feed Pump Suction Flow Transmitter

4. <u>Failure Mode</u> - Sensing lines to transmitter froze, causing a false signal of Low Feed Pump Flow.

   <u>Cause of Failure</u> - Heat tracing and insulation failed to protect sensing lines.

   <u>Contribution to overall failure of unit</u> - Unit tripped off line from 325 MW, due to automatic initiation of pump recirculation caused by false signal of low flow thru pump. Result was loss of feedwater flow to boiler and unit trip.

5. Heat tracing and insulation will be upgraded.

6. Corrective action to be completed 10/1/90.

7. $38,800 - Maintenance

1. Cedar Bayou Unit 1 : 740 MW

2. Design Temperature Range : 10°F to 105°F

3. Boiler Feedwater Flow Transmitter

4. Failure Mode - Loss of feedwater flow signal to feed pump control due to freezing of sensing line.

   Cause of Failure - Heat tracing and insulation failed to protect sensing line to transmitter.

   Contribution to overall failure of unit - Unit tripped on Low Feedwater Flow signal.

5. Heat tracing and insulation were upgraded.

6. Corrective action was completed 2/15/90.

7. $4800 - Maintenance

1. Cedar Bayou Unit 3 : 770 MW

2. Design Temperature Range : 10°F to 105°F

3. Fuel Oil Forwarding Pump Recirculation Valve

4. Failure Mode - Recirculation valve failed open on loss of instrument air pressure. This put fuel oil pump in recirculation, reducing fuel oil pressure at unit.

   Cause of Failure - Moisture in instrument air supply froze, reducing air pressure at valve.

   Contribution to overall failure of unit - Unit was derated 300 MW due to loss of fuel oil supply pressure, for a period of 19 minutes.

5. Install upsized instrument air dryer. Add moisture removal traps in instrument air system.

6. Corrective measures will be designed by 10/1/90. Completion date undetermined.

7. $90,000 - Capital

1. S R Bertron Unit 3 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Boiler Water Circulating Pump Differential Pressure Transmitter

   b. Frozen Gas Valves

   c. Low Condenser Vacuum

4. a. <u>Failure Mode</u> - False BWCP flow signal initiated a fuel trip.

   <u>Cause of Failure</u> - Correct BWCP flow signal lost because sensing lines to BWCP differential pressure transmitter froze.

   <u>Contribution to overall failure of unit</u> - Unit tripped on false signal of low BWCP flow.

   b. <u>Failure Mode</u> - Gas valve could not be operated, which caused fuel supply to be tripped.

   <u>Cause of Failure</u> - Lubricant in valve became very stiff at low temperature.

   <u>Contribution to overall failure of unit</u> - Unit tripped on loss of fuel supply.

   c. <u>Failure Mode</u> - Drip pump vent line to condenser froze and broke, causing loss of condenser vacuum.

   <u>Cause of Failure</u> - Vent line was not insulated.

   <u>Contribution to overall failure of unit</u> - Broken vent line caused unit to trip on loss of condenser vacuum.

5. a. Heat tracing and insulation on BWCP sensing lines will be upgraded.

   b. Gas valves will be lubricated when freezing conditions are imminent.

   c. Drip pump vent line and regulator were insulated.

(S R Bertron Unit 3 cont'd)

6. a. Corrective action will be completed by 10-01-90.
   b. N/A
   c. Corrective action was completed on 04-27-90.

7. a. $3,000 - Maintenance
   b. N/A
   c. $700 - Maintenance

1. S R Bertron Unit 4 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. Forced Draft Fan

4. Failure Mode - Ice formed in fan outlet ducts, fell and blocked fan rotation. Also broke damper.

   Cause of Failure - Water leaked into outlet ducts and formed large chunk of ice.

   Contribution to overall failure of unit - Unit tripped on loss of forced draft fans.

5. Maintenance action has been taken to prevent water intrusion into ducts.

6. Corrective action has been completed.

7. Negligible cost

1. Greens Bayou Unit 5 : 420 MW

2. Design Temperature Range : 10°F to 105°F

3. a. High-Pressure Turbine Pressure Switch

   b. Condensate Flow Control

4. a. <u>Failure Mode</u> - Frozen sensing lines caused false signal for throttle control valve position. This initiated turbine and fuel trips.

   <u>Cause of Failure</u> - Heat tracing and insulation failed to protect sensing lines.

   <u>Contribution to overall failure of unit</u> - Unit was tripped by turbine and burner controls upon signal that throttle valves were closed.

   b. <u>Failure Mode</u> - Instrument sensing lines froze, resulting in the loss of intelligence needed to open the polishing demineralizer bypass valve.

   <u>Cause of Failure</u> - Instrument lines were not insulated because the demineralizer is inside a building. The temperature inside the building dropped below freezing.

   <u>Contribution to overall failure of unit</u> - Unit tripped on low feedwater flow, resulting from reduced condensate flow.

5. a. Replace heat tracing and insulation on turbine pressure switch sensing lines.

   b. Replace heat tracing and insulation on condensate bypass valve. Temporary windbreak to be in use during freezing weather.

6. a. Corrective action scheduled for outage in Fall, 1990.

   b. Corrective action to be completed by 9/11/90.

7. a. $1050 - Maintenance

   b. $ 650 - Maintenance

1. Webster Gas Turbine : 13 MW

2. Design Temperature Range : 10°F to 105°F

3. Lubricating Oil Bypass Valve to Cooler

4. <u>Failure Mode</u> - Lubricating oil temperature was too low to start gas turbine.

   <u>Cause of Failure</u> - Moisture in instrument air piping froze, preventing air pressure sufficient to close bypass valve. Oil was bypassed to cooler, negating attempts to warm oil to proper temperature.

   <u>Contribution to overall failure of unit</u> - Gas turbine controls will not permit turbine to be started when lube oil temperature is out of range.

5. Add enclosure space heaters to maintain instrument air piping above freezing temperature.

6. Corrective action completed 2/15/90.

7. Negligible cost

1. **T H Wharton Gas Turbine Unit 21 : 13 MW**

2. **Design Temperature Range : 10°F to 105°F**

3. **Lubricating Oil Cooler Fans**

4. **Failure Mode - Lubricating oil cooler fans would not start, due to false lube oil temperature signal.**

   **Cause of Failure - Moisture in instrument air line froze, blocking the signal from lube oil temperature transmitter.**

   **Contribution to overall failure of unit - Control system shut down the gas turbine because of high lube oil temperature.**

5. **Moisture trap will be installed in instrument air line.**

6. **Corrective action will be completed by 7/1/90.**

7. **$1000 - Maintenance**

1. T H Wharton Unit 2 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. Loss of Cooling Air to Boiler Feed Pump Motor

4. Failure Mode - Boiler Feed Pump motor overheated and failed.

   Cause of Failure - Feed pump safety valve vent pipe leaked at a union, and water was blown onto motor. Ice formed, and obstructed cooling air intake on motor.

   Contribution to overall failure of the unit - When affected feed pump tripped, unit load was reduced 100 MW and unit operated on remaining boiler feed pumps.

5. Vent line was repaired.

6. Repair was completed 1/18/90.

7. $25,009 - Maintenance

1. T H Wharton Unit 3 : 285 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Drum Water Level Sensing Lines

   b. Feed Water Flow Transmitter

4. a. Failure Mode - One Heat Recovery Steam Generator was taken out of service by the control system, due to a false low drum level signal.

   Cause of Failure - Drum level sensing lines froze, due to failure of freeze protection measures.

   Contribution to overall failure of unit - The unit consists of 4 HRSGs, and 3 remained in operation. Unit was derated 23 MW.

   b. Failure Mode - Feedwater flow transmitter received a false low feedwater flow signal.

   Cause of Failure - Sensing lines to feedwater flow transmitter froze, which produced an errant signal to be generated by the transmitter. The control system tripped the boiler feed pump to protect the pump.

   Contribution to overall failure of unit - Loss of boiler feed pump caused the unit to be derated 85 MW.

5. a. Sensing lines heat tracing and insulation were upgraded. Wind breaks were added.

   b. Sensing lines heat tracing and insulation were upgraded.

6. a&b. Wind breaks were completed 2/15/90. Heat tracing and insulation on 2 HRSGs were upgraded by 5/2/90. Remaining heat tracing and insulation work will be completed during outage in Fall, 1990.

7. Wind Breaks - $6516 to install - Maintenance

   Heat Tracing and Insulation - $58,624 - Maintenance

1. **T H Wharton Unit 4 : 285 MW**

2. **Design Temperature Range : 10°F to 105°F**

3. **a. Drum Water Level Sensing Lines**

   **b. Steam Flow Transmitter**

4. **a. <u>Failure Mode</u> - One Heat Recovery Steam Generator was taken out of service by the control system, due to a false low drum level signal.**

   **<u>Cause of Failure</u> - Drum level sensing lines froze, due to failure of freeze protection measures.**

   **<u>Contribution to overall failure of unit</u> - The unit consists of 4 HRSGs, and 3 remained in service. Unit was derated 23 MW.**

   **b. <u>Failure Mode</u> - False signal of low steam flow resulted in loss of drum water level.**

   **<u>Cause of Failure</u> - Sensing lines to steam flow transmitter froze, causing false low steam flow signal. Boiler feed pump flow was reduced by the control system.**

   **<u>Contribution to overall failure of unit</u> - Unit was tripped by the control system, on low drum level. Unit was derated 85 MW.**

5. **a. Sensing lines heat tracing and insulation were upgraded. Wind breaks were added.**

   **b. Sensing lines heat tracing and insulation were upgraded.**

6. **a&b. Wind Breaks were completed 2/15/90.**
   **Heat Tracing and Insulation were upgraded 5/2/90.**

7. **Wind Breaks - $6516 installed - Maintenance**

   **Heat Tracing and Insulation - $102,750 - Maintenance**

1. T H Wharton Gas Turbine Unit 54 : 58 MW

2. Design Temperature Range : 10°F to 105°F

3. Loss of Fuel Oil Supply

4. Failure Mode - Fuel oil valve could not be operated.

   Cause of Failure - Ice formed in and immobilized fuel oil supply valve operator.

   Contribution to overall failure of unit - Gas turbine could not be operated without a fuel supply

5. The valve was replaced.

6. Valve was replaced 12/22/89.

7. Negligible cost

1. South Texas Project Unit 1 : 1250 MW

2. Operating Temperature Range : 3°F to 105°F *
Freeze Protection : 3°F

* This represents the maximum ambient conditions under which an engineering evaluation has determined the unit can operate. This evaluation, performed after the cold weather of December 1989, determined that the freeze protection and HVAC systems can operate at ambient temperatures lower than the nominal design minimums of 11°F for freeze protection and 29°F for HVAC systems.

3. a. Feedwater and Feedwater Booster Pumps
   b. Makeup Demineralizer System
   c. Deaerator Level and Pressure Instrumentation
   d. Emergency Cooling Water System Screen Wash Booster Pumps

4. a. Failure Mode - Seal water lines to feedwater and feedwater booster pumps froze, interrupting seal water supply to pumps.

   Cause of Failure - Seal water lines are uninsulated, by design.

   Contribution to overall failure of unit - Pumps were unable to operate without seal water. Unit could not be started without pumps.

   b. Failure Mode - Various level instruments, pumps and water lines froze, causing the demineralizer to be inoperable.

   Cause of Failure - Equipment was uninsulated by design, or was de-insulated for maintenance.

   Contribution to overall failure of unit - The lack of demineralized makeup water prevented continuation of unit start-up.

   c. Failure Mode - Level and pressure sensing lines froze.

   Cause of Failure - Sensing lines root valve stems and handles were not insulated.

   Contribution to overall failure of unit - Level and pressure indication are required during unit start-up and operation. Unit could not be started.

(STP Unit 1 cont'd)

d. <u>Failure Mode</u> - Screen wash booster pumps froze.

<u>Cause of Failure</u> - Plant operating procedures required cooling fans to run bringing outside air into pump enclosure which caused the pumps to freeze.

<u>Contribution to overall failure of unit</u> - Station declared Emergency Cooling Water System inoperable when Screen Wash Booster Pumps were found frozen. Plant Technical Specifications require the unit to be shut down when ECW is inoperable.

5. a. Engineering review is in progress to determine corrective action.
   b. Engineering review is in progress to determine corrective action.
   c. Instrument root valve stems and handles have been insulated.
   d. Plant operating procedures were revised to allow ECW cooling fans not to operate automatically in cold weather.

6. a. Corrective action will be completed 10/31/90.
   b. Corrective action will be completed 10/31/90.
   c. Corrective action was completed 2/16/90.
   d. Corrective action was completed 6/15/90.

7. a. Cost to be determined
   b. Cost to be determined
   c. $15,000 - Maintenance
   d. $5000 - Maintenance

ATTACHMENT B

| PLANT | CORRECTIVE ACTION | COMPLETION DATE FOR ENGRG OF CORRECTIVE ACTION | COST OF CORRECTIVE ACTION |
|---|---|---|---|
| LEGS 1 | Steam Drum End Enclosures | 06-30-90 | $10,000 - Maintenance |
| LEGS 1&2 | Electromatic Relief Valve Pressure Controller Relocation | 04-17-90 | $8,000 Maintenance |
| LEGS 1&2 | Sootblower Pressure Reducing Valve Relocation | 04-16-90 | $31,400 Maintenance |
| LEGS 1&2 | Bottom Ash Hopper Sluice Gate Pistons | 10-31-90 | Not Available |
| WAP 1,2&3 | Steam Drum End Enclosures | 09-30-90 | $30,000 - Maintenance |
| WAP 5,6,7&8 | Steam Drum End Enclosures | 08-31-90 | $40,000 - Maintenance |
| WAP 5 | Turbine Instrument Line Enclosure | 09-31-90 | $30,000 - Maintenance |
| WAP 1,2&3 | Turbine Instrument Line Heat Tracing & Insulation Upgrade | 08-31-90 | $33,000 - Maintenance |
| WAP 5,6&7 | Instrument Air Line Moisture Drains | 08-31-90 | $57,000 - Capital |
| PHR 1&2 | Instrument Air Line Moisture Drains | 06-30-90 | $38,000 - Capital |
| PHR 2 | Throttle Pressure Sensing Lines | 10-01-90 | $38,800 - Maintenance |
| PHR 3&4 | Instrument Air Line Moisture Drains | 06-30-90 | $38,000 - Capital |
| PHR 4 | Boiler Feed Tank Level Transmitter | 09-01-90 | $1,100 - Maintenance |
| PHR 3&4 | Aux Boilers Steam Drum End Enclosures | 10-31-90 | Not Available |
| SRB 1,2,3&4 | Steam Drum End Enclosures | 09-30-90 | $40,000 - Capital |
| SRB 1,2,3&4 | Turbine Instrument Line Heat Tracing & Insulation Upgrade | 03-30-90 | $44,000 - Maintenance |

| PLANT | CORRECTIVE ACTION | COMPLETION DATE FOR ENGRG OF CORRECTIVE ACTION | COST OF CORRECTIVE ACTION |
|---|---|---|---|
| SRB 1,2,3&4 | Instrument Air Line Moisture Drains | 09-30-90 | $76,000 - Capital |
| CBY 1&2<br>3 | Instrument Air Line Moisture Drains<br>Caustic Line Windbreak Wall | 09-30-90 | $38,000 - Capital<br>Maintenance |
| GBY 5 | Steam Drum End Enclosure | 06-30-90 | $10,000 - Maintenance |
| GBY 5 | BWCP LINE HEAT TRACING & Insulation Upgrade | 07-31-90 | $4,100 - Maintenance |
| GBY 5 | Burner Deck Enclosures | 10-31-90 | Not Available |
| THW 2 | Steam Drum End Enclosure | 06-08-90 | $10,000 - Maintenance |
| THW 2 | BWCP Line Heat Tracing & Insulation Upgrade | 06-30-90 | $5,500 - Maintenance |
| THW 2 | Turbine Instrument Line Heat Tracing & Insulation Upgrade | 04-18-90 | $11,000 - Maintenance |
| STP 1&2 | Additional freeze protection for auxiliary cooling surge tank | 10-21-90 | Not Available |
| STP 2 | Feedwater Booster Pumps | 10-31-90 | Not Available |
| STP 2 | Insulate Root Valves | 02-16-90 | $15,000 - Maintenance |
| STP 2 | ECW Screen Wash Booster Pumps | 06-15-90 | $5,000 - Maintenance |

**ATTACHMENT C**

**Cogenerator Responses**

**OxyChem®**

**Irv Kowenski**
Manager-Energy

June 12, 1990

Ms. Patricia E. Look
Sr. Contract Administrator
Cogeneration Department
Houston Lighting & Power
P. O. Box 1700
Houston, Texas 77001

Re: PUC Questionnaire

Dear Ms. Look:

Per your request, attached is information you requested concerning the severe cold weather period in December 1989. If you need any more information, please feel free to contact me.

Sincerely,

I. Kowenski

I. Kowenski
Manager-Energy

/ih

attachment

**Occidental Chemical Corporation**
Corporate Office
Occidental Tower, 5005 LBJ Freeway
P.O. Box 809050, Dallas, TX 75380-9050
214/404-3446

OxyChem.

Electrochemicals & Specialty Products – Houston Area

# MEMO

TO: Irv Kowenski - Dallas

FROM: Dwight Howell - Battleground

DATE: June 11, 1990

SUBJECT: PUC Questionnaire

1) Unit Name - OxyChem Cogeneration - Battleground Plant
Unit MW Capacity - 200

2) The unit site design conditions for capacity considerations are 30° F to 95° F.

The unit design temperature limitations are -25° F with no maximum limitation. Note: The instrumentation enclosures and heat trace tubing bundles in the plant are rated for a minus 25° F at 3 watts/FT electrical trace and 100 watts per enclosure.

3) The No. 2 Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG) was removed from service on December 23, 1989 due to instrumentation problems caused by the severe weather conditions. The power loss was approximately 100 megawatts with the unit being restarted after approximately twelve (12) hours.

4) On the No. 2 HRSG, the HP steam drum, pressure and level instruments, the deaerator pressure and level instruments and the high pressure steam flow and boiler feedwater instruments either froze or were erratic due to partial freezing. The GT experienced no failed instruments but is used to produce steam from the HRSG and therefore was shut down in conjunction with the HRSG.

Instruments started to freeze at about +25° F. For this to occur, there are problems with the installation, condition, operation and insulation of the instruments. Some of the problems were identified as tripped electrical circuits supplying heat trace and enclosures that were not completely tight and sealed.

5) and 6)

Corrective actions to ensure the reliability and operations of the instruments essential for the cogeneration plant will include the following:

1. The annual instrument freeze survey should be completed no later than the middle of November. Each installation must be inspected thoroughly.
2. Critical instruments to be upgraded or have new enclosures and heat trace installed as a top priority include:
   a. High pressure steam flows FT525/FT725 - completed 03/90.
   b. Boiler feedwater flows FT522/FT722 - completed 03/90.
   c. High pressure steam pressure PT538/PT738 - completed 04/90.
   d. High pressure steam drum level LT520/LT720 - expected completion 10/90.
   e. Low pressure steam drum level LT550/LT750 - expected completion 10/90.
   f. Deaerator level LT1121/LT1123 - expected completion 10/90.
   g. Deaerator pressure PT1120 - expected completion 10/90.
3. A method to determine that heat trace bundles are working will be developed, rather than relying on having power at the connections and feeling the temperature of the trace where it enters the bundle.
4. Instrument enclosures must be tight and sealed. This means replacing sealing gaskets and closing/repairing any cracks or holes in any part of the enclosure. This should be done on the survey each year.
5. Use of the fiberglass wrapping tape with the white sealer over it will be discontinued on instrument installations. The protection provided by this material is inadequate.
6. All installations must be inspected thoroughly for any openings or cracks, and must be repaired. The manufacturer's specifications are only valid if the installation is secure from heat loss.
7. Process block valves on the orifice plates, or on pressure outlets, should have the metal jacketed standard insulation installed. This end of the tubing bundle must be inspected carefully each year and all cracks and openings closed.
8. Thermometers should be installed on all critical instrument enclosures. This would eliminate the need for opening the enclosure during cold weather. The thermometer would indicate whether the heat system was operating sufficiently.

9. A priority list for upgrade of less critical instruments will be developed.

All of the above items are expected to be completed by November 1, 1990.

7) Cost per installation and upgrade will be about $800.00 plus labor of $500.00. The total estimated cost is estimated to be approximately $15,000.00. These corrective action costs will be classified as a maintenance expense.

H.D. Howell

H. D. Howell

HDH:ja

cc: M. Gough
F. Carelli
D. Scholes

**Clear Lake Cogeneration**
Limited Partnership

9602 Bayport Road Pasadena, Texas 77507-1404 (713) 474-7611

June 8, 1990
CL-DWR-1367

Ms. Patricia Look
HOUSTON LIGHTING & POWER COMPANY
P.O. Box 1700
Houston, Texas 77001

Subject: Freeze Modifications, Clear Lake Cogeneration

Dear Ms. Look,

Clear Lake Cogeneration, which currently supplies nonfirm energy, to HL&P, has taken the following actions as a result of the December 1989 freeze.

1. GT104; 100 MW 501D5 Westinghouse Combustion Turbine

   GT104 tripped on a power supply failure to the Woodward Netcon 5000 governor. A computer grade uninterruptible power supply was installed with the existing UPS system becoming a backup power supply. This was completed in January 1990 at a cost of $15,000.

2. GT103; 100 MW 501D5 Westinghouse Combustion Turbine

   GT103 tripped and was removed from service when a lube oil supply pump failed. The pumps were a Buffalo Forge grease lubricated bearing design. All pumps have been modified to an oil lubricated bearing design. This was completed in March 1990 at a cost of $36,000.

3. ST101; 50 MW Westinghouse Steam Turbine
   ST102; 14 MW Westinghouse Steam Turbine

   Both units were forced out of service upon loss of boiler feedwater from steam host. They are currently making several modifications to prevent their water plant from freezing.

RECEIVED

JUN 11 1990

COGENERATION & SMALL POWER PRODUCTION DEPARTMENT

4. Instrumentation Systems

Several transmitters froze in the plant due to inadequate design and installation of the original freeze protection systems. Although no shutdowns occurred due to freezing instrumentation, a complete plant upgrade of the heat tracing and insulation is planned for completion in the fourth quarter of 1990 at an estimated expense of $300,000. Design criteria used for this upgrade was 5°F.

Should you require any further information feel free to contact me.

Sincerely,

CLEAR LAKE COGENERATION

DeWayne W. Roberts
Plant Manager

/dd

DESTEC
ENERGY
P. O. Box 19398
Houston, Texas 77224

DESTEC ENERGY, INC.
2500 CITYWEST BLVD. SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

June 11, 1990

Ms. Patricia E. Look
Senior Contract Administrator
Cogeneration Department
Houston Lighting & Power
P. O. Box 1700
Houston, Tx 77001

Dear Ms. Look:

The attached sheet is our response to the questions requested by the Public Utility Commission Staff. Please inform us if additional information is needed.

Sincerely,

Jerry C. Dearing

Jerry C. Dearing
Asset Management

JCD:wb

cc: D. K. Mott
W. P. Ruwe

PUBLIC UTILITY COMMISSION OF TEXAS

The following is CoGen Lyondell's response to the PUC questions concerning operating reliability during the December 1989 cold weather emergency.

1. The steam turbine generator 001 was the only unit lost during the period. The unit is rated at 135MW.

2. The unit does not have design ambient temperature limitations.

3. There were several instrumentation failures (i.e. level transmitters) but they did not adversely affect the generating capacity of the plant.

4. The steam turbine generator 001 tripped due to a failed vacuum pump. The cause of the vacuum pump failure was a frozen water seal line. The pump failed causing a loss of a condenser vacuum which tripped the steam turbine generator.

5. A thermal barrier was added near the vacuum pump and heaters will be used in the area.

6. This preventive measure has been completed at minimal cost.

DESTEC
ENERGY

DESTEC ENERGY, INC.
2500 CITYWEST BLVD. SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

June 8, 1990

Patricia E. Look
Cogeneration Department
Houston Lighting & Power
Box 1700
Houston, Texas 77001

Dear Pat:

Please find attached our response to the questionnaire you forwarded to us in your letter of May 22, 1990, regarding the cold weather experience in December, 1989. Let me know if we can be any any further assistance.

Sincerely,

John J. Stauffacher

Attachment

RESPONSE TO HL&P COLD WEATHER QUESTIONS

1. UNIT NAME AND UNIT MW CAPACITY.

   ANSWER: Dow Chemical Freeport - Contract MWs - 325

2. UNIT GENERAL DESIGN TEMPERATURE LIMITATIONS (MAXIMUM AND MINIMUM), IN DEGREES F.

   ANSWER: All units are designed to operate between 0 and 120 degrees F provided freeze protection on controls and instrumentation is adequate.

3. LIST OF EQUIPMENT(S) (OR PLANT SYSTEMS) THAT WERE ADVERSELY AFFECTED BY THE COLD WEATHER.

   ANSWER: Boiler steam drum level controls
   Deaerator level controls
   Steam pressure controls
   Instrument air lines
   River water lines
   Potable water system
   Fire protection system
   Division condensate inventories

4. FOR EACH PIECE OF EQUIPMENT OR SYSTEM THAT FAILED, IDENTIFY THE FAILURE MODE, THE CAUSE OF THE FAILURE, AND HOW THE EQUIPMENT OR SYSTEM LOSS CONTRIBUTED TO THE OVERALL FAILURE OF THE UNIT.

   ANSWER: Drum level and steam pressure controls were adversely affected in most cases due to inability of the existing heat tracing systems to fully protect from the extreme temperatures and associated high winds experienced during the freeze. Inability to control drum levels caused brief run-back of one unit and a short-term trip of one boiler. Neither had significant effect on production capabilities.

   Problems with the various water systems were generally caused by freeze damaged valves and lines at various locations.

   Two units tripped when pre-filter pads plugged with snow at the inlet. Once down, associated condensate and cooling water lines froze and the unit could not be restarted until the freeze damage was repaired.

Some level and pressure controls experienced freezing problems when the heating capability of the existing heat tracing systems was exceeded due to the sub-freezing temperatures and high winds. These level and pressure control systems incorporate redundant transmitters and indications; therefore, when a primary control indication was lost a back-up was placed in service or the system was operated manually for a brief period while the primary was repaired. In one isolated case during the early stages of the freeze, the loss of a deaerator level control system caused one high pressure boiler feed pump to trip which resulted in a run-back of one unit. However, the level control was restored and the unit returned to full capacity within approximately 20 minutes.

5. FOR EACH PIECE OF EQUIPMENT OR SYSTEM, IDENTIFY THE NECESSARY CORRECTIVE ACTIONS(S) TO PREVENT RECURRENCE. PLEASE PROVIDE SUFFICIENT DETAIL TO DESCRIBE THE FULL RANGE OF ACTIVITIES NECESSARY TO REASONABLY PRECLUDE FUTURE FAILURE.

ANSWER: The following actions have been taken to prevent failure caused by a freeze of similar magnitude:

- Insulation and heat tracing systems were improved.

- Operating and freeze preparation procedures were modified.

- Temporary freeze protection equipment was purchased and inventoried and incorporated into procedures.

- Improvements were made in many of the existing transmitter locations.

6. FOR EACH PIECE OF EQUIPMENT OR SYSTEM IDENTIFIED ABOVE, REPORT THE ACTUAL OR ANTICIPATED DATE OF CORRECTIVE ACTION COMPLETION.

ANSWER: Implosion dampers on two units - these machines have no dampers to open to provide inlet air to the turbine in the event of plugged inlet filters. A project has been defined to install dampers on these two machines. Projected completion date is second quarter, 1991.

BAYOU COGENERATION PLANT
11777 Bay Area Blvd. / Pasadena, Texas 77507
(713) 474-8220 / Fax: (713) 474-8226

Richard H. Kidder
General Manager

June 1, 1990

Houston Lighting & Power Company
Patricia Look
Sr. Contract Administrator
Cogeneration Department
P. O. Box 1700
Houston, TX 77001

cc: WD Lindberg
BR Milam
RE McGinnis
CP Burckle

SUBJECT: PUC Request Dated May 10, 1990

Dear Ms. Look:

The Bayou Cogeneration Plant maintained 114.5% of our contract power during the 72 hour freeze from 12/22/89 through 12/24/89. We did however have problems with our plant when the temperature fell below 14 degrees Fahrenheit. I have attached the following documentation that will answer the questions asked by the PUC:

1. Net Plant Output vs Ambient Temperature
2. Bayou Cogeneration Plant Performance Characteristics
3. Sequence of Events on Problems
4. Generator Breaker Open and Closed Log
5. Corrective Action, Completion Dates and Estimated Costs

If you need additional information, please contact me.

Regards,

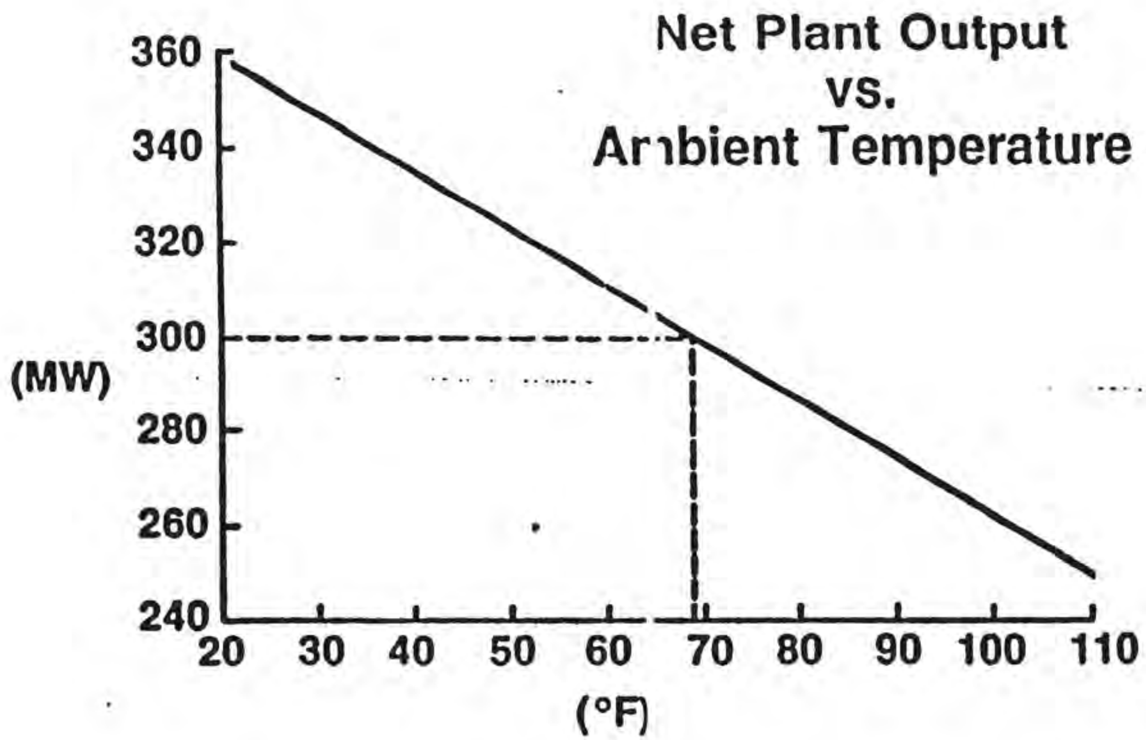
RH Kidder

Richard H. Kidder
General Manager

Attachment

kt/506

Attachment #1




Sensitivity to Inlet Temperature Is Characteristic of Gas Turbine Cycles

Attachment #2

# Bayou Cogeneration Plant Performance Characteristics

## (4) MS7001 E Gas Turbine/Heat Recovery Steam Generator Trains

| | |
|---|---|
| Net Power @ 69°F | 300.5 MW |
| Steam to Process | 1,380,000 lb/hr |
| Heat Consumption (HHV) | 3726 × $10^6$ Btu/hr Natural Gas |
| Overall Energy Efficiency (HHV) | 70% |
| Steam Injection for $NO_x$ Control | < 4[illegible] ppmv $NO_2$ @ 15% $0_2$ Dry Basis |

| | |
|---|---|
| PURPA Efficiency | 54% |
| – Thermal Fraction | 61% |

Attachment #3

SUBJECT: Big Freeze of "89"

The following sequence of events summarizes the Bayou Cogeneration Plant's problems during the freeze from December 22, 1990 through December 24, 1990:

The temperatures at the plant were below freezing for approximately 48 hours with the lowest temperature being 8 degrees F early on the 23rd. Starting about 8:30 a.m. on December 22nd, we started losing all flow and pressure transmitters due to freezing sensing legs. This caused operators to control the plant manually with local; visually drum level readings radioed from the outside operators. All NOX steam transmitters and control valves froze and we were unable to restore NOX steam for the duration of the freeze. At 11:13 p.m. plant feedwater supplied by Big 3 was lost due to pressure instrumentation freezing. This caused trips on units #1, #2, and #3. Units were restarted and loaded as fast as possible after feedwater was restored. Units #1 and #2 each tripped later that night due to false level indication caused by freezing and were immediately restarted.

At 10:50 a.m. on December 34th, unit #1 was shutdown with a leaking cooling water skid. One side of the skid was isolated and the unit restarted after 1.75 hours.

The Bayou Cogeneration Plant normally has a 3 man operating crew. During the over 48 hours of the freeze we utilized our full complement of 20 people to run the plant.

Attachment #4

| DATE | UNIT | REASON | BREAKER OPEN | BREAKER CLOSED | |
|---|---|---|---|---|---|
| 12/22 | 2 | BTI loss of feedwater | 2213 | 0433 | 12/23 |
| 12/22 | 3 | BTI loss of feedwater | 2314 | 0137 | 12/23 |
| 12/22 | 1 | BTI loss of feedwater | 2316 | 2349 | 12/22 |
| 12/23 | 1 | Instrument freeze on level indication | 0655 | 0723 | 12/23 |
| 12/23 | 1 | Instrument freeze on level indication | 1016 | 1046 | 12/23 |
| 12/24 | 1 | Cooling water skid | 1050 | 1235 | 12/24 |

Attachment #5

SUBJECT: Corrective Action Taken to Remedy Freeze Problems

The cause of our freeze problems were isolated to our instrument lines from our boilers. These lines were heat traced but could not withstand temperatures below 15 degrees Fahrenheit. The corrective action is as follows:

1. Replace heat tracing and reinsulate 1500 feet of instrument lines to 20 degrees below zero.
2. Heat trace approximately 16 instrument cabinets throughout the plant.
3. This corrective action will be completed by September 1, 1990.
4. The cost of this project will be approximately 100,000 dollars and will be categorized as maintenance expense.

AES
Deepwater
Inc.

June 11, 1990

Houston Lighting & Power
P. O. Box 1700
Houston, TX 77001

Attn: Ms. Patricia Look
Sr. Contract Administrator
Co-Generation Department

Subject: Public Utility Commission Questionnaire - Freeze Protection

Dear Ms. Look:

In response to your request dated May 22, 1990, we would like to provide the following information:

(1) Unit Name and Unit MW Capacity

AES Deepwater, Inc.
160 MW - Gross

(2) Design Temperature Limitations

Maximum - 120°F
Minimum - 0°F

(3) List of Equipment affected by cold weather:

Flow and Level Transmitters - Plant Wide

The AES Deepwater Cogeneration facility was off line a total of 13.86 hours during the freeze period (Dec. 22 thru Dec. 27) with actual unit outages occurring Dec. 22 (9.05 Hrs) and Dec. 23 (4.81 hrs). The unit operated at 49.5% capacity (reduced load) from Dec. 24 thru Dec. 27 with no outages. The facility returned to full load on Dec. 28.

Specific equipment affected is as follows:

- Throttle Pressure Transmitter
- Mass Blow Down Valve
- Drum Level Transmitter
- Fan Bearing Housings - Water Cooled

(4) Equipment Failure

A. Equipment - Throttle Pressure Transmitter
Failure Mode - Erratic Readings
Cause - Freeze
Contribution to Plant - Unit Trip

P.O. Box 6111
Pasadena, Texas 77506
(713) 472-8687
Telecopier:
(713) 472-0389

B. Equipment - Mass Blow Down Valve
Failure Mode - Stuck
Cause - Freeze
Contribution to Plant - Unit Trip

C. Equipment - Drum Level Transmitter
Failure Mode - Intermittent Operation
Cause - Freezing
Contribution to Plant - Reduced Load

D. Equipment - Water Cooled Fan Bearings
Failure Mode - Cracked
Cause - Freeze
Contribution to Plant - Reduced Load

5. Corrective Action

A. Throttle Pressure Transmitter -
Insulate and Heat Trace

B. Mass Blow Down Valve -
Insulate and Heat Trace
Possible Additional Dryer on Actuating Air

C. Drum Level Transmitter -
Re-insulate, Additional Heat Tracing,
Glycol in Dead Leg

D. Fan Bearings -
Install Water Flow and Temperature Monitors
Change Cold Weather Operating and Inspection Procedures

6. The anticipated completion date for all corrections is November 30, 1990.

7. Cost of Corrective Action (Estimated)

| | | |
|---|---|---|
| A. | Throttle Pressure Transmitter | $750.00 |
| B. | Mass Blow Down Valve | $1,000.00 |
| C. | Drum Level Transmitter | $750.00 |
| D. | Fan Bearings | $3,000.00 |

We trust this information will comply with your request.

Sincerely,

J. R. Johnson

J. R. Johnson
Manager, Support Services

Lower Colorado River Authority
Post Office Box 220 Austin, Texas 78767 • (512) 473-3200

June 15, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

RE: Project No. 9542

Dear Mr. Oberg:

Enclosed please find LCRA's response to your request for information regarding LCRA unit outages during the December 1989, cold weather period.

If you need any further assistance, please contact Jim Briley at 385-7131.

Sincerely,

Walter J. Reid
Executive Director of
Electric Operations

WJR:JB:bcm

Attachment

**LCRA RESPONSE - PROJECT 9542**

There were two LCRA unit outages during the December 1989, cold weather period attributable to weather-related equipment problems. The requested information for these outages is listed below:

OUTAGE #1
December 22, 1989

1) Unit Name and Unit MW Capacity

   Sim Gideon Unit #2; Capacity 140 MW Gross

2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

   No temperature design limitations were available; the unit was placed in commercial service in April, 1967.

3) List of equipment(s) or (plant systems) that were adversely affected by the cold weather.

   Deaerator Level transmitters.

4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

   Water in sensing lines to the deaerator level transmitters froze causing a loss of level indication. The unit operator then tripped the unit according to established procedures.

5) For each piece of equipment of system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

   At the time of the trip, the sensing lines were wrapped with asbestos-based insulation material. Additional foil-backed blanket duct insulation was added. These lines will be stripped and re-wrapped with new materials at a future time when the asbestos can be dealt with safely.

6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

   This work was done on February 8, 1990.

7) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

This work incurred a maintenance expense of $300.

OUTAGE #2
December 23, 1989

1) Unit Name and Unit MW Capacity

Sam K. Seymour Unit #3; Capacity 440 MW Gross

2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

General design temperature limitations (taken from Unit Design Specification CP 300(2.3.3), Section E. Temperatures are dry bulb, degrees Fahrenheit.

| | Temperature |
|---|---|
| Extreme Maximum | 110 |
| Temp. exceeded 1% of the time | 101 |
| Mean Daily Maximum | 80 |
| Mean | 69 |
| Mean Daily Minimum | 58 |
| Temp. exceeded 99% of the time | 25 |
| Extreme Minimum | 1 |

3) List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

A & B Drum Level transmitters

4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

Water in the A & B Drum Level transmitter sensing lines froze, causing the unit to trip automatically due to loss of level indication.

5) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

The sensing lines were re-insulated, leveled and installed in hangers to prevent excess water accumulation.

6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

**This work was completed on May 30, 1990.**

7) **For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.**

**This work incurred a maintenance expense of $420.**

TMPA

Serving the cities of Bryan Denton, Garland & Greenville

PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
JUN 12 1990
BY ____
ELECTRIC

June 8, 1990

Letter No. SP-90-0074
File Code: 513.75

Chester R. Oberg
Public Utility Commission of Texas
7800 Shoel Creek Blvd., Suite 400N
Austin, Texas 78757-0100

Subject: Winterizing Corrective Actions

Dear Mr. Oberg:

Enclosed is the information you requested concerning winterizing corrective actions.

If additional information or data is required, please advise.

Sincerely,

Gailord M. White
Manager of System
Planning & Operations

GMW/it

cc: Document Control

**TEXAS MUNICIPAL POWER AGENCY**

1. **Gibbons Creek Steam Electric Station Unit #1 - 440 MW**

2. **Unit Design Temperature Limitation - 15°F minimum**

   **107°F maximum**

3. **Actual Equipment Failures:**
   A) **Boiler Drum Level Transmitter** (see attached sheet for details)
   B) **(BWCP) Boiler Water Circulation Pump Differential Pressure Transmitter** (see attached sheet for details)

4. **Potential Equipment Failures:**
   A) **(D.A.) Deareator Storage Tank Level Transmitter** (see attached sheet for details)
   B) **Reheat Spray Trip Valve And Control Valves** (see attached sheet for details)

**Actual Equipment Failure: Boiler Drum Level Transmitter**

The boiler drum level transmitters are located in a weather enclosed building adjacent to the steam drum. Normally this enclosure has adequate heating supplied by the steam drum. At near $0^{o}F$ this protection became insufficient. The freezing of these transmitters tripped the boiler on erroneous low drum level indication.

We are in the process of redesigning the steam drum enclosure to provide greater access to the transmitters. We will reinsulate the transmitters, their associated taps and instrument lines.

We will be installing a floor that will reduce/eliminate cold air in leakage.

The operating procedures and the Winter preparedness checklist have been changed to include provisions for an additional heat source to be used whenever the outside ambient air temperature reaches $32^{o}F$.

Estimated completion date for redesigning and construction of the drum enclosure is October 1, 1990.

**Total Improvement Costs $20,000.00**

**Actual Equipment Failure: Boiler Water Circulation Pump Differential Pressure Transmitter**

The boiler waterwall circulation pump differential pressure transmitters are housed in an all weather building with an electric heater inside for freeze protection. Due to the freezing weather conditions near $0^oF$, the protection was insufficient. The transmitters froze creating a false indication of a low waterwall circulation which in turn tripped the boiler.

The heater was returned to service and an additional kerosene heater was placed inside the enclosure.

Operation procedures have since been modified to increase the awareness of all Operations personnel on the possible failure of electrical equipment associated with freeze protection. The Winter preparedness checklist has been changed to include the inspection of all heaters and breakers to insure their reliability.

**Total cost $0.00**

**Potential Equipment Failure: Deareator Storage Tank Level Transmitter**

The Deareator Storage Tank Level transmitter did not contribute (NC) to any unit trips or unit failure but the potential was there if corrective measures had not been taken.

The Deareator Storage Tank Level transmitter is presently enclosed in a insulated housing and is heat traced. The Deareator Storage Tank Level and its transmitter are located on the north side of the boiler structure about 150 feet above the ground. Additional heat tracing and insulation were added several years ago and generally can handle a typical winter cold spell, but the winter of 1989 was not typical. A portable heater was placed near the housing to provide additional protection.

Our long term plan is to enclose the whole Deareator Storage Tank Level area but this is a costly venture. Our short term improvements will be to install a permanent windbreak along the north wall and lay down a solid plate floor (replacing the grating) to protect the area from the bitter windchills.

**Total Cost $2,500** (short term corrective action)

**Potential Equipment Failure: Reheat Spray Trip Valve And Control Valves**

The superheat and reheat spray trip valves and control valves did not contribute to any unit failures, however, the potential was there for at least a major load reduction due to the failure of the valves. After the unit had tripped on Boiler Water Circulation Pump differential pressure, the valves closed as they are supposed to do. Before the unit was able to return to 20% load, the trip valves froze in the closed position. This limited our capability to spray for high steam temperatures. We erected a temporary wind break and placed a kerosene heater alongside the valve to thaw it out. Plans call for a permanent wind break to be installed before October 1, 1990.

**Total Cost $3,000.00**

TUELECTRIC

**Dwight Royall**
*Director*
*Regulatory Services*

June 18, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

RECEIVED
JUN 18 1990
PUBLIC UTILITY COMMISSION
GENERAL COUNSEL BY ____

Dear Mr. Oberg:

Pursuant to your letter dated May 10, 1990, attached is TU Electric's response to your questionnaire concerning the performance of our generating units during the cold weather emergency in December 1989.

Nine (9) TU Electric generating units were identified that had weather related failures and were unable to respond to the emergency conditions. These units were able to return to service soon after the units tripped. Please refer to the January 10, 1990 cold weather filing for the generating unit sequence of events. For clarity, three additional generating unit failures are described although the failures were not weather related. In addition to the above, reports from cogeneration facilities that experienced weather related difficulties are attached.

The effects of the December 1989 freeze were minimized due to the efforts of TU Electric's Freeze Protection Task Force commissioned in 1982 as a result of severe weather during the winter of 1981. The task force identified several areas of concern and developed recommendations to alleviate the causes for unit trips related to cold weather. During the period of time from Fall 1982 through Spring 1984, approximately five million dollars were expended to enhance the reliability of TU Electric generating units during freezing conditions.

Each Fall, a special effort is made to inspect the freeze protection on each TU Electric generating unit for adequacy in the event of freezing weather. Plant personnel evaluate the heat tracing circuits, wind breaks, fuel oil related equipment and the weather sensitive instrumentation. Operations personnel conduct testing and training on fuel oil burning prior to the winter peak period. As the extreme cold weather approaches, additional units are brought on-line for reserve as needed and when natural gas curtailments are imminent, units are transferred to oil burning.

If you have any questions, please let me know.

Yours very truly,

Dwight Loyall

ld
Attachment

1.) **Unit Name and Unit MW Capacity:**

**River Crest Unit 1; 110 MW.**

2.) **Unit general design temperature limitations (maximum and minimum), in degrees F:**

**Maximum limit: Designed to meet highest regional temperatures with only minor derations.**
**Minimum limit: -10 degrees F and 35 MPH wind velocity.**

3.) **List of equipment(s) (or plant systems) that were adversely affected by the cold weather:**

**Condenser plugging due to shad runs.**

4.) **For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:**

**<u>Failure Mode</u> - The condenser became plugged.**

**<u>Cause of the Failure</u> - The condenser became plugged due to an exhorbitant number of shad which entered the intake area, plugged the intake screens and carried over into the waterboxes of the condenser.**

**<u>Contribution to Unit Failure</u> - Excessive back pressure on the low pressure turbine caused a turbine trip.**

5.) **For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:**

**The shad were removed from the waterboxes of the condenser. A portable net was installed in front of the intake screens. An improved net will be available for installation during cold weather periods.**

6.) **For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:**

**Completion - August, 1990.**

7.) **For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:**

**Maintenance Expense - $900.**

1.) Unit Name and Unit MW Capacity:

Valley Unit 2; 550 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing pressure to Valve No. 263.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - Transmitter sensed low feedwater flow.

Cause of the Failure - The freeze protection circuit failed.

Contribution to Unit Failure - The transmitter, sensing low feedwater flow, closed Valve No. 263. The unit tripped on low feedwater flow.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The freeze protection circuit has been repaired by plant personnel.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $300.

1.) Unit Name and Unit MW Capacity:

Morgan Creek Combustion Turbine No 4; 65 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: 115 degrees F.
Minimum limit: - 5 degrees F.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Natural Gas Fuel Supply.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - Minimal natural gas supply pressure.

Cause of the Failure - Minimum natural gas supply pressure necessitated a fuel supply transfer to fuel oil which created a temperature mismatch in the combustion zone.

Contribution to Unit Failure - This temperature mismatch caused a runback to off-line for the combustion turbine.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

By design, the combustion turbines must operate within temperature mismatch limits in the combustion zone. If a loss of natural gas pressure can be anticipated, a manual fuel transfer at lower loads is preferable to an automatic fuel transfer at full load.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completion - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Mountain Creek Unit 7; 125 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - An increase in fuel/air flow resulting in high furnace pressure.

Cause of the Failure - While operating at high load, the unit responded to a frequency deviation.

Contribution to Unit Failure - The increase in fuel/air flow led to a high furnace pressure trip. A subsequent trip occurred upon restarting the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

A runback has been incorporated into the control system that will drop fuel/air flow a few percent upon a high furnace pressure condition.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Mountain Creek Unit 2; 33 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Circulating water screens.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A heavy shad run clogged the revolving and stationary intake screens.

Cause of the Failure - The clogged intake screens caused the circulating water pumps to loose suction.

Contribution to Unit Failure - The unit tripped on low vacuum.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The screens were immediately cleaned and the unit restarted. A new screen wash pump was installed to better wash the revolving screens when in use.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $13,000.

1.) Unit Name and Unit MW Capacity:

Monticello Unit 2; 575 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing waterwall pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The sensing line to the waterwall pressure transmitter froze.

Cause of the Failure - A pipe hangar, located near the sensing line, propagated low temperatures to the line.

Contribution to Unit Failure - The transmitter sent a high waterwall pressure signal to the control system, which tripped the unit to protect it.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The plant personnel have installed insulating material at these hanger locations to prevent the hangers from propagating low temperatures to the sensing line.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - December, 1989.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,000.

1.) Unit Name and Unit MW Capacity:

Tradinghouse Unit 1; 565 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing boiler convection pass outlet header pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - The sensing line at the pressure tap root valve froze.

<u>Cause of the Failure</u> - The transmitter enclosure heater was operating, but the heat tracing was found grounded.

<u>Contribution to Unit Failure</u> - The transmitter sent the control system a signal that the boiler convection pass outlet header pressure was high, which tripped the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The freeze protection circuit has been repaired and the root valve reinsulated.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $500.

1.) Unit Name and Unit MW Capacity:

Stryker Creek Unit 1; 175 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The combustion controls swung which caused low burner gas header pressure.

Cause of the Failure - While the unit was firing a combination of natural gas and fuel oil, a control upset caused the combustion controls to swing.

Contribution to Unit Failure - The low burner gas header pressure caused a low pressure trip.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The low gas block setting has been increased.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Monticello Unit 3; 750 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing primary superheater outlet pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A sensing line to the primary superheater outlet transmitter froze.

Cause of the Failure - Freeze protection, heat tracing wiring on the sensing line failed.

Contribution to Unit Failure - The transmitter sent a false indication to the control system that the unit was operating below supercritical pressure, which trip the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The plant personnel replaced the failed freeze protection, heat tracing wiring on the sensing line.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,700.

1.) Unit Name and Unit MW Capacity:

Martin Lake Unit 2; 750 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing low differential pressure on the boiler water circulation pump.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A sensing line to the low boiler water circulation pump differential pressure transmitter froze.

Cause of the Failure - Additional freeze protection was needed.

Contribution to Unit Failure - The transmitter sent a false indication to the control system for boiler circulation pump differential pressure, which tripped the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

Additional freeze protection has been added to this circuit. Plant personnel have added valves and drip legs in the sensing lines. During a freeze alert, the Instrument and Control technicians will drip these lines to allow water to flow to help prevent freezing. This will be monitored hourly during the freezing conditions.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,000.

1.) Unit Name and Unit MW Capacity:

Eagle Mountain Unit 3; 375 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Condenser plugging caused by shad and fish.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A heavy shad and fish run plugged one condenser while the other was being cleaned.

Cause of the Failure - The reduced circulating water flow through the condenser caused excessive back pressure.

Contribution to Unit Failure - Excessive back pressure on the low pressure turbine caused a low vacuum trip.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

Operations will closely monitor waterbox pressure and vacuum to minimize excessive plugging during shad and fish run. The use of a portable net during extreme cold weather conditions will be considered to avoid condenser plugging due to shed runs.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Handley Unit 5; 425 MW

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - An air flow transmitter feedback signal error was being investigated by plant personnel.

Cause of the Failure - The transmitter along with the air flow trip switch were inadvertently valved out.

Contribution to Unit Failure - When the trip switch was valved out the unit tripped.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The transmitter has been clearly marked to differentiate the trip switch from the flow transmitters.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

Texasgulf Cogeneration Facility
Newgulf (Wharton County) Texas
June 4, 1990
77 MW Capacity - 100F
96 MW Capacity - 20F
Design temperature range - 20F to 100F

Numerous control devices and systems were adversely affected by the extreme cold weather but only one failed and contributed to reduction in output. It is believed that the facility would have remained at maximum capacity and all other systems would have remained operative if the raw water supply had not been interrupted.

Raw Water Supply - Raw water which provides feedwater to Heat Recovery Unit, make-up to Cooling Tower, and process water to mining operation is gravity fed from a 265 acre reservoir through two 30" underground lines. Intake screens on each line prevent fish and debris from entering plant. At time of December freeze, reservoir level was about 5 feet lower than normal (dry weather), and the intake screens were dirty. Freezing temperatures caused slush and ice to be swept into screens interrupting flow of incoming water. It was necessary to take steam turbine off line and cease mine water production in order to conserve the small amount of water available and keep feedwater to the HRU.

**Corrective action**

1. Clean screens. - Completed
2. Maintain water level in reservoir higher. - Pump installed behind reservoir to capture water which leaks out of reservoir. - Completed
3. Provide tempering water at intakes to thaw slush. - Pipe run from abandoned water well (74F water). - Completed

Intake water flow was reestablished after about three hours, but steam turbine could not be returned to service until ambient temperatures rose above freezing.

Additional systems or equipment adversely affected but not contributing in the December 1989 freeze are listed below:

Raw Water

* In-line strainers became plugged with ice, fish, silt, etc. after intake screens were lifted. 12" valves and lines froze while cleaning the three strainers. - Wind barrier and homemade space heater to be installed - 12/01/90.
* Gas turbine lube oil cooling water heat exchanger, El-A or B, which is out of service will be cracked into service to prevent freezing. - Operating procedure
* Insulation and heat tracing on all flow and pressure transmitters to be inspected and repaired. Critical transmitters are PI-25002, LIT-25101. - 12/01/90
* Wind barrier to be erected near Pumps, P2, where cold air tunnels through opening. - 12/01/90

June 4, 1990

Treated Feedwater

* No significant problems on main line, but bleeders to be tagged on backwash line, brine dilution line, and drain. - Operating procedure - 12/01/90
* Low Pressure HRU drum level has three control devices, LIT-40302 & LI-40305 on the south side and LIT-40303 on north side. All are critical transmitters, but operator selects which transmitter is in control. Problems occurred with LIT-40303 on north side; control tubing insulation and heat tracing to be inspected. Additional blanket & heat tracing installed in O'Brien enclosure to prevent freezing, but will cause boiling if activated when ambient temperature is above 25F and/or wind is idle. Completed
* Medium Pressure HRU drum level has three control devices, LIT-41302 & LI-41305 on the south side and LIT-41303 on north side. Ditto low pressure drum. Completed
* 3-Sided enclosure to be erected around boiler chemical feed tank and pumps, D-11, P-114 A&B. - Completed

Steam System

* Critical transmitters to have tubing lines insulation and heat tracing inspected - 12/01/90
  - PIT-40304 LP Drum pressure
  - PIT-403 LP Drum pressure
  - PIT-40405 135 psig header
  - PIT-30303 Boiler 4 Master pressure
  - PIT-30304 Boiler 4 Master pressure
* 3-Sided enclosure to be erected around neutralizing amine tank and pumps, T-111, P-111 A&B. - 12/01/90

Condensate

* Deaerator level control, LIT-27123, insulation and heat tracing to be inspected - 12/01/90
* Feedwater transfer pump, P-271 A or B, which is out of service to have valves cracked permitting flow of water - Operating procedure

Cooling Tower

* Make-up water level transmitter, LIC-57002, to have insulation and heat trace inspected, plus enclosure to keep spray and resultant ice off. 12/01/90
* By-pass around flow control valve, LCV-57002, to be cracked. - Operating Procedure
* Chlorinator injection water to be placed on manual with continuous flow. - Operating procedure
* Blowdown to be placed on manual with by-pass cracked. - Operating procedure
* 3-Sided enclosure to be erected around Inhibitor feed tank & pumps, T-114, P-114 A&B. 12/01/90

Items marked with 12/01/90 completion dates will be completed as part of normal winterization. When temperatures are expected to fall below 20F, special operating procedures will be enacted.

Dow Chemical

6/8/90

**RESPONSE TO TUEC COLD WEATHER QUESTIONS**

1. UNIT NAME AND UNIT MW CAPACITY.

   ANSWER: Dow Chemical Freeport - Contract MWs - 300

2. UNIT GENERAL DESIGN TEMPERATURE LIMITATIONS (MAXIMUM AND MINIMUM), IN DEGREES F.

   ANSWER: All units are designed to operate between 0 and 120 degrees F provided freeze protection on controls and instrumentation is adequate.

3. LIST OF EQUIPMENT(S) (OR PLANT SYSTEMS) THAT WERE ADVERSELY AFFECTED BY THE COLD WEATHER.

   ANSWER: Boiler steam drum level controls
   Deaerator level controls
   Steam pressure controls
   Instrument air lines
   River water lines
   Potable water system
   Fire protection system
   Division condensate inventories

4. FOR EACH PIECE OF EQUIPMENT OR SYSTEM THAT FAILED, IDENTIFY THE FAILURE MODE, THE CAUSE OF THE FAILURE, AND HOW THE EQUIPMENT OR SYSTEM LOSS CONTRIBUTED TO THE OVERALL FAILURE OF THE UNIT.

   ANSWER: Drum level and steam pressure controls were adversely affected in most cases due to inability of the existing heat tracing systems to fully protect from the extreme temperatures and associated high winds experienced during the freeze. Inability to control drum levels caused brief run-back of one unit and a short-term trip of one boiler. Neither had significant effect on production capabilities.

   Problems with the various water systems were generally caused by freeze damaged valves and lines at various locations.

   Two units tripped when pre-filter pads plugged with snow at the inlet. Once down, associated condensate and cooling water lines froze and the unit could not be restarted until the freeze damage was repaired.

Some level and pressure controls experienced freezing problems when the heating capability of the existing heat tracing systems was exceeded due to the sub-freezing temperatures and high winds. These level and pressure control systems incorporate redundant transmitters and indications; therefore, when a primary control indication was lost a back-up was placed in service or the system was operated manually for a brief period while the primary was repaired. In one isolated case during the early stages of the freeze, the loss of a deaerator level control system caused one high pressure boiler feed pump to trip which resulted in a run-back of one unit. However, the level control was restored and the unit returned to full capacity within approximately 20 minutes.

5. FOR EACH PIECE OF EQUIPMENT OR SYSTEM, IDENTIFY THE NECESSARY CORRECTIVE ACTIONS(S) TO PREVENT RECURRENCE. PLEASE PROVIDE SUFFICIENT DETAIL TO DESCRIBE THE FULL RANGE OF ACTIVITIES NECESSARY TO REASONABLY PRECLUDE FUTURE FAILURE.

ANSWER: The following actions have been taken to prevent failure caused by a freeze of similar magnitude:

- Insulation and heat tracing systems were improved.

- Operating and freeze preparation procedures were modified.

- Temporary freeze protection equipment was purchased and inventoried and incorporated into procedures.

- Improvements were made in many of the existing transmitter locations.

6. FOR EACH PIECE OF EQUIPMENT OR SYSTEM IDENTIFIED ABOVE, REPORT THE ACTUAL OR ANTICIPATED DATE OF CORRECTIVE ACTION COMPLETION.

ANSWER: Implosion dampers on two units - these machines have no dampers to open to provide inlet air to the turbine in the event of plugged inlet filters. A project has been defined to install dampers on these two machines. Projected completion date is second quarter, 1991.

ATTACHMENT #1

COGEN LYONDELL

| Unit Name | Unit Capacity (mw) | Temperature Limitations ( F) | Failure mode | Equipment Affected | Cause of failure | Affect on overall system | Preventive measures |
|---|---|---|---|---|---|---|---|
| GTG101 | 75 | N/A | N/A | N/A | N/A | N/A | N/A |
| GTG201 | 75 | N/A | N/A | N/A | N/A | N/A | N/A |
| GTG301 | 75 | N/A | N/A | N/A | N/A | N/A | N/A |
| GTG401 | 75 | N/A | N/A | N/A | N/A | N/A | N/A |
| GTG501 | 75 | N/A | N/A | N/A | N/A | N/A | N/A |
| STG001 | 135. | N/A | TRIP | VACUUM PUMP | WATER SEAL FROZE | LOSS OF CONDENSOR VACUUM (TRIP CONDITION) | ADDITION OF THERMAL BARRIER IN THE FORM OF HEATERS (COMPLETE) |
| HRSG | 101 | N/A | N/A | N/A | N/A | N/A | N/A |
| HRSG | 201 | N/A | N/A | N/A | N/A | N/A | N/A |
| HRSG | 301 | N/A | N/A | N/A | N/A | N/A | N/A |
| HRSG | 401 | N/A | N/A | N/A | N/A | N/A | N/A |
| HRSG | 501 | N/A | N/A | N/A | N/A | N/A | N/A |

· Design Temperatures = 0°F min.
= 100°F max.

WICHITA FALLS ENERGY CO., LTD.
(A Limited Partnership)

Wichita Falls Energy Investments, Inc.
(Managing General Partner)

614 Ridglea Bank Building
Fort Worth, Texas 76116

817-731-7271 (Ft. Worth)
817-696-3270 (Wichita Falls)

P.O. Box 9349
Fort Worth, Texas 76147

Telecopy 817-732-8984 (Ft. Worth)
Telecopy 817-692-9018 (Wichita Falls)


June 5, 1990

TU Electric
Skyway Tower
400 N. Olive Street, L.B. 81
Dallas, Texas 75201

Attn: Mr. Kevin Delcarson
Cogeneration Department

Gentlemen:

In response to inquiry dated May 22, 1990 with respect to our plant's performance during the cold weather experienced in December, 1989, the following information is submitted in the same numbered order as set forth in the May 22 request.

1. Unit name and unit MW capacity:

   Wichita Falls Energy Co., Ltd. cogeneration facility; 74 megawatts.

2. Unit general design temperature limitations (maximum and minimum), in degrees F.:

   General design parameters were 0° Farenheit minimum and 120° Farenheit maximum. Added heat tracing has been implemented over and above design specs.

3. List of equipment (or plant systems) that were adversely affected by the cold weather [Dates specified]:

   12/21/89 - (1) HRSG B level transmitter froze at 0520 hours.
   (2) House service water tank level transmitter froze at 1938 hours.
   (3) HRSG B superheater outlet pressure transmitter froze at 1955 hours.

   12/22/89 - (1) HRSG superheater outlet pressure transmitter froze at 0522 hours.

RECEIVED
JUN 0.. 1990
COGENERATION

(2) Unit requested to curtail gas consumption by transportation company (Lone Star Gas) at 1004 hours; honoring this request resulted in reduced output.

12/23/89 - (1) Unit had to operate at reduced load from 1030 hours to 1247 hours due to high system frequency (60.00 to 60.14 Hz).

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

12/21/89 - (1) HRSG B level transmitter froze. No shutdown or reduction in output occurred. Operator took manual control of HRSG until transmitter was thawed out and additional insulation added.

(2) House service water tank level transmitter froze. No shutdown or reduction in output occurred. Operator manually controlled tank level until transmitter was thawed out and additional insulation added.

(3) HRSG B superheater outlet pressure transmitter froze. Failure of the pressure transmitter caused the HRSG damper to close resulting in a 2 megawatt drop in hourly averages. Efforts to thaw the transmitter failed and unit was subsequently disconnected so HRSG could be placed back in service before further freeze-ups occurred.

12/22/89 - (1) HRSG C superheater outlet pressure transmitter froze. Failure of the pressure transmitter caused the HRSG damper to close resulting in a 4 megawatt drop in hourly averages. Efforts to thaw the transmitter failed and unit was subsequently disconnected so HRSG could be placed back in service before further freeze-ups occurred.

(2) Unit requested to curtail gas consumption by transportation company (Lone Star Gas); honoring this request resulted in reduced output. At 1020 hours, the standby LPG system was activated, but the blending air compressors tripped on high discharge air temperature. Upon testing, it was

determined that the lubricant used in the blending air compressors was not adequate for existing ambient conditions (-5°F to -7°F). Compressors were reset and restarted without using the lube oil cooler fans until the lubricant warmed up and the units stabilized. LPG was then introduced and utilized until curtailment was lifted at 1430 hours, whereupon the unit went back on natural gas (100%).

12/23/89 - (1) Unit operated at reduced load from 1030 hours to 1247 hours due to high system frequency (60.00 to 60.14 Hz). Unit is designed to reduce output when the frequency rises above the 60.00 Hz range.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence:

12/21/89 - (1) Although the HRSG B level transmitter was adequately heat traced, the insulation was not sufficient to withstand the conditions (-35°F windchill factor) at the time it froze. Additional insulation, as well as the installation of weatherproof/windproof enclosures, required.

(2) Although the house service water tank level transmitter was heat traced and insulated, it was not adequate enough to withstand the conditions at the time. Additional heat trace and insulation required.

(3) Although the HRSG B superheater outlet pressure transmitter was adequately heat traced, the insulation around the transmitter was not sufficient to withstand the conditions at the time it froze. Insulation needed to be upgraded along with installation of weatherproof/windproof enclosures.

12/22/89 - (1) Although the HRSG C superheater outlet pressure transmitter was adequately heat traced, the insulation around the transmitter was not sufficient to withstand the conditions at the time it froze.

Insulation needed to be upgraded along with installation of weatherproof/windproof enclosures.

(2) The unit's gas supplier (Coastal) has a firm delivery transportation agreement with the transporter (Lone Star Gas). Prior to the cold weather period in December, the supplier was delivering quantities of natural gas to the transporter less than the unit's contract requirements in order to balance a previous oversupply scenario. Overlooking or mistaking this balancing agreement, the transporter's dispatcher contacted the unit's operator on duty requesting a consumption cut-back to the level or quantities the supplier was then furnishing the transporter. The unit's operator felt that he had no choice but to comply with this request, mistaken as it was. When this curtailment request was brought to the immediate attention of the supplier, supplier contacted transporter and the matter was resolved. With respect to LPG blending air compressor lubricant, the existing lubricant needed to be replaced with a lubricant which would allow operation of the compressors at ambient temperatures below -10°F.

12/23/89 - (1) No action required with respect to the design parameters of the unit wherein outputs reduce when frequency increases over 60.00 Hz.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

12/21/89 - (1) Additional insulation and weatherproof/windproof enclosures completed in April, 1990.
(2) Additional heat trace and insulation was completed in April, 1990.
(3) Insulation upgraded and weatherproof/windproof enclosures completed in April, 1990.

12/22/89 - (1) Insulation upgraded and weatherproof/windproof enclosures completed in April, 1990.

(2) Operators were instructed in January, 1990 not to comply with a curtailment request from the transporter except in cases of pipeline emergency on the transporter's system, but to refer any future weather-related curtailment request, if one should occur, directly to the supplier for appropriate action. Furthermore, cogeneration facility's personnel will routinely contact the supplier in the late fall of each year (beginning in 1990) to remind supplier that natural gas supply requirements must be met to contract limits throughout cold weather months to avoid a repeat of the December '89 mixup. With respect to the LPG blending air compressor lubricant, the lubricant was changed to a Mobil brand synthetic in January, 1990 rated to cope with the ambient conditions experienced in December, 1989.

12/23/89 - (1) No action was required.

Very truly yours,

WICHITA FALLS ENERGY INVESTMENTS, INC.

Gerald N. Craig
President

GNC:sz

PRI POWER RESOURCES, INC.

June 4, 1990

Mr. Kevin Delcarson
T.U. Electric
400 N. Olive
Suite 3118
Dallas, TX 75201

Dear Kevin:

The following comments are in reply to your correspondence of May 22nd, 1990, "Severe Cold Weather Operation":

1. Unit name and unit MW capacity.
   1. "Power Resources, Inc. " 200 MW

2. Unit general design temperature limitations (maximum & minimum), in degrees F.
   2. Summer Design Dry Bulb Temperature = 100°F.
      Winter Design Dry Bulb Temperature = 16°F.

3. List of equipment(s) (or plant systems) that were adversely affected by the cold weather.
   3. * Gas Turbine liquid fuel system (not directly due to cold weather)
      * Boiler instrumentation

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.
   4. <u>Gas Turbine liquid fuel system</u> - Purge air check valves mechanically failed allowing liquid fuel to bypass the burner. This caused starving of some of the burners which resulted in a high exhaust temperature spread. The unit was able to operate at a reduced output. The failure mode of the check valve, in our opinion, is caused by continuous vibration due to being hard piped to the gas turbine. This causes the "poppett" and seat to wear prematurely.

**P. O. Box 2700, Big Spring, Texas 79721 / Tel: (915)263-8468 / Fax: (915)267-9772**
*A Wholly Owned Subsidiary of Falcon Seaboard Oil Company*

Boiler Instrumentation - One level transmitter on each high pressure boiler drum was out of service due to the freezing. We are however, equipped with redundant level indicators and this caused no production problems. A few other instruments were out of service due to freezing but these did not affect production or plant safety and are therefore considered unimportant. Instrumentation freezups are caused by inadequate heat tracing and insulation of the process side instrument tubing and inadequate protection of the transmitter section of the instrument loop.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.
   5. Gas Turbine liquid fuel system -
      a. Isolation of each of 10 purge air check valves from the vibration caused by the gas turbine. We have accomplished this by installing "flexhose" between the check valve and turbine.
      b. Frequent wintertime testing of the liquid fuel system to be as confident as possible that all systems function properly.

   Boiler Instrumentation
      a. Provide heated instrument boxes for all critical instrument transmitters. We have budgeted to install 18 of these on the critical instruments before winter operation this year.
      b. Confirm proper operation of heat trace circuits before predicted cold weather.
      c. After maintenance activities, which involved tearing away of insulation and/or heat tracing, repair such immediately.
      d. Provide protection from the elements by using tarps or temporary buildings. This year we will enclose the ends of our boiler drums with buildings designed to be put up in the winter and removed during the summer. This will protect the ends of the drums where most of the critical boiler instrumentation is located.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.
   6. * Liquid fuel system modifications completed 5/15/90.
      * Instrumentation protection-completion of all projects by 11/15/90.

KHamby
Ken Hamby

KH:sc

Lone Star Energy Company

P.O. Box 548
Sweetwater, Texas 79556
915-235-4921

JAMES E. PACK
MANAGER

June 4, 1990

REF. DOC. NO.: 380

Kevin Delcarson
TU Electric
Skyway Tower
400 N. Olive St., L. B. 81
Dallas, TX 75201

RE: Severe Cold Weather Operation

Dear Mr. Delcarson:

This letter is in response to your letter dated May 22, 1990, which requested information on plant operations during severe cold weather experienced in December, 1989. Following are the specific requests, each accompanied by our response.

1. Unit name and unit MW capacity.

   Unit Name: Encogen One
   Unit Capacity: Nominal 255 MW
   Unit Location: Sweetwater, Texas

2. Unit general design temperature limitations (maximum and minimum), in degrees F.

   Maximum Design Temperature: Plant will operate at all summer ambient temperatures. Successful operation is expected at ambient temperatures somewhat above 115 degrees F.

   Minimum Design Temperature: Plant will operate at winter ambient temperatures of -10 degrees F and lower.

3. List of equipment or systems that were adversely affected by the cold weather.

   a. Steam turbine-generator / 87 MW
   b. Air cooled steam condenser

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

   a. Steam turbine-generator tripped due to freezing of turbine exhaust backpressure transmitters.

   b. Air cooled steam condenser experienced freeze problems due to extremely low steam loads. The steam turbine was not available due to previous freezing of exhaust pressure transmitters, and bypass steam loading did not provide sufficient load to keep the condenser free from ice.

5. For each piece of equipment or system, identify the necessary corrective actions to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

   a. Steam turbine-generator:

      1. Heat tracing of backpressure transmitters and piping.

      2. Installation of additional variable speed controls to allow variable speed control of 12 fans instead of 6.

      3. Installation of additional steam jet ejector capacity to keep the condenser coils free from non-condensables.

6. For each piece of equipment or system identified above, report the actual or anticipated date corrective action completion.

   a. Steam turbine-generator:

      1. Heat tracing of backpressure transmitters and piping is complete.

b. Air cooled steam condenser/steam turbine-generator:

1. Heat tracing of condensate hotwell and drain piping for each condenser tube bundle is complete.

2. Installation of additional variable speed controls to allow variable speed control of 12 fans instead of 6 will be completed prior to winter operation, 1990.

3. Installation of additional steam jet ejector capacity to keep the condenser coils free from non-condensables will be completed prior to winter operation, 1990.

Should you have any further questions, please do not hesitate to contact me.

Sincerely,

James Pack

James Pack
Plant Manager

JP/kdp

cc: D. Martin
N. Perry

**Cogenron Inc.**

3221 5th Avenue South Texas City, Texas 77590 (409) 945-7324

June 12, 1990
JJK-065-90

Mr. Kevin Delcarson
TU Electric
400 North Olive Street
Dallas, TX 75201

RE: Response to PUC requested freeze information.

Dear Kevin:

Question 1:

Enron Cogeneration One Company
3221 5th Avenue South
Texas City, TX 77590

MW Capacity: 400 MW

Question 2:

-Minimum Design Temperature: 8°F
-Maximum Design Temperature: 101°F

Question 3,4,5,6:

Deaerator instrumentation:

Deaerator instrumentation froze on all units until more insulation was added at which time the electric heat trace thawed the lines and they stayed in service. The 'B' unit deaerator level was lost for a short period of time and during this the safety valve lifted and would not reseat. This necessitated a unit shutdown to replace with the spare safety valve. Plant output was reduced by one hundred twenty megawatts.

To prevent this from happening again the wattage for the deaerator electric heat tracing was doubled and the insulation was increased. In addition, an internal electronic level indicator was added for additional reliability for level control. All projects are 95% complete and will be complete by the end of September.

Demineralization Plant:

The demineralization plant had frozen lines since it is not enclosed in a building. This reduced the amount of water that could be produced and the quality of the water suffered since regenerations were difficult. The result of this was that plant output had to be reduced because steam injection to the gas turbines was reduced.

It was not until a week after the freeze had occurred that we experienced tube problems with our boiler that were a result of the water quality produced during the freeze. Sections of high pressure boiler tubing needed replacing on the two boilers that ran thru the freeze.

By the end of July, bids for adding a heated enclosure around the demineralization plant will be received and by the end of August a decision will be made on the enclosure. This should eliminate the majority of problems associated with the freeze that this facility incurred.

Regards,

James J. Keegan
Plant Manager

JJK/cw

# TENASKA III TEXAS PARTNERS

General Office:
407 North 117 Street
Omaha, NE 68154
Telephone: (402) 691-9500
Telecopy: (402) 691-9526

Plant Office:
301 Lake Crook Road
Paris, TX 75460
Telephone: (214) 785-2992
Telecopy: (214) 785-1360

June 08, 1990

Mr. Kevin Delcarson
Cogeneration Department
TU ELECTRIC
Skyway Tower
400 N. Olive St., L.B. 81
Dallas, TX 75201

RE: Severe Cold Weather Operation (Letter Dated 05/22/90)

Question: Unit name and MW capacity.

Answer: TENASKA III (Nominal Capacity)
2 ea Gas Turbines @ 80 MW ea - 160 MW
1 ea Steam Turbine @ 90 MW ea - 90 MW
Plant Rating - 223,200 KW Total

Question: Unit general design temperature limitations

Answer: Minimum - 0°F
Maximum - 98°F dry bulb

Question: List of equipment or plant systems that were adversely affected by the cold weather.

Answer:
a. Heat Recovery Steam Generator #1
b. Heat Recovery Steam Generator #2
c. Plant Instrumentation
d. Assorted Water Lines

Question: For each piece of equipment or system that failed, identify failure mode, the cause of failure, and how the equipment or system loss contributed to the overall failure of the unit.

Answer: During the severe cold weather time frame December 21, 22, 23, 24 the TENASKA III Site was in the process of converting from a simple cycle (gas turbines only) operation to a combined cycle operation (gas turbines and steam turbine). In preparation for combined cycle commissioning, certain construction measures were taken that prevented running simple cycle and combined cycle equipment was still being debugged. Therefore, the entire plant was not available for service.

During the shutdown, it was discovered that an economized header on HRSG #1 was not drained due to a plugged drain valve. Several other boiler drain valves were also discovered plugged.

Heat tracing for a lot of the plant instruments was also incomplete.

Since the severe cold weather, the plant has been commissioned for combined cycle operation. All plant heat tracing has been completed and insulated houses were built around each plant transmitter.

Question: For each piece of equipment or system, identify the necessary corrective action(s) to prevent the recurrence.

Answer: If Plant is operating, follow the Freeze Protection Checklist.

If Plant is not operating then make sure that the Heat Recovery Steam Generator is drained and also follow the Freeze Protection Sheet if applicable.

Question: For each piece of equipment or system identified above, report actual or anticipated date of corrective action completion.

Answer: The Plant was restarted on Dec. 28, 1989 as a combined cycle plant. The plant heat tracing and new transmitter boxes were completed by March 1990.

All freeze damage on the Heat Recovery Steam Generators was completed by December 28, 1989.

If I may be of further assistance, please do not hesitate to call.

Sincerely,

Mike

Mike Hart, P.E.
Plant Manager

MH/se

cc: Tony Fontana
Duke Cockfield
Leo Finnegan
File

## ATTACHMENT NO. 4

## COGENERATOR RESPONSES

**ATTACHMENT NO. 4**

**COGENERATOR RESPONSES**

The following is a listing of cogeneration units that experienced problems during the December 1989 freeze. The cogenerator reports were submitted through HL&P and TU Electric.

## Occidental Chemical Corporation.

Battleground Plant, 200 MW Capacity
No. 2 Gas Turbine/Heat Recovery Steam Generator(HRSG)

Corrective actions to frozen instruments included instrument upgrading, installing heat tracing and enclosures, and instituting an annual instrument freeze survey.

Maintenance Costs: $ 15,000

## Clear Lake Cogeneration

GT 104; 100 MW Westinghouse Combustion Turbine

Power supply failed. Installed upgraded power supply with backup capability.

Maintenance Costs: $ 15,000

GT 103 100 MW Westinghouse Combustion Turbine

Lub oil supply pump failed. Replaced bearings with oil lubricated design.

Maintenance Costs: $ 36,000

ST 101; 50 MW Westinghouse Steam Turbine
ST 102; 14 MW Westinghouse Steam Turbine

Both units force out of service upon loss of boiler feedwater.

Maintenance Costs: (not provided)

Several instrument transmitters froze in the plant due to inadequate design and installation of the original freeze protection systems. An upgrading is planned for fourth quarter, 1990.

Maintenance Costs: $ 300,000

**Attachment No. 4 Cogenerator Responses**

## Destec Energy, Inc.

CoGen Lyondell
Steam Turbine Generator 001, 135 MW

Unit tripped due to loss of condenser vacuum pump, frozen seal water line. Thermal barrier added near vacuum pump.

Maintenance Costs: (minimal)

## Dow Chemical

Dow Chemical Freeport, 325 MW

Unit tripped when pre-filter pads plugged with snow at inlet. Once down associated water lines froze and could not be restarted until freeze damage was repaired. Existing heat tracing systems were unable to fully protect instruments. Corrective actions include installation of implosion dampers to bypass plugged inlet filters (second quarter 1991), and improved insulation and heat tracing systems.

Maintenance Costs: (not provided)

## Bayou Cogeneration Plant

Four MS7001 E Gas Turbine/Heat Recovery
Steam Generator Trains 300.5 MW

Heat tracing systems were inadequate to prevent instrumentation lines from freezing. Corrective measures include replacement of heat tracing and insulation (1500 feet of lines and 16 instrument cabinets).

Maintenance Costs: $ 100,000

## AES Deepwater Cogeneration

AES Deepwater Cogeneration Facility; 160 MW

Freezing weather caused the failure of the Throttle Pressure Transmitter, Mass Blow Down Valve, Drum Level Transmitter, and Water Cooled Fan Bearing Housings. Corrective actions include insulation and heat tracing and water temperature and flow monitors, and changes to operating procedures.

Maintenance Costs: $ 5,500

**Attachment No. 4 Cogenerator Responses**

## Texasgulf Cogeneration Facility

Newgulf (Warton County) Texas
Gas Turbine and Steam Turbine with Heat Recovery Unit, 77 MW

Clogged and frozen intake screens interrupted the supply of raw water (feedwater) to heat recovery unit. Corrective actions include replacement or repair of heat tracing systems and insulation on raw water system and instrumentation. (No costs reported)

## Wichita Falls Energy Investments, Inc.

Wichita Falls Energy Co., Ltd. Cogeneration Facility
74 MW Capacity

Primary problems with instrumentation freezing due to lack or inadequate heat tracing and insulation protection. Had limited gas curtailment problems. (No corrective action costs provided)

## Power Resources, Inc.

Power Resources, Inc. (PRI)
Gas Turbine, 200 MW

Problems encountered with the GT liquid fuel system and boiler instrumentation. Instrumentation problems caused by inadequate heat tracing and insulation. (No corrective action costs provided.)

## Lone Star Energy Company

Encogen One, 255 MW
Steam Turbine generator 87 MW

Weather caused freezing of instrumentation and controls for the steam turbine and air cooled steam condenser. Corrective actions included heat tracing, additional insulation, and additional steam jet ejector capacity. (No corrective action costs provided.)

**Attachment No. 4 Cogenerator Responses**

## Cogenron, Inc.

Enron Cogeneration One Company
400 MW Capacity

Freezing problems occurred in the deaerator instrumentation and demineralizer plant water lines. Corrective actions included adding a heated enclosure around the demineralizing plant and additional heat tracing and insulation on instrumentation lines. (No corrective action costs were provided.)

## Tenaska III Texas Partners

Tenaska III
Two gas turbines, 160 MW; One steam turbine 90 MW; Total Capacity of plant: 250 MW (Combined Cycle Plant)

Freezing problems were encountered with steam generator heat recovery systems, plant instrumentation and water lines. The plant was in the process of being "debugged" and heat tracing system was not complete. The plant has been completed and the heat tracing and insulation has been completed. (No corrective action costs were provided.)

## ATTACHMENT NO. 3

## INDIVIDUAL UTILITY RESPONSES

Utility Responses:

- Brazos Electric Power Cooperative, Inc.
- Central Power and Light Company
- Houston Lighting and Power Company
- Lower Colorado River Authority
- Texas Municipal Power Agency
- Texas Utilities Electric Company

ATTACHMENT NO. 5

PLANT DESIGN TEMPERATURES

**ATTACHMENT NO. 5**

**PLANT DESIGN TEMPERATURES**

Central Power and Light Company

| Unit Name | Design Temperature Ranges (Degrees F) |
|---|---|
| Barney Davis 1<br>Barney Davis 2 | All units designed to operate at 10 degrees F, with wind velocity of 30 MPH. |
| Caleto Creek 1<br>E. S. Joslin 1 | |
| J. L. Bates 1<br>J. L. Bates 2 | |
| La Palma 6 | |
| Laredo 1<br>Laredo 2<br>Laredo 3 | |
| Lon C Hill 3<br>Lon C Hill 4 | |
| Nueces Bay 6<br>Nueces Bay 7 | |
| Victoria 6 | |

**Attachment No. 5 Plant Design Temperatures**

**Houston Light & Power Company**

| Unit Name | Design Temperature Range (Degrees F.) |
|---|---|
| Cedar Bayou 1<br>Cedar Bayou 2<br>Cedar Bayou 3 | 10 - 105 |
| Greens Bayou 5 | 10 - 105 |
| Limestone 1<br>Limestone 2 | 10 - 110<br>(Freeze Protection to 5) |
| P H Robinson 1<br>P H Robinson 2<br>P H Robinson 3<br>P H Robinson 4 | 10 - 105 |
| S R Bertron 1<br>S R Bertron 2<br>S R Bertron 3<br>S R Bertron 4 | 10 - 105 |
| South Texas 1<br>South Texas 2 | 3 - 105* |
| T H Wharton 2<br>T H Wharton 3<br>T H Wharton 4 | 10 - 105 |
| T H Wharton GT21<br>T H Wharton GT54 | 10 - 105 |
| W A Parish 1<br>W A Parish 2<br>W A Parish 3<br>W A Parish 5<br>W A Parish 6<br>W A Parish 7<br>W A Parish 8<br>W A Parish GT21 | 10 - 105 |
| Webster GT | 10 - 105 |

* This represents the maximum ambient conditions under which and engineering evaluation has determined the unit can operate. This evaluation, performed after the cold weather of 1989, determined that the freeze protection and HVAC systems can operate at ambient temperatures lower than the nominal design minimums of 11 degrees F for freeze protection and 29 degrees F for HVAC systems.

**Attachment No. 5 Plant Design Temperatures**

Texas Utilities Electric Company (TU Electric)

| Unit Name | Design Temperature Range (Degrees F) |
|---|---|
| Eagle Mountain 3 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Handley 5 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Martin Lake 2 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Monticello 2<br>Monticello 3 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Morgan Creek CT4 | -5 to 115 |
| Mountain Creek 2<br>Mountain Creek 7 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| River Crest 1 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Stryker Creek 1 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Tradinghouse 1 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |
| Valley 2 | -10 - and 35 MPH wind velocity to (Highest Regional Temperatures |

**Attachment No. 5 Plant Design Temperatures**

Lower Colorado River Authority (LCRA)

| Unit Name | Design Temperature Range (Degrees F) |
| --- | --- |
| Sim Gideon 2 | No design temperature limitations available. |
| Sam K Seymour 3 | 1 to 110 |

Texas Municipal Power Agency (TMPA)

| Unit Name | Design Temperature Range (Degrees F) |
| --- | --- |
| Gibbons Creek 1 | 15 - 107 |

# Exhibit G

**Complaint of Michael Mabee Related to**
**Mandatory Reliability Standards**
**in the Texas Grid Collapse of 2021**

# Analysis of OE-417 Data

# 2010 -2020

Utility companies and grid operators are required to submit reports[1] on electric disturbance events to the Department of Energy (DOE) on a form known as an OE-417. The publicly available information from these reports is difficult to find, incomplete and confusing.

I did an analysis of all the publicly available OE-417 data from January 1, 2010 through December 31, 2020. First of all, there were 166 different “event types” reported many of which were either duplicates or related. For example, there were at least 24 different “event types” that denoted a physical attack. There were at least 50 “event types” that denoted a disturbance caused by weather. I grouped these 166 “event types” into 15 categories (actually “causes”) so that we could get a sense of what has actually threatened the electric grid in the past 10 years.

Unfortunately, the public OE-417 data is so bad that there were 496 electric disturbance events where I was unable to identify a cause. These are highlighted in yellow in the chart. I was able to identify a cause in 1827 electric disturbance events, or 80% of the OE-417 reports filed. Moreover, some data such as the number of “customers affected” does not appear accurate in some cases. Many OE-417’s do not appear to be updated. Reports from years ago show “unknown” under the number of customers affected, or show “0” when we know there were blackouts associated with those events.

I included separate charts for the TRE Region (Texas Reliability Entity a.k.a. Texas RE) in order to give the public better access to what has caused electric disturbances in Texas.

Electric disturbance events where I was unable to identify a cause are highlighted in yellow in the charts. The underlying data from the charts is also included for reference. This is available in a searchable database and CSV format on my website: https://michaelmabee.info/oe-417-database/

[1] See: https://www.oe.netl.doe.gov/oe417.aspx

# OE-417 Analysis 2010-2020

| All NERC Regions | | |
|---|---|---|
| **Events From 2010-2020** | **Total** | **%** |
| Weather | 961 | 52.6% |
| Cyber Attack | 37 | 2.0% |
| Physical Attack | 721 | 39.5% |
| Fuel Supply Deficiency | 74 | 4.1% |
| Equipment | 15 | 0.8% |
| Natural Disaster | 14 | 0.8% |
| Wildfire | 5 | 0.3% |
| Generation Interruption | 17 | 3.4% |
| Transmission Interruption | 113 | 22.8% |
| Distribution Interruption | 9 | 1.8% |
| Operations | 185 | 37.3% |
| Islanding | 67 | 13.5% |
| Load Shed | 30 | 6.0% |
| Public Appeal | 65 | 13.1% |
| ? | 10 | 2.0% |
| **Total OE-417 Reports** | **2323** | |
| **Cause Known from OE-417** | **1827** | |
| **Cannot Determine Cause** | **496** | |

| Texas RE Only | | |
|---|---|---|
| **Events From 2010-2020** | **Total** | **%** |
| Weather | 83 | 70.9% |
| Cyber Attack | 3 | 2.6% |
| Physical Attack | 28 | 23.9% |
| Fuel Supply Deficiency | 3 | 2.6% |
| Equipment | 0 | 0.0% |
| Natural Disaster | 0 | 0.0% |
| Wildfire | 0 | 0.0% |
| Generation Interruption | 4 | 7.1% |
| Transmission Interruption | 17 | 30.4% |
| Distribution Interruption | 2 | 3.6% |
| Operations | 11 | 19.6% |
| Islanding | 1 | 1.8% |
| Load Shed | 0 | 0.0% |
| Public Appeal | 21 | 37.5% |
| ? | 0 | 0.0% |
| **Total OE-417 Reports** | **173** | |
| **Cause Known from OE-417** | **117** | |
| **Cannot Determine Cause** | **56** | |

# OE-417 Analysis 2010-2020

| All NERC Regions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Event** | **2020** | **2019** | **2018** | **2017** | **2016** | **2015** | **2014** | **2013** | **2012** | **2011** | **2010** | **Total** |
| Weather | 161 | 92 | 94 | 80 | 42 | 65 | 82 | 55 | 82 | 133 | 75 | **961** |
| Cyber Attack | 7 | 2 | 4 | 3 | 5 | 0 | 3 | 2 | 3 | 8 | 0 | **37** |
| Physical Attack | 94 | 80 | 58 | 44 | 49 | 44 | 73 | 79 | 86 | 114 | 0 | **721** |
| Fuel Supply Deficiency | 7 | 7 | 5 | 7 | 7 | 2 | 18 | 6 | 6 | 6 | 3 | **74** |
| Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 2 | 3 | 3 | **15** |
| Natural Disaster | 4 | 0 | 8 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | **14** |
| Wildfire | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 2 | **5** |
| Generation Interruption | 0 | 2 | 0 | 4 | 4 | 0 | 0 | 0 | 0 | 7 | 0 | **17** |
| Transmission Interruption | 42 | 36 | 10 | 9 | 4 | 0 | 0 | 3 | 2 | 2 | 5 | **113** |
| Distribution Interruption | 0 | 3 | 0 | 0 | 2 | 0 | 1 | 2 | 0 | 1 | 0 | **9** |
| Operations | 67 | 56 | 31 | 1 | 16 | 13 | 1 | 0 | 0 | 0 | 0 | **185** |
| Islanding | 0 | 0 | 2 | 1 | 7 | 10 | 15 | 13 | 6 | 4 | 9 | **67** |
| Load Shed | 0 | 0 | 0 | 0 | 1 | 4 | 2 | 4 | 4 | 5 | 10 | **30** |
| Public Appeal | 1 | 0 | 8 | 1 | 4 | 5 | 11 | 0 | 4 | 17 | 14 | **65** |
| ? | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 3 | 1 | 0 | 2 | **10** |
| **Total OE-417 Reports** | 383 | 278 | 220 | 150 | 141 | 143 | 214 | 174 | 196 | 301 | 123 | **2323** |
| **Cause Known from OE-417** | 273 | 181 | 169 | 134 | 103 | 111 | 180 | 149 | 179 | 265 | 83 | **1827** |
| **Cannot Determine Cause** | 110 | 97 | 51 | 16 | 38 | 32 | 34 | 25 | 17 | 36 | 40 | **496** |

| Texas RE Only | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Event** | **2020** | **2019** | **2018** | **2017** | **2016** | **2015** | **2014** | **2013** | **2012** | **2011** | **2010** | **Total** |
| Weather | 20 | 17 | 5 | 9 | 5 | 8 | 2 | 3 | 4 | 5 | 5 | **83** |
| Cyber Attack | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | **3** |
| Physical Attack | 9 | 6 | 3 | 2 | 2 | 1 | 0 | 0 | 2 | 3 | 0 | **28** |
| Fuel Supply Deficiency | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | **3** |
| Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| Natural Disaster | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| Wildfire | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| Generation Interruption | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 2 | 0 | **4** |
| Transmission Interruption | 7 | 8 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **17** |
| Distribution Interruption | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | **2** |
| Operations | 6 | 2 | 2 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | **11** |
| Islanding | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | **1** |
| Load Shed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| Public Appeal | 0 | 0 | 0 | 0 | 3 | 4 | 9 | 0 | 0 | 5 | 0 | **21** |
| ? | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Total OE-417 Reports** | 44 | 34 | 12 | 11 | 13 | 14 | 13 | 4 | 8 | 15 | 5 | **173** |
| **Cause Known from OE-417** | 31 | 23 | 8 | 11 | 7 | 9 | 3 | 4 | 8 | 8 | 5 | **117** |
| **Cannot Determine Cause** | 13 | 11 | 4 | 0 | 6 | 5 | 10 | 0 | 0 | 7 | 0 | **56** |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-01-06 | 6:00 p.m. | 6:00 p.m. January 08 | | Southwest Louisiana | SERC | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-01-11 | 3:45 a.m. | 9:57 a.m. January 11 | | Northern and Central Florida | FRCC/SERC | | Interruptible Load Shed/Made Public Appeals | N/A | N/A | Load Shed |
| | 2010-01-18 | 11:30 a.m. | 8:00 a.m. January 28 | | Northern and Central California | WECC | | Severe Storm | 290 | 1,700,000 | Weather |
| | 2010-01-19 | 2:30 p.m. | 3:00 p.m. January 20 | | San Diego and Orange Counties | WECC | | Severe Storm | 2,650 | 50,000 | Weather |
| | 2010-01-19 | 7:30 a.m. | 12:24 p.m. January 19 | | San Francisco | WECC | | Severe Storm | 300 | 30,000 | Weather |
| | 2010-01-20 | 1:00 p.m. | 6:10 p.m. January 24 | | City of Los Angeles, California | WECC | | Severe Storm | N/A | 147,223 | Weather |
| | 2010-01-28 | 12:00 p.m. | 12:00 p.m. February 02 | | Oklahoma | SPP | | Ice Storm | N/A | 68,705 | Weather |
| | 2010-02-01 | 2:32 p.m. | 5:00 p.m. February 01 | | Oklahoma | SPP | | Ice Storm/Electrical System Separation | 30 | 0 | Weather |
| | 2010-02-05 | 10:30 p.m. | 12:00 p.m. February 12 | | Southwestern Pennsylvania | RFC | | Winter Storm | N/A | 57,000 | Weather |
| | 2010-02-05 | 11:30 p.m. | 2:38 a.m. February 07 | | Indiana, Ohio, W. Virginia and Virginia | RFC | | Winter Storm | N/A | 102,225 | Weather |
| | 2010-02-05 | 3:00 p.m. | 4:00 p.m. February 13 | | Southern NJ | RFC | | Winter Storm | N/A | 221,000 | Weather |
| | 2010-02-05 | 6:48 p.m. | 5:00 p.m. February 07 | | North and South Carolina | SERC | | Winter Storm | 500 | 74,000 | Weather |
| | 2010-02-05 | 7:00 p.m. | 3:46 p.m. February 12 | | District of Columbia, Prince Georges and Montgomery Co. MD | RFC | | Winter Storm | N/A | 97,651 | Weather |
| | 2010-02-06 | 2:30 a.m. | 7:00 a.m. February 07 | | Virginia, North Carolina | SERC | | Winter Storm | 600 | 104,736 | Weather |
| | 2010-02-06 | 8:00 a.m. | 9:00 a.m. February 06 | | Delmarva Peninsula | RFC | | Winter Storm | N/A | 58,491 | Weather |
| | 2010-02-09 | 6:00 p.m. | 4:00 p.m. February 14 | | Southeastern Pennsylvania | RFC | | Winter Storm | N/A | 223,000 | Weather |
| | 2010-02-11 | 12:00 p.m. | 9:00 p.m. February 15 | | Dallas/Fort Worth and East Texas | TRE | | Winter Storm | N/A | 500,000 | Weather |
| | 2010-02-12 | 5:00 a.m. | 5:00 p.m. February 12 | | East Texas, Western Arkansas, Northern Lousiania | SPP | | Winter Storm | N/A | 52,999 | Weather |
| | 2010-02-14 | 10:00 a.m. | 12:00 p.m. February 14 | | Western Pennsylvania nd Northeast Central WV | RFC | | Winter Storm | 900 | 190,000 | Weather |
| | 2010-02-19 | 8:30 p.m. | 4:01 a.m. February 20 | | San Joaquin Field Division/Bakersfield, CA | WECC | | Firm System Load Shed | 1,000 | N/A | Load Shed |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-02-23 | 10:00 p.m. | 4:00 p.m. February 25 | | Upstate New York | NPCC | | Winter Storm | N/A | 150,000 | Weather |
| | 2010-02-25 | 11:53 p.m. | 4:40 p.m. March 01 | | Southern Maine and New Hampshire | NPCC | | Winter Storm | 510 | 509,606 | Weather |
| | 2010-02-25 | 12:01 a.m. | 9:00 p.m. February 26 | | Southeastern New York, Northern New Jersey | NPCC | | Winter Storm | N/A | 65,000 | Weather |
| | 2010-02-25 | 5:00 p.m. | 7:00 p.m. March 02 | | New York City | NPCC | | Winter Storm | N/A | 55,000 | Weather |
| | 2010-03-13 | 1:00 a.m. | 6:40 p.m. March 16 | | Southeasten Pennsylvania | RFC | | High Winds and rain | N/A | 177,528 | Weather |
| | 2010-03-13 | 12:00 p.m. | 8:05 p.m. March 15 | | Connecticut | NPCC | | High Winds and Rain | 50 | 50,246 | Weather |
| | 2010-03-13 | 3:00 p.m. | 4:00 p.m. March 17 | | Long Island | NPCC | | High Winds and Rain | N/A | 153,000 | Weather |
| | 2010-03-13 | 4:00 p.m. | 12:00 a.m. March 16 | | Central New Jersey and Northern New Jersey | RFC | | High Winds and Flooding | N/A | 180,000 | Weather |
| | 2010-03-13 | 6:00 p.m. | 12:59 p.m. March 20 | | Southern, Central and Northern New Jersey | RFC | | High Winds and Rain | 100 | 360,000 | Weather |
| | 2010-03-13 | 6:00 p.m. | 9:00 a.m. March 20 | | New York City and Westchester County | NPCC | | High Winds and Rain | N/A | 173,000 | Weather |
| | 2010-03-31 | 11:59 p.m. | 12:55 a.m. April 01 | | San Diego and Orange Counties | WECC | | Shed Firm Load | 324 | 290,000 | Load Shed |
| | 2010-03-31 | 11:59 p.m. | 12:38 a.m. April 01 | | San Diego | WECC | | Shed Firm Load | 324 | N/A | Load Shed |
| | 2010-04-16 | 5:15 p.m. | 5:00 p.m. April 18 | | Southwestern Pennsylvania | RFC | | Severe Thunderstorms | 15 | 120,000 | Weather |
| | 2010-04-21 | 3:05 p.m. | 8:00 p.m. April 21 | | Iberville, Parish, Louisiana | SERC | | Generator Tripped | N/A | N/A | Equipment |
| | 2010-04-27 | 2:55 p.m. | 2:55 p.m. April 27 | | Rocky Mount, NC | SERC | | Transmission System Interruption | N/A | 29,376 | Transmission Interruption |
| | 2010-05-02 | 2:40 p.m. | 7:30 p.m. May 09 | | Tennessee and Mississippi | SERC | | Thunderstorms | N/A | 50,500 | Weather |
| | 2010-05-18 | 8:15 a.m. | 10:46 p.m. May 18 | | Central California | WECC | | Breakers Tripped | 318 | N/A | Equipment |
| | 2010-05-26 | 11:45 a.m. | 3:00 p.m. May 26 | | Maryland, Pennsylvania, West Virginia, Virginia | RFC, SERC | | Made Public Appeal - System Drill | N/A | N/A | Public Appeal |
| | 2010-06-01 | 10:03 p.m. | 12:30 a.m. June 18 | | Southwestern Indiana | RFC | | Firm Load Shed | 500 | 1 | Load Shed |
| | 2010-06-02 | 8:18 p.m. | 8:00 a.m. June 04 | | San Antonio, TX | TRE | | Severe Weather | N/A | 126,000 | Weather |
| | 2010-06-06 | 4:45 a.m. | 5:35 a.m. June 06 | | Northern California | WECC | | Electric System Separation | 3 | 2,650 | Islanding |
| | 2010-06-07 | 6:29 p.m. | 1:00 a.m. June 08 | | Denver Metropolitan Area | WECC | | Firm Load Shed | 300 | 31,000 | Load Shed |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-06-08 | 11:00 a.m. | 5:00 p.m. June 08 | | Southeastern Texas | TRE | | Thunderstorms | N/A | 79,741 | Weather |
| | 2010-06-09 | 2:18 p.m. | 3:00 p.m. June 09 | | Edenton, NC | SERC | | Transmission System Interruption | N/A | 4,196 | Transmission Interruption |
| | 2010-06-16 | 11:11 a.m. | 11:32 a.m. June 16 | | New York (Rockland and Orange Counties) | NPCC | | Voltage Reduction (System Test) | N/A | N/A | ? |
| | 2010-06-17 | 10:49 a.m. | 11:02 a.m. June 17 | | Eastern Montana | MRO | | Electrical System Separation | N/A | N/A | Islanding |
| | 2010-06-17 | 8:30 a.m. | 5:47 p.m. June 17 | | Morgan City, LA | SPP | | Made Public Appeal | N/A | N/A | Public Appeal |
| | 2010-06-17 | 9:30 a.m. | 5:17 p.m. June 17 | | Southern Louisiana | SERC | | Made Public Appeal | N/A | N/A | Public Appeal |
| | 2010-06-17 | 9:30 a.m. | 4:40 p.m. June 17 | | Southern Louisiana | SERC | | Made Public Appeal | N/A | N/A | Public Appeal |
| | 2010-06-17 | 9:30 a.m. | 4:40 p.m. June 17 | | Southwestern Louisiana | SPP | | Made Public Appeal | N/A | N/A | Public Appeal |
| | 2010-06-18 | 3:30 p.m. | 12:30 a.m. June 20 | | Northwest Indiana | RFC | | Thunderstorms | N/A | 94,345 | Weather |
| | 2010-06-18 | 4:00 p.m. | 1:00 p.m. June 20 | | Chicago, IL | RFC | | Severe Weather | N/A | 400,000 | Weather |
| | 2010-06-18 | 7:00 p.m. | 5:00 a.m. June 19 | | Southern Portion of Lower Michigan | RFC | | Thunderstorms | N/A | 100,000 | Weather |
| | 2010-06-18 | 8:00 p.m. | 10:45 a.m. June 21 | | Indiana, Michigan | RFC | | Severe Weather | N/A | 79,000 | Weather |
| | 2010-06-18 | 8:00 p.m. | 7:30 p.m. June 22 | | Detroit, MI | RFC | | Severe Weather | N/A | 150,000 | Weather |
| | 2010-06-21 | 1:48 p.m. | 8:31 p.m. June 22 | | Cincinnati, OH | RFC | | Thunderstorms | 400 | 50,636 | Weather |
| | 2010-06-22 | 3:34 p.m. | 7:00 p.m. June 22 | | West/Central Arkansas | SERC | | Made Public Appeal/Transmission Equipment Failure | 84 | 25,159 | Transmission Interruption |
| | 2010-06-23 | 5:00 p.m. | 1:40 p.m. June 25 | | Chicago, IL | RFC | | Severe Weather | N/A | 300,000 | Weather |
| | 2010-06-23 | 5:48 p.m. | 2:21 a.m. June 24 | | Northwest Indiana | RFC | | Thunderstorms | N/A | 53,000 | Weather |
| | 2010-06-24 | 3:00 p.m. | 12:00 p.m. June 29 | | Southwestern New Jersey | RFC | | Thunderstorms | N/A | 150,000 | Weather |
| | 2010-06-24 | 3:30 p.m. | 11:59 p.m. June 29 | | Southeastern Pennsylvania | RFC | | Thunderstorms | N/A | 355,000 | Weather |
| | 2010-06-25 | 11:36 p.m. | 1:38 a.m. June 26 | | Northern California | WECC | | Electrical System Separation | N/A | N/A | Islanding |
| | 2010-07-06 | 3:47 a.m. | 4:37 a.m. July 06 | | Newark, DE | RFC | | Transformer Outage | 95 | 18,400 | Equipment |
| | 2010-07-07 | 4:13 p.m. | 10:29 p.m. July 07 | | York, South Central Pennsylvania | RFC | | Loss of Transmission Equipment | N/A | 43,903 | Transmission Interruption |
| | 2010-07-15 | 7:00 p.m. | 11:30 p.m. July 19 | | Southeastern Michigan | RFC | | Severe Weather | 540 | 127,534 | Weather |
| | 2010-07-17 | 8:30 p.m. | 10:00 p.m. July 19 | | Minnesota | MRO | | Strong Winds, Tornadoes | N/A | 63,000 | Weather |
| | 2010-07-21 | 6:44 p.m. | 8:00 p.m. July 21 | | Connecticut | NPCC | | Thunderstorms | N/A | 50,100 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-07-23 | 10:00 a.m. | 11:55 p.m. July 24 | | Northern Utah | WECC | | Made Public Appeals | 8-Jun | N/A | Public Appeal |
| | 2010-07-23 | 7:30 p.m. | 6:30 p.m. July 26 | | Southeastern Michigan | RFC | | Severe Weather | 400 | 82,000 | Weather |
| | 2010-07-25 | 3:10 p.m. | 11:30 p.m. July 30 | | Washington, DC Region | RFC | | Severe Weather | N/A | 297,700 | Weather |
| | 2010-07-25 | 3:20 p.m. | 6:00 p.m. July 27 | | Central Maryland | RFC | | Severe Weather | 480 | 124,000 | Weather |
| | 2010-07-25 | 4:11 p.m. | 8:06 p.m. July 25 | | Northern Virginia | SERC | | Severe Weather | 900-1000 | 81,000 | Weather |
| | 2010-07-29 | 5:43 p.m. | 8:07 p.m. July 29 | | Virginia | SERC | | Thunderstorms | N/A | 55,000 | Weather |
| | 2010-07-29 | 6:39 p.m. | 7:26 p.m. July 29 | | Southern California | WECC | | Shed Interruptible Load, Wildfire | 522 | N/A | Wildfire |
| | 2010-07-29 | 6:39 p.m. | 7:26 p.m. July 29 | | Southern California | WECC | | Shed Interruptible Load, Wildfire | 522 | N/A | Wildfire |
| | 2010-08-02 | 12:00 p.m. | 11:00 p.m. August 02 | | Central California | WECC | | Fuel Supply Deficiency (Hydro) | N/A | N/A | Fuel Supply Deficiency |
| | 2010-08-02 | 12:45 p.m. | 11:00 a.m. August 04 | | Southern Louisiana | SERC | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-08-02 | 12:45 p.m. | 11:00 a.m. August 04 | | Southern Louisiana | SERC | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-08-02 | 12:45 p.m. | 11:00 a.m. August 04 | | Southwestern Louisiana | SERC | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-08-02 | 12:45 p.m. | 11:00 a.m. August 04 | | Southern Louisiana | SPP | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-08-04 | 12:00 p.m. | 10:00 p.m. August 04 | | Northern Texas, Eastern New Mexico | SPP | | Made Public Appeals | N/A | N/A | Public Appeal |
| | 2010-08-04 | 4:45 p.m. | 12:00 a.m. August 07 | | Western Pennsylvania, Northwestern and Central West Virginia | RFC | | Thunderstorms | 60 | 11,186 | Weather |
| | 2010-08-04 | 5:00 p.m. | 4:00 a.m. August 06 | | Ohio, West Virginia, Kentucky | RFC | | Severe Weather | N/A | 37,000 | Weather |
| | 2010-08-05 | 3:30 p.m. | 10:00 p.m. August 05 | | District of Columbia, Maryland | RFC | | Thunderstorms | N/A | 76,729 | Weather |
| | 2010-08-05 | 3:54 p.m. | 12:00 a.m. August 08 | | Northern Virginia | RFC | | Thunderstorms | N/A | 145,157 | Weather |
| | 2010-08-09 | 12:00 p.m. | 12:00 p.m. August 16 | | Upstate New York | RFC | | Fuel Supply Defiency | N/A | N/A | Fuel Supply Deficiency |
| | 2010-08-11 | 3:21 p.m. | 12:12 p.m. August 11 | | Ohio | RFC | | Severe Weather | N/A | 57,000 | Weather |
| | 2010-08-12 | 3:42 p.m. | 10:10 p.m. August 12 | | City of Oshkosh, Wisconsin | MRO | | Made Public Appeals | 30 | 7,600 | Public Appeal |
| | 2010-08-12 | 8:21 a.m. | 11:00 a.m. August 12 | | Central Nebraska | SPP | | Made Public Appeals | 65 | N/A | Public Appeal |
| | 2010-08-12 | 6:45 a.m. | 9:00 p.m. August 12 | | District of Columbia, Maryland | RFC | | Severe Weather | N/A | 101,003 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-08-19 | 6:00 p.m. | 3:30 p.m. August 23 | | Southeastern Michigan | RFC | | Severe Weather | 340 | 80,000 | Weather |
| | 2010-08-23 | 5:50 p.m. | 9:30 a.m. August 24 | | Houston, Texas | TRE | | Severe Weather | 746 | 81,586 | Weather |
| | 2010-09-01 | 10:20 a.m. | 12:44 p.m. September 01 | | Pittsburg (Bay Area), California | WECC | | Electrical System Separation (Islanding) | 31 | 15,000 | Islanding |
| | 2010-09-07 | 2:02 p.m. | 1:27 a.m. September 08 | | San Antonio, Texas | TRE | | Tropical Storm | N/A | 340,350 | Weather |
| | 2010-09-20 | 5:00 p.m. | 5:30 p.m. September 20 | | King George County, Virginia | SERC | | Low Flying Helicopter | N/A | N/A | ? |
| | 2010-09-21 | 9:31 p.m. | 2:30 p.m. September 22 | | Central and Southern Michigan | RFC | | Thunderstorms | N/A | 138,000 | Weather |
| | 2010-09-22 | 6:12 a.m. | 11:00 p.m. September 22 | | Bakersfield, California | WECC | | Firm Load Shed | 526 | N/A | Load Shed |
| | 2010-09-22 | 4:08 p.m. | 12:00 a.m. September 26 | | City of Pittsburgh, Pennsylvania | RFC | | Thunderstorms | 156 | 52,000 | Weather |
| | 2010-09-22 | 5:38 p.m. | 11:30 p.m. September 24 | | Western Pennsylvania | RFC | | Thunderstorms | 389 | 82,861 | Weather |
| | 2010-09-27 | 3:15 p.m. | 6:12 p.m. September 27 | | Central and Southern California | WECC | | Interruptible Load Shed | 595 | N/A | Load Shed |
| | 2010-10-05 | 5:45 a.m. | 6:00a.m. October 07 | | City of Los Angeles, California | WECC | | Rain and High Winds | N/A | 73,514 | Weather |
| | 2010-10-26 | 8:00 p.m. | 10:00 p.m. October 28 | | Minnesota | MRO | | High Winds | N/A | 70,000 | Weather |
| | 2010-10-26 | 9:00 a.m. | 11:00 a.m. October 28 | | Northern Illinois | RFC | | Thunderstorms | N/A | 192,106 | Weather |
| | 2010-10-27 | 5:16 p.m. | 5:27 p.m. October 27 | | Northern California | WECC | | Electrical System Separation-Islanding | 16 | 2,674 | Islanding |
| | 2010-10-27 | 4:00 a.m. | 12:00 p.m. October 27 | | Northeast and North Central Wisconsin | MRO | | High Winds | N/A | 63,000 | Weather |
| | 2010-10-27 | 5:00 p.m. | 4:00 a.m. October 29 | | Northern Illinois | RFC | | High Winds | N/A | 127,000 | Weather |
| | 2010-10-27 | 8:00 a.m. | 7:00 a.m. October 29 | | Michigan's Northerly Lower Peninsula | RFC | | High Winds | 240 | 285,000 | Weather |
| | 2010-10-31 | 10:26 p.m. | 1:45 a.m. November 01 | | Bakersfield, California | WECC | | Firm System Load Loss | 500 | N/A | Load Shed |
| | 2010-11-04 | 9:46 a.m. | 10:47 a.m. November 04 | | Rock Springs, Wyoming | WECC | | Transmission Equipment Failure/Interruptible Load Shed | N/A | N/A | Transmission Interruption |
| | 2010-11-06 | 3:53 p.m. | 6:08 p.m. November 06 | | Northern California | WECC | | Electrical System Separation - Islanding | 20 | 4 | Islanding |
| | 2010-11-08 | 6:47 a.m. | 6:00 p.m. November 08 | | Maine | NPCC | | Snow and High Winds | N/A | 60,863 | Weather |
| | 2010-11-13 | 3:00 p.m. | 10:00 p.m. November 14 | | Minnesota | MRO | | Winter Storm | N/A | 60,000 | Weather |
| | 2010-11-15 | 11:00 p.m. | 2:14 a.m. November 16 | | Puget Sound Region | WECC | | High Winds | 391 | 149,256 | Weather |
| | 2010-11-21 | 1:39 a.m. | 4:46 p.m. November 24 | | Northern and Central California | WECC | | Winter Storm | 75 | 60,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2010-11-22 | 11:00 p.m. | 8:00 p.m. November 24 | | Puget Sound Region, Washington | WECC | | Winter Storm | 420 | 123,535 | Weather |
| | 2010-11-23 | 2:01 p.m. | 6:12 p.m. November 23 | | Northern California | WECC | | Electrical System Separation - Islanding | 22 | 7,077 | Islanding |
| | 2010-12-03 | 9:32 p.m. | 2:00 a.m. December 04 | | California | WECC | | Electrical System Separation - Islanding | 22 | 7,077 | Islanding |
| | 2010-12-12 | 4:30 p.m. | 2:00 p.m. December 15 | | Southeastern Michigan | RFC | | Severe Weather | 210 | 60,175 | Weather |
| | 2010-12-14 | 7:20 a.m. | 7:25 a.m. December 14 | | California | WECC | | Electrical System Separation - Islanding | 9 | 6,635 | Islanding |
| | 2010-12-14 | 7:36 a.m. | 9:00 a.m. December 15 | | Southern California | WECC | | Transmission Equipment/Firm System Load | 464 | N/A | Load Shed |
| | 2010-12-18 | 5:00 a.m. | 10:00 p.m. December 19 | | Redmond, Washington | WECC | | Severe Weather | 184 | 92,090 | Weather |
| | 2010-12-26 | 8:15 a.m. | 4:15 p.m. December 26 | | Carolina | SERC | | Severe Weather | N/A | 42,000 | Weather |
| | 2010-12-30 | 2:00 p.m. | 6:00 a.m. January 12 | | New York | RFC | | Fuel Supply Deficiency | 300 | N/A | Fuel Supply Deficiency |
| | 2011-01-12 | 6:00 AM | 1/12/2011 | 2:00 PM | Massachusetts | NPCC | | Winter Storm | N/A | 80,000 | Weather |
| | 2011-01-13 | 7:21 AM | 1/13/2011 | 8:13 AM | North Florida | FRCC | | Firm System Load Shed | 150 | 20,900 | Load Shed |
| | 2011-01-18 | 2:00 PM | 1/18/2011 | 2:00 PM | Whitman, Auburn St Substation, Massachusetts | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-01-23 | 7:00 AM | 1/23/2011 | 1:00 PM | Franklin County, Idaho | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-01-24 | 1:20 PM | 1/24/2011 | 1:30 PM | Newman Power Plant, Texas | WECC | | Suspicious Activity | 0 | 0 | Physical Attack |
| | 2011-01-25 | 3:23 AM | 1/25/2011 | 11:00 AM | Newark, Delaware | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-01-26 | 9:25 AM | 1/27/2011 | 5:00 PM | Carson City, Nevada | WECC | | Suspected Telecommunications Attack | 0 | 0 | Cyber Attack |
| | 2011-01-26 | 9:33 AM | 1/27/2011 | 3:03 PM | Michigan | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-01-26 | 5:00 PM | 1/31/2011 | 8:00 AM | Montgomery and Prince George's County, Maryland and District of Columbia | RFC | | Winter Storm | N/A | 210,000 | Weather |
| | 2011-01-26 | 6:28 PM | 1/29/2011 | 5:00 PM | Maryland | RFC | | Winter Storm | N/A | 234,326 | Weather |
| | 2011-01-26 | 7:43 PM | 1/27/2011 | 6:18 PM | Northern Virginia | SERC | | Winter Storm | 600 | 150,084 | Weather |
| | 2011-01-27 | 5:00 PM | 1/30/2011 | 5:00 AM | Central New York | NPCC | | Fuel Supply Deficiency (Coal) | 108 | N/A | Fuel Supply Deficiency |
| | 2011-01-27 | 9:30 AM | 1/27/2011 | 9:30 AM | Hockessin, Delaware | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-01-31 | 10:00 PM | 2/3/2011 | 12:00 PM | Southwestern Ohio and Indiana | RFC | | Ice Storm | 996 | 272,880 | Weather |
| | 2011-02-01 | 3:00 PM | 2/3/2011 | 12:00 PM | Indiana, Ohio | RFC | | Winter Storm | UNK | 158,013 | Weather |
| | 2011-02-02 | 5:00 PM | 2/3/2011 | 10:00 PM | Texas Panhandle, Southeastern New Mexico | SPP | | Fuel Supply Deficiency (Natural Gas) | UNK | UNK | Fuel Supply Deficiency |
| | 2011-02-02 | 5:43 AM | 2/3/2011 | 10:00 AM | Texas | TRE | | Generation Inadequacy/Load Shed | 4,000 | 1,069,730 | Generation Interruption |
| | 2011-02-02 | 6:22 AM | 2/2/2011 | 9:57 AM | Central Arizona | WECC | | Generation Inadequacy/Load Shed | 3,963 | 69,000 | Generation Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-02-02 | 7:24 AM | 2/2/2011 | 10:23 PM | Dona Ana and El Paso Counties, Texas and Hudspeth County, New Mexico | WECC | | Generation Inadequacy/Load Shed | 280 | 178,000 | Generation Interruption |
| | 2011-02-02 | 3:00 AM | 2/4/2011 | 11:59 PM | Philadelphia area, Pennsylvania | RFC | | Winter Storm | UNK | 213,000 | Weather |
| | 2011-02-03 | 2:30 PM | 2/3/2011 | 2:30 PM | Bowie, Maryland | RFC | | Suspected Cyber Attack | N/A | 0 | Cyber Attack |
| | 2011-02-03 | 3:00 PM | 2/4/2011 | 12:00 PM | San Diego area, California | WECC | | Fuel Supply Deficiency (Natural Gas) | N/A | UNK | Fuel Supply Deficiency |
| | 2011-02-03 | 10:04 PM | 2/4/2011 | 12:32 PM | Texas | TRE | | Generation Inadequacy/Load Shed | 400 | 86,013 | Generation Interruption |
| | 2011-02-09 | 2:54 PM | 2/9/2011 | 5:00 PM | University Place, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-02-09 | 3:45 AM | 2/9/2011 | 9:12 AM | Western Houston, Texas | TRE | | Winter Storm | 399 | 60,000 | Weather |
| | 2011-02-09 | 4:30 PM | 2/10/2011 | 12:33 PM | Texas | TRE | | Cold Weather Event | N/A | N/A | Weather |
| | 2011-02-10 | 1:00 PM | 2/10/2011 | 1:00 PM | LaGrande, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-02-17 | 1:00 PM | 2/23/2011 | 4:53 PM | Roseville, California | WECC | | Suspected Cyber Attack | 0 | 0 | Cyber Attack |
| | 2011-02-17 | 1:25 AM | 2/19/2011 | 10:13 AM | Northern and Central California | WECC | | Major Storm | 91 | 80,000 | Weather |
| | 2011-02-19 | 4:34 PM | 2/19/2011 | 4:34 PM | Harrington, Delaware | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-02-19 | 12:30 PM | 2/20/2011 | 4:00 AM | Philadelphia area, Pennsylvania | RFC | | Major Storm | UNK | 118000 | Weather |
| | 2011-02-20 | 4:00 PM | 2/23/2011 | 4:00 PM | Southern Lower Peninsula, Michigan | RFC | | Winter Storm | 262 | 160,000 | Weather |
| | 2011-02-24 | 4:51 PM | 2/24/2011 | 4:54 PM | Arkansas | SPP | | Electrical System Separation (Islanding) | 4 | UNK | Islanding |
| | 2011-02-25 | 10:30 AM | 2/25/2011 | 10:45 AM | Salt Lake City, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-02-25 | 8:00 AM | 2/28/2011 | 5:30 PM | Northern and Central California | WECC | | Winter Storm | 91 | 80,000 | Weather |
| | 2011-02-25 | 3:20 PM | 2/25/2011 | 6:00 PM | Virginia | SERC | | Severe Weather | UNK | 50000 | Weather |
| | 2011-02-25 | 3:23 PM | 2/27/2011 | 6:00 PM | Maryland | RFC | | Severe Weather | UNK | 93000 | Weather |
| | 2011-03-01 | 8:00 AM | 3/5/2011 | 9:30 AM | Western New York | NPCC | | Fuel Supply Deficiency (Coal) | 675 | UNK | Fuel Supply Deficiency |
| | 2011-03-06 | 2:54 AM | 3/8/2011 | 8:00 AM | Salt Lake City Region, Utah | WECC | | Vandalism | UNK | 0 | Physical Attack |
| | 2011-03-10 | 12:03 PM | 3/11/2011 | 6:00 AM | Texas | TRE | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-03-11 | 7:02 AM | 3/11/2011 | 9:15 AM | Humboldt and Eureka, California | WECC | | Generation Inadequacy/Load Shed | 15 | 6,800 | Generation Interruption |
| | 2011-03-13 | 2:20 PM | 3/14/2011 | 3:46 PM | Oregon | WECC | | Severe Weather | UNK | 9,000 | Weather |
| | 2011-03-14 | 7:30 AM | 3/14/2011 | 4:55 PM | Baltimore, Maryland | RFC | | Suspected Cyber Attack | N/A | N/A | Cyber Attack |
| | 2011-03-15 | 6:00 PM | 3/15/2011 | 7:14 PM | The Woodlands, Texas | TRE | | Suspected Physical Attack | N/A | N/A | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-03-17 | 7:40 AM | 3/17/2011 | 11:00 AM | Deerfield, New Hampshire | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-03-18 | 9:54 AM | 3/18/2011 | 3:34 PM | Greene County, Ohio | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-03-19 | 11:56 PM | 3/24/2011 | 7:10 PM | Northern and Central California | WECC | | Major Storm | 91 | 128,000 | Weather |
| | 2011-03-20 | 9:44 AM | 3/21/2011 | 10:00 AM | Los Angeles, California | WECC | | Major Storm | UNK | 79,000 | Weather |
| | 2011-03-21 | 12:57 AM | 3/21/2011 | 2:29 AM | Deerfield, New Hampshire | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-03-21 | 12:35 PM | 3/21/2011 | 2:45 PM | Southern California | WECC | | Major Storm | 150 | 54,332 | Weather |
| | 2011-03-23 | 6:30 PM | 3/24/2011 | 4:55 AM | Indiana. Kentucky, Michigan, Ohio, Tennessee, Virginia, West Virginia | RFC | | Major Storm | UNK | 60,596 | Weather |
| | 2011-03-27 | 1:27 PM | 3/27/2011 | 5:00 PM | Sonoma and Central Valley, California | WECC | | Transmission Level Outage | 295 | 165,000 | Transmission Interruption |
| | 2011-03-31 | 11:30 AM | 3/31/2011 | 8:30 PM | Greater Tampa Bay, Florida | FRCC | | Severe Weather | 206 | 87,000 | Weather |
| | 2011-03-31 | 2:30 PM | 4/1/2011 | 11:59 PM | Central and Western Florida | FRCC | | Severe Weather | UNK | 50,000 | Weather |
| | 2011-04-03 | 8:23 PM | 4/5/2011 | 3:00 PM | Unknown | SERC | | Suspected Cyber Attack | 0 | 0 | Cyber Attack |
| | 2011-04-04 | 11:47 AM | 4/8/2011 | 12:01 AM | Memphis, Tennessee | SERC | | Severe Weather | 359 | 63,000 | Weather |
| | 2011-04-04 | 1:00 PM | 4/5/2011 | 12:00 AM | Shelby County, Tennessee | SERC | | Severe Weather | 300 | 63,000 | Weather |
| | 2011-04-04 | 7:00 PM | 4/5/2011 | 8:00 PM | Southeast Arkansas, Southeast Louisiana, Western Mississippi, Eastern Texas | SERC | | Severe Weather | UNK | 74,645 | Weather |
| | 2011-04-04 | 7:00 PM | 4/5/2011 | 12:00 PM | Kentucky, West Virginia | RFC | | Severe Weather | UNK | 52,920 | Weather |
| | 2011-04-04 | 9:00 PM | 4/5/2011 | 11:30 PM | Alabama, Florida, Georgia, Mississippi | SERC | | Severe Weather | 674 | 303,434 | Weather |
| | 2011-04-05 | 2:00 AM | 4/7/2011 | 11:00 PM | North Carolina, South Carolina | SERC | | Severe Weather | 1,200 | 256,000 | Weather |
| | 2011-04-06 | 10:50 AM | 4/6/2011 | 10:50 AM | Felton, Delaware | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-04-11 | 5:40 PM | 4/11/2011 | 5:51 PM | Salt Lake City, Utah | WECC | | Suspicious Activity | 0 | 0 | Physical Attack |
| | 2011-04-16 | 2:16 PM | 4/17/2011 | 4:30 PM | Central and Eastern North Carolina | SERC | | Severe Weather | UNK | 220,000 | Weather |
| | 2011-04-19 | 2:01 PM | 4/19/2011 | 4:04 PM | Graham, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-04-19 | 8:00 PM | 4/19/2011 | 10:00 PM | Illinois | SERC | | Severe Weather | UNK | 80,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-04-19 | 10:44 PM | 4/20/2011 | 2:00 AM | Memphis, Tennessee | SERC | | Severe Weather | 100 | 64,000 | Weather |
| | 2011-04-19 | 11:02 PM | 4/21/2011 | 5:32 PM | Memphis, Tennessee | SERC | | Severe Weather | 300 | 105,000 | Weather |
| | 2011-04-19 | 11:13 PM | 4/20/2011 | 7:14 PM | Osceola, Arkansas | SERC | | Severe Weather | 22 | UNK | Weather |
| | 2011-04-20 | 8:07 AM | 4/20/2011 | 8:14 AM | Ruston, Louisiana | SERC | | Equipment Malfunction | 33 | 11,000 | Equipment |
| | 2011-04-20 | 2:00 AM | 4/21/2011 | 12:00 PM | Indiana, Kentucky, Ohio | RFC | | Severe Weather - High Winds | UNK | 165,711 | Weather |
| | 2011-04-21 | 7:15 AM | 4/21/2011 | 4:50 PM | Oquirrh Substation, Salt Lake City, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-04-21 | 7:00 PM | 4/29/2011 | 7:05 PM | Trenton, Michigan | RFC | | Suspicious Activity | UNK | UNK | Physical Attack |
| | 2011-04-22 | 9:00 PM | 4/22/2011 | 11:00 PM | Metro St. Louis area, Missouri | SERC | | Severe Weather | 0 | 55,000 | Weather |
| | 2011-04-25 | 4:33 PM | 4/25/2011 | 5:19 PM | Northeast Tennessee | SERC | | Equipment Malfunction | 140 | UNK | Equipment |
| | 2011-04-25 | 5:30 PM | 4/27/2011 | 6:00 PM | Arkansas, Louisiana, Mississippi | SPP | | Severe Weather | UNK | 141,700 | Weather |
| | 2011-04-26 | 1:04 PM | 4/26/2011 | 2:00 PM | Salt Lake City, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-04-26 | 5:49 AM | 4/27/2011 | 9:59 AM | Southern Louisiana | SPP | | Severe Weather | 120 | UNK | Weather |
| | 2011-04-26 | 9:51 AM | 4/28/2011 | 9:51 AM | Alabama, Georgia, Mississippi, Tennessee | SERC | | Severe Weather | UNK | 55,000 | Weather |
| | 2011-04-26 | 6:14 PM | 4/28/2011 | 5:00 PM | Eastern Arkansas | SPP | | Severe Weather | 50 | 13,000 | Weather |
| | 2011-04-27 | 8:00 AM | 5/2/2011 | 4:03 PM | Alabama, Florida, Georgia, Mississippi | SERC | | Severe Weather | 1,422 | 426,640 | Weather |
| | 2011-04-27 | 10:00 AM | 4/29/2011 | 4:29 PM | Alabama, Georgia, Mississippi, Tennessee | SERC | | Severe Weather | UNK | 612,000 | Weather |
| | 2011-04-27 | 10:00 PM | 4/28/2011 | 10:00 AM | Ohio, Tennessee, Virginia | SERC | | Severe Weather | 0 | 69,000 | Weather |
| | 2011-04-28 | 4:09 PM | 4/28/2011 | 4:10 PM | Phoenix, Arizona | WECC | | Equipment Malfunction | 960 | UNK | Equipment |
| | 2011-04-28 | 5:00 AM | 4/30/2011 | 6:30 PM | Cleveland area, Ohio | RFC | | Severe Weather | UNK | 86,000 | Weather |
| | 2011-05-02 | 8:52 AM | 5/2/2011 | 10:46 AM | N. Ogden Substation, Ogden, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-02 | 2:00 PM | 5/2/2011 | 2:00 PM | West River Substation, New Haven, Connecticut | NPCC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-05-02 | 5:06 PM | 5/2/2011 | 8:00 PM | Hawaii | N/A | | Severe Weather | 220 | 62,000 | Weather |
| | 2011-05-03 | 12:00 PM | 5/5/2011 | 12:00 PM | St. Lawrence Power Dam, New York | NPCC | | Suspected Physical Attack | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-05-04 | 12:20 PM | 5/4/2011 | 3:40 PM | Michigan | RFC | | Suspected Sabotage | 0 | 0 | Physical Attack |
| | 2011-05-05 | 9:15 AM | 5/5/2011 | 9:15 AM | New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-06 | 6:56 AM | 5/6/2011 | 10:30 AM | Alderwood Substation, Portland, Oregon | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-08 | 7:35 PM | 5/8/2011 | 7:35 PM | New York | NPCC | | Vandalism | UNK | 0 | Physical Attack |
| | 2011-05-09 | 4:08 AM | 5/9/2011 | 6:40 AM | Holtwood, Pennsylvania | RFC | | Suspected Physical Attack | 630 | UNK | Physical Attack |
| | 2011-05-09 | 1:11 PM | 5/9/2011 | 1:11 PM | Milton, New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-10 | 3:25 AM | 5/11/2011 | 2:10 PM | Upper Peninsula, Michigan | RFC | | Generation Inadequacy; Load Shed; Electrical System Separation (Islanding) | 585 | 78,213 | Islanding |
| | 2011-05-10 | 1:45 PM | 5/10/2011 | 3:00 PM | New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-10 | 10:21 PM | 5/11/2011 | 2:25 PM | Kentucky, West Virginia | RFC | | Severe Weather | UNK | 58,000 | Weather |
| | 2011-05-11 | 11:00 AM | 5/11/2011 | 11:30 AM | North Chelsea Substation, New York | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-11 | 1:35 PM | 5/11/2011 | 1:35 PM | Green River, Wyoming | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-11 | 3:55 PM | 5/12/2011 | 1:57 PM | Colbyville, Haines Road and Arrowhead Substations, Minnesota | MRO | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-11 | 12:15 AM | 5/11/2011 | 5:20 PM | Charlotte, North Carolina | SERC | | Severe Weather | 300 | 71,000 | Weather |
| | 2011-05-13 | 6:00 AM | 5/13/2011 | 6:00 AM | Salt Lake, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-05-21 | 5:00 PM | 5/22/2011 | 6:34 PM | Dixie Valley Area, Nevada | WECC | | Physical Attack | 56 | UNK | Physical Attack |
| | 2011-05-22 | 5:09 PM | 5/31/2011 | 12:01 PM | Joplin, Sarcoxie, and Wentworth, Missouri | SPP | | Severe Weather | 200 | 20,000 | Weather |
| | 2011-05-23 | 12:30 PM | 5/25/2011 | 12:30 PM | St. Louis County, Missouri | SERC | | Severe Weather | UNK | 70,000 | Weather |
| | 2011-05-23 | 4:45 PM | 5/25/2011 | 11:59 PM | Central, Indiana | RFC | | Severe Weather | 1,024 | 215,387 | Weather |
| | 2011-05-24 | 9:00 AM | 5/25/2011 | 9:10 AM | Chicago, Illinois | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2011-05-24 | 4:35 PM | 5/25/2011 | 12:40 PM | Eastern Virginia | SERC | | Severe Weather | 790 | 175,000 | Weather |
| | 2011-05-24 | 4:45 PM | 5/26/2011 | 5:00 PM | Central Oklahoma | SPP | | Severe Weather | UNK | 54,000 | Weather |
| | 2011-05-25 | 10:14 PM | 5/28/2011 | 11:00 AM | Central Indiana | RFC | | Severe Weather | 200 | 141,000 | Weather |
| | 2011-05-26 | 1:00 AM | 5/26/2011 | 6:00 AM | Greenwood, Mississippi | SERC | | Transmission Level Interruption | 30 | 10,000 | Transmission Interruption |
| | 2011-05-26 | 6:30 PM | 5/28/2011 | 4:44 AM | Southern Balancing Area, Georgia | SERC | | Severe Weather | 729 | 218,783 | Weather |
| | 2011-05-26 | 7:56 PM | 5/27/2011 | 6:00 PM | Central Pennsylvania | RFC | | Severe Weather | 150 | 120,001 | Weather |
| | 2011-05-29 | 6:30 PM | 5/31/2011 | 10:00 PM | Mid and Southern Lower Peninsula, Michigan | RFC | | Severe Weather | 250 | 113,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-06-02 | 11:45 PM | 6/4/2011 | 4:00 PM | Greater Columbia, South Carolina | SERC | | Severe Weather | 0 | 50,465 | Weather |
| | 2011-06-04 | 1:17 AM | 6/4/2011 | 3:25 AM | Midway, California | WECC | | Vandalism | UNK | 420 | Physical Attack |
| | 2011-06-05 | 8:02 PM | 6/5/2011 | 8:55 PM | Melones, California | WECC | | Electrical System Separation (Islanding) | 10 | 5,314 | Islanding |
| | 2011-06-05 | 5:30 AM | 6/6/2011 | 1:30 AM | Houston Metro-Area, Texas | TRE | | Severe Thunderstorms | 473 | 78,000 | Weather |
| | 2011-06-06 | 12:13 AM | 6/6/2011 | 3:15 AM | El Paso County, Texas; Dona Ana County, New Mexico | SPP | | Load Shed/ Automatic undervoltage relay action | 450 | 162,000 | Load Shed |
| | 2011-06-07 | 2:00 PM | 6/8/2011 | 6:00 AM | Ohio | RFC | | Severe Weather | UNK | 52,747 | Weather |
| | 2011-06-08 | 12:58 PM | 6/8/2011 | 12:58 PM | Fredrickson Substation, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-06-09 | 2:15 PM | 6/9/2011 | 2:15 PM | San Antonio Dam Area, Los Angeles County, California | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-06-09 | 4:30 AM | 6/9/2011 | 12:00 PM | Illinois | RFC | | Severe Thunderstorms | UNK | 169,000 | Weather |
| | 2011-06-09 | 5:51 PM | 6/10/2011 | 12:00 PM | Western, Massachusetts; Connecticut | NPCC | | Severe Thunderstorms | 0 | 100,000 | Weather |
| | 2011-06-12 | 7:00 PM | 6/12/2011 | 8:30 PM | Virginia | RFC | | Severe Thunderstorms | 250 | 56,000 | Weather |
| | 2011-06-15 | 4:00 PM | 6/16/2011 | 6:30 AM | Bingham County, Idaho | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-06-15 | 7:15 PM | 6/16/2011 | 6:00 AM | Georgia | SERC | | Severe Thunderstorms | 563 | 169,000 | Weather |
| | 2011-06-15 | 7:17 PM | 6/16/2011 | 1:45 AM | Piedmont, North Carolina | SERC | | Severe Thunderstorms | 300 | 70,135 | Weather |
| | 2011-06-18 | 4:45 PM | 6/20/2011 | 11:59 PM | Eastern, Arkansas | SPP | | Public Appeal to Reduce Electricity Usage | UNK | UNK | Public Appeal |
| | 2011-06-18 | 3:30 PM | 6/19/2011 | 3:42 PM | Northern, Georgia | SERC | | Severe Thunderstorms | 312 | 93,828 | Weather |
| | 2011-06-18 | 5:00 PM | 6/18/2011 | 9:33 PM | North Carolina; South Carolina | SERC | | Severe Thunderstorms | 300 | 70,000 | Weather |
| | 2011-06-20 | 10:36 AM | 6/20/2011 | 10:36 AM | Collins Substation, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-06-21 | 6:30 PM | 6/22/2011 | 7:00 AM | AEP Region | RFC | | Severe Weather | UNK | 56,000 | Weather |
| | 2011-06-21 | 9:45 PM | 6/23/2011 | 2:00 AM | Illinois | RFC | | Severe Thunderstorms | UNK | 300,000 | Weather |
| | 2011-06-22 | 8:12 PM | 6/22/2011 | 8:12 PM | Knoble Substation, Spanaway, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-06-22 | 9:46 AM | 6/22/2011 | 9:46 AM | Knoxville, Tennessee | SERC | | Severe Weather | UNK | 106,300 | Weather |
| | 2011-06-22 | 7:00 PM | 6/23/2011 | 1:00 AM | Alabama; Georgia | SERC | | Severe Thunderstorms | 316 | 75,101 | Weather |
| | 2011-06-23 | 8:10 AM | 6/23/2011 | 9:00 AM | Highgate, Vermont | NPCC | | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-06-24 | 6:30 PM | 6/25/2011 | 1:30 AM | North/North Central Alabama; Georgia | SERC | | Severe Thunderstorms | 340 | 102,275 | Weather |
| | 2011-06-26 | 4:46 PM | 6/27/2011 | 7:59 AM | Southwest Kansas | SPP | | Public Appeal to Reduce Electricity Usage | UNK | UNK | Public Appeal |
| | 2011-06-26 | 6:00 PM | 6/27/2011 | 1:00 PM | Alabama; Georgia | SERC | | Severe Thunderstorms | 300 | 90,160 | Weather |
| | 2011-06-27 | 6:55 PM | 6/27/2011 | 6:55 PM | Olympic Pipeline Substation, Washington | WECC | | Vandalism | UNK | UNK | Physical Attack |
| | 2011-06-27 | 3:00 PM | 6/27/2011 | 7:00 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-06-27 | 12:00 AM | 6/29/2011 | 1:00 AM | Illinois; Missouri | SERC | | Severe Thunderstorms | UNK | 80,000 | Weather |
| | 2011-06-29 | 11:30 AM | 6/29/2011 | 6:04 PM | Panhandle and Muleshoe, Texas | SPP | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-06-30 | 2:11 PM | 6/30/2011 | 11:25 PM | Phoenix, Arizona | WECC | | Major System Interruption/Load Shed | 5,299 | 160,000 | Load Shed |
| | 2011-06-30 | 10:31 PM | 6/30/2011 | 10:31 PM | Olympic Pipeline Substation, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-06-30 | 10:30 PM | 7/1/2011 | 5:00 PM | Illinois | RFC | | Severe Weather | UNK | 121,000 | Weather |
| | 2011-07-01 | 8:00 AM | 7/1/2011 | 8:01 AM | CONVEX Local Control Center, Connecticut | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-01 | 4:38 PM | 7/1/2011 | 10:38 PM | Greene County Ohio | RFC | | Vandalism | N/A | 0 | Physical Attack |
| | 2011-07-01 | 5:00 PM | 7/3/2011 | 8:00 PM | Southwest and South Central Minnesota | MRO | | Severe Weather | UNK | 70,000 | Weather |
| | 2011-07-02 | 8:15 PM | 7/6/2011 | 10:00 PM | South East, Lower Peninsula, Michigan | RFC | | Severe Weather | UNK | 182,000 | Weather |
| | 2011-07-04 | 6:00 PM | 7/4/2011 | 9:00 PM | Virginia | SERC | | Severe Weather | 150 | 51,580 | Weather |
| | 2011-07-05 | 10:40 AM | 7/5/2011 | 11:37 AM | West Valley Substation Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-06 | 9:51 AM | 7/6/2011 | 9:52 AM | Vermont | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-08 | 10:00 AM | 7/11/2011 | 9:00 AM | PJM Corporate Office, Pennsylvania | RFC | | Suspected Cyber Attack | UNK | UNK | Cyber Attack |
| | 2011-07-08 | 10:00 AM | 7/8/2011 | 10:00 AM | Saginaw, Minnesota | MRO | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-11 | 1:13 PM | 7/11/2011 | 1:13 PM | Southwest Ohio | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-11 | 1:30 PM | 7/11/2011 | 1:30 PM | Maine | NPCC | | Vandalism | N/A | 0 | Physical Attack |
| | 2011-07-11 | 9:00 AM | 7/11/2011 | 9:00 AM | Illinois | RFC | | Severe Weather | UNK | 500,000 | Weather |
| | 2011-07-11 | 9:00 AM | 7/11/2011 | 10:25 AM | Michigan | RFC | | Severe Weather | 254 | 103,000 | Weather |
| | 2011-07-11 | 11:15 AM | 7/12/2011 | 8:15 AM | Western and Southern Lower Peninsula Michigan | RFC | | Severe Weather | UNK | 85,000 | Weather |
| | 2011-07-11 | 2:27 PM | 7/12/2011 | 3:50 PM | Indiana, Michigan, Ohio | RFC | | Severe Weather | UNK | 120,000 | Weather |
| | 2011-07-12 | 12:00 PM | 7/12/2011 | 12:00 PM | Maine | NPCC | | Vandalism | N/A | 0 | Physical Attack |
| | 2011-07-12 | 8:20 PM | 7/12/2011 | 9:30 PM | California | WECC | | Suspected Physical Attack | UNK | UNK | Physical Attack |
| | 2011-07-13 | 5:19 PM | 7/13/2011 | 10:03 PM | Pueblo, Colorado | WECC | | Load Shed | 580 | N/A | Load Shed |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-07-14 | 11:00 AM | 7/14/2011 | 7:00 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-07-18 | 5:00 PM | 7/24/2011 | 1:30 PM | Southeast Michigan | RFC | | Severe Weather | N/A | 197,166 | Weather |
| | 2011-07-19 | 11:45 AM | 7/19/2011 | 3:00 PM | Maine | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-20 | 9:10 AM | 7/20/2011 | 4:30 PM | Frederickson Substation, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-21 | 12:32 PM | 7/22/2011 | 6:30 AM | Lower Peninsula, Michigan | RFC | | Public Appeal to Reduce Electricity Usage | 8,881 | N/A | Public Appeal |
| | 2011-07-21 | 1:00 PM | 7/21/2011 | 3:00 PM | Springfield, Illinois | SERC | | Public Appeal to Reduce Electricity Usage | N/A | N/A | Public Appeal |
| | 2011-07-22 | 11:34 AM | 7/22/2011 | 5:26 PM | Ohio | RFC | | Load Shed | 206 | 23,000 | Load Shed |
| | 2011-07-22 | 11:00 AM | 7/22/2011 | 6:00 PM | Upstate, New York | NPCC | | Public Appeal to Reduce Electricity Usage | N/A | N/A | Public Appeal |
| | 2011-07-23 | 2:30 AM | 7/24/2011 | 9:00 AM | Illinois | RFC | | Severe Weather | UNK | 169,000 | Weather |
| | 2011-07-24 | 2:34 PM | 7/24/2011 | 3:47 PM | Southern, New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-26 | 12:01 PM | 7/26/2011 | 12:01 PM | Backup Control Center, Oklahoma | SPP | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-07-27 | 12:07 PM | 7/27/2011 | 12:08 PM | Fife, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-28 | 7:26 AM | 7/29/2011 | 7:26 AM | Daviess County, Kentucky | SERC | | Fuel Supply Deficiency (Coal) | N/A | N/A | Fuel Supply Deficiency |
| | 2011-07-28 | 1:32 PM | 7/28/2011 | 1:32 PM | Indiana | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-28 | 7:25 PM | 7/28/2011 | 7:25 PM | Spanaway, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-28 | 12:14 AM | 7/29/2011 | 12:00 PM | Entire ComEd Territory, Indiana | RFC | | Severe Weather | UNK | 201,000 | Weather |
| | 2011-07-29 | 11:46 AM | 7/29/2011 | 5:00 PM | Fredrickson, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-07-29 | 8:45 PM | 8/1/2011 | 4:24 AM | Central New Jersey | RFC | | Severe Weather | N/A | 67,900 | Weather |
| | 2011-08-01 | 2:18 PM | 8/1/2011 | 2:18 PM | Jefferson, Oregon | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-08-01 | 3:00 PM | 8/5/2011 | 7:00 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-08-02 | 10:15 AM | 8/3/2011 | 9:16 AM | Oklahoma | SPP | | Public Appeal to Reduce Electricity Usage | N/A | N/A | Public Appeal |
| | 2011-08-02 | 9:30 PM | 8/3/2011 | 7:00 PM | Northeast, Illinois | RFC | | Severe Weather | UNK | 71,500 | Weather |
| | 2011-08-03 | 10:00 AM | 8/19/2011 | 10:00 AM | Western New York | NPCC | | Fuel Supply Deficiency (Coal) | 675 | UNK | Fuel Supply Deficiency |
| | 2011-08-03 | 4:29 PM | 8/3/2011 | 11:40 PM | Northeast Oklahoma | SPP | | Public Appeal to Reduce Electricity Usage | 300 | N/A | Public Appeal |
| | 2011-08-03 | 4:30 PM | 8/3/2011 | 9:00 PM | Central Arkansas | SPP | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-08-04 | 10:30 AM | 8/4/2011 | 4:00 PM | Arkansas, Oklahoma, Texas | SPP | | Public Appeal to Reduce Electricity Usage | N/A | N/A | Public Appeal |
| | 2011-08-08 | 7:36 PM | 8/9/2011 | 12:00 PM | Oklahoma | SPP | | Electrical System Separation (Islanding) | 92 | 14,500 | Islanding |
| | 2011-08-08 | 9:30 AM | 8/8/2011 | 9:30 AM | Greene County, Ohio | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-08-08 | 9:35 AM | 8/8/2011 | 4:00 PM | Collins Substation, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-08-08 | 8:58 PM | 8/10/2011 | 4:30 PM | Northern and Central Oklahoma | SPP | | Severe Weather | N/A | 54,000 | Weather |
| | 2011-08-09 | 10:26 AM | 8/9/2011 | 5:00 PM | Polk Substation, Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-08-13 | 4:41 PM | 8/14/2011 | 7:00 PM | Kentucky | SERC | | Severe Weather | UNK | 181,700 | Weather |
| | 2011-08-15 | 2:05 AM | 8/15/2011 | 3:40 AM | Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-08-18 | 9:51 AM | 8/18/2011 | 4:00 PM | Collins Substation, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-08-20 | 5:42 PM | 8/23/2011 | 8:00 PM | Southeastern Michigan | RFC | | Severe Weather | 254 | 65,000 | Weather |
| | 2011-08-21 | 10:45 PM | 8/23/2011 | 10:45 PM | Puerto Rico | N/A | | Severe Weather | 2,200 | 931,000 | Weather |
| | 2011-08-22 | 10:05 AM | 8/22/2011 | 4:00 PM | Collins Substation, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-08-23 | 1:51 PM | 8/23/2011 | 1:51 PM | Virginia | RFC | | Earthquake | 0 | 0 | Natural Disaster |
| | 2011-08-23 | 10:30 AM | 8/23/2011 | 4:54 PM | Southeastern New Mexico, Texas Panhandle | SPP | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-08-23 | 3:43 PM | 8/23/2011 | 7:00 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-08-24 | 1:20 PM | 8/29/2011 | 7:00 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | 0 | 0 | Public Appeal |
| | 2011-08-24 | 7:45 AM | 8/25/2011 | 6:00 AM | Houston area, Texas | TRE | | Severe Weather | 485 | 79,000 | Weather |
| | 2011-08-24 | 2:51 PM | 8/24/2011 | 10:00 PM | Arkansas, Louisiana, Texas | SPP | | Severe Weather | N/A | 53,064 | Weather |
| | 2011-08-25 | 12:01 AM | 8/25/2011 | 12:01 AM | Maine | NPCC | | Suspected Physical Attack | 0 | 0 | Cyber Attack |
| | 2011-08-25 | 12:30 AM | 8/28/2011 | 8:00 PM | Cleveland area, Ohio | RFC | | Severe Weather | N/A | 107,833 | Weather |
| | 2011-08-26 | 12:30 AM | 8/28/2011 | 12:30 AM | Pennsylvania | RFC | | Severe Weather | N/A | 200,717 | Weather |
| | 2011-08-27 | 2:00 AM | 8/27/2011 | 5:15 AM | Wilson County North Carolina | SERC | | Distribution System Interruption | 2 | 1,200 | Distribution Interruption |
| | 2011-08-27 | 2:57 AM | 8/29/2011 | 11:30 PM | Eastern North Carolina | SERC | | Severe Weather | UNK | 285,465 | Weather |
| | 2011-08-27 | 10:33 AM | 8/29/2011 | 2:00 PM | North Carolina; Virginia | SERC | | Severe Weather | UNK | 1,000,000 | Weather |
| | 2011-08-27 | 1:00 PM | 8/29/2011 | 1:00 PM | Delaware; Maryland | RFC | | Severe Weather | N/A | 165,000 | Weather |
| | 2011-08-27 | 7:00 PM | 8/29/2011 | 1:31 PM | Eastern North Carolina | SERC | | Severe Weather | 200 | 136,000 | Weather |
| | 2011-08-27 | 8:30 PM | 9/4/2011 | 11:30 PM | Maryland | RFC | | Severe Weather | 1,114 | 760,113 | Weather |
| | 2011-08-27 | 10:00 PM | 8/29/2011 | 4:00 PM | Southern New Jersey | RFC | | Severe Weather | 320 | 140,000 | Weather |
| | 2011-08-27 | 10:00 PM | 8/29/2011 | 10:00 PM | Pennsylvania | RFC | | Severe Weather | N/A | 264,000 | Weather |
| | 2011-08-27 | 11:00 PM | 8/29/2011 | 8:00 AM | Maryland | RFC | | Severe Weather | UNK | 108,000 | Weather |
| | 2011-08-27 | 11:05 PM | 8/29/2077 | 3:30 PM | District of Columbia; Maryland | RFC | | Severe Weather | N/A | 220,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-08-28 | 8:55 PM | 8/28/2011 | 11:39 PM | Calapooya Substation, Oregon | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-08-28 | 12:01 AM | 8/30/2011 | 12:01 AM | Mid-Hudson, New York | NPCC | | Severe Weather | N/A | 180,000 | Weather |
| | 2011-08-28 | 12:23 AM | 8/30/2011 | 12:23 AM | New Jersey | RFC | | Severe Weather | 500 | 665,000 | Weather |
| | 2011-08-28 | 12:30 AM | 8/30/2011 | 12:30 AM | Northern and Central New Jersey | RFC | | Severe Weather | N/A | 650,000 | Weather |
| | 2011-08-28 | 2:58 AM | 8/30/2011 | 2:58 AM | Eastern and Northeastern Pennsylvania | RFC | | Severe Weather | 110 | 284,000 | Weather |
| | 2011-08-28 | 5:00 AM | 8/30/2011 | 5:00 AM | Long Island, New York | NPCC | | Severe Weather | UNK | 152,261 | Weather |
| | 2011-08-28 | 5:01 AM | 9/3/2011 | 5:01 AM | Borough's and Westshester County New York | NPCC | | Severe Weather | N/A | 50000 | Weather |
| | 2011-08-28 | 7:00 AM | 9/3/2011 | 12:01 AM | New York | NPCC | | Severe Weather | UNK | 99,700 | Weather |
| | 2011-08-28 | 7:40 AM | 8/29/2011 | 7:40 AM | Southwest Connecticut | NPCC | | Severe Weather | N/A | 158,000 | Weather |
| | 2011-08-28 | 9:42 AM | 8/30/2011 | 12:01 AM | Eastern New York | NPCC | | Severe Weather | N/A | 100,000 | Weather |
| | 2011-08-28 | 12:10 PM | 8/28/2011 | 12:11 PM | Eastern Massachusetts | NPCC | | Severe Weather | N/A | 50,000 | Weather |
| | 2011-08-28 | 12:30 PM | 8/28/2011 | 12:31 PM | New York | NPCC | | Severe Weather | N/A | 116,000 | Weather |
| | 2011-08-31 | 12:52 PM | 8/31/2011 | 12:52 PM | Southwest Ohio | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-09-01 | 8:13 AM | 9/1/2011 | 4:00 PM | Graham Substaion, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-03 | 2:00 PM | 9/8/2011 | 6:00 PM | Southeast Lower Peninsula, Michigan | RFC | | Severe Weather | UNK | 105,000 | Weather |
| | 2011-09-05 | 4:30 PM | 9/7/2011 | 3:45 PM | Alabama; Georgia | SERC | | Severe Weather | 177 | 53,295 | Weather |
| | 2011-09-07 | 12:08 AM | 9/7/2011 | 10:50 AM | Western Connecticut; New York | NPCC | | Actual Physical Attack | 0 | 0 | Physical Attack |
| | 2011-09-08 | 3:28 PM | 9/10/2011 | 3:30 PM | Arizona; California | WECC | | Transmission/Distribution Interruption; Load Shed; Generation Inadequacy | 7,000 | 2,000,000 | Generation Interruption |
| | 2011-09-08 | 7:53 PM | 9/9/2011 | 4:00 PM | Collins Substation, Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-12 | 9:15 AM | 9/12/2011 | 3:30 PM | English Creek, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-09-13 | 11:43 AM | 9/14/2011 | 4:00 PM | Lacamas Substation, Roy, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-13 | 2:03 PM | 9/13/2011 | 6:21 PM | Saranac, New York | NPCC | | Vandalism | N/A | 0 | Physical Attack |
| | 2011-09-14 | 9:00 AM | 9/14/2011 | 2:00 PM | Salt Lake County, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-09-20 | 12:55 PM | 9/20/2011 | 5:00 PM | Lacamas Substaion, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-21 | 2:37 PM | 9/21/2011 | 3:47 PM | Puerto Rico | N/A | | Generation Inadequacy; Load Shed | 600 | 319,616 | Generation Interruption |
| | 2011-09-21 | 10:30 AM | 9/21/2011 | 10:30 AM | Hockessin, Delaware | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-09-22 | 2:50 PM | 9/22/2011 | 2:51 PM | Montgomery County, Ohio | RFC | | Vandalism | N/A | 0 | Physical Attack |
| | 2011-09-23 | 9:04 AM | 9/23/2011 | 9:04 AM | North Haven, Connecticut | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-09-24 | 4:17 PM | 9/25/2011 | 4:00 PM | Collins Substation, Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-26 | 10:15 AM | 9/26/2011 | 10:15 AM | McKee City, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-09-28 | 9:30 AM | 9/28/2011 | 1:00 PM | Watertown, Connecticut | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-28 | 2:59 PM | 9/28/2011 | 2:59 PM | Dorothy, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-09-28 | 4:41 PM | 9/28/2011 | 4:41 PM | Bethany Beach, Delaware | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-09-29 | 6:44 PM | 9/30/2011 | 4:00 PM | Collins Substation, Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-09-29 | 5:00 AM | 9/30/2011 | 6:00 AM | Houston metro area, Texas | TRE | | Severe Weather | N/A | 65000 | Weather |
| | 2011-09-30 | 8:22 AM | 9/30/2011 | 8:22 AM | Wilmington, Delaware | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-10-06 | 11:07 AM | 10/6/2011 | 11:07 AM | Oquirrh Substation, Utah | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-10-07 | 8:04 AM | 10/7/2011 | 4:00 PM | Olympic Pipeline, Spanaway, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-10-14 | 2:20 PM | 10/14/2011 | 2:20 PM | English Creek, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-10-17 | 3:34 AM | 10/17/2011 | 10:42 AM | Seat Pleasant, Maryland | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-10-17 | 3:44 PM | 10/17/2011 | 3:44 PM | Southwest Ohio | RFC | | Vandalism | 7 | 2,000 | Physical Attack |
| | 2011-10-18 | 3:45 AM | 10/18/2011 | 5:25 AM | Holmesburg Substation, Philadelphia, Pennsylvania | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-10-20 | 7:15 AM | 10/20/2011 | 7:15 AM | McKee, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-10-24 | 11:37 PM | 10/26/2011 | 11:00 PM | Holmesburg Substation, Philadelphia, Pennsylvania | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-10-26 | 5:00 AM | 10/27/2011 | 3:00 PM | Denver; Ft. Collins, Colorado | WECC | | Severe Weather | UNK | 204,000 | Weather |
| | 2011-10-27 | 1:00 AM | 10/27/2011 | 2:36 AM | Munster, Indiana | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2011-10-29 | 8:59 AM | 11/7/2011 | 7:58 PM | Pennsylvania | RFC | | Severe Weather | UNK | 312,359 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-10-29 | 8:59 AM | 11/7/2011 | 3:00 PM | Pennsylvania | RFC | | Severe Weather | UNK | 50,000 | Weather |
| | 2011-10-29 | 9:59 AM | 11/7/2011 | 1:00 PM | Northwest and Central New Jersey | RFC | | Severe Weather | UNK | 379,000 | Weather |
| | 2011-10-29 | 11:18 AM | 11/4/2011 | 12:00 AM | Southeast New York | NPCC | | Severe Weather | UNK | 161,151 | Weather |
| | 2011-10-29 | 12:57 PM | 11/3/2011 | 11:00 PM | Harrisburg, Lehigh Valley, Lancaster Region Pennsylvania | RFC | | Severe Weather | UNK | 146,721 | Weather |
| | 2011-10-29 | 2:00 PM | 10/31/2011 | 14:00 | Southeast Pennsylvania | RFC | | Severe Weather | UNK | 109,335 | Weather |
| | 2011-10-29 | 2:30 PM | 11/6/2011 | 12:00 PM | New Jersey | RFC | | Severe Weather | 125 | 197,000 | Weather |
| | 2011-10-29 | 3:00 PM | 11/2/2011 | 8:15 AM | Mid-Hudson Valley Region, New York | NPCC | | Severe Weather | N/A | 145,000 | Weather |
| | 2011-10-29 | 4:14 PM | 11/7/2011 | 4:00 PM | Connecticut; Maine; Massachusetts; New Hampshire; Rhode Island | NPCC | | Severe Weather | UNK | 1,418,100 | Weather |
| | 2011-10-29 | 4:16 PM | 11/2/2011 | 9:30 PM | New York City area | NPCC | | Severe Weather | UNK | 50,000 | Weather |
| | 2011-10-29 | 8:00 PM | 10/31/2011 | 8:00 PM | New Jersey; New York | NPCC, RFC | | Severe Weather | N/A | 74,000 | Weather |
| | 2011-11-04 | 10:46 AM | 11/4/2011 | 10:46 AM | Sweetwater County, Wyoming | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-11-13 | 11:30 AM | 11/13/2011 | 12:00 PM | Cate Road, Deerfield, New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-11-14 | 2:24 PM | 11/14/2011 | 2:24 PM | McKee, New Jersey | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-11-22 | 11:16 PM | 11/22/2011 | 11:16 PM | Indiana | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-11-30 | 10:00 AM | 11/30/2011 | 11:00 AM | Orchard Substation, Washington | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2011-11-30 | 4:56 PM | 12/2/2011 | 10:00 AM | City of Los Angeles, California | WECC | | Severe Weather | UNK | 150,000 | Weather |
| | 2011-12-01 | 12:45 AM | 12/7/2011 | 9:00 PM | Southern California | WECC | | Severe Weather | UNK | 91,690 | Weather |
| | 2011-12-01 | 3:29 AM | 12/2/2011 | 1:05 PM | Northern California | WECC | | Severe Weather | 300 | 100,000 | Weather |
| | 2011-12-01 | 10:00 AM | 12/2/2011 | 1:11 PM | Wasatch Front Area Utah | WECC | | Severe Weather | UNK | 60,000 | Weather |
| | 2011-12-02 | 4:15 PM | 12/2/2011 | 8:30 PM | Rusk County Texas | TRE | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-12-05 | 2:00 PM | 12/6/2011 | 5:00 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-12-06 | 5:38 PM | 12/7/2011 | 11:04 AM | Montague, Michigan | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2011-12-06 | 8:00 AM | 12/6/2011 | 8:00 PM | Bismarck-Mandan, North Dakota | MRO | | Public Appeal to Reduce Electricity Usage | 155 | 34,500 | Public Appeal |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011-12-07 | 7:29 PM | 12/7/2011 | 10:57 PM | Central Virginia | SERC | | Severe Weather | 240 | 60,000 | Weather |
| | 2011-12-08 | 8:45 AM | 12/8/2011 | 4:30 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-12-13 | 3:19 AM | 12/14/2011 | 3:19 AM | Clinton County Ohio | RFC | | Suspected Physical Attack | N/A | 0 | Physical Attack |
| | 2011-12-19 | 8:48 AM | 12/19/2011 | 4:00 PM | Croft Substation, Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-12-20 | 7:45 AM | 12/20/2011 | 8:45 AM | Sweet Home, Oregon | WECC | | Suspected Physical Attack | 12 | 2,500 | Physical Attack |
| | 2011-12-20 | 9:30 AM | 12/20/2011 | 9:31 AM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2011-12-21 | 10:30 AM | 12/21/2011 | 10:30 AM | Boise, Idaho | WECC | | Suspected Cyber Attack | 0 | 0 | Cyber Attack |
| | 2011-12-31 | 9:26 PM | 12/31/2011 | 9:26 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-01-04 | 12:14 PM | 1/4/2012 | 12:14 PM | Tacoma, Washington | WECC | | Suspected physical attack | N/A | N/A | Physical Attack |
| | 2012-01-05 | 10:28 AM | 1/5/2012 | 12:25 PM | Creek County, Oklahoma | SPP | | Suspected physical attack | N/A | N/A | Physical Attack |
| | 2012-01-05 | 10:35 AM | 1/5/2012 | 12:25 PM | CSWS/AEP West territory, Oklahoma | SPP | | Sabotage | 0 | 0 | Physical Attack |
| | 2012-01-09 | 1:36 PM | 1/11/2012 | 1:05 AM | Louisiana | SERC | | Load Shed | 150 | 1 | Load Shed |
| | 2012-01-09 | 2:30 PM | 1/9/2012 | 3:30 PM | Watertown, Connecticut | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-01-10 | 9:30 PM | 1/10/2012 | 9:30 PM | Rusk County, Texas | TRE | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-01-11 | 7:19 AM | 1/11/2012 | 9:07 AM | Nevada | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-01-12 | 8:26 AM | 1/12/2012 | 8:26 AM | Newark, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-01-13 | 9:20 AM | 1/13/2012 | 9:20 AM | Newark, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-01-15 | 9:35 AM | 1/15/2012 | 9:35 AM | Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-01-17 | 10:31 AM | 1/17/2012 | 5:21 PM | Austin, Texas | TRE | | Suspected Cyber Attack | N/A | 0 | Cyber Attack |
| | 2012-01-19 | 7:00 AM | 1/20/2012 | 3:00 PM | King, Pierce and Thurston Counties, Washington | WECC | | Severe Weather - Winter Storm | 1,600 | 426,000 | Weather |
| | 2012-01-24 | 11:22 AM | 1/24/2012 | 11:22 AM | Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-01-27 | 9:40 AM | 1/27/2012 | 9:40 AM | Frederickson Substation, Spanaway, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-01-29 | 12:45 PM | 1/29/2012 | 12:45 PM | Roosevelt Substation, Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-02-11 | 8:47 AM | 2/11/2012 | 10:30 AM | Lamar, Colorado | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-02-11 | 8:55 AM | 2/11/2012 | 8:55 AM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-02-13 | 7:02 AM | 2/13/2012 | 4:25 PM | Asheville, North Carolina | SERC | | Suspected Physical Attack | N/A | N/A | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-02-14 | 7:20 PM | 2/15/2012 | 4:00 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-02-15 | 5:33 AM | 2/15/2012 | 5:30 PM | Port Orchard, Washington | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-02-17 | 3:00 AM | 2/17/2012 | 11:33 AM | Little Rock, Arkansas | SERC | | Suspected Cyber Attack | UNK | UNK | Cyber Attack |
| | 2012-02-19 | 5:00 PM | 2/21/2012 | 7:33 AM | Kentucky, Virginia, West Virginia | SERC | | Severe Weather - Winter Storm | UNK | 90,000 | Weather |
| | 2012-02-23 | 5:45 AM | 2/23/2012 | 3:02 PM | South East College Station, Texas | TRE | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-02-23 | 11:12 PM | 2/24/2012 | 1:00 AM | Londonderry, New Hampshire | NPCC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-02-24 | 11:24 AM | 2/24/2012 | 11:49 AM | Spanaway, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-02-28 | 2:59 AM | 2/28/2012 | 6:12 AM | Sacramento, California | WECC | | Electrical System Separation (Islanding) | 1 | 1 | Islanding |
| | 2012-02-28 | 7:00 AM | 2/28/2012 | 7:00 AM | Coos County Oregon | WECC | | Suspected Physical Attack | UNK | UNK | Physical Attack |
| | 2012-03-02 | 1:45 PM | 3/2/2012 | 3:30 PM | Piggott, Arkansas | SERC | | Operational Failure/Equipment Malfunction | N/A | N/A | Equipment |
| | 2012-03-02 | 12:37 PM | 3/5/2012 | 12:01 PM | Northern Alabama; Southeast Tennessee | SERC | | Severe Weather - Tornadoes | 500 | UNK | Weather |
| | 2012-03-02 | 9:00 PM | 3/5/2012 | 4:30 PM | Southeastern, Michigan | RFC | | Severe Weather - Winter Storm | 371 | 130,000 | Weather |
| | 2012-03-02 | 9:00 PM | 3/4/2012 | 5:30 PM | Lower Peninsula, Michigan | RFC | | Severe Weather - Winter Storm | 50 | 140,000 | Weather |
| | 2012-03-04 | 1:27 AM | 3/4/2012 | 6:58 AM | Prince Georges County, Maryland | RFC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-03-04 | 1:38 PM | 3/5/2012 | 11:00 AM | Texas | SERC | | Suspected Physical Attack | UNK | UNK | Physical Attack |
| | 2012-03-16 | 4:00 PM | 3/16/2012 | 4:00 PM | New Castle, Delaware | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-03-20 | 8:00 AM | 3/20/2012 | 1:00 PM | Houston, Texas | TRE | | Severe Weather - Thunderstorms | N/A | 96,000 | Weather |
| | 2012-03-23 | 7:34 PM | 3/23/2012 | 7:34 PM | Newark, Delaware | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-03-26 | 1:24 PM | 3/26/2012 | 1:24 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-03-28 | 10:17 AM | 3/28/2012 | 10:17 AM | Graham, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-03-29 | 12:01 PM | 3/29/2012 | 12:02 PM | Lansing, Michigan | RFC | | Electrical System Separation (Islanding) | UNK | 0 | Islanding |
| | 2012-03-30 | 11:10 AM | 3/30/2012 | 11:30 AM | Vermont | NPCC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-01 | 8:27 PM | 4/3/2012 | 8:28 AM | Council Bluffs, Iowa | MRO | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-04-03 | 11:10 AM | 4/3/2012 | 11:25 AM | West Rutland, Vermont | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-04-03 | 3:33 PM | 4/3/2012 | 8:25 PM | Seattle, Washington | WECC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-04-04 | 3:32 PM | 4/6/2012 | 3:30 PM | WAPA-SNR Regional Office, California | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-04-07 | 9:31 AM | 4/7/2012 | 9:32 AM | Newark, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-04-07 | 12:25 PM | 4/7/2012 | 12:26 PM | Newark, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-04-07 | 2:35 PM | 4/7/2012 | 2:36 PM | Newark, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-04-11 | 9:00 AM | 4/11/2012 | 9:00 AM | North Attleboro, Massachusetts | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-04-12 | 8:08 AM | 4/12/2012 | 4:30 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-15 | 7:38 PM | 4/15/2012 | 9:26 PM | Georgia | SERC | | Suspected Physical Attack | UNK | UNK | Physical Attack |
| | 2012-04-16 | 3:46 PM | 4/19/2012 | 2:00 AM | Southeast, Michigan | RFC | | Severe Weather - High Winds | 218 | 111,393 | Weather |
| | 2012-04-17 | 6:11 AM | 4/17/2012 | 5:48 PM | San Diego County, California | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-04-19 | 7:53 AM | 4/19/2012 | 4:00 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-20 | 2:27 PM | 4/21/2012 | 4:27 AM | Metropolitan Houston, Texas | TRE | | Severe Weather - Thunderstorms | N/A | 120,377 | Weather |
| | 2012-04-21 | 3:02 PM | 4/21/2012 | 8:09 PM | East Bridgewater, Massachusetts | NPCC | | Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-21 | 8:55 PM | 4/23/2012 | 4:30 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-23 | 8:11 AM | 4/23/2012 | 12:47 PM | Northwest Indiana | RFC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-04-23 | 11:56 AM | 4/23/2012 | 3:35 PM | Snohomish County, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-05-07 | 12:50 PM | 5/7/2012 | 2:00 PM | Williston, Vermont | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-05-07 | 5:45 PM | 5/7/2012 | 6:06 PM | Eastern Ohio | RFC | | Load Shed/Severe Weather - Lightning Storm | 420 | 1 | Weather |
| | 2012-05-11 | 11:05 AM | 5/11/2012 | 11:20 AM | Lakewood, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-05-24 | 3:20 PM | 5/25/2012 | 5:29 PM | Tyngsborough, Massachusetts | NPCC | | Physical Attack | UNK | UNK | Physical Attack |
| | 2012-05-29 | 6:30 PM | 5/29/2012 | 7:40 PM | Alder Dam, Pierce County, Washington | WECC | | Physical Attack | N/A | N/A | Weather |
| | 2012-05-29 | 8:35 PM | 5/31/2012 | 10:00 AM | Oklahoma City Metro Area, Oklahoma | SPP | | Severe Weather - Thunderstorms | UNK | 112,000 | Weather |
| | 2012-05-31 | 11:45 PM | 6/1/2012 | 4:30 AM | Columbus, Ohio | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-06-02 | 7:30 AM | 6/2/2012 | 11:35 AM | San Francisco, California | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-06-06 | 8:00 AM | 6/6/2012 | 8:00 AM | Delhi, New York | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-06-06 | 12:37 PM | 6/6/2012 | 12:37 PM | Columbia Heights, NW, Washington DC | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-06-08 | 5:20 PM | 6/8/2012 | 5:25 PM | Denver Metro Area, Colorado | WECC | | Load Shed | 120 | 30,379 | Load Shed |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-06-11 | 7:50 PM | 6/12/2012 | 3:00 PM | North/Central Alabama; North/Central Georgia | SERC | | Severe Weather - Thunderstorms | 368 | 110,591 | Weather |
| | 2012-06-12 | 3:57 PM | 6/14/2012 | 4:57 AM | Houston, Texas | TRE | | Severe Weather - Thunderstorms | 920 | 175,000 | Weather |
| | 2012-06-13 | 4:55 PM | 6/13/2012 | 10:09 PM | San Juan County, New Mexico | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-06-19 | 5:30 AM | 6/21/2012 | 5:30 AM | CAISO Territory California | WECC | | Fuel Supply Deficiency (Water) | UNK | UNK | Fuel Supply Deficiency |
| | 2012-06-19 | 4:30 AM | 6/20/2012 | 11:00 PM | Minneapolis/St. Paul, Minnesota | MRO | | Severe Weather - Thunderstorms | UNK | 68,200 | Weather |
| | 2012-06-23 | 6:57 PM | 6/23/2012 | 7:28 PM | North Shore, Massachusetts | NPCC | | Load Shed | 51 | 29,250 | Load Shed |
| | 2012-06-25 | 4:04 PM | 6/26/2012 | 1:45 PM | Central Virginia | SERC | | Severe Weather - Wind & Rain | 600 | 190,000 | Weather |
| | 2012-06-29 | 12:10 PM | 6/29/2012 | 5:02 PM | Puerto Rico | N/A | | Equipment Trip & Failure | 1,800 | 900,000 | Equipment |
| | 2012-06-29 | 10:45 AM | 6/29/2012 | 10:45 AM | New Castle, Delaware | RFC | | Physical Attack | 0 | 0 | Physical Attack |
| | 2012-06-29 | 4:00 PM | 6/29/2012 | 9:00 PM | Eastern, Arkansas | SERC | | Public Appeal to Reduce Electricity Usage | 45 | 7,935 | Public Appeal |
| | 2012-06-29 | 2:10 PM | 7/4/2012 | 6:00 PM | Dayton, Ohio | RFC | | Severe Weather - Thunderstorms | 500 | 175,000 | Weather |
| | 2012-06-29 | 4:00 PM | 7/2/2012 | 4:00 PM | Indiana; Michigan; Ohio; West Virginia | RFC | | Severe Weather - Thunderstorms | UNK | 1,355,919 | Weather |
| | 2012-06-29 | 5:15 PM | 7/2/2012 | 11:59 PM | Eastern Indiana; Northern Kentucky; Greater Cincinnati area Ohio | RFC | | Severe Weather - Thunderstorms | 2,946 | 4,645,572 | Weather |
| | 2012-06-29 | 6:24 PM | 7/6/2012 | 10:00 AM | West Virginia | RFC | | Severe Weather - Thunderstorms | 700 | 265,000 | Weather |
| | 2012-06-29 | 7:00 PM | 7/7/2012 | 7:43 PM | Maryland; West Virginia | RFC | | Severe Weather - Thunderstorms | UNK | 145,000 | Weather |
| | 2012-06-29 | 10:15 PM | 7/5/2012 | 12:52 PM | Montgomery and Prince Georges Counties, Maryland; District of Columbia | RFC | | Severe Weather - Thunderstorms | 3,000 | 425,000 | Weather |
| | 2012-06-29 | 10:29 PM | 7/4/2012 | 3:36 PM | Virginia | SERC | | Severe Weather - Thunderstorms | 5,000 | 880,000 | Weather |
| | 2012-06-29 | 10:43 PM | 7/5/2012 | 11:50 AM | Greater Baltimore area, Maryland | RFC | | Severe Weather - Thunderstorms | 1,465 | 600,000 | Weather |
| | 2012-06-29 | 11:30 PM | 6/30/2012 | 2:00 AM | Northeast Illinois | RFC | | Severe Weather - Thunderstorms | UNK | 109,000 | Weather |
| | 2012-06-30 | 3:00 PM | 7/2/2012 | 12:00 PM | Northeast Tennessee | SERC | | Public Appeal to Reduce Electricity Usage | UNK | UNK | Public Appeal |
| | 2012-06-30 | 1:00 AM | 7/3/2012 | 1:00 AM | Delaware; Maryland | RFC | | Severe Weather - Thunderstorms | 0 | 86,390 | Weather |
| | 2012-06-30 | 1:15 AM | 7/7/2012 | 5:33 PM | Atlantic City Electric Service Territory New Jersey | RFC | | Severe Weather - Thunderstorms | UNK | 205,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-06-30 | 10:30 PM | 7/2/2012 | 8:11 AM | Calvert, Charles, St. Mary's, Prince Georges Counties Maryland | RFC | | Severe Weather - Thunderstorms | 354 | 60,000 | Weather |
| | 2012-07-01 | 1:00 PM | 7/3/2012 | 3:00 PM | Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 320,000 | Weather |
| | 2012-07-01 | 4:47 PM | 7/1/2012 | 11:00 PM | Tarboro, North Carolina | SERC | | Operational Failure; Storm Damage | 48 | 6,100 | Weather |
| | 2012-07-01 | 5:45 PM | 7/1/2012 | 10:15 PM | Northern, Central and Eastern North Carolina | SERC | | Severe Weather | Unknown | 69,106 | Weather |
| | 2012-07-05 | 12:00 AM | 7/6/2012 | 8:30 PM | Lower Peninsula Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 111,000 | Weather |
| | 2012-07-05 | 7:00 PM | 7/6/2012 | 4:00 PM | Northeast Tennessee | SERC | | Severe Weather - Wind & Storms | N/A | 50,001 | Weather |
| | 2012-07-06 | 3:05 PM | 7/6/2012 | 3:06 PM | Tacoma, Washington | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-07-07 | 4:00 AM | 7/10/2012 | 4:00 AM | CAISO California | WECC | | Fuel Supply Deficiency (Water) | Unknown | 0 | Fuel Supply Deficiency |
| | 2012-07-07 | 6:06 AM | 7/9/2012 | 11:00 PM | Lower Valley, Central, Susquehanna Regions Pennsylvania | RFC | | Severe Weather - Thunderstorms | N/A | 64,500 | Weather |
| | 2012-07-07 | 6:00 PM | 7/9/2012 | 7:01 PM | Central and Northern New Jersey | RFC | | Severe Weather - Thunderstorms | N/A | 95,400 | Weather |
| | 2012-07-09 | 12:15 PM | 7/9/2012 | 4:14 PM | Alberta, Canada | WECC | | Energy Deficiency Alert | 9896 | Unknown | Fuel Supply Deficiency |
| | 2012-07-16 | 11:27 AM | 7/16/2012 | 12:29 PM | Little Rock, Arkansas | SPP | | Public Appeal to Reduce Energy Usage | N/A | N/A | Public Appeal |
| | 2012-07-18 | 2:16 PM | 7/19/2012 | 11:58 PM | Southeast Ohio, Northern Kentucky, Southern Indiana | RFC | | Severe Weather - Thunderstorms | 480 | 103,000 | Weather |
| | 2012-07-18 | 4:20 PM | 7/18/2012 | 7:05 PM | Eastern Ohio | RFC | | Severe Weather - Thunderstorms | Unknown | 67,000 | Weather |
| | 2012-07-18 | 11:00 PM | 7/19/2012 | 6:00 AM | Northern Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 181,000 | Weather |
| | 2012-07-19 | 10:30 AM | 7/31/2012 | 11:00 AM | Niagara County, New York | NPCC | | Fuel Supply Deficiency (Coal) | 675 | Unknown | Fuel Supply Deficiency |
| | 2012-07-19 | 12:32 PM | 7/19/2012 | 12:33 PM | Newark, Delaware | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2012-07-21 | 2:19 AM | 7/21/2012 | 5:20 AM | City of Lubbock, Texas | SPP | | Severe Weather; Equipment Failure | 220 | 70,000 | Weather |
| | 2012-07-24 | 7:01 AM | 7/24/2012 | 4:30 PM | Northern Indiana | RFC | | Severe Weather - Thunderstorms | N/A | 82,621 | Weather |
| | 2012-07-24 | 7:30 AM | 7/24/2012 | 10:00 PM | Northern Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 330,000 | Weather |
| | 2012-07-26 | 6:14 PM | 7/27/2012 | 6:14 PM | Western Pennsylvania | RFC | | Severe Weather - Thunderstorms | N/A | 65,112 | Weather |
| | 2012-07-26 | 6:21 PM | 7/28/2012 | 11:30 PM | North/Central Pennsylvania | RFC | | Severe Weather - Thunderstorms | N/A | 65,000 | Weather |
| | 2012-07-26 | 6:30 PM | 7/27/2012 | 5:22 PM | Eastern Ohio | RFC | | Severe Weather - Thunderstorms | Unknown | 57,054 | Weather |
| | 2012-07-27 | 5:19 PM | 7/28/2012 | 5:19 PM | Central Indiana | RFC | | Severe Weather - Thunderstorms | Unknown | 52,702 | Weather |
| | 2012-08-01 | 12:00 PM | 8/1/2012 | 12:00 PM | Oklahoma, Arkansas | SPP | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-08-04 | 3:55 AM | 8/4/2012 | 4:21 AM | Temblor Substation in McKittrick, California | WECC | | Electrical System Separation (Islanding) | 5 | 127 | Islanding |
| | 2012-08-04 | 4:00 AM | 8/4/2012 | 7:20 AM | Northern Indiana | RFC | | Severe Weather - Thunderstorms | N/A | 61,413 | Weather |
| | 2012-08-04 | 5:30 PM | 8/5/2012 | 12:10 PM | Northeast Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 325,000 | Weather |
| | 2012-08-11 | 12:45 PM | 8/11/2012 | 5:00 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-08-13 | 1:15 PM | 8/13/2012 | 1:15 PM | Knoxville, Tennessee | SERC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2012-08-13 | 3:52 PM | 8/13/2012 | 7:44 PM | CFE (Mexico & U.S.) | WECC | | Severe Weather - Dust Storm; Load Shed Event | 655 | Unknown | Weather |
| | 2012-08-16 | 1:13 PM | 8/16/2012 | 1:13 PM | Northern Indiana | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-08-19 | 8:42 AM | 8/19/2012 | 12:08 PM | El Paso, Texas | WECC | | Suspected Physical Attack | 12 | 3,314 | Physical Attack |
| | 2012-08-26 | 10:04 PM | 8/27/2012 | 2:04 AM | Florida | FRCC | | Severe Weather - TS Isaac | N/A | 440,000 | Weather |
| | 2012-08-28 | 6:00 AM | 9/4/2012 | 8:00 AM | Arkansas, Louisiana, Mississippi | SERC | | Severe Weather - Hurricane Isaac | Unknown | 770,000 | Weather |
| | 2012-08-29 | 6:53 AM | 8/30/2012 | 2:00 PM | Louisiana | SERC | | Severe Weather - Hurricane Isaac | 150 | 68,018 | Weather |
| | 2012-08-29 | 9:00 AM | 8/31/2012 | 12:00 PM | Louisiana | SERC | | Severe Weather - Hurricane Isaac | 300 | 50,000 | Weather |
| | 2012-08-29 | 9:48 AM | 8/31/2012 | 12:55 PM | Louisiana | SPP | | Severe Weather - Hurricane Isaac | Unknown | 95,000 | Weather |
| | 2012-09-05 | 10:56 AM | 9/5/2012 | 11:27 AM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | 0 | 0 | Islanding |
| | 2012-09-06 | 4:45 AM | Ongoing | Ongoing | Oroville, California | WECC | | Fuel Supply Deficiency (Water) | N/A | N/A | Fuel Supply Deficiency |
| | 2012-09-07 | 9:30 PM | 9/8/2012 | 1:00 AM | Arkansas | SERC | | Severe Weather - Thunderstorms | UNK | 64,951 | Weather |
| | 2012-09-08 | 3:40 PM | 9/8/2012 | 6:45 PM | Prince George's County, Montgomery County Maryland; D.C. | RFC | | Severe Weather - Thunderstorms | UNK | 65,000 | Weather |
| | 2012-09-08 | 3:53 PM | 9/9/2012 | 7:46 PM | Virginia | SERC | | Severe Weather - Thunderstorms | 475 | 119,000 | Weather |
| | 2012-09-11 | 1:00 PM | 9/11/2012 | 1:58 PM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | 0 | 0 | Islanding |
| | 2012-09-24 | 12:00 AM | 9/25/2012 | 12:00 AM | Brighton, Maryland | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-09-26 | 9:16 PM | 9/26/2012 | 10:18 PM | Puerto Rico | N/A | | Voltage Reduction | 600 | 371,526 | ? |
| | 2012-10-05 | 5:30 PM | 10/5/2012 | 5:50 PM | Greater Sacramento, California | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-10-09 | 12:00 AM | 10/9/2012 | 12:01 AM | Seat Pleasant, Maryland | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-11 | 12:00 AM | 10/11/2012 | 12:01 AM | Seat Pleasant, Maryland | RFC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-14 | 10:36 AM | 10/14/2012 | 10:50 AM | Northern California | WECC | | Electrical System Separation (Islanding) | 3 | 2,035 | Islanding |
| | 2012-10-15 | 2:15 PM | 10/15/2012 | 2:16 PM | Southeast Vermont | NPCC | | Vandalism; Theft | 0 | 0 | Physical Attack |
| | 2012-10-22 | 12:00 AM | 10/22/2012 | 12:01 AM | Norbeck, Maryland | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-23 | 9:10 AM | 10/23/2012 | 9:16 AM | Crawfordsville, Indiana | RFC | | Transmission System Interruption | 49 | 9,800 | Transmission Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-10-24 | 12:00 AM | 10/24/2012 | 12:01 AM | Kingswood, Maryland | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-24 | 12:00 AM | 10/24/2012 | 12:01 AM | Brighton, Maryland | RFC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-10-24 | 3:15 PM | 10/24/2012 | 3:16 PM | Frankford, Delaware | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-25 | 12:00 AM | 10/25/2012 | 12:01 AM | West Lanham, Maryland | RFC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2012-10-25 | 2:39 PM | 10/25/2012 | 6:00 PM | Pueblo, Colorado | WECC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-25 | 6:51 PM | 10/25/2012 | 7:30 PM | Newark, Delaware | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-29 | 12:00 AM | 11/9/2012 | 11:59 PM | West Virginia | RFC | | Severe Weather - Hurricane Sandy | 0 | 208,000 | Weather |
| | 2012-10-29 | 8:00 AM | 11/4/2012 | 11:00 PM | New Jersey | RFC | | Severe Weather - Hurricane Sandy | Unknown | Unknown | Weather |
| | 2012-10-29 | 9:00 AM | 10/29/2012 | 9:01 AM | LaGrande, Washington | WECC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-29 | 9:00 AM | 11/2/2012 | 6:00 PM | Delaware, Maryland | RFC | | Severe Weather - Hurricane Sandy | Unknown | 70,000 | Weather |
| | 2012-10-29 | 12:00 PM | 11/4/2012 | 11:00 PM | New Jersey | RFC | | Severe Weather - Hurricane Sandy | Unknown | 217,000 | Weather |
| | 2012-10-29 | 1:00 PM | 11/12/2012 | 2:00 PM | Long Island, New York | NPCC | | Severe Weather - Hurricane Sandy | 0 | 632,816 | Weather |
| | 2012-10-29 | 2:40 PM | 10/30/2012 | 6:16 PM | Boston, Southeast Massachusetts | NPCC | | Severe Weather - Hurricane Sandy | Unknown | 50,000 | Weather |
| | 2012-10-29 | 2:45 PM | 11/1/2012 | 1:30 AM | Eastern Massachusetts | NPCC | | Severe Weather - Hurricane Sandy | Unknown | 50,000 | Weather |
| | 2012-10-29 | 3:00 PM | 10/29/2012 | 3:01 PM | Las Vegas, Nevada | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2012-10-29 | 3:15 PM | 11/4/2012 | 8:00 PM | Connecticut, Western Massachusetts | NPCC | | Severe Weather - Hurricane Sandy | 0 | 649,075 | Weather |
| | 2012-10-29 | 4:00 PM | 11/7/2012 | 11:48 PM | Eastern Pennsylvania | RFC | | Severe Weather - Hurricane Sandy | 0 | 270,000 | Weather |
| | 2012-10-29 | 4:00 PM | 11/8/2012 | 5:08 PM | Maryland; West Virginia | RFC | | Severe Weather - Hurricane Sandy | Unknown | 150,000 | Weather |
| | 2012-10-29 | 4:00 PM | 11/5/2012 | 11:59 PM | Greater Cleveland Ohio | RFC | | Severe Weather - Hurricane Sandy | 0 | 346,000 | Weather |
| | 2012-10-29 | 4:01 PM | 11/8/2012 | 7:00 PM | Greater New York City, New York | NPCC | | Severe Weather - Hurricane Sandy | 0 | 818,000 | Weather |
| | 2012-10-29 | 4:03 PM | 11/6/2012 | 12:00 PM | New Jersey | NPCC | | Severe Weather - Hurricane Sandy | Unknown | 50,000 | Weather |
| | 2012-10-29 | 4:45 PM | 10/31/2012 | 11:00 AM | New Hampshire | NPCC | | Severe Weather - Hurricane Sandy | N/A | 50,000 | Weather |
| | 2012-10-29 | 5:13 PM | 10/31/2012 | 11:00 AM | Greater Baltimore Maryland | RFC | | Severe Weather - Hurricane Sandy | 0 | 219,000 | Weather |
| | 2012-10-29 | 5:30 PM | 11/6/2012 | 12:00 AM | Greater Philadelphia Pennsylvania | RFC | | Severe Weather - Hurricane Sandy | Unknown | 850,000 | Weather |
| | 2012-10-29 | 6:11 PM | 11/4/2012 | 10:50 PM | Central Pennsylvania | RFC | | Severe Weather - Hurricane Sandy | Unknown | 400,000 | Weather |
| | 2012-10-29 | 6:12 PM | 10/30/2012 | 7:35 PM | Virginia | RFC | | Severe Weather - Hurricane Sandy | 520 | 156,000 | Weather |
| | 2012-10-29 | 6:46 PM | 11/3/2012 | 10:45 AM | Southeast New York; New Jersey | NPCC; RFC | | Severe Weather - Hurricane Sandy | Unknown | 200,000 | Weather |
| | 2012-10-29 | 6:48 PM | 11/4/2012 | 11:36 AM | New York | NP | | Severe Weather - Hurricane Sandy | Unknown | 371,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012-10-29 | 7:00 PM | 11/2/2012 | 5:00 AM | Indiana; Kentucky; Michigan; Ohio | RFC; SERC | | Severe Weather - Nor'easter | Unknown | 173,273 | Weather |
| | 2012-10-29 | 7:15 PM | 10/30/2012 | 3:02 PM | Southeast and Seacoast Maine | NPCC | | Severe Weather - Hurricane Sandy | Unknown | 50,000 | Weather |
| | 2012-10-30 | 12:00 AM | 10/30/2012 | 12:02 AM | Hyattsville, Maryland | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-30 | 2:00 AM | 11/1/2012 | 10:00 PM | Greater Detroit Michigan | RFC | | Severe Weather - Nor'easter | Unknown | 133,777 | Weather |
| | 2012-10-30 | 1:20 PM | 10/30/2012 | 1:25 PM | Fitzwilliam, New Hampshire | NPCC | | Vandalism | 0 | 0 | Physical Attack |
| | 2012-10-30 | 3:00 PM | 10/30/2012 | 3:01 PM | Pueblo, Colorado | WECC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2012-11-02 | 9:30 AM | 11/2/2012 | 12:10 PM | Concord, Vermont | NPCC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-11-07 | 2:21 PM | 11/7/2012 | 2:48 PM | New Hampshire | NPCC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-11-08 | 9:34 AM | 11/8/2012 | 9:35 AM | Bishopville, Maryland | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-11-15 | 9:09 PM | 11/15/2012 | 9:26 PM | Iowa; Michigan | MRO | | Suspected Cyber Attack | Unknown | Unknown | Cyber Attack |
| | 2012-11-15 | 5:38 AM | 11/15/2012 | 5:39 AM | Southeast Massachusetts | NPCC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-11-17 | 10:00 AM | 11/18/2012 | 10:00 AM | Comanche Peak, Texas | TRE | | Fuel Supply Deficiency | 1,231 | 0 | Fuel Supply Deficiency |
| | 2012-11-21 | 2:50 PM | 11/21/2012 | 2:51 PM | Bethany Beach, Delaware | RFC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2012-11-26 | 12:37 PM | 11/26/2012 | 12:38 PM | Frankfort, Delaware | RFC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-11-26 | 3:07 PM | 11/26/2012 | 3:08 PM | Georgetown, Delaware | RFC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2012-11-27 | 1:07 PM | 11/27/2012 | 1:40 PM | New Hampshire | NPCC | | Physical Attack; Vandalism | 0 | 0 | Physical Attack |
| | 2012-12-02 | 5:20 AM | 12/4/2012 | 9:00 AM | Northern California | WECC | | Severe Weather - Winter Storm | 250 | 125,000 | Weather |
| | 2012-12-03 | 12:02 PM | 12/3/2012 | 12:30 PM | Tacoma, Washington | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-12-06 | 9:18 PM | 12/6/2012 | 9:31 PM | Greater San Jose, California | WECC | | Load Shed | 390 | Unknown | Load Shed |
| | 2012-12-17 | 6:55 AM | 12/17/2012 | 7:00 AM | Tacoma, Washington | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2012-12-25 | 12:45 AM | 12/28/2012 | 4:15 PM | Arkansas; Louisiana; Mississippi; Texas | SPP | | Severe Weather - Winter Storm | Unknown | 242,509 | Weather |
| | 2012-12-25 | 9:28 AM | 12/26/2012 | 4:28 PM | Houston, Texas | TRE | | Severe Weather - Cold Front, High Winds | 294 | 262,000 | Weather |
| | 2012-12-26 | 2:50 PM | 12/26/2012 | 7:40 PM | Stantonsburg, North Carolina | SERC | | Severe Weather - Thunderstorm | 3 | 1,200 | Weather |
| | 2012-12-31 | 2:21 PM | 12/31/2012 | 4:30 PM | North Carolina | SERC | | Transmission Interruption | 40 | 12,000 | Transmission Interruption |
| | 2013-01-07 | 10:43 AM | 1/7/2013 | 10:43 AM | Denton, Maryland | RFC | | Physcial Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-01-16 | 7:41 AM | 1/17/2013 | 10:58 AM | Webster County, Iowa | MRO | | Physical Attack | N/A | N/A | Physical Attack |
| | 2013-01-16 | 2:25 PM | 1/16/2013 | 2:25 PM | Denton, Maryland | RFC | | Physcial Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-01-16 | 4:45 PM | 1/16/2013 | 7:26 PM | San Juan County, New Mexico | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-01-17 | 8:35 PM | 1/17/2013 | 9:20 PM | Elizabeth City, North Carolina | SERC | | Distribution Interruption | 40 | 12,000 | Distribution Interruption |
| | 2013-01-17 | 6:07 PM | 1/20/2013 | 7:30 PM | Southwest Virginia, Southern West Virginia | RFC | | Severe Weather - Winter Storm | Unknown | 127,000 | Weather |
| | 2013-01-17 | 7:02 PM | 1/19/2013 | 6:00 PM | Northeast Tennessee | SERC | | Severe Weather - Winter Storm | Unknown | 80,000 | Weather |
| | 2013-01-20 | 3:30 AM | 1/23/2013 | 6:15 AM | Southeastern Michigan | RFC | | Severe Weather - Wind Storm | Unknown | 146,500 | Weather |
| | 2013-01-28 | 4:46 PM | 1/28/2013 | 6:00 PM | Tacoma Narrows Crossing, Washington | WECC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-01-31 | 3:05 AM | 1/31/2013 | 4:48 AM | Central and Eastern Virginia | SERC | | Severe Weather - Wind Storm | 188 | 119,000 | Weather |
| | 2013-01-31 | 6:30 AM | 1/31/2013 | 10:00 AM | Connecticut | NPCC | | Severe Weather - Wind Storm | 75 | 75,000 | Weather |
| | 2013-02-02 | 9:15 PM | 2/2/2013 | 10:15 PM | El Paso, New Mexico | WECC | | Vandalism | N/A | N/A | Physical Attack |
| | 2013-02-07 | 8:32 AM | 2/7/2013 | 9:47 AM | Cincinnati, Ohio | RFC | | Vandalism | Unknown | 0 | Physical Attack |
| | 2013-02-08 | 11:38 AM | 2/8/2013 | 2:17 PM | District of Columbia; Prince George's County Maryland | RFC | | Equipment Trip & Failure | 140 | 52,000 | Equipment |
| | 2013-02-08 | 8:00 PM | 2/11/2013 | 8:30 PM | Central and eastern Massachusetts; Rhode Island | NPCC | | Severe Weather - Winter Storm Nemo | N/A | 50,000 | Weather |
| | 2013-02-08 | 8:55 PM | 2/12/2013 | 4:00 AM | Boston area and Southeast Massachusetts | NPCC | | Severe Weather - Winter Storm Nemo | Unknown | 50,000 | Weather |
| | 2013-02-09 | 8:30 AM | 2/9/2013 | 3:00 PM | El Paso, New Mexico | WECC | | Vandalism; Equipment Fault | Unknown | Unknown | Physical Attack |
| | 2013-02-10 | 7:46 PM | 2/10/2013 | 8:15 PM | Puerto Rico | N/A | | Generator Trip; Voltage Reduction | 350 | Unknown | Equipment |
| | 2013-02-13 | 5:39 PM | 2/15/2013 | 5:50 PM | Eastern Massachusetts | NPCC | | Fuel Supply Emergency - Petroleum | 1 | 1 | Fuel Supply Deficiency |
| | 2013-02-13 | 9:30 AM | 2/13/2013 | 9:30 AM | Fort Washington, Maryland | RFC | | Vandalism | 1 | 1 | Physical Attack |
| | 2013-02-15 | 12:00 AM | 2/15/2013 | 12:01 AM | Tuxedo, Maryland | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2013-02-16 | 7:54 AM | 2/16/2013 | 7:54 AM | Prince George's County Maryland | RFC | | Vandalism | 1 | 1 | Physical Attack |
| | 2013-02-19 | 4:01 PM | 2/20/2013 | 12:55 PM | Stockton, California | WECC | | Electrical System Separation (Islanding) | 13,850 | 6,810 | Islanding |
| | 2013-02-21 | 11:00 AM | 2/21/2013 | 11:30 AM | Las Cruces, New Mexico | WECC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-02-26 | 1:00 PM | 3/1/2013 | 10:00 AM | Northern Missouri | SERC | | Severe Weather - Winter Storm Nemo | Unknown | 56,444 | Weather |
| | 2013-03-03 | 4:27 PM | 3/3/2013 | 6:20 PM | Tacoma Park, Maryland | RFC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-03-03 | 6:39 AM | 3/3/2013 | 10:29 AM | Merced County, California | WECC | | Transmission System Interruption | 300 | 58,850 | Transmission Interruption |
| | 2013-03-04 | 9:49 AM | 3/4/2013 | 10:00 PM | Metropolitan area Puerto Rico | N/A | | Equipment Failure; Transmission System Interruption | Unknown | Unknown | Transmission Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-03-06 | 8:22 AM | 3/7/2013 | 10:27 AM | Northwest Virginia | SERC | | Severe Weather - Winter Storm | 400 | 233,000 | Weather |
| | 2013-03-18 | 5:21 AM | 3/18/2013 | 5:41 AM | Systemwide Puerto Rico | N/A | | Generator Trip; Load Shed | 350 | 262,937 | Equipment |
| | 2013-03-18 | 5:50 PM | 3/18/2013 | 6:07 PM | Northeast Florida | FRCC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2013-03-18 | 7:30 PM | 3/20/2013 | 2:30 PM | North/Central Alabama; Georgia | SERC | | Severe Weather - Thunderstorms | 800 | 240,000 | Weather |
| | 2013-03-23 | 7:00 AM | 3/23/2013 | 9:00 AM | Connecticut | NPCC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-03-27 | 10:25 AM | 3/27/2013 | 12:19 PM | Western Massachusetts | NPCC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-03-28 | 1:01 PM | 3/28/2013 | 1:02 PM | Wilmington, Delaware | RFC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-03-29 | 10:16 AM | 3/29/2013 | 10:17 AM | Maryland | RFC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-04-01 | 8:40 AM | 4/1/2013 | 8:41 AM | Connecticut | NPCC | | Vandalism - Copper Wire Theft | Unknown | Unknown | Physical Attack |
| | 2013-04-03 | 11:05 AM | 4/3/2013 | 2:00 PM | Colorado Springs, Colorado | WECC | | Sabotage; Vandalism | 0 | 0 | Physical Attack |
| | 2013-04-09 | 11:30 AM | 4/9/2013 | 11:31 AM | Delaware City, Delaware | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2013-04-16 | 1:47 AM | 4/18/2013 | 3:25 PM | California | WECC | | Loss of Part of a High Voltage Substation, Physical Attack | N/A | 0 | Physical Attack |
| | 2013-04-17 | 3:36 PM | 4/17/2013 | 4:53 PM | Colbert Steam Plant in Cherokee, Alabama | SERC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-04-18 | 3:00 PM | 4/21/2013 | 3:30 AM | Southeast Michigan, Michigan | RFC | | Severe Weather - Storms and Wind | Unknown | 99,188 | Weather |
| | 2013-04-21 | 2:11 AM | 4/21/2013 | 12:30 PM | East Tennessee | SERC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2013-04-23 | 12:49 AM | 4/23/2013 | 4:04 AM | South of Humboldt, California | WECC | | Electrical System Separation (Islanding) | 80 | 1 | Islanding |
| | 2013-04-23 | 11:00 AM | 4/23/2013 | 11:01 AM | Newark, Delaware | RFC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-04-25 | 4:00 PM | 4/26/2013 | 10:55 AM | Sunol, California | WECC | | Vandalism | 0 | 0 | Physical Attack |
| | 2013-05-01 | 9:22 AM | 5/1/2013 | 9:24 AM | Northeast Colorado | WECC | | Electrical System Separation (Islanding) | 123 | 35,230 | Islanding |
| | 2013-05-02 | 6:52 AM | 5/2/2013 | 10:07 AM | Unknown | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2013-05-09 | 1:21 PM | 5/9/2013 | 4:21 PM | Alberta, Canada; Washington State | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2013-05-13 | 12:52 PM | Ongoing | Ongoing | Central California | WECC | | Fuel Supply Emergency - Hydro | 176 | Unknown | Fuel Supply Deficiency |
| | 2013-05-14 | 12:01 AM | 5/14/2013 | 1:59 PM | Portland, Oregon | WECC | | Vandalism/Theft | N/A | N/A | Physical Attack |
| | 2013-05-14 | 10:25 AM | 5/14/2013 | 11:42 AM | New Hampshire | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2013-05-15 | 2:11 PM | 5/15/2013 | 2:12 PM | Wilmington, Delaware | RFC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-05-17 | 8:35 AM | 5/17/2013 | 8:36 AM | Newcastle, Delaware | RFC | | Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-05-20 | 5:22 PM | 5/20/2013 | 9:09 PM | Gonzales Area Louisiana | SERC | | Generator Trip; Load Shed 100+ MW | 103 | 21,800 | Equipment |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-05-20 | 3:00 PM | 5/22/2013 | 5:00 PM | Moore, Oklahoma | SPP | | Severe Weather - Tornadoes | Unknown | 41,306 | Weather |
| | 2013-05-22 | 10:51 AM | 5/22/2013 | 10:57 AM | System wide Puerto Rico | N/A | | System Wide Voltage Reduction | 280 | 197,287 | ? |
| | 2013-05-28 | 1:00 PM | 5/28/2013 | 6:00 PM | Maine | NPCC | | Vandalism/Theft | None | None | Physical Attack |
| | 2013-05-29 | 12:00 AM | 5/29/2013 | 12:02 AM | Henrico County, Virginia | SERC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-05-29 | 9:52 AM | 5/29/2013 | 9:53 AM | Wilmington, Delaware | RFC | | Vandalism/Theft | N/A | N/A | Physical Attack |
| | 2013-05-29 | 8:58 PM | 5/31/2013 | 2:53 PM | Central and Eastern New York | NPCC | | Severe Weather - Thunderstorms | Unknown | 61,795 | Weather |
| | 2013-05-30 | 10:15 AM | 5/30/2013 | 10:16 AM | Saranac, New York | NPCC | | Vandalism | N/A | N/A | Physical Attack |
| | 2013-05-31 | 7:07 PM | 6/1/2013 | 2:15 PM | Southeast Kansas, Northeast Oklahoma | MRO | | Transmission System Interruption | 102 | 6,300 | Transmission Interruption |
| | 2013-05-31 | 1:00 AM | 5/31/2013 | 1:30 AM | Maumelle, Arkansas | SPP | | Severe Weather - Lightning | N/A | N/A | Weather |
| | 2013-05-31 | 6:00 PM | 6/4/2013 | 10:30 AM | El Reno, S. Oklahoma City, Oklahoma | SPP | | Severe Weather - Tornadoes | Unknown | 127,000 | Weather |
| | 2013-05-31 | 7:30 PM | 6/1/2013 | 8:00 PM | St. Louis Metro Area Missouri | SERC | | Severe Weather - Thunderstorms | Unknown | 100,000 | Weather |
| | 2013-06-03 | 12:50 PM | 6/3/2013 | 1:36 PM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2013-06-13 | 1:17 PM | 6/14/2013 | 5:35 PM | Western Piedmont North Carolina | SERC | | Severe Weather - Thunderstorms | 1,000 | 175,000 | Weather |
| | 2013-06-13 | 3:20 PM | 6/14/2013 | 9:10 PM | Ohio; Virginia; West Virginia | RFC; SERC | | Severe Weather - Thunderstorms | Unknown | 90,247 | Weather |
| | 2013-06-13 | 3:30 PM | 6/13/2013 | 4:00 PM | District of Columbia; Maryland | RFC | | Loss of 300+ MW Load; Severe Weather - Thunderstorms | 700 | 40,000 | Weather |
| | 2013-06-13 | 4:08 PM | 6/14/2013 | 5:16 PM | Richmond Metro area, Virginia | SERC | | Severe Weather - Thunderstorms | 900 | 283,000 | Weather |
| | 2013-06-13 | 5:45 PM | 6/14/2013 | 6:30 PM | Central and Eastern North Carolina | SERC | | Severe Weather - Thunderstorms | Unknown | 53,000 | Weather |
| | 2013-06-13 | 8:47 PM | 6/14/2013 | 10:47 PM | Southern Company Territory | SERC | | Severe Weather - Thunderstorms | 550 | 165,798 | Weather |
| | 2013-06-17 | 4:17 PM | 6/17/2013 | 6:49 PM | Hillsborough County Florida | FRCC | | Load Shed of 100+ MW Under Emergency Operational Policy | 180 | 37 | Load Shed |
| | 2013-06-18 | 3:51 PM | 6/18/2013 | 4:23 PM | Wyoming | WECC | | Electrical System Separation (Islanding) | 6 | Unknown | Islanding |
| | 2013-06-19 | 7:57 PM | 6/19/2013 | 8:09 PM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2013-06-20 | 6:00 PM | 6/21/2013 | 10:00 AM | Richie Station (No. 123), Maryland | RFC | | Physcial Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-06-21 | 8:31 AM | 10/30/2013 | 2:09 PM | Michigan, Iowa | MRO | | Suspected Cyber Attack | Unknown | Unknown | Cyber Attack |
| | 2013-06-21 | 7:40 AM | 6/21/2013 | 12:14 PM | Pahrump Nevada | WECC | | Physical Attack; Vandalism & Sabotage | Unknown | 1,100 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-06-21 | 11:14 PM | 6/21/2013 | 11:15 PM | New Castle Delaware | RFC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-06-21 | 3:00 AM | 6/26/2013 | 12:00 PM | Minnesota | MRO | | Severe Weather - Hailstorm | Unknown | 193,000 | Weather |
| | 2013-06-21 | 5:39 PM | 6/24/2013 | 6:00 AM | Minneapolis/St. Paul area Minnesota | MRO | | Severe Weather - Hailstorm | Unknown | 400,000 | Weather |
| | 2013-06-22 | 4:59 AM | 6/22/2013 | 9:28 PM | Medford Oregon | WECC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2013-06-22 | 4:12 PM | 6/22/2013 | 5:45 PM | Eastern Montana | WECC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-06-23 | 9:20 PM | 6/24/2013 | 1:35 AM | Central Coast California | WECC | | Severe Weather - Fog | Unknown | 148,000 | Weather |
| | 2013-06-24 | 7:30 PM | 6/25/2013 | 5:46 PM | Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 283,451 | Weather |
| | 2013-06-24 | 7:30 PM | 6/26/2013 | 5:00 PM | Indiana | RFC | | Severe Weather - Thunderstorms | Unknown | 86,615 | Weather |
| | 2013-06-27 | 1:10 AM | 6/27/2013 | 2:45 AM | Richie Substation,Seat Pleasant, Maryland | RFC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-06-27 | 5:00 PM | 6/28/2013 | 12:00 AM | South Eastern Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 138,000 | Weather |
| | 2013-06-28 | 6:02 PM | 6/28/2013 | 8:46 PM | Los Angeles and Orange Counties, California | WECC | | Equipment Failure | 240 | 65,255 | Equipment |
| | 2013-06-28 | 1:00 PM | 6/28/2013 | 1:01 PM | Vermont | NPCC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-06-28 | 5:14 PM | 6/28/2013 | 5:15 PM | New Castle Delaware | RFC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-07-02 | 2:20 PM | 7/5/2013 | 3:30 PM | Alberta, Canada | WECC | | Load Shed 100+MW | 200 | Unknown | Load Shed |
| | 2013-07-03 | 12:04 PM | 7/3/2013 | 12:48 PM | System-wide Puerto Rico | N/A | | Voltage Reduction; Line and Generator Trip | 480 | 393,000 | Equipment |
| | 2013-07-03 | 9:34 AM | 7/3/2013 | 10:52 AM | Sacramento California | WECC | | Suspected Physical Attack | 0 | 0 | Physical Attack |
| | 2013-07-05 | 12:05 AM | 7/5/2013 | 1:51 AM | California | WECC | | Physical Attack; Vandalism | Unknown | 2,500 | Physical Attack |
| | 2013-07-10 | 2:30 PM | 7/10/2013 | 2:45 PM | Boston, Massachusetts | NPCC | | Physical Attack; Copper Theft | 0 | 0 | Physical Attack |
| | 2013-07-10 | 5:30 PM | 7/11/2013 | 8:00 PM | AEP Ohio Power Footprint | RFC | | Severe Weather - Thunderstorms | N/A | 122,314 | Weather |
| | 2013-07-11 | 11:20 PM | 7/14/2013 | 3:22 PM | Arizona | WECC | | Physical Attack; Vandalism | 455 | Unknown | Physical Attack |
| | 2013-07-12 | 10:00 AM | 7/12/2013 | 10:01 AM | Washington | WECC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-07-17 | 3:30 PM | 7/19/2013 | 6:45 AM | Holtsville, New York | NPCC | | Fuel Supply Emergency (Natural Gas) | 417 | Unknown | Fuel Supply Deficiency |
| | 2013-07-18 | 11:45 PM | 7/19/2013 | 10:05 AM | Southern Orange County California | WECC | | Equipment Failure | 200 | 123,000 | Equipment |
| | 2013-07-18 | 3:15 AM | 7/18/2013 | 3:59 AM | Utah | WECC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2013-07-18 | 11:30 AM | 7/19/2013 | 5:30 PM | Upstate New York | NPCC | | Public Appeal - Heatwave | Unknown | Unknown | Weather |
| | 2013-07-19 | 6:00 PM | 7/20/2013 | 9:00 AM | Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 156,627 | Weather |
| | 2013-07-19 | 10:30 PM | 7/21/2013 | 8:00 PM | New York | NPCC | | Severe Weather - Thunderstorms | Unknown | 74,300 | Weather |
| | 2013-07-22 | 7:00 AM | 7/22/2013 | 3:00 PM | California | WECC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-07-23 | 11:38 PM | 7/25/2013 | 4:30 AM | Tulsa, Oklahoma | SPP | | Severe Weather - Thunderstorms | 500 | 92,748 | Weather |
| | 2013-07-25 | 1:10 PM | 7/25/2013 | 1:15 PM | Polk Substation, Tacoma Washington | WECC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2013-08-01 | 11:19 PM | 8/2/2013 | 12:49 AM | Daytona Beach Florida | FRCC | | Loss of 300+ MW Load | 297 | 104,498 | ? |
| | 2013-08-01 | 6:54 PM | 8/1/2013 | 7:37 PM | Western British Columbia | WECC | | Electrical System Separation (Islanding | 420 | Unknown | Islanding |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-08-01 | 11:00 AM | 8/1/2013 | 4:00 PM | Newburgh, New York | NPCC | | Physical Attack; Copper Theft | N/A | N/A | Physical Attack |
| | 2013-08-04 | 3:00 AM | 8/4/2013 | 4:00 AM | Utah | WECC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2013-08-05 | 6:35 PM | 8/5/2013 | 6:45 PM | Vancouver, British Columbia | WECC | | Electrical System Separation (Islanding); Severe Weather | Unknown | Unknown | Islanding |
| | 2013-08-06 | 4:00 PM | 8/6/2013 | 5:32 PM | Holloman Air Force Base, New Mexico | WECC | | Physcial Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-08-07 | 7:30 AM | 8/7/2013 | 9:14 AM | Green Bay, Wisconsin | MRO | | Fuel Supply Emergency (Natural Gas & Fuel Oil) | Unknown | Unknown | Fuel Supply Deficiency |
| | 2013-08-07 | 2:30 PM | 8/8/2013 | 1:00 PM | Arlington, Oregon | WECC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-08-07 | 12:15 AM | 8/7/2013 | 9:27 PM | Eastern Central Wisconsin | MRO | | Severe Weather - Thunderstorms | 220 | 51,160 | Weather |
| | 2013-08-12 | 11:55 AM | 8/12/2013 | 11:59 AM | Portland, Oregon | WECC | | Suspicious Activity | Unknown | Unknown | Physical Attack |
| | 2013-08-16 | 4:58 PM | 8/17/2013 | 11:58 PM | Houston Service Area Texas | TRE | | Severe Weather - Thunderstorms | Unknown | 219,681 | Weather |
| | 2013-08-19 | 7:06 PM | 8/20/2013 | 6:02 AM | Central California | WECC | | Severe Weather - Lightning Strike | 685 | 124,000 | Weather |
| | 2013-08-21 | 2:00 PM | 8/21/2013 | 2:01 PM | Cabot, Arkansas | SERC | | Physcial Attack; Sabotage | N/A | N/A | Physical Attack |
| | 2013-08-22 | 8:40 AM | 8/22/2013 | 11:49 AM | Gila River, Arizona | WECC | | Physcial Attack; Sabotage | N/A | N/A | Physical Attack |
| | 2013-08-22 | 12:55 PM | 8/22/2013 | 2:45 PM | New Castle, Delaware | RFC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-08-23 | 7:30 AM | 8/23/2013 | 7:31 AM | New Castle, Delaware | RFC | | Physical Attack; Vandalism | Unknown | N/A | Physical Attack |
| | 2013-08-26 | 8:15 PM | 8/26/2013 | 8:16 PM | Tacoma Washington | WECC | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-08-28 | 9:30 AM | 8/28/2013 | 9:31 AM | Sweetwater County Wyoming | WECC | | Physical Attack; Vandalism | N/A | N/A | Physical Attack |
| | 2013-08-29 | 2:57 PM | 8/29/2013 | 3:29 PM | Ashland, Wisconsin | MRO | | Electrical System Separation (Islanding); Severe Weather | 15 | 7,000 | Islanding |
| | 2013-08-29 | 9:50 AM | 8/29/2013 | 9:50 AM | Joplin, Missouri | N/A | | Physical Attack; Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-08-30 | 7:30 PM | 8/31/2013 | 1:30 AM | Entire ComEd territory Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 157,000 | Weather |
| | 2013-09-10 | 5:42 PM | 9/11/2013 | 12:02 AM | Erie, Pennsylvania | RFC | | Load Shed of 100+ MW | 105 | Unknown | Load Shed |
| | 2013-09-11 | 4:00 PM | 9/15/2013 | 4:00 PM | Southeastern Michigan | RFC | | Severe Weather - Thunderstorms | 400 | 75,000 | Weather |
| | 2013-09-29 | 12:00 AM | 9/29/2013 | 1:00 AM | Cabot Arkansas | SERC | | Physical Attack; Sabotage | Unknown | Unknown | Physical Attack |
| | 2013-10-06 | 7:25 AM | 10/6/2013 | 9:15 AM | Jacksonville, Arkansas | SPP | | Physical Attack | Unknown | 9,200 | Physical Attack |
| | 2013-10-11 | 2:30 PM | 10/11/2013 | 6:30 PM | Keo, Arkansas | SERC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-10-16 | 11:15 AM | 10/16/2013 | 6:00 PM | Roxboro Plant, North Carolina | SERC | | Cyber Event with Potential to Cause Impact | 0 | 0 | Cyber Attack |
| | 2013-10-19 | 2:32 PM | 10/19/2013 | 10:00 PM | California | WECC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-10-21 | 5:18 AM | 10/21/2013 | 5:33 AM | Location Unknown | WECC | | Electrical System Separation (Islanding) | 115 | 433 | Islanding |
| | 2013-10-26 | 7:13 AM | 10/26/2013 | 7:14 AM | Arizona | WECC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-10-27 | 4:27 AM | 10/27/2013 | 10:27 PM | Houston, Texas | TRE | | Severe Weather - Hailstorm | Unknown | 171,117 | Weather |
| | 2013-11-01 | 1:26 PM | 11/1/2013 | 1:27 PM | Wilmington, Delaware | RFC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-11-02 | 8:25 AM | 11/2/2013 | 8:26 AM | Salt Lake City, Utah | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-11-02 | 12:00 AM | 11/4/2013 | 6:00 AM | King, Whatcom, and Skagit, Washington | WECC | | Severe Weather - Heavy Winds | Unknown | 105,000 | Weather |
| | 2013-11-04 | 9:04 AM | 11/4/2013 | 9:05 AM | Connecicut | NPCC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-11-05 | 10:10 AM | 11/7/2013 | 10:10 AM | Indiana | RFC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-11-12 | 9:14 AM | 11/12/2013 | 10:30 AM | Eastern Central New Mexico | SPP | | Loss of Power from Wholesale Provider; Major Distribution Disruption | Unknown | Unknown | Distribution Interruption |
| | 2013-11-12 | 2:04 PM | 11/12/2013 | 2:05 PM | Valle, California | WECC | | Electrical System Separation (Islanding) | 55 | 48,400 | Islanding |
| | 2013-11-16 | 3:15 PM | 11/16/2013 | 3:16 PM | Salt Lake County, Utah | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2013-11-17 | 12:35 PM | 11/17/2013 | 1:40 PM | Rochelle, Indiana | RFC | | System-wide voltage reductions of 3 percent or more | 38 | 7,500 | ? |
| | 2013-11-17 | 7:00 AM | 11/20/2013 | 6:54 PM | Michigan | RFC | | Severe Weather - Ice and Snow Storm | Unknown | 325,325 | Weather |
| | 2013-11-17 | 12:35 PM | 11/20/2013 | 11:00 AM | Central Missouri, Central Illinois | SERC | | Severe Weather - Tornadoes | Unknown | 200,000 | Weather |
| | 2013-11-17 | 1:06 PM | 11/20/2013 | 1:06 PM | North Central Indiana | RFC | | Severe Weather - Thunderstorms | Unknown | 75,065 | Weather |
| | 2013-11-17 | 2:31 PM | 11/17/2013 | 10:30 PM | Entire ComEd Territory Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 190,000 | Weather |
| | 2013-11-17 | 4:19 PM | 11/18/2013 | 6:00 PM | Indiana, Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 77,346 | Weather |
| | 2013-11-17 | 4:45 PM | 11/21/2013 | 4:45 PM | Entire Lower Peninsula Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 50,000 | Weather |
| | 2013-11-17 | 4:47 PM | 11/20/2013 | 4:47 PM | Central Indiana | RFC | | Severe Weather - Thunderstorms | Unknown | 61,705 | Weather |
| | 2013-11-17 | 4:47 PM | 11/20/2013 | 11:59 AM | Central Indiana | RFC | | Severe Weather - Tornadoes | 535 | 61,705 | Weather |
| | 2013-11-20 | 3:08 AM | 11/20/2013 | 3:09 AM | Salt Lake County Utah | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2013-11-21 | 7:45 PM | 11/22/2013 | 3:20 AM | Northern California | WECC | | Severe Weather - Wind Storm | 150 | 89,500 | Weather |
| | 2013-11-24 | 7:38 AM | 11/24/2013 | 7:39 AM | Salt Lake County Utah | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2013-12-04 | 5:00 AM | 12/4/2013 | 4:17 PM | Idaho Falls Area Idaho, Utah-Idaho Border Utah | WECC | | Load Shed 100+ MW | 150 | Unknown | Load Shed |
| | 2013-12-06 | 8:47 AM | 12/6/2013 | 8:49 AM | Saratoga, Utah | WECC | | Physical Attack - Vandalism, Theft | N/A | N/A | Physical Attack |
| | 2013-12-06 | 1:51 AM | 12/11/2013 | 12:00 PM | Greater Houston, Texas | TRE | | Severe Weather - Ice/Snow | Unknown | 881,000 | Weather |
| | 2013-12-09 | 6:54 AM | 12/9/2013 | 2:22 PM | Virginia Service Territory | SERC | | Severe Weather - Ice/Snow | 293 | 88,000 | Weather |
| | 2013-12-10 | 1:01 AM | 12/11/2013 | 1:01 AM | Arizona | WECC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2013-12-13 | 11:00 AM | 12/27/2013 | 11:00 AM | Texas | TRE | | Fuel Supply Emergencies (Coal) | Unknown | Unknown | Fuel Supply Deficiency |
| | 2013-12-13 | 11:00 AM | 12/27/2013 | 11:00 AM | Texas | TE | | Fuel Supply Emergencies (Coal) | Unknown | Unknown | Fuel Supply Deficiency |
| | 2013-12-22 | 3:28 AM | 12/28/2013 | 11:45 PM | Southern Lower Penninsula, Michigan | RFC | | Severe Weather - Ice/Snow | Unknown | 50,000 | Weather |
| | 2013-12-22 | 6:16 AM | 12/24/2013 | 11:59 PM | Frontier/Genesee/Northern New York | NPCC | | Severe Weather - Ice/Snow | Unknown | 59,000 | Weather |
| | 2013-12-22 | 6:30 AM | 12/25/2013 | 5:12 AM | Michigan | RFC | | Severe Weather - Ice/Snow | 350 | 140,735 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013-12-23 | 3:20 PM | 12/25/2013 | 11:32 AM | Central Maine Maine | NPCC | | Severe Weather - Ice/Snow | Unknown | 52,500 | Weather |
| | 2013-12-27 | 9:43 AM | 12/27/2013 | 12:43 PM | Gilabend Arizona | WECC | | Physical Attack | N/A | N/A | Physical Attack |
| | 2013-12-30 | 11:00 AM | 12/30/2013 | 11:01 AM | Salt Lake County Utah | WECC | | Physical Attack | N/A | N/A | Physical Attack |
| | 2013-12-30 | 11:00 AM | 1/1/2014 | 8:00 AM | North of Roosevelt lake Arizona | WECC | | Physical Attack | N/A | N/A | Physical Attack |
| | 2014-01-06 | 2:37 PM | 1/6/2014 | 2:38 PM | Utah | RFC | | Vandalism | N/A | N/A | Physical Attack |
| | 2014-01-06 | 7:01 AM | 1/7/2014 | 9:00 AM | Texas | TRE | | Public Appeal due to Severe Weather - Cold | N/A | N/A | Public Appeal |
| | 2014-01-06 | 8:45 PM | 1/7/2014 | 9:00 PM | Unknown | RFC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Public Appeal |
| | 2014-01-06 | 10:00 PM | 1/6/2014 | 10:01 PM | Kentucky | RFC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Public Appeal |
| | 2014-01-06 | 7:50 PM | 1/6/2014 | 8:44 PM | District of Columbia | RFC | | Voltage Reduction due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-06 | 7:50 PM | 1/6/2014 | 8:44 PM | Unknown | RFC | | Voltage Reduction due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-06 | 7:50 PM | 1/6/2014 | 8:49 PM | Pennsylvania | RFC | | Voltage Reduction due to Severe Weather - Cold | 200 | 62,000 | Weather |
| | 2014-01-06 | 7:50 PM | 1/6/2014 | 8:44 PM | Pennsylvania | RFC | | Voltage Reduction due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-06 | 7:52 PM | 1/6/2014 | 8:45 PM | Delaware | RFC | | Voltage Reduction due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-07 | 9:30 AM | 1/8/2014 | 9:30 AM | Piedmont North Carolina, Piedmont South Carolina | SERC | | Fuel Supply Emergency due to Severe Weather - Cold | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-01-07 | 10:59 AM | 1/9/2014 | 9:00 AM | Illinois | RFC | | Fuel Supply Emergency - Natural Gas | N/A | N/A | Fuel Supply Deficiency |
| | 2014-01-07 | 6:00 AM | 1/7/2014 | 8:30 AM | Northeast Tennessee | SERC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-07 | 6:00 AM | 1/7/2014 | 8:30 AM | Tennessee | SERC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-07 | 6:18 AM | 1/7/2014 | 6:19 AM | Pennsylvania | RFC | | Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-07 | 7:58 AM | 1/7/2014 | 11:00 AM | North Carolina | SERC | | Voltage Reduction; Public Appeal due to Severe Weather - Cold | 14,435 | Unknown | Weather |
| | 2014-01-07 | 4:15 PM | 1/8/2014 | 1:20 PM | North Carolina | SERC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-07 | 6:00 PM | 1/7/2014 | 11:00 PM | South Carolina | SERC | | Voltage Reduction; Public Appeal; Load Shed 100+MW due to Severe Weather - Cold | 4,853 | 677,858 | Weather |
| | 2014-01-07 | 9:00 PM | 1/8/2014 | 9:00 AM | Unknown | RFC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-08 | 5:00 AM | 1/8/2014 | 6:30 AM | Unknown | RFC | | Voltage Reduction due to Severe Weather - Cold | 576 | Unknown | Weather |
| | 2014-01-08 | 6:00 AM | 1/8/2014 | 9:00 AM | South Carolina | SERC | | Voltage Reduction; Public Appeal; Load Shed 100+MW due to Severe Weather - Cold | 4,545 | 677,858 | Weather |
| | 2014-01-13 | 4:44 PM | 1/13/2014 | 4:45 PM | Arizona | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-01-15 | 2:32 PM | 1/15/2014 | 2:45 PM | Utah | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-16 | 12:30 PM | 1/16/2014 | 1:57 PM | Arizona | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-01-17 | 10:30 AM | 1/28/2014 | 9:00 AM | Illinois | RFC | | Fuel Supply Emergency - Natural Gas | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-01-17 | 12:20 PM | 1/17/2014 | 12:20 PM | Ohio | RFC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-01-18 | 5:39 PM | Unknown | Unknown | Unknown | RFC | | Electrical System Islanding | Unknown | Unknown | Islanding |
| | 2014-01-18 | 9:00 AM | 1/18/2014 | 9:45 AM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |
| | 2014-01-21 | 12:14 PM | 1/21/2014 | 12:39 PM | Missouri | SERC | | Physical Attack - Vandalism | 10 | Unknown | Physical Attack |
| | 2014-01-21 | 5:00 PM | Unknown | Unknown | New Jersey | RFC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-22 | 12:30 AM | 1/22/2014 | 2:45 AM | Wisconsin | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-22 | 9:45 AM | 1/22/2014 | 8:19 PM | Ohio | RFC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-22 | 1:55 PM | 1/22/2014 | 2:55 PM | Wisconsin | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-22 | 9:15 PM | 1/23/2014 | 3:08 AM | Burlington County, New Jersey | RFC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-01-23 | 9:17 PM | 1/24/2014 | 5:00 PM | Wynoochee, Washington | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-23 | 4:00 AM | 1/24/2014 | 12:00 PM | Tennessee | SERC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-23 | 1:04 PM | 1/24/2014 | 9:00 AM | Maryland | RFC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-23 | 4:00 PM | 1/24/2014 | 12:00 PM | Tennessee | SERC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-24 | 12:00 AM | 4/9/2014 | 11:53 AM | Wisconsin | RFC | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-01-24 | 3:30 PM | 1/24/2014 | 5:00 PM | Wisconsin | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-25 | 10:00 AM | 1/25/2014 | 11:00 AM | Madison, Wisconsin | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-26 | 9:00 PM | 1/27/2014 | 11:00 AM | Oregon | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-01-26 | 11:00 PM | Unknown | Unknown | New Jersey | RFC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-01-27 | 2:20 PM | 1/28/2014 | 9:00 PM | Maryland | RFC | | Public Appeal due to Severe Weather - Cold | Unknown | Unknown | Weather |
| | 2014-01-29 | 4:00 PM | 1/29/2014 | 4:44 PM | Unknown | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-01-30 | 3:00 PM | Unknown | Unknown | Arizona | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-02-05 | 7:00 AM | 2/23/2014 | 7:00 AM | New York | NPCC | | Fuel Supply Emergency - Coal | 300 | Unknown | Fuel Supply Deficiency |
| | 2014-02-05 | 12:00 AM | 2/9/2014 | 6:00 PM | Maryland, West Virginia | RFC | | Severe Weather - Snow/Ice | Unknown | 101,580 | Weather |
| | 2014-02-05 | 1:00 AM | 2/9/2014 | 8:40 PM | Pennsylvania | RFC | | Severe Weather - Snow/Ice | Unknown | 144,000 | Weather |
| | 2014-02-05 | 5:00 AM | 2/5/2014 | 5:01 AM | Pennsylvania | RFC | | Severe Weather - Snow/Ice | Unknown | 715,000 | Weather |
| | 2014-02-05 | 7:35 AM | 2/7/2014 | 4:03 AM | Lancaster Region, Pennsylvania | RFC | | Severe Weather - Snow/Ice | Unknown | 62,159 | Weather |
| | 2014-02-05 | 8:05 AM | 2/5/2014 | 8:06 AM | Baltimore, Maryland | RFC | | Severe Weather - Ice | 800 | 181,000 | Weather |
| | 2014-02-06 | 1:00 PM | 2/6/2014 | 10:00 PM | California | WECC | | Fuel Supply Emergency - Natural Gas | 4,000 | Unknown | Fuel Supply Deficiency |
| | 2014-02-06 | 1:05 PM | 2/6/2014 | 7:15 PM | Northern California | WECC | | Fuel Supply Emergency - Natural Gas | 160 | Unknown | Fuel Supply Deficiency |
| | 2014-02-06 | 2:15 PM | 2/6/2014 | 7:39 PM | California | WECC | | Fuel Supply Emergency - Natural Gas | 611 | Unknown | Fuel Supply Deficiency |
| | 2014-02-06 | 1:58 PM | 2/6/2014 | 8:40 PM | Rio Grande Valley Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |
| | 2014-02-06 | 3:35 PM | 2/7/2014 | 11:30 AM | ERCOT Region Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |
| | 2014-02-07 | 7:00 AM | 3/21/2014 | 8:00 AM | Niagara County New York | NPCC | | Fuel Supply Emergency - Coal | 675 | Unknown | Fuel Supply Deficiency |
| | 2014-02-07 | 4:30 PM | 2/8/2014 | 9:00 AM | ERCOT Region Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |
| | 2014-02-07 | 4:50 PM | 2/7/2014 | 8:30 PM | Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | Unknown | Public Appeal |
| | 2014-02-12 | 2:15 PM | 2/12/2014 | 2:16 PM | Vermont | NPCC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-02-12 | 7:48 AM | 2/15/2014 | 4:30 AM | Northern/Northeastern Georgia | SERC | | Severe Weather - Snow/Ice | 1,246 | 373,835 | Weather |
| | 2014-02-12 | 11:03 AM | 2/15/2014 | 8:40 AM | South Carolina | SERC | | Severe Weather - Snow/Ice | 700 | 120,124 | Weather |
| | 2014-02-12 | 12:10 PM | 2/15/2014 | 3:20 PM | North Carolina | SERC | | Severe Weather - Snow/Ice | Unknown | 200,000 | Weather |
| | 2014-02-14 | 1:00 PM | 2/14/2014 | 3:00 PM | Portland, Oregon | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-02-18 | 6:43 PM | 2/18/2014 | 6:44 PM | Bend, Oregon | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-02-20 | 4:40 PM | 2/21/2014 | 11:59 PM | Missouri, Illinois | SERC | | Severe Weather - Snow/Ice | Unknown | 66,000 | Weather |
| | 2014-02-21 | 2:53 AM | 2/21/2014 | 9:00 PM | Northern/Northeastern Georgia | SERC | | Severe Weather - Thunderstorms/High Winds | 221 | 66,445 | Weather |
| | 2014-03-02 | 7:00 PM | 3/4/2014 | 9:00 AM | ERCOT Region Texas | TRE | | Public Appeal due to Severe Weather - Cold | N/A | N/A | Islanding |
| | 2014-03-03 | 1:48 AM | 3/3/2014 | 1:49 AM | Mid-Columbia River Generation, Washington | WECC | | Fuel Supply Emergency - Hydro | 630 | Unknown | Fuel Supply Deficiency |
| | 2014-03-03 | 5:25 PM | 3/3/2014 | 5:25 PM | New York | NPCC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-03-03 | 6:40 AM | 3/3/2014 | 3:28 PM | Tennessee | SERC | | Severe Weather - Winter Storm | Unknown | 65,904 | Weather |
| | 2014-03-04 | 9:06 AM | 3/17/2014 | 9:06 AM | Weston, Wisconsin | MRO | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-03-05 | 5:06 PM | 3/5/2014 | 5:07 PM | Salt Lake City, Utah | WECC | | Physical Attack | Unknown | Unknown | physical Attack |
| | 2014-03-07 | 3:30 AM | 3/7/2014 | 9:00 PM | Triad, North Carolina | SERC | | Severe Weather - Winter Storm | 1500 | 370,900 | Weather |
| | 2014-03-11 | 12:00 AM | 3/13/2014 | 12:00 AM | Boone County, Iowa | MRO | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-03-12 | 7:35 PM | 3/13/2014 | 12:00 PM | North Carolina | SERC | | Severe Weather - High Winds | 250 | 61,377 | Weather |
| | 2014-03-14 | 12:34 PM | 3/14/2014 | 4:45 PM | Boone County, Iowa | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-03-17 | 5:25 PM | 3/18/2014 | 12:56 AM | Glendale, Arizona | WECC | | Physical Attack - Sabatoge | N/A | N/A | Physical Attack |
| | 2014-03-20 | 12:00 AM | 3/20/2014 | 12:01 AM | New York | NPCC | | Suspected Cyber Attack | Unknown | Unknown | Cyber Attack |
| | 2014-03-24 | 11:07 AM | 3/24/2014 | 11:08 AM | Salt Lake City, Utah | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-03-26 | 1:37 PM | 3/26/2014 | 2:33 PM | Montana | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-03-26 | 4:00 PM | 4/10/2014 | 12:00 PM | Iowa | MRO | | Physical Attack | N/A | N/A | Physical Attack |
| | 2014-03-31 | 3:41 PM | 3/31/2014 | 8:08 PM | Puerto Rico | N/A | | System Wide Voltage Reduction | Unknown | Unknown | ? |
| | 2014-04-03 | 12:00 AM | Unknown | Unknown | Texas | TRE | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-04-03 | 2:45 PM | 4/9/2014 | 11:53 AM | Wisconsin | MRO | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-04-04 | 3:30 AM | 4/4/2014 | 8:15 AM | Central Arkansas | SERC | | Severe Weather - Wind | Unknown | 57,200 | Weather |
| | 2014-04-08 | 11:09 AM | 4/8/2014 | 11:20 AM | Puerto Rico | N/A | | Voltage Reduction | Unknown | Unknown | ? |
| | 2014-04-08 | 1:00 PM | 4/8/2014 | 1:01 PM | Davis, California | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-04-12 | 6:15 PM | 4/14/2014 | 9:00 AM | Western and Central Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 50,000 | Weather |
| | 2014-04-12 | 8:00 PM | 4/15/2014 | 7:30 PM | Michigan | RFC | | Severe Weather | Unknown | 164,000 | Weather |
| | 2014-04-23 | 7:45 PM | 4/23/2014 | 8:37 PM | Baton Rouge, Louisiana | SERC | | Load shedding of 100 Megawatts | 163 | 28,000 | Load Shed |
| | 2014-04-24 | 3:02 PM | 4/24/2014 | 5:13 PM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-04-25 | 7:00 AM | 4/25/2014 | 7:30 AM | Delaware | RFC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-04-27 | 9:15 AM | Unknown | Unknown | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | 9750 | 4,000,000 | Islanding |
| | 2014-04-27 | 12:07 PM | 4/27/2014 | 12:09 PM | Albany, Oregon | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-04-29 | 9:37 AM | 5/1/2014 | 9:00 AM | Northeastern Mississippi, Northern Alabama | SERC | | Severe Weather - Thunderstorms | Unknown | 57,000 | Weather |
| | 2014-04-29 | 11:30 PM | 4/29/2014 | 12:30 PM | Mississippi, Alabama | SERC | | Severe Weather - Thunderstorms | 355 | 106,648 | Weather |
| | 2014-04-30 | 3:50 AM | 4/30/2014 | 2:00 PM | Alabama, Florida, Georgia | SERC | | Severe Weather - Thunderstorms | 296 | 89,000 | Weather |
| | 2014-05-08 | 1:00 AM | 5/8/2014 | 1:01 AM | Mississippi | SERC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-05-08 | 8:39 AM | 5/8/2014 | 8:40 AM | Imperial Valley, California | WECC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-05-09 | 6:00 PM | 5/11/2014 | 1:00 PM | Indiana | RFC | | Severe Weather - Heavy Winds | Unknown | 56,000 | Weather |
| | 2014-05-11 | 6:38 PM | 5/11/2014 | 6:39 PM | MISO North, Minnesota | MRO | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-05-12 | 1:14 PM | 5/12/2014 | 1:15 PM | Layton, Utah | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-05-14 | 3:34 PM | Unknown | Unknown | San Diego & Orange Counties, California | WECC | | Public Appeal to Reduce Electricity Usage - Wild Fires | N/A | 426 | Wildfire |
| | 2014-05-15 | 12:10 PM | 5/15/2014 | 12:13 PM | Whiting, Indiana | RFC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2014-05-15 | 10:43 AM | Unknown | Unknown | San Diego & Orange Counties, California | WECC | | Public Appeal to Reduce Electricity Usage - Wild Fires | 3,300 | 1,400,000 | Wildfire |
| | 2014-05-16 | 10:43 AM | 5/16/2014 | 9:00 PM | San Diego & Orange Counties, California | WECC | | Public Appeal to Reduce Electricity Usage - Wild Fires | 3,900 | 1,400,000 | Wildfire |
| | 2014-05-20 | 7:01 AM | 5/20/2014 | 7:02 AM | Duchesne County, Utah | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-05-23 | 3:00 PM | 5/25/2014 | 7:00 PM | North Carolina | SERC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-05-26 | 12:31 PM | 5/26/2014 | 1:18 PM | British Columbia & Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-05-27 | 11:00 AM | 5/27/2014 | 4:53 PM | Phoenix, Arizona | WECC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-06-03 | 3:32 PM | 6/3/2014 | 3:59 PM | Alberta, Canada | WECC | | Electrical System Islanding | 338 | N/A | Islanding |
| | 2014-06-03 | 1:38 AM | 6/3/2014 | 1:43 AM | Texas | ERCOT | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-06-05 | 3:00 AM | 6/7/2014 | 11:45 PM | Shelby County, Tennessee | SERC | | Severe Weather - Thunderstorms | 494 | 38,500 | Weather |
| | 2014-06-05 | 1:06 PM | 6/5/2014 | 1:07 PM | West Tennessee | SERC | | Severe Weather - Thunderstorms | Unknown | 56,475 | Weather |
| | 2014-06-06 | 1:00 PM | Unknown | Unknown | Texas | ERCOT | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-06-07 | 11:00 PM | 6/8/2014 | 5:30 AM | North and Central , Alabama | SERC | | Severe Weather - Thunderstorms | 217 | 65,000 | Weather |
| | 2014-06-09 | 11:07 AM | 6/9/2014 | 11:30 AM | Alberta, Canada | WECC | | Electrical System Islanding | Unknown | Unknown | Islanding |
| | 2014-06-10 | 9:50 PM | 6/11/2014 | 2:30 PM | West Virginia | RFC | | Severe Weather - Thunderstorms | Unknown | 66,383 | Weather |
| | 2014-06-11 | 9:30 AM | 6/11/2014 | 9:31 AM | Nogales, Arizona | WECC | | Suspected Physical Attack | N/A | N/A | Physical Attack |
| | 2014-06-11 | 4:00 PM | 6/11/2014 | 4:30 PM | Southern Mississippi | SERC | | Physical Attack - Vandalism | N/A | N/A | Physical Attack |
| | 2014-06-12 | 9:10 AM | 6/12/2014 | 9:11 AM | Somervell County, Texas | ERCOT | | Suspected Physical Attack | Unknown | Unknown | physical Attack |
| | 2014-06-15 | 12:00 AM | 6/15/2014 | 1:00 AM | Central Minnesota | MRO | | Severe Weather - Thunderstorms | Unknown | 55,951 | Weather |
| | 2014-06-18 | 9:52 AM | 6/18/2014 | 7:00 PM | Washington | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-06-18 | 5:00 PM | 6/20/2014 | 3:00 PM | Southeast Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 138,802 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-06-19 | 8:47 AM | 6/19/2014 | 8:48 AM | Nashville, Tennessee | SERC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-06-24 | 2:54 PM | 6/24/2014 | 2:55 PM | Nashville, Tennessee | SERC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-06-27 | 1:21 PM | Unknown | Unknown | Wisconsin | MRO | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-06-30 | 5:55 PM | 7/1/2014 | 2:53 AM | Southeast Wisconsin | MRO | | Severe Weather - Thunderstorms | 424 | 120,000 | Weather |
| | 2014-06-30 | 8:00 PM | 7/2/2014 | 6:30 PM | Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 420,000 | Weather |
| | 2014-06-30 | 11:20 PM | 7/1/2014 | 5:00 PM | North Central Indiana | RFC | | Severe Weather - Thunderstorms | Unknown | 127,000 | Weather |
| | 2014-07-01 | 3:30 AM | Unknown | Unknown | Southwest Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 51,000 | Weather |
| | 2014-07-01 | 4:00 AM | 7/3/2014 | 11:30 PM | Southeast Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 140,000 | Weather |
| | 2014-07-01 | 5:00 AM | 7/2/2014 | 2:00 AM | Indiana, Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 57,237 | Weather |
| | 2014-07-02 | 8:39 AM | 7/28/2014 | 3:13 PM | Wisconsin | MRO | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-07-03 | 6:00 PM | 7/6/2014 | 12:00 PM | Pennsylvania | RFC | | Severe Weather - Thunderstorms | Unknown | 298,165 | Weather |
| | 2014-07-03 | 10:55 PM | 7/4/2014 | 1:50 AM | Vermont, New Hampshire, Maine, Rhode Island, Massachusetts, Connecticut | NPCC | | Severe Weather - Thunderstorms | Unknown | 64,000 | Weather |
| | 2014-07-08 | 5:30 PM | 7/12/2014 | 11:20 PM | Maryland, West Virginia | RFC | | Severe Weather - Thunderstorms | Unknown | 96,000 | Weather |
| | 2014-07-08 | 5:30 PM | 7/12/2014 | 11:30 PM | West Virginia | RFC | | Severe Weather - Thunderstorms | Unknown | 71,000 | Weather |
| | 2014-07-08 | 5:30 PM | 7/10/2014 | 3:00 PM | Central and Northeastern Pennsylvania | RFC | | Severe Weather - Thunderstorms | Unknown | 66,000 | Weather |
| | 2014-07-08 | 6:00 PM | 7/11/2014 | 5:53 PM | Eastern Pennsylvania | RFC | | Severe Weather - Thunderstorms | Unknown | 69,000 | Weather |
| | 2014-07-08 | 7:21 PM | 7/11/2014 | 7:00 AM | Upstate New York | NPCC | | Severe Weather - Thunderstorms | Unknown | 65,000 | Weather |
| | 2014-07-08 | 8:30 PM | 7/11/2014 | 11:00 PM | Pennsylvania | RFC | | Severe Weather - Thunderstorms | Unknown | 260,000 | Weather |
| | 2014-07-08 | 9:31 PM | Unknown | Unknown | Maryland | RFC | | Severe Weather - Thunderstorms | Unknown | 56,600 | Weather |
| | 2014-07-14 | 4:00 PM | 7/14/2014 | 4:15 PM | Washington | WECC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-07-23 | 7:14 PM | 7/24/2014 | 12:23 AM | Arkansas, Louisiana | SERC | | Severe Weather - Thunderstorms | Unknown | 57,299 | Weather |
| | 2014-07-24 | 4:29 PM | 7/24/2014 | 11:32 PM | California | WECC | | Load shedding of 100 Megawatts | 126 | 26,856 | Load Shed |
| | 2014-07-27 | 11:00 PM | 7/28/2014 | 4:00 AM | Central California | WECC | | Uncontrolled Loss of 300 Megawatts | 480 | 1 | ? |
| | 2014-07-27 | 5:00 PM | 7/28/2014 | 11:00 PM | Southeast Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 156,611 | Weather |
| | 2014-08-01 | 3:03 PM | 8/1/2014 | 3:04 PM | Utah | WECC | | Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-08-13 | 6:08 AM | 8/13/2014 | 6:34 AM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | 370 | Unknown | Islanding |
| | 2014-08-20 | 1:21 AM | 8/20/2014 | 1:41 AM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-08-23 | 4:39 PM | 8/24/2014 | 1:46 AM | City of Highland, Illinois | RFC | | Operational Failure of Electrical System | 31 | 6,549 | Operations |
| | 2014-08-24 | 3:20 AM | 8/25/2014 | 7:05 AM | North of San Francisco, California | WECC | | Earthquake | 95 | 70,000 | Natural Disaster |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-08-26 | 3:30 PM | Unknown | Unknown | Southeast Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | Unknown | Weather |
| | 2014-08-27 | 12:49 PM | 8/27/2014 | 1:30 PM | Delaware | RFC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-08-30 | 3:30 PM | 9/1/2014 | 2:30 PM | Luzerne County, Pennsylvania | RFC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-09-05 | 4:30 PM | 9/6/2014 | 2:00 PM | Illinois | RFC | | Severe Weather - Thunderstorms | Unknown | 180,400 | Weather |
| | 2014-09-05 | 7:14 PM | 9/6/2014 | 1:00 PM | Lower Peninsula of Michigan | RFC | | Severe Weather - Thunderstorms | 50 | 60,000 | Weather |
| | 2014-09-05 | 8:00 PM | Unknown | Unknown | Michigan | RFC | | Severe Weather - Thunderstorms | Unknown | 324,000 | Weather |
| | 2014-09-09 | 8:18 AM | 9/9/2014 | 11:59 PM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-09-11 | 4:56 AM | 9/11/2014 | 5:37 AM | Alberta, Canada | WECC | | Electrical System Separation (Islanding) | Unknown | Unknown | Islanding |
| | 2014-09-14 | 9:50 PM | 9/17/2014 | 3:08 PM | Oregon | WECC | | Electrical System Separation (Islanding) | 1 | 123 | Islanding |
| | 2014-09-16 | 11:56 AM | 9/16/2014 | 11:57 AM | California | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-09-17 | 1:30 PM | 9/17/2014 | 2:00 PM | Michigan | RFC | | Suspected Physical Attack - Suspcious Activity | Unknown | Unknown | Physical Attack |
| | 2014-09-19 | 2:20 PM | 9/23/2014 | 1:10 PM | Estacada, Oregon | WECC | | Electrical System Separation (Islanding) | 1 | 123 | Islanding |
| | 2014-09-21 | 1:30 PM | Unknown | Unknown | New York | NPCC | | Physical Attack - Suspcious Activity | Unknown | Unknown | Physical Attack |
| | 2014-09-22 | 11:00 AM | 9/22/2014 | 11:01 AM | Northeast Minnesota | MRO | | Fuel Supply Emergency - Coal | 1,000 | 140,000 | Fuel Supply Deficiency |
| | 2014-09-23 | 1:13 AM | 9/23/2014 | 3:00 AM | New York | NPCC | | Physical Attack - Suspcious Activity | N/A | N/A | Physical Attack |
| | 2014-09-24 | 11:30 AM | 9/24/2014 | 3:43 PM | Washington | WECC | | Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-02 | 3:00 PM | 10/2/2014 | 3:01 PM | Cave Junction, Oregon | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-02 | 4:00 PM | 10/7/2014 | 10:00 AM | Texas | TRE | | Severe Weather - Thunderstorms | Unknown | 500,000 | Weather |
| | 2014-10-02 | 10:15 PM | Unknown | Unknown | Arkansas | SERC | | Severe Weather - Thunderstorms | Unknown | 67,300 | Weather |
| | 2014-10-06 | 10:52 AM | 10/7/2014 | 12:52 AM | Houston, Texas | TRE | | Severe Weather - Thunderstorms | 292 | 129,237 | Weather |
| | 2014-10-07 | 12:00 PM | 10/7/2014 | 12:01 PM | Maryland | RFC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-08 | 4:47 PM | 10/8/2014 | 6:29 PM | Rio Grande Valley Texas | TRE | | Public Appeal to Reduce Electricity Usage; Load Shed of 100 MW | Unknown | Unknown | Public Appeal |
| | 2014-10-08 | 4:49 PM | 10/8/2014 | 6:23 PM | Rio Grande Valley Texas | TRE | | Public Appeal to Reduce Electricity Usage; Load Shed of 100 MW | 585 | 120,000 | Public Appeal |
| | 2014-10-09 | 9:27 AM | Unknown | Unknown | Rio Grande Valley Texas | TRE | | Public Appeal to Reduce Electricity Usage | Unknown | 2,800 | Public Appeal |
| | 2014-10-13 | 12:45 PM | 10/13/2014 | 4:15 PM | Louisiana | SERC | | Severe Weather - Thunderstorms | Unknown | 68,600 | Weather |
| | 2014-10-14 | 6:20 PM | 10/14/2014 | 6:28 PM | Puerto Rico | N/A | | Voltage Reduction | Unknown | Unknown | ? |
| | 2014-10-14 | 7:33 AM | 10/14/2014 | 7:34 AM | Oregon | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-14 | 5:44 AM | 10/14/2014 | 5:50 PM | Alabama, Florida, Georgia | SERC | | Severe Weather - Thunderstorms | 191 | 57,475 | Weather |
| | 2014-10-15 | 7:46 AM | 10/15/2014 | 7:47 AM | Oregon | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-16 | 9:12 AM | 10/17/2014 | 3:00 PM | Garden City, Kansas | MRO | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-16 | 1:25 PM | 10/16/2014 | 5:26 PM | Manitoba | MRO | | Suspected Physical Attack | 129 | Unknown | Physical Attack |
| | 2014-10-20 | 12:00 AM | Unknown | Unknown | Howard County, Texas | MRO | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-21 | 8:25 AM | 10/21/2014 | 10:08 AM | Carmel, Indiana | MRO | | Suspected Cyber Attack | Unknown | Unknown | Cyber Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-10-22 | 10:46 PM | 10/22/2014 | 10:47 PM | New Hampshire, Maine, Massachusetts, Rhode Island, Connecticut, Vermont | NPCC | | Severe Weather | Unknown | 66,650 | Weather |
| | 2014-10-24 | 4:00 PM | 10/24/2014 | 5:50 PM | Howard County, Texas | MRO | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-24 | 6:16 PM | 10/25/2014 | 1:51 PM | Enfield, Connecticut | NPCC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-10-25 | 4:00 PM | 10/25/2014 | 10:00 PM | Greater Portland and Salem, Oregon | WECC | | Severe Weather - Wind | 216 | 78,000 | Weather |
| | 2014-10-25 | 6:00 PM | Unknown | Unknown | King County, Thurston County and Kitsap County, Washington | WECC | | Severe Weather - Wind | 154 | 96,000 | Weather |
| | 2014-11-01 | 1:00 AM | 11/1/2014 | 1:01 AM | Portland, Oregon | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-02 | 1:46 PM | Unknown | Unknown | Massachusetts, Maine, Vermont, New Hampshire, Rhode Island, Connecticut | NPCC | | Severe Weather - Winter Storm | Unknown | 63,719 | Weather |
| | 2014-11-11 | 6:00 PM | 11/14/2014 | 3:00 PM | Washington | WECC | | Severe Weather - Wind | 132 | 68,000 | Weather |
| | 2014-11-12 | 2:59 AM | 11/12/2014 | 3:00 AM | Unknown | SERC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-13 | 7:07 AM | 11/13/2014 | 7:08 AM | Howard County,Texas | MRO | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-14 | 9:50 AM | 11/14/2014 | 1:18 PM | Estacada, Oregon | WECC | | Electrical System Islanding | 1 | 123 | Islanding |
| | 2014-11-19 | 2:44 PM | 11/19/2014 | 2:45 PM | Victorville, California | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-21 | 11:26 AM | 11/23/2014 | 5:20 PM | Sand Springs - Fort Rock, Oregon | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-21 | 8:29 PM | 11/23/2014 | 12:16 AM | Twin Falls, Idaho | WECC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-11-24 | 12:00 AM | Unknown | Unknown | Nebraska, Kansas, Texas, Arkansas, Louisiana, New Mexico | SPP | | Fuel Supply Emergency - Coal | Unknown | Unknown | Fuel Supply Deficiency |
| | 2014-11-24 | 12:00 PM | 11/27/2014 | 1:00 PM | Michigan | RFC | | Severe Weather - Wind | Unknown | 186,154 | Weather |
| | 2014-11-26 | 5:50 PM | 11/28/2014 | 7:00 AM | New Hampshire, Massachusetts, Maine, Rhode Island, Connecticut, Vermont | NPCC | | Severe Weather - Winter Storm | Unknown | 79,530 | Weather |
| | 2014-12-01 | 10:44 AM | 12/1/2014 | 10:45 AM | Fayetteville, North Carolina | SERC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |
| | 2014-12-03 | 12:15 PM | 12/3/2014 | 12:16 PM | Maine | NPCC | | Suspected Physical Attack - Vandalism | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014-12-11 | 7:21 AM | 12/11/2014 | 9:53 PM | San Francisco, California | WECC | | Distribution Interruption - Unknown Cause | 225 | 75,000 | Distribution Interruption |
| | 2014-12-11 | 6:40 AM | Unknown | Unknown | Northern California | WECC | | Severe Weather- High Winds | Unknown | Unknown | Weather |
| | 2014-12-11 | 4:05 PM | 12/11/2014 | 9:00 PM | Portland, Oregon | WECC | | Severe Weather- High Winds | 250 | 85,470 | Weather |
| | 2014-12-11 | 5:00 PM | 12/12/2014 | 10:00 AM | Kitsap, Thurston, Whatcom counties Washington | WECC | | Severe Weather- High Winds | 116 | 264,000 | Weather |
| | 2014-12-11 | 11:15 PM | Unknown | Unknown | Northern California | WECC | | Severe Weather- High Winds | Unknown | Unknown | Weather |
| | 2014-12-17 | 11:00 AM | 12/17/2014 | 12:15 PM | Washington | WECC | | Suspected Physical Attack | Unknown | Unknown | Physical Attack |
| | 2014-12-30 | 3:50 PM | 12/31/2014 | 11:00 AM | New Hampshire, Massachusetts, Maine, Rhode Island, Connecticut, Vermont | NPCC | | Suspected Cyber Attack | Unknown | Unknown | Cyber Attack |
| | 2014-12-30 | 1:08 PM | 1/1/2015 | 4:50 PM | Northern California | WECC | | Severe Weather- High Winds | 127 | 84,500 | Weather |
| January | 2015-01-07 | 5:00 PM | 1/8/2015 | 8:35 AM | Tennessee | SERC | Public appeal to reduce the use of electricity | Severe Weather - Winter | Unknown | Unknown | Weather |
| January | 2015-01-07 | 5:00 PM | 1/8/2015 | 8:35 AM | Tennessee, Kentucky, Virginia, North Carolina, Georgia, Alabama, Missouri | SERC | Public appeal to reduce the use of electricity | Severe Weather - Winter | Unknown | Unknown | Weather |
| January | 2015-01-22 | 4:24 AM | 1/22/2015 | 5:55 AM | Portland, Oregon | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| January | 2015-01-26 | 2:39 PM | 1/26/2015 | 2:40 PM | Cave Junction, Oregon | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| January | 2015-01-27 | 10:30 AM | 1/27/2015 | 10:31 AM | Kountze, Texas | SERC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| February | 2015-02-01 | 11:24 AM | 2/1/2015 | 11:44 AM | Weber County, Utah | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-02 | 9:40 AM | 2/2/2015 | 9:41 AM | Conroe, Texas | TRE | Suspected Physical Attack | Sabotage | Unknown | Unknown | Physical Attack |
| February | 2015-02-04 | 11:55 AM | 2/4/2015 | 11:56 AM | Vollmers, California | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-05 | 8:15 AM | 2/5/2015 | 8:17 AM | Cameron, Arizona | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-05 | 11:20 AM | 2/5/2015 | 11:21 AM | Dunismuir, California | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-06 | 8:58 PM | Unknown | Unknown | Northern California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Wind | Unknown | 65,000 | Weather |
| February | 2015-02-09 | 11:30 AM | 2/9/2015 | 1:15 PM | Colorado Springs, Colorado | WECC | Suspected Physical Attack | Sabotage | Unknown | Unknown | Physical Attack |
| February | 2015-02-16 | 9:00 PM | 2/18/2015 | 2:00 PM | Tennessee, Kentucky, Virginia, North Carolina, Georgia, Alabama, Missouri | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | Unknown | 67,189 | Weather |
| February | 2015-02-16 | 9:41 PM | 2/18/2015 | 7:00 AM | Northern/North Eastern, Georgia | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | 620 | 186,035 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2015-02-17 | 6:20 AM | 2/17/2015 | 7:30 AM | Prescott Valley, Arizona | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-17 | 2:12 AM | 2/18/2015 | 4:00 PM | North Carolina, South Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | Unknown | 68,000 | Weather |
| February | 2015-02-17 | 9:00 AM | 2/18/2015 | 11:00 PM | North Carolina, South Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | Unknown | 52,000 | Weather |
| February | 2015-02-18 | 3:00 PM | 2/20/2015 | 9:00 AM | Tennessee, Kentucky, Virginia, North Carolina, Georgia, Alabama, Missouri | SERC | Public appeal to reduce the use of electricity | Severe Weather - Winter | Unknown | Unknown | Weather |
| February | 2015-02-19 | 2:30 PM | 2/19/2015 | 3:20 PM | Winslow, Arizona | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| February | 2015-02-20 | 6:00 AM | 2/20/2015 | 10:00 AM | North Carolina, South Carolina | SERC | System-wide voltage reductions of 3 percent or more | Severe Weather - Winter | Unknown | Unknown | Weather |
| February | 2015-02-21 | 8:34 AM | 2/21/2015 | 12:45 PM | Fentress County, Tennessee | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | Unknown | 50,000 | Weather |
| February | 2015-02-26 | 3:12 AM | 2/26/2015 | 8:00 PM | North Carolina, South Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | Unknown | 124,000 | Weather |
| February | 2015-02-26 | 3:30 AM | 2/27/2015 | 12:00 PM | North Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Winter | 400 | 103,776 | Weather |
| March | 2015-03-04 | 9:05 AM | 3/4/2015 | 2:15 PM | Johnson City , Tennessee | SERC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| March | 2015-03-09 | 11:50 PM | 3/10/2015 | 10:53 AM | Washington | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| March | 2015-03-15 | 3:30 PM | 3/15/2015 | 7:00 PM | Greater Portland & Salem , Oregon | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Wind | 210 | 71,000 | Weather |
| March | 2015-03-16 | 7:31 AM | 3/16/2015 | 10:06 AM | Winona , Minnesota | MRO | Suspected Physical Attack | Sabotage | 20 | 5,941 | Physical Attack |
| March | 2015-03-19 | 6:30 PM | 3/19/2015 | 9:37 PM | Southwest Kansas | SPP | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| March | 2015-03-22 | 4:25 PM | 3/22/2015 | 4:26 PM | West Virginia | RFC | Suspected Physical Attack | Vandalism | 24 | 0 | Physical Attack |
| March | 2015-03-26 | 3:21 PM | 3/26/2015 | 4:59 PM | Contra Costa County, California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 15 | Unknown | Islanding |
| March | 2015-03-29 | 4:26 AM | 3/29/2015 | 9:21 AM | California | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| April | 2015-04-01 | 6:25 PM | 4/1/2015 | 6:26 PM | San Juan County, Utah | WECC | Suspected Physical Attack | Vandalism | Unknown | 37 | Physical Attack |
| April | 2015-04-02 | 7:04 AM | 4/2/2015 | 8:57 AM | San Juan County, Utah | WECC | Suspected Physical Attack | Vandalism | 6 | 5,763 | Physical Attack |
| April | 2015-04-03 | 2:00 AM | 4/3/2015 | 7:48 AM | Harvey, Reno, and Sedgwick Counties, Kansas | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather - Thunderstorms | Unknown | 70,000 | Weather |
| April | 2015-04-06 | 8:12 AM | 4/6/2015 | 12:08 PM | Butte County, California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | System Operations | Unknown | 80,000 | Operations |
| April | 2015-04-07 | 3:34 PM | 4/7/2015 | 3:46 PM | California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 0 | 0 | Islanding |
| April | 2015-04-07 | 12:30 PM | 4/7/2015 | 5:34 PM | Unknown | RFC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | Unknown | Unknown | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2015-04-17 | 9:16 AM | 4/17/2015 | 11:00 AM | Canada | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 9,300 | Unknown | Islanding |
| April | 2015-04-17 | 9:30 PM | 4/19/2015 | 11:50 PM | Houston, Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 280,982 | Weather |
| April | 2015-04-18 | 9:00 PM | 4/21/2015 | 4:00 AM | Dallas, Fort Worth, Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 89,000 | Weather |
| April | 2015-04-24 | 7:10 PM | 4/26/2015 | 4:00 PM | Dallas, Fort Worth, Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57,000 | Weather |
| April | 2015-04-27 | 10:30 AM | 4/28/2015 | 6:45 PM | Louisiana and Texas | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 199,000 | Weather |
| May | 2015-05-02 | 10:51 PM | 5/3/2015 | 12:26 AM | Franklin County, Tennessee | SERC | Suspected Physical Attack | Vandalism | 1 | 215 | Physical Attack |
| May | 2015-05-04 | 3:25 PM | 5/4/2015 | 3:26 PM | Salt Lake County, Utah | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| May | 2015-05-11 | 8:32 AM | 5/11/2015 | 8:33 AM | Shasta County, California | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| May | 2015-05-12 | 12:40 AM | 5/12/2015 | 12:45 AM | Coahoma County, Mississippi | SERC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| May | 2015-05-18 | 3:28 PM | 5/18/2015 | 3:47 PM | Washington | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | Severe Weather | 275 | 0 | Weather |
| May | 2015-05-25 | 6:00 PM | 5/29/2015 | 7:15 AM | North Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 454,000 | Weather |
| May | 2015-05-25 | 8:30 PM | 5/26/2015 | 6:30 PM | Texas | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57,531 | Weather |
| May | 2015-05-25 | 8:30 PM | Unknown | Unknown | Texas, Louisiana, Arkansas | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57,351 | Weather |
| May | 2015-05-25 | 10:45 PM | 5/28/2015 | 1:25 AM | Fort Bend County, & Harris County ,Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 61,000 | Weather |
| May | 2015-05-26 | 5:30 AM | 5/27/2015 | 7:00 PM | Texas, Louisiana, Arkansas, Mississippi | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 78,515 | Weather |
| June | 2015-06-01 | 7:19 PM | 6/2/2015 | 8:36 AM | California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 5 | 484 | Islanding |
| June | 2015-06-01 | 12:27 AM | 6/1/2015 | 2:15 AM | Daviess County, Kentucky | SERC | Suspected Physical Attack | Vandalism | 2 | 110 | Physical Attack |
| June | 2015-06-02 | 6:58 PM | 6/2/2015 | 7:24 PM | California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 5 | 727 | Islanding |
| June | 2015-06-03 | 3:00 PM | 6/5/2015 | 5:00 PM | Texas | TRE | Public appeal to reduce the use of electricity | System Operations | Unknown | Unknown | Public Appeal |
| June | 2015-06-07 | 1:52 PM | 6/7/2015 | 2:13 PM | Tennessee | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | Unknown | Unknown | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2015-06-07 | 1:54 PM | 6/7/2015 | 2:13 PM | Shelby County, Tennessee | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident<br><br>System-wide voltage reductions of 3 percent or more | System Operations | 926 | Unknown | Operations |
| June | 2015-06-08 | 12:00 AM | Unknown | Unknown | Merced County, California | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | System Operations | 176 | Unknown | Fuel Supply Deficiency |
| June | 2015-06-20 | 1:52 PM | 6/20/2015 | 3:30 PM | Solano County, California | WECC | Suspected Physical Attack | Vandalism | Unknown | 0 | Physical Attack |
| June | 2015-06-23 | 6:18 PM | 6/23/2015 | 8:30 PM | New Jersey | RFC | Load shedding of 100 Megawatts or more implemented under emergency operational policy<br><br>Loss of electric service to more than 50,000 customers for 1 hour or more | System Operations | 198 | 156,338 | Load Shed |
| June | 2015-06-23 | 5:06 PM | 6/26/2015 | 4:00 PM | New Castle County, Delaware | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 65,000 | Weather |
| June | 2015-06-23 | 5:30 PM | 6/23/2015 | 7:00 PM | Delaware County, PA; Chester County, PA | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 200,000 | Weather |
| June | 2015-06-23 | 6:00 PM | 6/30/2015 | 6:00 PM | Gloucester County, Burlington County, Atlantic County, Cape May County, New Jersey | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 263,000 | Weather |
| June | 2015-06-23 | 6:26 PM | Unknown | Unknown | New Jersey | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 90 | 73,000 | Weather |
| June | 2015-06-23 | 6:30 PM | 6/24/2015 | 5:00 AM | Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 62,442 | Weather |
| June | 2015-06-26 | 2:00 AM | Unknown | Unknown | Kansas | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 110,000 | Weather |
| June | 2015-06-27 | 5:00 PM | 6/30/2015 | 5:18 PM | Wayne County, Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 68,000 | Weather |
| June | 2015-06-29 | 7:21 PM | 6/29/2015 | 7:42 PM | Washington | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | Severe Weather | 0 | 0 | Weather |
| June | 2015-06-30 | 10:50 AM | 7/1/2015 | 9:00 PM | California | WECC | Public appeal to reduce the use of electricity | Severe Weather | Unknown | Unknown | Weather |
| June | 2015-06-30 | 2:00 PM | 6/30/2015 | 9:00 PM | California | WECC | Public appeal to reduce the use of electricity | Severe Weather | Unknown | Unknown | Weather |
| July | 2015-07-03 | 5:17 PM | 7/3/2015 | 11:30 PM | Texas | TRE | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 350 | 30,000 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2015-07-03 | 8:30 AM | 7/3/2015 | 2:30 PM | Butte County, California | WECC | Suspected Physical Attack | Suspicious Activity | 0 | 0 | physical Attack |
| July | 2015-07-13 | 2:14 PM | 7/16/2015 | 6:00 AM | Ohio, Kentucky | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 480 | 68,339 | Weather |
| July | 2015-07-13 | 7:40 PM | 7/15/2015 | 12:15 PM | Virginia | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 52,739 | Weather |
| July | 2015-07-14 | 3:29 PM | 7/15/2015 | 11:55 AM | Arkansas | SPP | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Severe Weather | Unknown | Unknown | Weather |
| July | 2015-07-14 | 8:00 PM | 7/15/2015 | 9:23 AM | Alabama | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 366 | 111,644 | Weather |
| July | 2015-07-15 | 2:00 AM | 7/15/2015 | 2:55 AM | California | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 360 | 0 | Operations |
| July | 2015-07-16 | 4:45 PM | 7/16/2015 | 5:48 PM | Texas | SPP | Load shedding of 100 Megawatts or more implemented under emergency operational policy | System Operations | 117 | 17,311 | Load Shed |
| July | 2015-07-18 | 6:26 PM | 7/18/2015 | 9:03 PM | California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 30 | 70 | Islanding |
| July | 2015-07-18 | 2:00 AM | 7/19/2015 | 7:00 AM | Henepin and Ramsey County, Minnesota | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 250 | 250,000 | Weather |
| July | 2015-07-18 | 7:59 PM | 7/18/2015 | 10:45 PM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 160 | 78,164 | Weather |
| July | 2015-07-21 | 12:47 PM | 7/21/2015 | 1:12 PM | Washington | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | System Operations | 200 | Unknown | Load Shed |
| July | 2015-07-27 | 3:52 AM | 7/27/2015 | 4:36 AM | California | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | Unknown | 484 | Islanding |
| July | 2015-07-28 | 12:05 PM | 7/28/2015 | 12:26 PM | Puerto Rico | N/A | System-wide voltage reductions of 3 percent or more | System Operations | 150 | Unknown | Operations |
| July | 2015-07-29 | 4:45 PM | 7/29/2015 | 9:00 PM | New York | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | System Operations | 500 | 0 | Fuel Supply Deficiency |
| July | 2015-07-30 | 1:00 PM | Unknown | Unknown | Tennessee | SERC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| July | 2015-07-30 | 9:50 AM | 7/30/2015 | 7:00 PM | Texas | TRE | Public appeal to reduce the use of electricity | System Operations | Unknown | Unknown | Public Appeal |
| July | 2015-07-31 | 10:55 AM | Unknown | Unknown | Washington | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | System Operations | 9 | 0 | Islanding |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2015-08-02 | 5:45 PM | 8/4/2015 | 3:00 AM | Michigan: Emmet County; Grand Traverse County; Leelanau County; Kalkaska County; Benzie County; Manistee County; Wexford County; Missaukee County; Mecosta County; | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 162,000 | Weather |
| August | 2015-08-03 | 8:27 AM | 8/4/2015 | 1:18 AM | Arizona: New Mexico | WECC | Suspected Physical Attack | Sabotage | 0 | Unknown | Physical Attack |
| August | 2015-08-03 | 12:30 AM | 8/3/2015 | 2:00 AM | Illinois | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 115,000 | Weather |
| August | 2015-08-03 | 1:00 AM | 8/5/2015 | 12:00 AM | Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 72,520 | Weather |
| August | 2015-08-04 | 7:17 AM | 8/5/2015 | 12:52 PM | Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 132,000 | Weather |
| August | 2015-08-11 | 7:30 PM | 8/13/2015 | 4:05 AM | Texas: Houston; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 100,000 | Weather |
| August | 2015-08-13 | 3:15 PM | 8/13/2015 | 7:00 PM | Texas: Williamson County; | TRE | Public appeal to reduce the use of electricity | Other | Unknown | Unknown | Public Appeal |
| August | 2015-08-27 | 9:51 PM | 8/28/2015 | 6:00 PM | Puerto Rico | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident / Loss of electric service to more than 50,000 customers for 1 hour or more | System Operations | 360 | Unknown | Operations |
| August | 2015-08-29 | 10:00 AM | Unknown | Unknown | Washington | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 500,000 | Weather |
| August | 2015-08-29 | 11:00 AM | 9/4/2015 | 3:00 PM | King County, Skagit County, Whatcom County, Kitsap County, Pierce County, Thurston County, Island County, Washington | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 250 | 250,000 | Weather |
| August | 2015-08-29 | 1:00 PM | 8/31/2015 | 7:00 AM | Washington: King County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 1,200 | 64,000 | Weather |
| September | 2015-09-03 | 2:33 AM | 9/3/2015 | 6:25 AM | Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 50,114 | Weather |
| September | 2015-09-13 | 5:56 PM | 9/13/2015 | 8:37 PM | New York: Dutchess County; | NPCC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| September | 2015-09-20 | 1:12 PM | 9/20/2015 | 1:44 PM | California | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | System Operations | 150 | Unknown | Load Shed |
| September | 2015-09-29 | 3:40 PM | 9/29/2015 | 3:41 PM | Oregon | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| October | 2015-10-13 | 6:30 AM | 10/13/2015 | 8:30 AM | Utah: Emery County; | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2015-10-13 | 10:25 AM | 10/13/2015 | 6:00 PM | Texas | TRE | Public appeal to reduce the use of electricity | Other | Unknown | Unknown | Public Appeal |
| October | 2015-10-13 | 4:32 PM | 10/13/2015 | 8:39 PM | California | WECC | Public appeal to reduce the use of electricity | Other | 41,788 | Unknown | Public Appeal |
| October | 2015-10-16 | 12:25 PM | 10/16/2015 | 12:56 PM | Utah | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| October | 2015-10-18 | 7:00 AM | 10/18/2015 | 11:29 PM | California: Central Coast area; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 88 | 55,677 | Weather |
| October | 2015-10-23 | 9:42 AM | 10/23/2015 | 1:26 PM | Puerto Rico | N/A | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational / Load shedding of 100 Megawatts or more implemented under emergency operational policy / System-wide voltage reductions of 3 percent of more / Loss of electric service to more than 50,000 customers for 1 hour or more | System Operations | 500 | 300,000 | Islanding |
| October | 2015-10-28 | 1:38 PM | 10/29/2015 | 5:00 PM | Pennsylvania: Columbia County; Montour County; Northumberland County; | RFC | Suspected Physical Attack | Other | Unknown | 35,000 | physical Attack |
| October | 2015-10-30 | 3:00 PM | 10/30/2015 | 4:00 PM | Oregon: Josephine County; | WECC | Suspected Physical Attack | Other | 0 | 0 | physical Attack |
| October | 2015-10-31 | 12:45 AM | 11/1/2015 | 4:05 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 130,252 | Weather |
| November | 2015-11-01 | 11:53 AM | 11/1/2015 | 12:00 PM | Ohio: Hamilton County; | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | physical Attack |
| November | 2015-11-02 | 5:37 PM | 11/4/2015 | 9:00 AM | Arkansas: Hot Spring County; | SERC | Suspected Physical Attack | Sabotage | 4 | 0 | physical Attack |
| November | 2015-11-10 | 12:00 PM | 11/10/2015 | 2:00 PM | Indiana: Dearborn County; | RFC | Suspected Physical Attack | Sabotage | 0 | 0 | physical Attack |
| November | 2015-11-13 | 11:30 AM | 11/13/2015 | 11:35 AM | New York | NPCC | Suspected Physical Attack | Suspicious Activity | Unknown | Unknown | physical Attack |
| November | 2015-11-17 | 9:00 AM | Unknown | Unknown | Washington: Snohomish County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 900 | 89,000 | Weather |
| November | 2015-11-17 | 10:00 AM | Unknown | Unknown | Washington | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 300,000 | Weather |
| November | 2015-11-17 | 1:30 PM | Unknown | Unknown | Washington: Stevens County, Lincoln County, Adams County, Whitman County, Spokane County; Idaho: Bonner County, Kootenai County, Shoshone County, Benewah County, Idaho County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 182,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2015-11-21 | 8:30 PM | 11/23/2015 | 1:00 AM | Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 60,000 | Weather |
| November | 2015-11-28 | 6:00 AM | 11/30/2015 | 1:00 PM | Oklahoma | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 55,609 | Weather |
| November | 2015-11-28 | 6:00 AM | Unknown | Unknown | Oklahoma | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 35,000 | Weather |
| November | 2015-11-29 | 4:48 PM | 11/29/2015 | 6:20 PM | Puerto Rico | N/A | System-wide voltage reductions of 3 percent or more | System Operations | 0 | 0 | Operations |
| November | 2015-11-30 | 6:18 AM | 11/30/2015 | 9:18 PM | Puerto Rico | N/A | System-wide voltage reductions of 3 percent or more | System Operations | 100 | 86,559 | Operations |
| December | 2015-12-02 | 1:03 PM | 12/3/2015 | 12:29 PM | Kansas: Thomas County; | SPP | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| December | 2015-12-05 | 7:22 PM | 12/6/2015 | 5:27 AM | New York: Orange County, Sullivan County; Pennsylvania: Pike County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Other | 110 | 52,476 | Operations |
| December | 2015-12-05 | 9:00 PM | 12/5/2015 | 10:30 PM | Kansas | SPP | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| December | 2015-12-08 | 2:00 PM | 12/8/2015 | 2:01 PM | Nevada: Clark County; | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| December | 2015-12-09 | 6:06 PM | 12/9/2015 | 9:52 PM | Puerto Rico | | System-wide voltage reductions of 3 percent or more | System Operations | 0 | 0 | Operations |
| December | 2015-12-09 | 4:00 AM | 12/9/2015 | 11:00 AM | Washington | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 115 | 76,300 | Weather |
| December | 2015-12-10 | 3:53 AM | 12/10/2015 | 4:08 AM | California: Plumas County | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | Severe Weather | 24 | 9,956 | Islanding |
| December | 2015-12-10 | 9:25 PM | 12/10/2015 | 10:30 PM | Missouri: New Madrid County; | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 400 | 1 | Operations |
| December | 2015-12-10 | 5:55 PM | 12/10/2015 | 5:56 PM | California: Stanislaus County; | WECC | Suspected Physical Attack | Vandalism | Unknown | Unknown | Physical Attack |
| December | 2015-12-10 | 6:01 AM | 12/10/2015 | 7:13 AM | California: Northern; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational | Severe Weather | 29 | 9,956 | Weather |
| December | 2015-12-24 | 3:00 AM | 12/26/2015 | 12:00 AM | Michigan: Antrim County, Charlevoix County, Manistee County, Mecosta County, Kalkaska County, Grand Traverse County, Osceola County, Lake County, Newaygo County, Clare County, Isabella County; | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 168,000 | Weather |
| December | 2015-12-26 | 6:00 PM | 12/30/2015 | 6:00 AM | Texas: Oklahoma: | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 116,800 | Weather |
| December | 2015-12-26 | 7:30 PM | Unknown | Unknown | Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 70,000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2015-12-27 | 5:00 PM | Unknown | Unknown | Oklahoma | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 50,500 | Weather |
| December | 2015-12-27 | 11:38 PM | 12/28/2015 | 5:00 PM | Oklahoma | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 54,476 | Weather |
| December | 2015-12-29 | 8:30 AM | 12/29/2015 | 8:31 AM | Maine | NPCC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| December | 2015-12-31 | 11:00 AM | Unknown | Unknown | Missouri | SERC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| December | 2015-12-31 | 5:00 PM | 12/31/2015 | 9:40 PM | Oklahoma: Blaine County; | SPP | Public appeal to reduce the use of electricity | Severe Weather | 8 | 1,500 | Weather |
| January | 2016-01-04 | 5:15 AM | 1/5/2016 | 8:00 AM | Wisconsin: Milwaukee County; | MRO | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| January | 2016-01-10 | 8:46 PM | 1/11/2016 | 5:25 AM | Maine: Connecticut: Massachusetts: Vermont: New Hampshire: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 59,859 | Weather |
| January | 2016-01-11 | 8:16 PM | 1/11/2016 | 11:00 PM | Pennsylvania: Chester County; | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| January | 2016-01-14 | 8:27 AM | 1/14/2016 | 12:00 PM | Delaware: | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| January | 2016-01-17 | 12:00 PM | 1/17/2016 | 1:00 PM | Utah: Salt Lake County; | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| January | 2016-01-22 | 3:52 PM | 1/24/2016 | 12:30 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 150,000 | Weather |
| January | 2016-01-23 | 7:49 AM | 1/23/2016 | 9:05 AM | New Jersey: | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 50,900 | Weather |
| February | 2016-02-05 | 11:21 AM | 2/6/2016 | 3:48 PM | Connecticut: Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 115057 | Weather |
| February | 2016-02-07 | 11:30 AM | Unknown | Unknown | New York: Orange County | NPCC | Suspected Cyber Attack | Cyber Attack | Unknown | Unknown | Cyber Attack |
| February | 2016-02-07 | 1:21 PM | 2/7/2016 | 1:42 PM | Utah: Salt Lake County | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| February | 2016-02-07 | 2:58 PM | Unknown | Unknown | Oregon: Klamath County | WECC | Suspected Physical Attack | Sabotage | Unknown | Unknown | Physical Attack |
| February | 2016-02-13 | 12:44 PM | 2/13/2016 | 4:27 PM | California | SERC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 7 | 4300 | Islanding |
| February | 2016-02-16 | 8:35 AM | 2/16/2016 | 5:28 PM | Virginia: Roanoke County, Montgomery County; West Virginia: Kanawha County, Cabell County; Tennessee: Sullivan County; | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 52640 | Weather |
| February | 2016-02-19 | 10:00 PM | 2/20/2016 | 11:13 PM | Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 145314 | Weather |
| February | 2016-02-21 | 3:54 PM | 2/21/2016 | 5:07 PM | Oregon: Klamath County | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2016-02-24 | 9:10 AM | 2/24/2016 | 10:15 AM | Delaware | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | physical Attack |
| February | 2016-02-24 | 2:45 PM | 2/25/2016 | 5:00 AM | North Carolina: South Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | 400 | 284610 | Weather |
| February | 2016-02-25 | 1:44 AM | 2/25/2016 | 2:45 PM | Connecticut: Maine: Massachusetts: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 114190 | Weather |
| February | 2016-02-26 | 12:01 AM | Unknown | Unknown | California: San Bernardino County | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| February | 2016-02-26 | 4:35 PM | 2/26/2016 | 8:22 PM | Arizona: Maricopa County | WECC | Suspected Physical Attack | Sabotage - Operator Action(s) | 2 | 2713 | physical Attack |
| March | 2016-03-01 | 1:35 PM | Unknown | Unknown | Idaho: Ada County; | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | physical Attack |
| March | 2016-03-01 | 3:00 PM | Unknown | Unknown | Washington: King County, Whatcom County, Kitsap County, Skagit County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 56000 | Weather |
| March | 2016-03-03 | 11:00 AM | 4/6/2016 | 7:47 PM | California: San Bernardino County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| March | 2016-03-08 | 12:00 AM | 3/8/2016 | 12:00 AM | Idaho: Bannock County; | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | physical Attack |
| March | 2016-03-10 | 4:00 AM | 3/11/2016 | 11:59 AM | Washington: Kitsap County, King County, Whatcom County, Island County, Skagit County; | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| March | 2016-03-13 | 2:00 PM | Unknown | Unknown | Washington: Island County, Skagit County, Whatcom County, King County, Kitsap County, Pierce County, Thurston County; | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| March | 2016-03-13 | 4:55 PM | Unknown | Unknown | Washington: | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| March | 2016-03-23 | 5:00 AM | 3/25/2016 | 11:59 PM | Colorado: Denver, City and County of[12]; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | 0 | 0 | Weather |
| March | 2016-03-27 | 12:00 PM | 3/27/2016 | 1:00 PM | Nevada: Clark County; | WECC | Suspected Physical Attack | Sabotage | Unknown | 110000 | Physical Attack |
| March | 2016-03-30 | 9:12 PM | 3/31/2016 | 3:00 PM | Massachusetts: Middlesex County[13]; | NPCC | Suspected Physical Attack | Sabotage | 200 | 50500 | Physical Attack |
| April | 2016-04-01 | 4:37 PM | 4/1/2016 | 6:00 PM | Florida: Hillsborough County | FRCC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2016-04-02 | 11:08 AM | 4/2/2016 | 11:33 AM | California | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 360 | 0 | Operations |
| April | 2016-04-12 | 11:30 AM | 4/12/2016 | 4:43 PM | Washington: Pend Oreille County | WECC | Suspected Cyber Attack | Cyber Attack | 0 | 0 | Cyber Attack |
| April | 2016-04-14 | 4:49 PM | 4/15/2016 | 8:42 PM | Maryland: Baltimore County | RFC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| April | 2016-04-15 | 10:00 AM | 4/15/2016 | 11:00 AM | Utah: Weber County | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| April | 2016-04-18 | 5:05 AM | 4/20/2016 | 7:55 AM | Texas: Harris County | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 415103 | Weather |
| April | 2016-04-27 | 1:36 PM | Unknown | Unknown | Tennessee | SERC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| April | 2016-04-27 | 6:00 PM | 4/27/2016 | 6:05 PM | Texas: Rusk County | TRE | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| April | 2016-04-27 | 5:50 AM | 4/28/2016 | 1:35 AM | Texas: Harris County | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 214864 | Weather |
| May | 2016-05-07 | 7:49 AM | 5/7/2016 | 9:02 AM | New York: Dutchess County; | NPCC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| May | 2016-05-08 | 9:12 AM | Unknown | Unknown | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | Unknown | Unknown | Islanding |
| May | 2016-05-10 | 8:45 PM | 5/13/2016 | 3:00 AM | Texas: Dallas County, Tarrant County, Parker County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Distribution Interruption | Unknown | 85000 | Distribution Interruption |
| May | 2016-05-14 | 9:25 PM | 5/15/2016 | 5:24 PM | Missouri: | SERC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| May | 2016-05-19 | 9:36 PM | 5/20/2016 | 1:00 AM | Utah: | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 461 | 85179 | Operations |
| May | 2016-05-20 | 12:00 AM | 5/22/2016 | 5:00 AM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Distribution Interruption | Unknown | 85000 | Distribution Interruption |
| May | 2016-05-20 | 1:15 AM | Unknown | Unknown | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | Unknown | 57184 | Weather |
| May | 2016-05-24 | 8:00 AM | Unknown | Unknown | Missouri: | SERC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| May | 2016-05-26 | 9:29 PM | 5/27/2016 | 12:40 AM | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Transmission Interruption | 82 | 56645 | Transmission Interruption |
| May | 2016-05-31 | 7:30 AM | 6/13/2016 | 7:27 AM | New York: Tompkins County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 150 | Unknown | Fuel Supply Deficiency |
| June | 2016-06-07 | 12:00 PM | 6/7/2016 | 12:15 PM | Utah | WECC | Suspected Physical Attack | Sabotage | 0 | 0 | Physical Attack |
| June | 2016-06-14 | 7:59 AM | 6/14/2016 | 8:00 AM | New Jersey | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| June | 2016-06-17 | 4:30 AM | 6/17/2016 | 4:31 AM | Delaware | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| June | 2016-06-17 | 3:40 PM | 6/18/2016 | 8:34 AM | Georgia, Alabama, Mississippi, Florida | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather | 304 | 91260 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2016-07-02 | 4:00 AM | 7/4/2016 | 12:40 AM | Oregon: Multnomah County | WECC | Suspected Physical Attack | Actual Physical Event | 0 | 0 | Physical Attack |
| July | 2016-07-05 | 2:45 AM | 7/6/2016 | 3:00 AM | Texas: Dallas County, Tarrant County | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 52000 | Weather |
| July | 2016-07-05 | 5:30 PM | 7/6/2016 | 4:00 PM | Minnesota, Wisconsin | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 250000 | Weather |
| July | 2016-07-07 | 5:53 AM | 7/7/2016 | 8:40 AM | North Carolina: New Hanover County | SERC | Actual Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| July | 2016-07-07 | 4:20 AM | 7/7/2016 | 8:00 AM | Kansas: Johnson County; Missouri: Jackson County, Platte County, Cass County, Buchanan County, Atchison County, Andrew County, Clay County, Nodaway County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 58500 | Weather |
| July | 2016-07-08 | 6:00 PM | Unknown | Unknown | West Virginia: Virginia | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 62961 | Weather |
| July | 2016-07-08 | 7:00 PM | 7/9/2016 | 12:00 AM | Michigan: Wayne County, Oakland County, Macomb County, St. Clair County, Lapeer County, Tuscola County, Sanilac County, Huron County | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 160895 | Weather |
| July | 2016-07-08 | 8:50 PM | 7/9/2016 | 7:25 PM | North Carolina | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 600 | 203345 | Weather |
| July | 2016-07-09 | 5:45 PM | 7/11/2016 | 2:00 PM | Texas: Dallas County | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 62000 | Weather |
| July | 2016-07-12 | 2:10 PM | 7/12/2016 | 8:33 PM | Puerto Rico | PR | Voltage Reduction | System Operations | 450 | 218000 | Operations |
| July | 2016-07-13 | 1:00 PM | 7/13/2016 | 1:01 PM | Washington | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| July | 2016-07-13 | 3:00 PM | Unknown | Unknown | Tennessee: Shelby County | SERC | Public Appeal | System Operations | Unknown | Unknown | Public Appeal |
| July | 2016-07-14 | 2:44 PM | 7/15/2016 | 4:00 AM | Oklahoma | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 96966 | Weather |
| July | 2016-07-14 | 4:30 PM | 7/16/2016 | 12:00 AM | Arkansas: Louisiana: Mississippi: Texas | SPP, SERC, TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 170244 | Weather |
| July | 2016-07-14 | 5:30 PM | 7/16/2016 | 8:00 PM | Oklahoma: Arkansas | SPP | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 7300 | Weather |
| July | 2016-07-19 | 3:45 PM | 7/19/2016 | 7:29 PM | Idaho | WECC | Islanding, Uncontrolled Loss 300+ MW | System Operations | 290 | Unknown | Operations |
| July | 2016-07-19 | 3:45 PM | 7/19/2016 | 7:25 PM | Idaho | WECC | Islanding, Uncontrolled Loss 300+ MW | System Operations | 485 | Unknown | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2016-07-21 | 7:21 PM | 7/22/2016 | 12:09 AM | Puerto Rico | PR | Load Shed 100+ MW, Voltage Reduction | System Operations | 200 | 266000 | Load Shed |
| July | 2016-07-21 | 6:18 AM | 7/21/2016 | 2:45 PM | Delaware: New Castle County | RFC | Suspected Physical Attack | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2016-07-22 | 11:50 PM | 7/23/2016 | 9:10 AM | Massachusetts: Connecticut: Rhode Island: New Hampshire: Vermont: Maine | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57058 | Weather |
| July | 2016-07-23 | 3:15 PM | 7/23/2016 | 7:53 PM | Pennsylvania: Cambria County | RFC | Voltage Reduction | System Operations | 87 | Unknown | Operations |
| July | 2016-07-23 | 7:30 PM | 7/24/2016 | 7:30 AM | Connecticut: Massachusetts: New Hampshire: Vermont: Rhode Island | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 101073 | Weather |
| July | 2016-07-25 | 6:51 PM | 7/26/2016 | 2:19 AM | Puerto Rico | PR | Voltage Reduction | System Operations | 0 | 0 | Operations |
| July | 2016-07-26 | 6:51 PM | 7/27/2016 | 1:45 AM | Puerto Rico | PR | Voltage Reduction | System Operations | 25 | 37100 | Operations |
| July | 2016-07-27 | 6:50 PM | 7/28/2016 | 1:38 AM | Puerto Rico | PR | Voltage Reduction | System Operations | 80 | 106300 | Operations |
| July | 2016-07-28 | 6:51 PM | 7/29/2016 | 2:02 AM | Puerto Rico | PR | Voltage Reduction | System Operations | 22 | 21600 | Operations |
| July | 2016-07-29 | 7:09 PM | 7/29/2016 | 7:57 PM | Puerto Rico | PR | Voltage Reduction | System Operations | 0 | 0 | Operations |
| August | 2016-08-04 | 2:15 PM | 8/4/2016 | 2:23 PM | Delaware: New Castle County; | RFC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |
| August | 2016-08-07 | 6:39 PM | 8/7/2016 | 8:27 PM | New Mexico: Bernalillo County; | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | Unknown | Unknown | Operations |
| August | 2016-08-10 | 6:00 AM | Unknown | Unknown | California: Butte County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| August | 2016-08-11 | 4:30 PM | 8/11/2016 | 7:15 PM | Ohio: | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 62140 | Weather |
| August | 2016-08-13 | 11:42 AM | 8/13/2016 | 2:07 PM | South Carolina: | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 506 | 0 | Operations |
| August | 2016-08-20 | 2:18 PM | 8/20/2016 | 9:19 PM | New York: | NPCC | Actual Physical Attack | Actual Physical Event | Unknown | 40000 | Physical Attack |
| August | 2016-08-23 | 5:00 PM | 8/24/2016 | 12:05 AM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 72200 | Weather |
| August | 2016-08-24 | 7:18 PM | 8/24/2016 | 7:47 PM | Washington: King County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 9232 | Unknown | Islanding |
| August | 2016-08-24 | 6:13 PM | 8/24/2016 | 7:14 PM | Puerto Rico: | PR | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | System Operations | 600 | 400000 | Operations |
| August | 2016-08-25 | 6:40 PM | 8/26/2016 | 6:19 PM | Oregon: Crook County; | WECC | Suspected Physical Attack | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2016-08-31 | 2:52 PM | Unknown | Unknown | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 0 | 0 | Islanding |
| August | 2016-08-31 | 9:45 AM | 8/31/2016 | 9:55 AM | Colorado: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| September | 2016-09-01 | 10:00 PM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 100 | Unknown | Weather |
| September | 2016-09-02 | 12:40 AM | 9/4/2016 | 8:00 PM | Florida: Leon County, Wakulla County; | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 450 | 75000 | Weather |
| September | 2016-09-02 | 4:00 AM | 9/2/2016 | 4:00 PM | Florida: Alachua County, Bay County, Citrus County, Columbia County, Dixie County, Franklin County, Gilchrist County, Gulf County, Hamilton County, Hardee County, Hernando County, Highlands County, Jefferson County, Lafayette County, Lake County, Levy County, Madison County, Marion County, Orange County, Osceola County, Pasco County, Pinellas County, Polk County, Seminole County, Sumter County, Suwannee County, Taylor County, Volusia County, Wakulla County; | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 225 | 90000 | Weather |
| September | 2016-09-02 | 5:45 AM | 9/3/2016 | 12:30 AM | Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2016-09-06 | 6:12 PM | 9/6/2016 | 9:24 PM | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 300 | Unknown | Islanding |
| September | 2016-09-08 | 8:30 AM | 9/25/2016 | 12:00 AM | New York: Tompkins County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 210 | Unknown | Fuel Supply Deficiency |
| September | 2016-09-08 | 2:49 PM | 9/8/2016 | 3:03 PM | Washington: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 0 | 0 | Islanding |
| September | 2016-09-10 | 9:42 AM | 9/10/2016 | 9:57 AM | Washington: Clark County; | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Generation Inadequacy | 135 | Unknown | Generation Interruption |
| September | 2016-09-11 | 12:05 PM | 9/11/2016 | 3:10 PM | Connecticut: Massachusetts: New Hampshire: Rhode Island: Vermont: Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 57960 | Weather |
| September | 2016-09-12 | 12:30 PM | 9/12/2016 | 5:56 PM | New Mexico: Bernalillo County, Sandoval County, Santa Fe County, Valencia County; | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Generation Inadequacy | 110 | 53753 | Generation Interruption |
| September | 2016-09-21 | 2:30 PM | 9/24/2016 | 2:30 AM | Puerto Rico: | | Complete operational failure or shut-down of the transmission and/or distribution electrical system | System Operations | 2750 | 1475000 | Operations |
| September | 2016-09-21 | 7:44 PM | 9/21/2016 | 9:17 PM | Texas: Lubbock County; | TRE | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Event | 0 | 0 | Physical Attack |
| September | 2016-09-22 | 10:56 AM | 9/22/2016 | 11:41 AM | Iowa: Black Hawk County; | MRO | Complete operational failure or shut-down of the transmission and/or distribution electrical system | System Operations | 69 | 19124 | Operations |
| September | 2016-09-25 | 12:49 PM | 9/25/2016 | 6:20 PM | Utah: Kane County, Garfield County; Arizona: Coconino County, Mohave County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 20 | 10000 | Physical Attack |
| October | 2016-10-01 | 12:24 PM | 10/02/2016 | 2:04 AM | California: Mendocino County; | WECC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Actual Physical Event | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2016-10-02 | 11:30 PM | 10/05/2016 | 8:00 AM | Utah: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Transmission Interruption | 50 | 4000 | Transmission Interruption |
| October | 2016-10-03 | 3:09 PM | 10/04/2016 | 7:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Public Appeal | Unknown | Unknown | Public Appeal |
| October | 2016-10-05 | 3:51 PM | Unknown | Unknown | California: Imperial County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2016-10-05 | 11:32 AM | 10/05/2016 | 7:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Public Appeal | Unknown | Unknown | Public Appeal |
| October | 2016-10-06 | 9:50 AM | 10/06/2016 | 7:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Public Appeal | Unknown | Unknown | Public Appeal |
| October | 2016-10-06 | 7:30 PM | 10/8/2016 | 6:00 PM | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 5600 | 1200000 | Weather |
| October | 2016-10-07 | 11:08 AM | 10/07/2016 | 7:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Generation Inadequacy | Unknown | Unknown | Generation Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2016-10-07 | 8:00 AM | 10/09/2016 | 1:00 PM | Florida: Alachua County, Bay County, Citrus County, Columbia County, Dixie County, Franklin County, Gilchrist County, Gulf County, Hamilton County, Hardee County, Hernando County, Highlands County, Jefferson County, Lafayette County, Lake County, Levy County, Madison County, Marion County, Orange County, Osceola County, Pasco County, Pinellas County, Polk County, Seminole County, Sumter County, Suwannee County, Taylor County, Volusia County, Wakulla County; | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 413 | 165000 | Weather |
| October | 2016-10-07 | 4:22 PM | 10/12/2016 | 11:00 AM | Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 122 | 36384 | Weather |
| October | 2016-10-07 | 10:45 PM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2016-10-07 | 11:00 PM | Unknown | Unknown | South Carolina: Allendale County, Bamberg County, Beaufort County, Berkeley County, Charleston County, Chesterfield County, Clarendon County, Colleton County, Darlington County, Dorchester County, Florence County, Georgetown County, Hampton County, Horry County, Jasper County, Kershaw County, Lee County, Marion County, Marlboro County, Orangeburg County, Richland County, Sumter County, Williamsburg County; | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | Unknown | Weather |
| October | 2016-10-08 | 1:10 AM | Unknown | Unknown | South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 1050 | 290824 | Weather |
| October | 2016-10-08 | 8:21 AM | 10/13/2016 | 5:30 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | Unknown | Weather |
| October | 2016-10-08 | 2:05 PM | 10/09/2016 | 6:06 AM | North Carolina: | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Severe Weather | Unknown | 44875 | Weather |
| October | 2016-10-10 | 1:15 PM | 10/10/2016 | 7:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Generation Inadequacy | Unknown | Unknown | Generation Interruption |
| October | 2016-10-12 | 12:09 PM | 10/12/2016 | 1:16 PM | Nevada: Clark County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 4 | 1671 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2016-10-18 | 2:06 PM | 10/21/2016 | 3:00 PM | Oregon: Deschutes County, Lake County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2016-10-20 | 12:30 PM | 10/20/2016 | 12:31 PM | Oregon: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2016-10-25 | 7:40 AM | 10/27/2016 | 7:40 AM | Tennessee: Shelby County; | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2016-10-26 | 5:26 AM | 10/26/2016 | 5:27 AM | Wyoming: Sweetwater County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2016-10-28 | 1:29 PM | 10/28/2016 | 1:38 PM | California: Plumas County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Islanding | 4 | 482 | Islanding |
| October | 2016-10-31 | 8:06 AM | 10/31/2016 | 3:53 PM | North Carolina: Stokes County; | SERC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Actual Physical Event | 0 | 0 | Physical Attack |
| November | 2016-11-01 | 8:55 PM | Unknown | Unknown | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| November | 2016-11-09 | 11:59 AM | 11/09/2016 | 6:15 PM | California: Stanislaus County, San Joaquin County, Alameda County, Tuolumne County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability | Cyber Attack | 0 | 0 | Cyber Attack |
| November | 2016-11-09 | 6:44 AM | 11/09/2016 | 7:44 AM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2016-12-08 | 1:00 AM | 12/08/2016 | 2:30 AM | Oregon: Multnomah County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2016-12-11 | 7:45 AM | 12/11/2016 | 7:46 AM | Utah: Utah County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2016-12-13 | 2:09 PM | 12/13/2016 | 2:30 PM | California: Riverside County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability | Cyber Event | 0 | 0 | Cyber Attack |
| December | 2016-12-15 | 6:30 AM | Unknown | Unknown | California: Merced County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | Unknown | Unknown | Fuel Supply Deficiency |
| December | 2016-12-16 | 7:45 AM | 12/16/2016 | 8:45 AM | Oregon: Multnomah County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2016-12-26 | 4:00 AM | 12/26/2016 | 6:00 AM | Washington: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2016-12-28 | 4:03 AM | 12/31/2016 | 6:00 AM | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| December | 2016-12-30 | 8:55 AM | 12/30/2016 | 8:56 AM | Vermont: Chittenden County; | NPCC | Cyber event that could potentially impact electric power system adequacy or reliability | Other | 0 | 0 | Cyber Attack |
| December | 2016-12-30 | 2:30 AM | 12/30/2016 | 7:00 PM | Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Weather or Natural Disaster | Unknown | 85263 | Weather |
| January | 2017-01-05 | 4:56 PM | 01/05/2017 | 4:57 PM | Florida: Martin County; | FRCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspected Physical Attack | 0 | 0 | Physical Attack |
| January | 2017-01-08 | 11:59 PM | Unknown | Unknown | California | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| January | 2017-01-08 | 9:07 AM | 01/13/2017 | 2:30 PM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 106000 | Weather |
| January | 2017-01-10 | 7:30 PM | 01/13/2017 | 2:30 PM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 87000 | Weather |
| January | 2017-01-15 | 6:35 AM | 01/15/2017 | 7:44 AM | California: Los Angeles County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Transmission Disruption | 176 | 126000 | Transmission Interruption |
| January | 2017-01-15 | 9:27 AM | 01/17/2017 | 1:58 AM | Oklahoma: Harper County; | SPP | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | 1 | 788 | Weather |
| January | 2017-01-18 | 6:05 PM | 01/19/2017 | 12:05 AM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 75000 | Weather |
| January | 2017-01-22 | 6:00 AM | Unknown | Unknown | California | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2017-01-22 | 4:15 AM | 01/24/2017 | 2:00 PM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 97 | 64000 | Weather |
| January | 2017-01-22 | 4:00 PM | 01/23/2017 | 3:26 AM | Alabama: Georgia: Mississippi: Florida: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 100 | 29965 | Weather |
| February | 2017-02-02 | 1:04 AM | 2/2/2017 | 5:00 AM | New Mexico: Bernalillo County, Santa Fe County; | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Transmission Interruption | 396 | 149223 | Transmission Interruption |
| February | 2017-02-02 | 1:11 AM | Unknown | Unknown | New Mexico: Bernalillo County; | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Transmission Interruption | 400 | Unknown | Transmission Interruption |
| February | 2017-02-06 | 1:00 AM | 2/6/2017 | 7:30 PM | Washington: Skagit County, King County, Kitsap County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 103000 | Weather |
| February | 2017-02-09 | 4:05 PM | 2/10/2017 | 5:15 AM | Connecticut: Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 11525 | Weather |
| February | 2017-02-11 | 3:46 PM | 2/11/2017 | 3:50 PM | Utah | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | 0 | 0 | Physical Attack |
| February | 2017-02-13 | 1:00 PM | 2/15/2017 | 1:35 PM | North Carolina: Union County; | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| February | 2017-02-17 | 4:32 AM | 2/17/2017 | 5:02 AM | Missouri: Arkansas: Oklahoma: Texas: | SPP | Cyber event that could potentially impact electric power system adequacy or reliability | System Operations | 0 | 0 | Cyber Attack |
| February | 2017-02-17 | 1:00 PM | 2/17/2017 | 1:15 PM | Nevada: Clark County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| February | 2017-02-17 | 8:09 AM | 2/22/2017 | 7:30 PM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 254 | 169250 | Weather |
| February | 2017-02-17 | 3:00 PM | 2/20/2017 | 11:00 AM | California: Los Angeles County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 111591 | Weather |
| March | 2017-03-01 | 8:30 AM | 03/01/2017 | 2:00 PM | Tennessee: Kentucky: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 58000 | Weather |
| March | 2017-03-01 | 11:49 AM | 03/02/2017 | 9:30 PM | Kentucky: West Virginia: | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 98575 | Weather |
| March | 2017-03-02 | 12:20 PM | 03/02/2017 | 11:45 PM | Connecticut: Maine: Massachusetts: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 54316 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2017-03-06 | 8:00 PM | 03/07/2017 | 1:00 AM | Missouri: Jackson County, Platte County, Cass County, Lafayette County, Chariton County, Carroll County, Clay County, Johnson County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 97734 | Weather |
| March | 2017-03-08 | 9:30 AM | 03/11/2017 | 5:00 AM | Michigan: Jackson County, Calhoun County, Ingham County, Hillsdale County, Washtenaw County, Kent County, Ottawa County, Midland County, Saginaw County; | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 343000 | Weather |
| March | 2017-03-08 | 11:30 AM | 03/08/2017 | 7:52 PM | Ohio | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 71012 | Weather |
| March | 2017-03-08 | 12:00 PM | 03/11/2017 | 11:31 AM | Michigan | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 800000 | Weather |
| March | 2017-03-08 | 1:30 PM | 03/08/2017 | 4:30 PM | New York | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather/Transmission Interruption | Unknown | 106869 | Weather |
| March | 2017-03-08 | 3:33 PM | Unknown | Unknown | New York | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 50000 | Weather |
| March | 2017-03-12 | 9:56 AM | 03/12/2017 | 11:20 AM | California: Imperial County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 1 | Physical Attack |
| March | 2017-03-14 | 12:32 PM | Unknown | Unknown | Connecticut: Massachusetts: Rhode Island: New Hampshire: Maine: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 69647 | Weather |
| March | 2017-03-21 | 8:00 PM | 03/22/2017 | 9:15 AM | Georgia | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 857 | 257000 | Weather |
| March | 2017-03-24 | 6:29 AM | 03/24/2017 | 7:13 AM | Oregon: Clatsop County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Sabotage | 0 | 0 | Physical Attack |
| March | 2017-03-28 | 4:07 PM | 03/28/2017 | 4:08 PM | Oregon: Josephine County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | 0 | 0 | Physical Attack |
| March | 2017-03-29 | 3:30 AM | 03/31/2017 | 6:00 AM | Texas | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 175000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2017-03-31 | 7:15 PM | 03/31/2017 | 9:07 PM | Mississippi: DeSoto County; | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2017-04-03 | 11:00 AM | 04/03/2017 | 8:00 PM | Alabama, Georgia | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 290 | 86330 | Weather |
| April | 2017-04-06 | 7:00 PM | Unknown | Unknown | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 100000 | Weather |
| April | 2017-04-07 | 4:16 AM | Unknown | Unknown | California: Fresno County | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| April | 2017-04-07 | 4:33 AM | 04/07/2017 | 8:20 AM | Oregon | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 100 | 64852 | Weather |
| April | 2017-04-07 | 8:15 AM | 04/08/2017 | 12:14 AM | Oregon: Multnomah County, Washington County, Marion County, Clackamas County | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 153867 | Weather |
| April | 2017-04-13 | 7:50 AM | 04/13/2017 | 8:07 AM | Washington: Pierce County | WECC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Sabotage | 53 | 10000 | Physical Attack |
| April | 2017-04-17 | 9:25 AM | 04/17/2017 | 9:26 AM | Utah: Emery County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Sabotage | 0 | 0 | Physical Attack |
| April | 2017-04-20 | 4:00 PM | 04/20/2017 | 6:00 PM | Wyoming: Converse County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2017-04-21 | 9:06 AM | 04/21/2017 | 5:45 PM | California: San Francisco, City and County of[10] | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | System Operations | 130 | 88000 | Operations |
| April | 2017-04-21 | 10:34 AM | 04/21/2017 | 3:55 PM | Kentucky: Bullitt County | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2017-04-23 | 11:55 PM | 04/23/2017 | 11:56 PM | Oregon: Multnomah County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2017-04-24 | 5:32 AM | 04/24/2017 | 6:33 AM | North Carolina: Mecklenburg County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 240 | 74698 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2017-04-30 | 1:00 AM | 04/30/2017 | 5:45 PM | Arkansas, Louisiana, Mississippi | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 145174 | Weather |
| May | 2017-05-01 | 11:14 PM | 05/01/2017 | 11:34 PM | Ohio | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 92390 | Weather |
| May | 2017-05-03 | 6:58 PM | 05/03/2017 | 9:15 PM | California | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Generation Inadequacy | 572 | 0 | Generation Interruption |
| May | 2017-05-03 | 7:05 PM | 05/03/2017 | 9:00 PM | California | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Generation Inadequacy | 878 | Unknown | Generation Interruption |
| May | 2017-05-03 | 11:00 PM | Unknown | Unknown | Pennsylvania: Philadelphia County, Montgomery County | RFC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| May | 2017-05-04 | 5:00 AM | 05/04/2017 | 10:00 PM | Alabama: Georgia | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 200 | 60377 | Weather |
| May | 2017-05-07 | 5:15 AM | Unknown | Unknown | California: Fresno County | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| May | 2017-05-07 | 11:30 PM | 05/08/2017 | 5:00 AM | Kentucky: Daviess County | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Generation Inadequacy | 80 | 0 | Generation Interruption |
| May | 2017-05-11 | 11:05 AM | 05/11/2017 | 1:05 PM | Washington: Yakima County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| May | 2017-05-19 | 5:30 AM | Unknown | Unknown | Missouri: St. Louis County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 70696 | Weather |
| May | 2017-05-21 | 4:44 PM | 05/21/2017 | 5:43 PM | Idaho: Lincoln County, Jerome County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 21 | 9598 | Physical Attack |
| May | 2017-05-23 | 5:02 AM | 05/23/2017 | 8:40 AM | Tennessee: Davidson County | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 10 | 4700 | Physical Attack |
| May | 2017-05-27 | 11:00 PM | Unknown | Unknown | Tennessee: Shelby County, Putnam County, Knox County, Davidson County, Hamilton County; Alabama: Madison County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 116000 | Weather |
| May | 2017-05-27 | 11:10 PM | Unknown | Unknown | Tennessee: Shelby County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 391 | 188000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | 2017-05-28 | 4:27 PM | 05/28/2017 | 4:28 PM | Nevada: Clark County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| May | 2017-05-28 | 7:30 PM | 05/29/2017 | 10:00 PM | Louisiana: Texas | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 103000 | Weather |
| May | 2017-05-28 | 7:30 PM | 05/29/2017 | 10:00 PM | Texas: Louisiana | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 103000 | Weather |
| June | 2017-06-07 | 1:12 PM | 06/07/2017 | 1:13 PM | Washington: Yakima County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| June | 2017-06-11 | 2:39 PM | 06/11/2017 | 5:55 PM | Michigan | RFC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 63 | Unknown | Transmission Interruption |
| June | 2017-06-11 | 7:00 AM | 06/11/2017 | 11:22 AM | Minnesota | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 70000 | Weather |
| June | 2017-06-11 | 1:25 PM | 06/11/2017 | 7:15 PM | Wisconsin | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 53610 | Weather |
| June | 2017-06-15 | 5:00 PM | 06/15/2017 | 10:00 PM | Alabama, Georgia | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 275 | 82713 | Weather |
| June | 2017-06-16 | 8:00 PM | 06/17/2017 | 6:00 AM | Arkansas | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 76000 | Weather |
| June | 2017-06-16 | 8:00 PM | Unknown | Unknown | Nebraska: Cass County, Douglas County, Sarpy County | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 76000 | Weather |
| June | 2017-06-17 | 9:00 PM | 06/18/2017 | 7:00 AM | Kansas, Missouri: Jackson County, Platte County, Clay County, Cass County | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 84737 | Weather |
| June | 2017-06-21 | 12:00 AM | 06/21/2017 | 1:00 AM | Oregon: Baker County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Physical Attack | 0 | 0 | Physical Attack |
| June | 2017-06-22 | 6:00 PM | 06/25/2017 | 12:45 PM | Michigan: Wayne County, Monroe County | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 118631 | Weather |
| June | 2017-06-29 | 4:00 AM | Unknown | Unknown | Louisiana: Orleans Parish | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 130 | 6467 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2017-06-30 | 7:45 AM | 06/30/2017 | 7:46 AM | Idaho: Ada County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| July | 2017-07-06 | 12:00 AM | Unknown | Unknown | Idaho: Jerome County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| July | 2017-07-07 | 3:30 AM | 07/08/2017 | 7:30 PM | Michigan: Kent County, Ottawa County, Muskegon County, Barry County, Oceana County, Eaton County | RFC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 160000 | Weather |
| July | 2017-07-08 | 6:52 PM | 07/09/2017 | 8:00 AM | California: Los Angeles County | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Transmission Interruption | 645 | 176867 | Transmission Interruption |
| July | 2017-07-11 | 10:00 AM | 07/11/2017 | 12:00 PM | Minnesota | MRO | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| July | 2017-07-12 | 12:25 PM | 07/15/2017 | 9:00 AM | Tennessee | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| July | 2017-07-12 | 12:25 PM | Unknown | Unknown | Tennessee: Shelby County | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | Unknown | Unknown | Physical Attack |
| July | 2017-07-18 | 4:03 AM | Unknown | Unknown | Missouri | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | Unknown | 700 | Physical Attack |
| July | 2017-07-18 | 4:23 PM | 07/18/2017 | 6:39 PM | Nevada | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Severe Weather | 0 | 0 | Weather |
| July | 2017-07-20 | 1:00 AM | 07/20/2017 | 9:46 AM | Utah: Beaver County | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2017-07-22 | 10:00 PM | 07/23/2017 | 12:00 PM | Missouri: Clay County, Jackson County, Lafayette County, Platte County; Kansas: Johnson County, Miami County, Wyandotte County | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 112540 | Weather |
| July | 2017-07-22 | 10:00 PM | Unknown | Unknown | Missouri | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 131000 | Weather |
| July | 2017-07-22 | 10:00 PM | Unknown | Unknown | Missouri | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 115000 | Weather |
| July | 2017-07-23 | 4:00 AM | Unknown | Unknown | Missouri: Illinois | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 82000 | Weather |
| July | 2017-07-27 | 6:00 AM | 07/27/2017 | 11:29 AM | California: Butte County | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| August | 2017-08-05 | 1:20 PM | 08/05/2017 | 2:20 PM | California: Humboldt County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| August | 2017-08-21 | 11:41 PM | 08/22/2017 | 12:21 AM | California: Plumas County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | System Operations | 1 | 2 | Islanding |
| August | 2017-08-25 | 6:17 PM | 09/02/2017 | 5:00 PM | Texas: Matagorda County, Nueces County, Aransas County, Refugio County, San Patricio County, Calhoun County, Victoria County, Jackson County, Live Oak County, Jim Wells County, Bee County, Lavaca County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 220400 | Weather |
| August | 2017-08-25 | 6:30 PM | 09/05/2017 | 5:00 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 330000 | Weather |
| August | 2017-08-26 | 12:39 AM | 08/26/2017 | 12:52 AM | Texas: | TRE | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | Unknown | Unknown | Weather |
| August | 2017-08-26 | 6:26 AM | 09/08/2017 | 12:00 AM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 1076868 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2017-08-27 | 5:10 AM | 09/08/2017 | 12:00 AM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 1076868 | Weather |
| August | 2017-08-30 | 2:15 AM | Unknown | Unknown | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 78500 | Weather |
| August | 2017-08-31 | 2:49 PM | 08/31/2017 | 5:14 PM | California: Los Angeles County; | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Severe Weather | 100 | 0 | Weather |
| September | 2017-09-01 | 3:41 PM | 09/01/2017 | 8:30 PM | California: | WECC | Load shedding of 100 Megawatts or more implemented under emergency operational policy | Severe Weather | 337 | 0 | Weather |
| September | 2017-09-09 | 12:00 AM | Unknown | Unknown | Florida: Hillsborough County, Pasco County, Polk County; | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 1275 | 425000 | Weather |
| September | 2017-09-09 | 12:30 PM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 3500000 | Weather |
| September | 2017-09-10 | 6:35 PM | 09/13/2017 | 5:00 PM | Florida: Alachua County, Bay County, Brevard County, Citrus County, Columbia County, Dixie County, Flagler County, Franklin County, Gilchrist County, Gulf County, Hamilton County, Hardee County, Hernando County, Highlands County, Jefferson County, Lafayette County, Lake County, Leon County, Levy County, Madison County, Marion County, Orange County, Osceola County, Pasco County, Pinellas County, Polk County, Seminole County, Sumter County, Suwannee County, Taylor County, Volusia County, Wakulla County; | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 4500 | 1000000 | Weather |
| September | 2017-09-10 | 8:37 PM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 452555 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2017-09-11 | 12:30 AM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 200 | 20000 | Weather |
| September | 2017-09-11 | 2:27 AM | 09/15/2017 | 8:44 PM | Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 132 | 39659 | Weather |
| September | 2017-09-11 | 12:55 PM | 09/12/2017 | 8:00 AM | South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 687 | 154832 | Weather |
| September | 2017-09-11 | 5:30 PM | 09/13/2017 | 9:30 AM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 365 | 265729 | Weather |
| October | 2017-10-04 | 1:20 AM | 10/04/2017 | 3:00 AM | Mississippi: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | Unknown | Unknown | Physical Attack |
| October | 2017-10-04 | 2:30 AM | Unknown | Unknown | Tennessee: Shelby County; | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2017-10-08 | 3:00 AM | Unknown | Unknown | Alabama: Florida: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 306 | 91945 | Weather |
| October | 2017-10-09 | 2:03 AM | 10/17/2017 | 1:30 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather/Transmission Interruption | 177 | 117900 | Weather |
| October | 2017-10-09 | 6:44 AM | Unknown | Unknown | California: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | 100 | Unknown | Weather |
| October | 2017-10-12 | 9:09 AM | Unknown | Unknown | Mississippi: Coahoma County; | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | Unknown | Unknown | Public Appeal |
| October | 2017-10-16 | 3:45 PM | 10/16/2017 | 4:09 PM | Washington: Montana: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2017-10-16 | 3:55 PM | 10/16/2017 | 4:10 PM | Washington: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2017-10-19 | 4:01 PM | 10/19/2017 | 4:02 PM | Utah: Salt Lake County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspected Physical Attack | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2017-10-20 | 6:30 PM | 10/20/2017 | 10:22 PM | Texas: | TRE | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2017-10-20 | 3:44 AM | 10/20/2017 | 3:45 AM | Washington: | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Severe Weather | 900 | Unknown | Weather |
| October | 2017-10-22 | 8:45 AM | 10/22/2017 | 2:00 PM | Louisiana: Mississippi: Arkansas: Texas: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | Unknown | Weather |
| October | 2017-10-23 | 5:50 PM | 10/24/2017 | 6:17 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 440 | 115144 | Weather |
| October | 2017-10-25 | 12:00 PM | 10/25/2017 | 4:00 PM | California: | WECC | Cyber event that could potentially impact electric power system adequacy or reliability | Suspicious Activity | Unknown | Unknown | Cyber Attack |
| October | 2017-10-26 | 5:50 PM | Unknown | Unknown | Montana: Big Horn County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | 0 | 0 | Physical Attack |
| October | 2017-10-26 | 8:17 AM | 10/26/2017 | 8:41 AM | Washington: Whatcom County; Montana: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2017-10-26 | 8:17 AM | 10/26/2017 | 8:41 AM | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2017-10-29 | 11:40 PM | 11/01/2017 | 6:08 PM | Connecticut: Massachusetts: New Hampshire: Maine: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 310453 | Weather |
| November | 2017-11-01 | 3:40 PM | 11/01/2017 | 10:00 PM | Kentucky: Daviess County; | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Generation Inadequacy | 0 | 0 | Generation Interruption |
| November | 2017-11-05 | 7:35 PM | 11/05/2017 | 11:09 PM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 89216 | Weather |
| November | 2017-11-07 | 12:29 PM | Unknown | Unknown | Louisiana: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | 0 | 0 | Physical Attack |
| November | 2017-11-09 | 8:45 AM | 11/09/2017 | 2:00 PM | Colorado: Weld County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability | System Operations | 0 | 0 | Cyber Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2017-11-13 | 2:00 AM | 11/15/2017 | 8:17 AM | Washington: Island County, King County, Kitsap County, Thurston County, Skagit County, Whatcom County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 236100 | Weather |
| November | 2017-11-13 | 4:33 PM | 11/16/2017 | 6:00 AM | Washington: King County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 85 | 68430 | Weather |
| November | 2017-11-16 | 3:05 PM | 11/16/2017 | 3:06 PM | Oregon: Tillamook County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| November | 2017-11-24 | 5:06 PM | 11/26/2017 | 5:22 PM | Nevada: Clark County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2017-12-04 | 9:53 PM | Unknown | Unknown | California: | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Severe Weather/Transmission Interruption | 540 | 263000 | Weather |
| December | 2017-12-05 | 6:50 AM | 12/05/2017 | 9:00 AM | Louisiana: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2017-12-05 | 6:30 AM | 12/06/2017 | 10:00 AM | Michigan: Oscoda County, Isabella County, Roscommon County, Ogemaw County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 117500 | Weather |
| December | 2017-12-07 | 8:00 PM | 12/08/2017 | 5:00 PM | Texas: Bexar County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 88000 | Weather |
| December | 2017-12-08 | 9:30 AM | 12/08/2017 | 10:30 PM | Louisiana: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 79000 | Weather |
| December | 2017-12-08 | 10:00 AM | 12/10/2017 | 8:50 PM | Alabama: Georgia: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 865 | 301872 | Weather |
| December | 2017-12-10 | 1:25 AM | 12/10/2017 | 2:30 AM | California: Ventura County, Santa Barbara County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather/Transmission Interruption | 110 | 51323 | Weather |
| December | 2017-12-12 | 2:22 AM | 12/12/2017 | 2:25 AM | New York: Saratoga County; | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | 3 | 1208 | Physical Attack |
| December | 2017-12-13 | 9:55 AM | 12/13/2017 | 2:45 PM | New York: Suffolk County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2017-12-13 | 8:50 AM | Unknown | Unknown | Connecticut: New Haven County[13]; | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | 0 | 0 | Physical Attack |
| December | 2017-12-18 | 1:00 PM | 12/18/2017 | 5:00 PM | Mississippi: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2017-12-19 | 8:40 AM | 12/19/2017 | 10:36 AM | Florida: Alachua County; | FRCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| December | 2017-12-29 | 7:00 AM | Unknown | Unknown | New York: Tompkins County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 210 | Unknown | Fuel Supply Deficiency |
| December | 2017-12-29 | 6:15 AM | 12/29/2017 | 11:44 AM | Texas: Calhoun County; | TRE | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | Unknown | Unknown | Physical Attack |
| December | 2017-12-31 | 11:54 PM | 01/01/2018 | 2:14 PM | Colorado: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| January | 2018-01-01 | 9:37 PM | 01/02/2018 | 10:30 AM | Tennessee: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | Unknown | Unknown | Public Appeal |
| January | 2018-01-01 | 5:43 PM | Unknown | Unknown | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | Unknown | Unknown | Weather |
| January | 2018-01-01 | 6:21 PM | 01/02/2018 | 6:11 PM | Tennessee: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | Unknown | Unknown | Weather |
| January | 2018-01-02 | 10:00 AM | 02/12/2018 | 8:00 AM | New York: Niagara County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 675 | Unknown | Fuel Supply Deficiency |
| January | 2018-01-02 | 6:45 AM | 01/02/2018 | 9:00 AM | North Carolina: South Carolina: | SERC | System-wide voltage reductions of 3 percent or more | Severe Weather | 14998 | Unknown | Weather |
| January | 2018-01-02 | 7:30 AM | Unknown | Unknown | South Carolina: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | 0 | 717000 | Weather |
| January | 2018-01-04 | 1:49 AM | 01/04/2018 | 2:09 AM | Texas: Midland County; | TRE | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | Unknown | 500 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2018-01-12 | 1:08 PM | 01/12/2018 | 2:53 PM | Michigan: Midland County, Genesee County; | RF | Cyber event that causes interruptions of electrical system operations | System Operations | 41 | 23007 | Cyber Attack |
| January | 2018-01-15 | 4:20 AM | 01/18/2018 | 5:48 AM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | Unknown | Unknown | Weather |
| January | 2018-01-16 | 3:00 PM | 01/18/2018 | 1:00 PM | Tennessee: Shelby County; | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | Unknown | Unknown | Public Appeal |
| January | 2018-01-16 | 1:57 PM | 01/16/2018 | 2:32 PM | Texas: | TRE | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | Unknown | Unknown | Weather |
| January | 2018-01-16 | 3:00 PM | 01/18/2018 | 1:00 PM | Tennessee: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | Unknown | Unknown | Weather |
| January | 2018-01-17 | 5:10 AM | 01/17/2018 | 1:00 PM | Mississippi: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | 1788 | 420000 | Public Appeal |
| January | 2018-01-17 | 6:10 AM | 01/17/2018 | 2:00 PM | Louisiana: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | Unknown | Unknown | Public Appeal |
| January | 2018-01-18 | 5:00 AM | 01/18/2018 | 9:45 AM | Mississippi: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | 1760 | 420000 | Public Appeal |
| January | 2018-01-18 | 6:00 AM | Unknown | Unknown | Louisiana: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | System Operations | Unknown | Unknown | Public Appeal |
| January | 2018-01-18 | 5:00 AM | 01/18/2018 | 11:00 AM | Arkansas: Mississippi: Louisiana: Texas: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | 31500 | Unknown | Weather |
| January | 2018-01-25 | 8:19 PM | 01/26/2018 | 2:00 AM | Pennsylvania: Montgomery County; | RF | Cyber event that could potentially impact electric power system adequacy or reliability | Suspicious Activity | Unknown | Unknown | Cyber Attack |
| February | 2018-02-04 | 1:42 PM | 02/04/2018 | 3:25 PM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 9760 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2018-02-08 | 1:25 PM | 02/08/2018 | 1:31 PM | California: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | System Operations | 30 | 10900 | Islanding |
| February | 2018-02-17 | 4:33 PM | 02/18/2018 | 12:00 AM | Oregon: Washington: California: | WECC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Vandalism | 2330 | 0 | Physical Attack |
| February | 2018-02-17 | 5:56 PM | 02/18/2018 | 4:11 AM | Oregon: Washington: California: | WECC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Vandalism | 2327 | 0 | Physical Attack |
| February | 2018-02-28 | 12:08 PM | 03/01/2018 | 3:45 PM | Florida: | FRCC | Cyber event that could potentially impact electric power system adequacy or reliability | System Operations | 0 | 0 | Cyber Attack |
| February | 2018-02-28 | 12:08 PM | 03/01/2018 | 3:45 PM | Florida: | FRCC | Cyber event that could potentially impact electric power system adequacy or reliability | System Operations | 0 | 0 | Cyber Attack |
| March | 2018-03-01 | 11:43 AM | 03/01/2018 | 11:56 AM | California: | WECC | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | 38 | 10898 | Weather |
| March | 2018-03-01 | 9:57 PM | 03/02/2018 | 10:14 AM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 86501 | Weather |
| March | 2018-03-01 | 10:20 PM | 03/04/2018 | 8:00 PM | Michigan: Wayne County, Washtenaw County, Oakland County, Macomb County, Monroe County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 95000 | Weather |
| March | 2018-03-02 | 11:17 PM | 03/03/2018 | 12:51 AM | Washington: Clark County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| March | 2018-03-02 | 7:00 AM | Unknown | Unknown | New York: Dutchess County, Orange County, Greene County, Ulster County, Putnam County, Sullivan County, Albany County, Columbia County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 90000 | Weather |
| March | 2018-03-02 | 8:00 AM | 03/03/2018 | 11:00 PM | Virginia: West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 65198 | Weather |
| March | 2018-03-02 | 8:42 AM | Unknown | Unknown | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 63331 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2018-03-02 | 11:34 AM | Unknown | Unknown | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 50000 | Weather |
| March | 2018-03-02 | 11:58 AM | Unknown | Unknown | Pennsylvania: Berks County, Bucks County, Carbon County, Chester County, Clinton County, Columbia County, Cumberland County, Dauphin County, Juniata County, Lackawanna County, Lancaster County, Lebanon County, Lehigh County, Luzerne County, Lycoming County, Monroe County, Montgomery County, Montour County, Northampton County, Northumberland County, Pike County, Schuylkill County, Snyder County; | RF | Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system | Severe Weather | Unknown | 126000 | Weather |
| March | 2018-03-02 | 12:00 PM | 03/05/2018 | 12:00 AM | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 630000 | Weather |
| March | 2018-03-02 | 12:00 PM | Unknown | Unknown | Maryland: | RF | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system | Severe Weather | 670 | 474019 | Weather |
| March | 2018-03-02 | 1:51 PM | 03/05/2018 | 1:18 PM | Connecticut: Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 325000 | Weather |
| March | 2018-03-02 | 1:51 PM | 03/04/2018 | 12:11 PM | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 233136 | Weather |
| March | 2018-03-02 | 3:10 PM | 03/06/2018 | 4:57 AM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 249322 | Weather |
| March | 2018-03-02 | 3:46 PM | 03/04/2018 | 7:46 PM | New York: New York County, Westchester County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 72353 | Weather |
| March | 2018-03-02 | 5:00 PM | 03/06/2018 | 11:00 AM | Delaware: Maryland: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 60000 | Weather |
| March | 2018-03-07 | 12:00 PM | 03/07/2018 | 5:00 PM | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 120000 | Weather |
| March | 2018-03-07 | 4:10 PM | 03/10/2018 | 11:32 AM | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 216800 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2018-03-07 | 5:15 PM | Unknown | Unknown | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 50 | 58000 | Weather |
| March | 2018-03-07 | 7:37 PM | 03/10/2018 | 4:35 PM | Connecticut: Massachusetts: Maine: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 102000 | Weather |
| March | 2018-03-12 | 12:00 AM | 04/06/2018 | 11:00 AM | New York: Dutchess County; | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| March | 2018-03-13 | 12:10 AM | 03/13/2018 | 12:34 AM | Colorado: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | 0 | 0 | Physical Attack |
| March | 2018-03-13 | 8:50 AM | 03/14/2018 | 11:22 PM | Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 123629 | Weather |
| March | 2018-03-19 | 11:29 PM | 03/20/2018 | 3:37 AM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 261 | 78220 | Weather |
| March | 2018-03-20 | 7:00 PM | 03/25/2018 | 6:30 AM | New Jersey: Atlantic County, Camden County, Cape May County, Gloucester County, Salem County, Cumberland County, Burlington County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 80 | 124000 | Weather |
| March | 2018-03-24 | 10:30 PM | 03/26/2018 | 8:00 PM | Virginia: West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 81227 | Weather |
| March | 2018-03-26 | 3:05 AM | 03/26/2018 | 3:35 AM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| March | 2018-03-28 | 3:00 PM | 03/28/2018 | 4:00 PM | Washington: Walla Walla County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 12 | 1185 | Physical Attack |
| April | 2018-04-03 | 11:15 AM | 04/03/2018 | 11:30 AM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2018-04-04 | 4:42 PM | 04/07/2018 | 6:22 AM | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 72896 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2018-04-05 | 12:50 AM | 04/05/2018 | 4:00 PM | Connecticut: Maine: Massachusetts: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 65932 | Weather |
| April | 2018-04-09 | 10:07 AM | 04/09/2018 | 4:00 PM | Washington: Walla Walla County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| April | 2018-04-09 | 11:10 PM | 04/10/2018 | 6:47 AM | Florida: Palm Beach County; | FRCC | Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations | Sabotage | 55 | 27000 | Physical Attack |
| April | 2018-04-09 | 11:16 AM | Unknown | Unknown | Utah: | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Transmission Interruption | 300 | 250000 | Transmission Interruption |
| April | 2018-04-09 | 12:16 PM | 04/09/2018 | 1:52 PM | Utah: Salt Lake County; | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident | Transmission Interruption | 806 | 57000 | Transmission Interruption |
| April | 2018-04-14 | 9:30 AM | 04/14/2018 | 10:00 AM | Louisiana: Arkansas: Mississippi: Texas: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 56350 | Weather |
| April | 2018-04-15 | 7:30 AM | 04/18/2018 | 7:30 AM | Michigan: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 389591 | Weather |
| April | 2018-04-15 | 5:14 PM | 04/15/2018 | 11:25 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 78100 | Weather |
| May | 2018-05-02 | 2:52 PM | 05/02/2018 | 4:14 PM | North Carolina: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| May | 2018-05-04 | 12:00 PM | 05/06/2018 | 1:00 PM | Michigan: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 300000 | Weather |
| May | 2018-05-04 | 2:00 PM | 05/05/2018 | 9:30 AM | Michigan: Calhoun County, Genesee County, Ingham County, Kent County, Macomb County, Midland County, Saginaw County, Gratiot County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 90000 | Weather |
| May | 2018-05-04 | 8:10 PM | Unknown | Unknown | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 106150 | Weather |
| May | 2018-05-04 | 11:10 PM | 05/05/2018 | 12:40 AM | New Hampshire: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 56000 | Weather |
| May | 2018-05-05 | 4:30 AM | 05/05/2018 | 3:30 PM | Vermont: New Hampshire: Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 31900 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | 2018-05-07 | 10:30 AM | 05/07/2018 | 10:36 AM | New York: Tompkins County; | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspected Physical Attack | 0 | 0 | Physical Attack |
| May | 2018-05-08 | 4:00 PM | 05/08/2018 | 4:01 PM | Utah: Washington County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Actual Physical Attack | 0 | 0 | Physical Attack |
| May | 2018-05-14 | 7:08 PM | Unknown | Unknown | Virginia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 112000 | Weather |
| May | 2018-05-15 | 3:00 PM | 05/18/2018 | 1:48 PM | Massachusetts: | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| May | 2018-05-15 | 2:50 PM | Unknown | Unknown | Pennsylvania: Lehigh County, Schuylkill County, Cumberland County, Lancaster County, Northampton County, Berks County, Clinton County, Susquehanna County, Bucks County, Carbon County, Chester County, Columbia County, Juniata County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 114000 | Weather |
| May | 2018-05-15 | 4:00 PM | Unknown | Unknown | New York: Dutchess County, Ulster County, Orange County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 72000 | Weather |
| May | 2018-05-15 | 5:15 PM | Unknown | Unknown | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 49999 | Weather |
| May | 2018-05-15 | 5:25 PM | Unknown | Unknown | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 82372 | Weather |
| May | 2018-05-15 | 6:14 PM | 05/15/2018 | 7:00 PM | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 52872 | Weather |
| May | 2018-05-15 | 6:35 PM | 05/18/2018 | 3:57 PM | Connecticut: Massachusetts: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 120000 | Weather |
| May | 2018-05-17 | 1:11 AM | 05/18/2018 | 12:38 AM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Transmission Disruption | 124 | 70000 | Transmission Interruption |
| May | 2018-05-17 | 1:11 AM | Unknown | Unknown | California: Contra Costa County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 70 | 70000 | Weather |
| May | 2018-05-26 | 6:40 PM | 05/27/2018 | 11:50 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 163932 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2018-06-02 | 5:00 AM | 06/02/2018 | 11:00 AM | Missouri: Jackson County, Clay County, Platte County, Andrew County; Kansas: Johnson County; | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 103535 | Weather |
| June | 2018-06-04 | 8:50 AM | 06/04/2018 | 2:00 PM | Florida: Alachua County; | FRCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| June | 2018-06-09 | 9:54 AM | 06/09/2018 | 12:12 PM | Georgia: | SERC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more | System Operations | 0 | 0 | Operations |
| June | 2018-06-10 | 2:25 PM | 06/11/2018 | 5:58 AM | Kentucky: | SERC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more | System Operations | Unknown | Unknown | Operations |
| June | 2018-06-12 | 3:00 PM | 06/12/2018 | 3:15 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2018-06-12 | 4:15 PM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2018-06-18 | 6:20 PM | 06/19/2018 | 12:15 AM | Connecticut: Maine: Massachusetts: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 112927 | Weather |
| June | 2018-06-20 | 10:58 PM | 06/21/2018 | 6:05 AM | Florida: Palm Beach County; | FRCC | Complete operational failure or shut-down of the transmission and/or distribution of electrical system | Transmission Interruption | 73 | 27000 | Transmission Interruption |
| June | 2018-06-22 | 2:38 PM | Unknown | Unknown | Washington: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system | Severe Weather | 10000 | 4200000 | Weather |
| June | 2018-06-27 | 2:30 PM | 06/27/2018 | 2:33 PM | New York: New York County; | NPCC | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center | Suspicious Activity | 0 | 0 | Physical Attack |
| June | 2018-06-28 | 2:50 PM | 06/29/2018 | 9:00 AM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 160 | 48109 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2018-06-28 | 6:36 PM | 07/01/2018 | 7:00 AM | Missouri: Illinois: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 112000 | Weather |
| June | 2018-06-29 | 3:38 AM | Unknown | Unknown | Kentucky: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more | System Operations | Unknown | Unknown | Operations |
| June | 2018-06-29 | 7:35 AM | 06/29/2018 | 9:30 AM | Minnesota: St. Louis County; | MRO | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident | Severe Weather | 350 | Unknown | Weather |
| June | 2018-06-30 | 10:45 AM | 06/30/2018 | 11:28 AM | Texas: Travis County, Williamson County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more | System Operations | 0 | 0 | Operations |
| June | 2018-06-30 | 12:30 PM | 06/30/2018 | 12:31 PM | California: Los Angeles County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| July | 2018-07-04 | 5:54 PM | 07/04/2018 | 7:20 PM | Tennessee: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2018-07-04 | 10:00 PM | 07/04/2018 | 10:30 PM | Colorado: Pueblo County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 5058 | Physical Attack |
| July | 2018-07-09 | 1:10 PM | 07/09/2018 | 2:45 PM | California: Merced County, Kern County; Nevada: Clark County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2018-07-11 | 12:58 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| July | 2018-07-11 | 3:40 PM | 07/11/2018 | 4:00 PM | Tennessee: | SERC | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident | Transmission Interruption | 425 | 26195 | Transmission Interruption |
| July | 2018-07-14 | 10:20 AM | Unknown | Unknown | Ohio: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | Unknown | Unknown | Operations |
| July | 2018-07-16 | 5:15 AM | Unknown | Unknown | California: Merced County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| July | 2018-07-18 | 4:00 AM | Unknown | Unknown | California: Fresno County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| July | 2018-07-18 | 5:28 PM | 07/18/2018 | 5:31 PM | Oregon: | WECC | Total generation loss, within one minute of: greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection. | Severe Weather/Transmission Interruption | Unknown | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2018-07-19 | 12:38 PM | 07/19/2018 | 1:22 PM | Louisiana: Rapides Parish; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2018-07-19 | 8:25 PM | Unknown | Unknown | Kentucky: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | Unknown | Unknown | Operations |
| July | 2018-07-20 | 12:46 PM | 07/20/2018 | 1:30 PM | Maine: Hancock County; | NPCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | System Operations | 0 | 0 | Physical Attack |
| July | 2018-07-20 | 4:19 PM | 07/20/2018 | 4:48 PM | Kentucky: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 87833 | Weather |
| July | 2018-07-21 | 4:45 AM | 07/21/2018 | 11:15 AM | Arkansas: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 64930 | Weather |
| July | 2018-07-21 | 7:20 AM | 07/21/2018 | 11:30 AM | Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 143 | 42901 | Weather |
| July | 2018-07-23 | 4:16 AM | 07/23/2018 | 4:29 AM | Florida: Pinellas County; | FRCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 40 | Unknown | Weather |
| July | 2018-07-26 | 8:24 PM | Unknown | Unknown | California: Shasta County; | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System | Natural Disaster | Unknown | Unknown | Natural Disaster |
| July | 2018-07-27 | 9:34 AM | 07/27/2018 | 9:51 AM | Washington: Clark County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system | System Operations | Unknown | Unknown | Islanding |
| July | 2018-07-27 | 4:28 PM | 07/27/2018 | 4:33 PM | New York: New York County; | NPCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 0 | 0 | Weather |
| July | 2018-07-28 | 11:11 PM | 07/29/2018 | 1:51 AM | Nevada: Nye County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2018-07-29 | 2:33 PM | 07/29/2018 | 6:23 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Natural Disaster | 83 | 57670 | Natural Disaster |
| July | 2018-07-30 | 6:30 AM | 07/30/2018 | 11:00 PM | Arizona: Maricopa County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 82000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2018-07-31 | 11:44 AM | 07/31/2018 | 2:17 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Suspicious Activity | Unknown | Unknown | Physical Attack |
| August | 2018-08-01 | 9:11 AM | 08/01/2018 | 10:56 AM | Montana: | WECC | Physical attack that causes major interruptions or impacts to critical infrastructure or to operations. | Vandalism | 0 | 0 | Physical Attack |
| August | 2018-08-04 | 8:20 AM | 08/04/2018 | 8:21 AM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | Unknown | Physical Attack |
| August | 2018-08-07 | 1:22 AM | 08/07/2018 | 1:59 AM | California: Butte County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Natural Disaster | 5 | 485 | Natural Disaster |
| August | 2018-08-07 | 1:22 AM | 08/07/2018 | 7:04 PM | California: Butte County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Natural Disaster | 27 | 11383 | Natural Disaster |
| August | 2018-08-14 | 9:00 PM | 08/14/2018 | 9:01 PM | Virginia: Hanover County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2018-08-15 | 12:00 AM | 08/15/2018 | 1:00 AM | Missouri: Boone County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2018-08-17 | 1:07 PM | 08/17/2018 | 1:40 PM | California: | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2018-08-19 | 3:20 PM | 08/19/2018 | 3:21 PM | Utah: Box Elder County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2018-08-20 | 10:46 PM | 08/21/2018 | 12:14 AM | Louisiana: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2018-08-24 | 12:24 PM | 08/24/2018 | 12:59 PM | Virginia: Roanoke County; | SERC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2018-08-26 | 10:00 PM | 08/27/2018 | 4:56 AM | Michigan: Muskegon County, Newaygo County, Oceana County, Mason County, Kent County, Mecosta County, Montcalm County, Isabella County, Midland County, Saginaw County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 67000 | Weather |
| August | 2018-08-28 | 11:41 PM | 08/29/2018 | 12:13 AM | Ohio: Montgomery County; | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2018-08-28 | 8:00 PM | 08/30/2018 | 2:59 PM | Michigan: Benzie County, Barry County, Grand Traverse County, Kalkaska County, Mason County, Oceana County, Muskegon County, Kent County, Newaygo County, Montcalm County, Mecosta County, Antrim County, Eaton County, Ionia County, Isabella County, Clare County, Saginaw County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 110000 | Weather |
| August | 2018-08-29 | 3:27 AM | 08/29/2018 | 4:00 AM | Maryland: Montgomery County; District of Columbia: | RF | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR suspicious device or activity at its Bulk Electric System control center. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2018-08-29 | 9:00 AM | 08/29/2018 | 9:06 AM | Arkansas: | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2018-08-29 | 12:00 AM | 08/30/2018 | 12:00 AM | Illinois: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 100000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2018-08-30 | 12:00 PM | 08/30/2018 | 12:20 PM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| August | 2018-08-31 | 3:07 PM | 08/31/2018 | 3:31 PM | Oregon: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Natural Disaster/Transmission Interruption | 96 | 50000 | Natural Disaster |
| August | 2018-08-31 | 6:34 PM | 08/31/2018 | 6:40 PM | New York: New York County, Westchester County; | NPCC | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR suspicious device or activity at its Bulk Electric System control center. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2018-09-01 | 12:00 AM | 09/01/2018 | 3:22 PM | Arkansas: | SPP RE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2018-09-05 | 1:00 PM | 09/05/2018 | 1:01 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | Unknown | Physical Attack |
| September | 2018-09-06 | 2:26 AM | 09/06/2018 | 2:27 AM | Florida: Hillsborough County; | FRCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| September | 2018-09-12 | 10:00 PM | 09/12/2018 | 10:05 PM | Texas: | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2018-09-13 | 8:30 PM | 09/19/2018 | 5:00 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 300 | 325000 | Weather |
| September | 2018-09-13 | 8:56 PM | 09/20/2018 | 7:00 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 1457583 | Weather |
| September | 2018-09-15 | 3:00 PM | 09/15/2018 | 6:00 PM | Mississippi: Forrest County; | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | System Operations | 1322 | 420000 | Public Appeal |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2018-09-15 | 3:00 PM | 09/15/2018 | 6:00 PM | Louisiana: | SERC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | System Operations | Unknown | Unknown | Public Appeal |
| September | 2018-09-15 | 1:05 AM | 09/17/2018 | 4:00 PM | South Carolina: Horry County, Chesterfield County, Dillon County, Georgetown County, Marlboro County, Darlington County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 50100 | Weather |
| September | 2018-09-16 | 8:00 AM | 09/18/2018 | 7:40 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 50000 | Weather |
| September | 2018-09-19 | 11:00 AM | 09/20/2018 | 12:00 PM | Indiana: Benton County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2018-09-20 | 12:39 PM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| September | 2018-09-22 | 3:23 PM | 09/22/2018 | 11:00 PM | California: Los Angeles County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Natural Disaster | 3507 | 2500 | Natural Disaster |
| September | 2018-09-25 | 12:33 AM | 09/25/2018 | 3:10 AM | Illinois: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2018-09-26 | 1:54 PM | 09/26/2018 | 5:58 PM | Texas: Harris County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| September | 2018-09-28 | 6:58 PM | 09/28/2018 | 7:29 PM | Ohio: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2018-10-01 | 12:44 PM | 10/01/2018 | 5:32 PM | Ohio: Indiana: Michigan: Kentucky: West Virginia: Virginia: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | Unknown | Unknown | Operations |
| October | 2018-10-03 | 7:38 AM | 10/03/2018 | 7:48 AM | Illinois: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2018-10-04 | 6:00 AM | 10/04/2018 | 8:00 AM | Oklahoma: Osage County; | SPP RE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 4 | 2089 | Physical Attack |
| October | 2018-10-04 | 4:01 PM | 10/04/2018 | 6:25 PM | California: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Suspicious Activity | 0 | 0 | Physical Attack |
| October | 2018-10-09 | 8:12 PM | 10/09/2018 | 9:12 PM | Colorado: El Paso County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more; Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2018-10-10 | 5:41 AM | 10/10/2018 | 7:54 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2018-10-10 | 5:00 PM | 10/15/2018 | 5:00 AM | Utah: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2018-10-10 | 11:59 AM | Unknown | Unknown | Florida: Alabama: Georgia: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 152 | 45604 | Weather |
| October | 2018-10-10 | 2:00 PM | 10/11/2018 | 6:00 AM | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 135 | 60717 | Weather |
| October | 2018-10-10 | 4:00 PM | 10/19/2018 | 6:00 AM | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 330 | 55000 | Weather |
| October | 2018-10-11 | 7:21 AM | 10/11/2018 | 3:00 PM | South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 71654 | Weather |
| October | 2018-10-11 | 1:15 PM | Unknown | Unknown | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 240807 | Weather |
| October | 2018-10-11 | 4:42 PM | 10/12/2018 | 9:00 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 170222 | Weather |
| October | 2018-10-11 | 6:55 PM | 10/12/2018 | 12:00 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 117000 | Weather |
| October | 2018-10-12 | 3:36 AM | 10/12/2018 | 1:56 PM | Maryland: Garrett County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2018-10-14 | 10:11 PM | Unknown | Unknown | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more | Natural Disaster | Unknown | 60000 | Natural Disaster |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2018-10-16 | 4:15 AM | 10/16/2018 | 5:11 PM | Connecticut: Rhode Island: Massachusetts: Vermont: New Hampshire: Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 18000 | Weather |
| October | 2018-10-21 | 12:16 AM | 10/21/2018 | 4:14 PM | West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | Unknown | 63408 | Weather |
| October | 2018-10-22 | 10:25 AM | 10/22/2018 | 10:31 AM | Utah: Salt Lake County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| October | 2018-10-24 | 12:32 PM | 10/24/2018 | 1:33 PM | Michigan: Wayne County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2018-10-29 | 5:00 AM | 11/07/2018 | 7:00 AM | California: Shasta County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2018-10-29 | 8:39 AM | Unknown | Unknown | Minnesota: Douglas County; | MRO | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems | Vandalism | 0 | 0 | Physical Attack |
| October | 2018-10-30 | 2:02 PM | 10/30/2018 | 2:42 PM | Maryland: Baltimore, City of; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2018-10-31 | 7:30 PM | 11/01/2018 | 6:55 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more | Severe Weather | 402 | 140932 | Weather |
| November | 2018-11-02 | 9:50 AM | Unknown | Unknown | Minnesota: Douglas County; | MRO | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| November | 2018-11-03 | 5:53 AM | 11/03/2018 | 5:57 AM | Illinois: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2018-11-03 | 5:20 PM | 11/04/2018 | 2:30 PM | Connecticut: Massachusetts: New Hampshire: Vermont: Maine: Rhode Island: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 62000 | Weather |
| November | 2018-11-06 | 9:49 AM | 11/09/2018 | 2:05 PM | Tennessee: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 61000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2018-11-08 | 7:16 AM | 11/28/2018 | 4:32 PM | California: Butte County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system | Natural Disaster/Transmission Interruption | 32 | 11844 | Natural Disaster |
| November | 2018-11-08 | 4:00 PM | Unknown | Unknown | Nevada: Carson City, Consolidated Municipality of[19]; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| November | 2018-11-09 | 9:02 AM | 11/09/2018 | 10:23 AM | Iowa: Muscatine County; | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2018-11-10 | 5:02 PM | 11/14/2018 | 3:00 PM | Wisconsin: | MRO | Fuel supply emergencies that could impact electric power system adequacy or reliability | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| November | 2018-11-13 | 6:19 PM | 11/13/2018 | 7:40 PM | Arkansas: Oklahoma: Louisiana: Texas: | SPP RE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2018-11-15 | 3:23 AM | 11/15/2018 | 5:35 PM | Kentucky: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 150000 | Weather |
| November | 2018-11-15 | 5:28 AM | 11/15/2018 | 8:35 AM | Indiana: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 55000 | Weather |
| November | 2018-11-15 | 5:38 AM | 11/16/2018 | 6:00 AM | Kentucky: Ohio: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 104000 | Weather |
| November | 2018-11-15 | 10:50 AM | 11/17/2018 | 1:12 PM | Virginia: West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 50600 | Weather |
| November | 2018-11-18 | 1:10 PM | Unknown | Unknown | Nebraska: Holt County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 2 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2018-11-25 | 10:30 PM | 11/28/2018 | 8:17 PM | Illinois: Will County, DuPage County, Kane County, McHenry County, Winnebago County, Ogle County, DeKalb County, Lee County, Grundy County, Lake County, Cook County, Livingston County, Stephenson County, LaSalle County, Kankakee County, Kendall County, Boone County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 313448 | Weather |
| November | 2018-11-27 | 8:00 AM | 11/28/2018 | 4:50 PM | Maine: New Hampshire: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 32000 | Weather |
| December | 2018-12-01 | 4:23 PM | 12/01/2018 | 5:09 PM | Florida: Leon County; | FRCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2018-12-01 | 9:40 AM | 12/04/2018 | 5:17 PM | Pennsylvania: | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-02 | 4:17 PM | 12/02/2018 | 8:30 PM | Maryland: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2018-12-03 | 3:15 AM | 12/03/2018 | 3:44 AM | Texas: | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 16 | Unknown | Transmission Interruption |
| December | 2018-12-05 | 8:00 AM | 12/06/2018 | 8:00 AM | Alabama: Chambers County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-05 | 12:48 PM | 12/05/2018 | 12:49 PM | California: Los Angeles County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2018-12-07 | 3:10 AM | 12/07/2018 | 4:35 AM | Utah: Weber County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Actual Physical Attack | 0 | 0 | Physical Attack |
| December | 2018-12-09 | 11:28 PM | 12/10/2018 | 1:30 AM | Virginia: Loudoun County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-09 | 3:35 AM | 12/10/2018 | 11:45 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | Unknown | 50000 | Weather |
| December | 2018-12-09 | 8:41 AM | 12/09/2018 | 6:00 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 70000 | Weather |
| December | 2018-12-09 | 12:23 AM | 12/09/2018 | 11:54 AM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 137 | 41126 | Weather |
| December | 2018-12-11 | 9:10 AM | 12/11/2018 | 10:26 AM | Texas: Travis County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2018-12-11 | 7:00 AM | 12/13/2018 | 2:00 PM | Oregon: Josephine County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-12 | 10:00 AM | 12/12/2018 | 10:31 AM | Oregon: Gilliam County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-13 | 10:00 AM | Unknown | Unknown | California: Stanislaus County, San Joaquin County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| December | 2018-12-14 | 8:40 AM | 12/14/2018 | 10:00 AM | Texas: Jasper County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2018-12-14 | 4:00 PM | 12/17/2018 | 2:00 AM | Washington: King County, Kitsap County, Island County, Pierce County, Thurston County, Whatcom County, Skagit County, Kittitas County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 150000 | Weather |
| December | 2018-12-14 | 6:00 PM | Unknown | Unknown | Washington: Snohomish County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 200 | 60000 | Weather |
| December | 2018-12-18 | 8:47 AM | 12/18/2018 | 8:48 AM | Utah: Salt Lake County; California: Oregon: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-20 | 9:30 AM | 12/20/2018 | 5:00 PM | Washington: Skagit County, Snohomish County, King County, Kitsap County, Island County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 165000 | Weather |
| December | 2018-12-26 | 1:00 AM | 01/03/2019 | 10:27 AM | California: Kern County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-27 | 12:05 AM | 12/27/2018 | 1:05 AM | Maryland: Montgomery County, Prince George's County; District of Columbia: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2018-12-27 | 12:50 PM | 12/27/2018 | 1:00 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2018-12-27 | 9:12 PM | 12/27/2018 | 9:16 PM | New York: New York County; | NPCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| December | 2018-12-30 | 11:41 AM | 12/30/2018 | 1:20 PM | Washington: King County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2019-01-05 | 1:19 PM | 01/05/2019 | 3:07 PM | Washington: | WECC | Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | Unknown | Operations |
| January | 2019-01-06 | 1:00 AM | 01/06/2019 | 12:00 PM | Washington: King County, Thurston County, Pierce County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 230000 | Weather |
| January | 2019-01-06 | 3:00 AM | 01/09/2019 | 7:00 AM | Washington: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 230 | 230000 | Weather |
| January | 2019-01-06 | 5:56 PM | 01/06/2019 | 9:52 PM | California: Sacramento County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 300 | 90382 | Weather |
| January | 2019-01-07 | 8:57 PM | 01/07/2019 | 9:32 PM | Michigan: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2019-01-09 | 11:55 AM | 01/09/2019 | 11:56 AM | New Mexico: San Juan County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| January | 2019-01-10 | 12:19 PM | 01/10/2019 | 12:48 PM | Montana: Valley County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | System Operations | 11 | 2 | Operations |
| January | 2019-01-11 | 11:36 AM | 01/11/2019 | 12:43 PM | Maine: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2019-01-12 | 7:20 PM | 01/12/2019 | 9:38 PM | New Hampshire: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2019-01-12 | 11:30 AM | 01/13/2019 | 10:00 PM | Missouri: Jackson County; Kansas: Johnson County; | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 112530 | Weather |
| January | 2019-01-12 | 11:30 AM | Unknown | Unknown | Missouri: Nebraska: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 116600 | Weather |
| January | 2019-01-13 | 5:30 AM | 01/15/2019 | 5:00 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 133200 | Unknown | Weather |
| January | 2019-01-14 | 11:10 AM | Unknown | Unknown | Michigan: | RF | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Actual Physical Attack | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2019-01-15 | 8:00 AM | 01/15/2019 | 8:02 AM | Pennsylvania: | RF | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| January | 2019-01-16 | 5:19 AM | 01/16/2019 | 7:14 AM | Texas: Nueces County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2019-01-16 | 5:26 PM | 01/17/2019 | 12:19 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 190 | 126700 | Weather |
| January | 2019-01-18 | 9:54 PM | 01/19/2019 | 12:19 AM | Nebraska: | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 8 | Unknown | Transmission Interruption |
| January | 2019-01-23 | 7:26 AM | 01/23/2019 | 5:05 PM | Colorado: Larimer County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | System Operations | 0 | 0 | Operations |
| January | 2019-01-24 | 4:39 AM | 01/24/2019 | 5:16 AM | Ohio: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2019-01-28 | 1:35 PM | 01/28/2019 | 1:40 PM | Utah: Iron County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 0 | 0 | Physical Attack |
| January | 2019-01-29 | 6:34 PM | 01/29/2019 | 6:36 PM | Louisiana: Washington Parish; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| January | 2019-01-30 | 4:23 AM | 02/02/2019 | 9:00 AM | Illinois: Scott County; | SERC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | Unknown | Unknown | Fuel Supply Deficiency |
| January | 2019-01-30 | 4:30 PM | Unknown | Unknown | Washington: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| January | 2019-01-30 | 7:00 AM | 01/30/2019 | 8:08 AM | Illinois: Pike County; | SERC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Severe Weather | Unknown | Unknown | Weather |
| January | 2019-01-30 | 9:30 AM | 01/31/2019 | 6:00 PM | Michigan: | RF | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2019-01-31 | 9:33 PM | 01/31/2019 | 9:34 PM | California: | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| February | 2019-02-01 | 5:35 AM | 02/01/2019 | 6:10 AM | Massachusetts | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| February | 2019-02-01 | 11:57 PM | 02/02/2019 | 8:49 AM | Nevada | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 1 | Physical Attack |
| February | 2019-02-02 | 10:28 AM | 02/02/2019 | 10:29 AM | California | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| February | 2019-02-05 | 6:17 PM | 02/05/2019 | 8:26 PM | California | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Severe Weather | 42 | 33200 | Weather |
| February | 2019-02-07 | 7:39 AM | 02/07/2019 | 7:40 AM | Arkansas | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 3 | 3370 | Weather |
| February | 2019-02-07 | 8:55 AM | 02/09/2019 | 4:30 PM | Michigan | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 233000 | Weather |
| February | 2019-02-08 | 10:00 AM | 02/08/2019 | 10:30 AM | Pennsylvania | RF | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| February | 2019-02-08 | 6:30 PM | Unknown | Unknown | Washington | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 50940 | Weather |
| February | 2019-02-13 | 2:48 AM | 02/15/2019 | 12:28 AM | California | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 182 | 121000 | Weather |
| February | 2019-02-14 | 8:50 AM | 02/14/2019 | 12:10 PM | New Jersey | RF | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2019-02-14 | 12:15 PM | 02/14/2019 | 12:16 PM | Utah | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| February | 2019-02-19 | 9:45 AM | Unknown | Unknown | Texas | TRE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| February | 2019-02-20 | 12:50 PM | 02/20/2019 | 1:32 PM | Wisconsin, Minnesota, Iowa, Illinois | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 740 | 0 | Operations |
| February | 2019-02-23 | 2:05 PM | Unknown | Unknown | Virginia | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | Unknown | Unknown | Weather |
| February | 2019-02-24 | 11:21 AM | 02/26/2019 | 5:29 PM | Ohio, Virginia, West Virginia | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 118781 | Weather |
| February | 2019-02-24 | 12:31 PM | 02/24/2019 | 2:57 PM | Ohio | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 157274 | Weather |
| February | 2019-02-24 | 2:33 PM | 02/24/2019 | 6:03 PM | Pennsylvania | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 94048 | Weather |
| February | 2019-02-24 | 6:00 PM | 02/25/2019 | 10:00 PM | Pennsylvania | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 132000 | Weather |
| February | 2019-02-24 | 6:47 PM | 02/25/2019 | 1:55 PM | Pennsylvania | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 137216 | Weather |
| February | 2019-02-24 | 8:02 PM | 02/25/2019 | 2:30 PM | Michigan | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 115000 | Weather |
| February | 2019-02-25 | 7:45 AM | 02/25/2019 | 6:40 PM | Massachusetts | NPCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| February | 2019-02-25 | 1:35 PM | 02/26/2019 | 2:50 AM | Connecticut, Massachusetts, New Hampshire, Maine, Vermont, Rhode Island | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 72332 | Weather |
| February | 2019-02-27 | 9:35 PM | 02/27/2019 | 9:45 PM | South Carolina | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2019-02-27 | 11:25 AM | 02/27/2019 | 5:39 PM | Iowa | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| February | 2019-02-28 | 7:02 AM | 02/28/2019 | 7:33 AM | Oklahoma, Arkansas, Louisiana | SPP RE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2019-03-04 | 11:39 AM | 03/08/2019 | 4:52 PM | Oklahoma: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2019-03-05 | 9:12 AM | 03/05/2019 | 6:57 PM | California: Kern County, Los Angeles County; Utah: Salt Lake County; Wyoming: Converse County; | WECC | Cyber event that causes interruptions of electrical system operations. | System Operations | 0 | 0 | Cyber Attack |
| March | 2019-03-13 | 6:12 AM | 03/13/2019 | 6:13 AM | California: Los Angeles County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2019-03-13 | 5:50 AM | 03/13/2019 | 10:30 AM | Texas: Midland County, Ector County, Tarrant County, Dallas County, Wichita County, Brown County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 154124 | Weather |
| March | 2019-03-13 | 11:29 AM | 03/14/2019 | 9:11 PM | Colorado: Jefferson County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 58 | 58379 | Weather |
| March | 2019-03-13 | 3:00 PM | 03/14/2019 | 12:00 AM | Texas: Kansas: Oklahoma: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | Unknown | 66000 | Weather |
| March | 2019-03-13 | 3:51 PM | 03/16/2019 | 6:00 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 50 | 54290 | Weather |
| March | 2019-03-19 | 10:53 PM | 03/19/2019 | 10:54 PM | Oklahoma: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2019-03-21 | 10:00 AM | 03/21/2019 | 10:05 AM | Utah: Salt Lake County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| March | 2019-03-25 | 7:47 AM | 03/25/2019 | 7:48 AM | Oregon: Lane County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Actual Physical Attack | 5 | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2019-03-29 | 11:36 PM | 03/30/2019 | 2:00 AM | California: San Diego County, Los Angeles County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Suspicious Activity | 0 | 0 | Physical Attack |
| April | 2019-04-01 | 6:51 AM | 04/01/2019 | 7:53 AM | New York: Broome County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2019-04-01 | 6:51 AM | 04/01/2019 | 7:53 AM | New York: Monroe County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2019-04-01 | 2:15 PM | 04/06/2019 | 5:20 PM | Nevada: Carson City, Consolidated Municipality of[19], Washoe County, Churchill County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 0 | 0 | Physical Attack |
| April | 2019-04-02 | 8:33 AM | 04/02/2019 | 9:00 AM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-02 | 10:15 AM | 04/02/2019 | 10:16 AM | Utah: Salt Lake County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-03 | 5:15 AM | 04/03/2019 | 12:39 PM | California: Fresno County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| April | 2019-04-04 | 10:13 AM | 04/04/2019 | 12:08 PM | Montana: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2019-04-07 | 1:46 PM | 04/08/2019 | 5:50 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 537 | 231956 | Weather |
| April | 2019-04-10 | 11:59 AM | 04/10/2019 | 12:00 PM | Virginia: | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2019-04-11 | 7:48 PM | 04/11/2019 | 8:00 PM | Oregon: Washington: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2019-04-12 | 11:20 AM | 04/12/2019 | 12:46 PM | Minnesota: Martin County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2019-04-13 | 6:15 PM | 04/13/2019 | 11:15 PM | Mississippi: Arkansas: Texas: Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 60467 | Weather |
| April | 2019-04-15 | 10:00 AM | 04/15/2019 | 2:00 PM | Minnesota: | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-15 | 4:35 AM | 04/15/2019 | 2:40 PM | Virginia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 75290 | Weather |
| April | 2019-04-16 | 10:30 AM | 04/16/2019 | 11:00 AM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-17 | 7:38 PM | 04/17/2019 | 11:52 PM | Arizona: | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2019-04-18 | 8:08 PM | 04/19/2019 | 11:00 AM | Colorado: Clear Creek County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2019-04-18 | 7:55 PM | 04/19/2019 | 5:29 PM | Alabama: Mississippi: Georgia: Florida: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 116 | 34695 | Weather |
| April | 2019-04-21 | 10:40 AM | 04/21/2019 | 10:45 AM | Utah: Salt Lake County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-25 | 6:03 PM | 04/25/2019 | 6:32 PM | Arizona: Maricopa County; | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Generation Inadequacy | 150 | 51366 | Generation Interruption |
| April | 2019-04-26 | 1:00 AM | 04/26/2019 | 1:27 PM | Pennsylvania: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 7 | 5830 | Transmission Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2019-04-26 | 3:16 PM | 04/26/2019 | 3:17 PM | Massachusetts: Hampden County[13]; | NPCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 0 | 0 | Weather |
| April | 2019-04-26 | 5:46 PM | 04/27/2019 | 11:49 AM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 54071 | Weather |
| April | 2019-04-28 | 1:40 PM | 04/28/2019 | 2:49 PM | South Carolina: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2019-04-28 | 10:43 AM | 04/29/2019 | 2:06 AM | Ohio: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2019-04-29 | 5:17 PM | 04/30/2019 | 9:22 AM | Virginia: Surry County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2019-04-30 | 12:25 PM | 04/30/2019 | 1:11 PM | Indiana: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2019-05-08 | 9:22 AM | 05/08/2019 | 9:56 AM | Pennsylvania: Mercer County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 29 | 1 | Transmission Interruption |
| May | 2019-05-08 | 3:50 PM | 05/13/2019 | 12:00 AM | Louisiana: Texas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | Unknown | 65844 | Weather |
| May | 2019-05-09 | 5:55 PM | 05/11/2019 | 8:50 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 691 | 238015 | Weather |
| May | 2019-05-09 | 7:06 PM | 05/10/2019 | 2:57 AM | Texas: Harris County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 0 | 0 | Weather |
| May | 2019-05-10 | 2:00 AM | 05/10/2019 | 12:15 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 61008 | Weather |
| May | 2019-05-11 | 2:08 PM | 05/11/2019 | 3:00 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2019-05-15 | 12:10 PM | 05/15/2019 | 12:11 PM | West Virginia: | RF | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | 2019-05-18 | 1:55 AM | 05/18/2019 | 3:06 PM | Colorado: Wyoming: Nebraska: Utah: Daggett County; New Mexico: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 30 | 0 | Physical Attack |
| May | 2019-05-18 | 3:45 PM | 05/20/2019 | 4:00 AM | Texas: Ector County, Midland County, Tarrant County, Dallas County, Stephens County, Anderson County, McLennan County, Ellis County, Hunt County, Young County, Bell County, Limestone County, Collin County, Rockwall County, Henderson County, Parker County, Falls County, Freestone County, Kaufman County, Grayson County, Smith County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 68000 | Weather |
| May | 2019-05-23 | 1:11 AM | 05/23/2019 | 12:00 PM | Indiana: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 0 | 0 | Weather |
| May | 2019-05-23 | 4:55 PM | 05/23/2019 | 11:40 PM | Virginia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 100000 | Weather |
| May | 2019-05-24 | 7:28 AM | 05/24/2019 | 8:30 AM | Kentucky: Shelby County; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2019-05-24 | 8:09 PM | 05/25/2019 | 2:23 PM | North Dakota: Minnesota: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2019-05-24 | 9:47 PM | 05/24/2019 | 11:58 PM | California: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system | Severe Weather | 20 | 10961 | Weather |
| May | 2019-05-27 | 10:07 PM | 05/28/2019 | 3:00 AM | Ohio: Montgomery County, Darke County, Mercer County, Miami County, Greene County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 347 | 70000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2019-06-02 | 6:19 PM | 06/02/2019 | 8:43 PM | California: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Severe Weather/Transmission Interruption | Unknown | Unknown | Weather |
| June | 2019-06-04 | 10:15 AM | 06/04/2019 | 1:15 PM | Nevada: Washoe County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| June | 2019-06-05 | 8:37 AM | 06/05/2019 | 8:40 AM | Idaho: Bannock County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-05 | 10:16 AM | 06/05/2019 | 10:17 AM | South Dakota: Lincoln County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-05 | 9:46 AM | 06/05/2019 | 12:00 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-06 | 6:09 PM | 06/06/2019 | 6:35 PM | Texas: Bexar County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 55017 | Weather |
| June | 2019-06-07 | 2:43 PM | 06/07/2019 | 4:20 PM | Texas: Pecos County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 8 | 1 | Transmission Interruption |
| June | 2019-06-08 | 3:50 PM | 06/08/2019 | 7:40 PM | Texas: Potter County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| June | 2019-06-09 | 2:45 PM | 06/13/2019 | 10:30 PM | Texas: Collin County, Dallas County, Denton County, Palo Pinto County, Tarrant County, Ellis County, Williamson County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 558000 | Weather |
| June | 2019-06-11 | 3:11 PM | 06/11/2019 | 5:00 PM | North Dakota: Mountrail County, Williams County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-11 | 7:52 AM | 06/11/2019 | 7:53 AM | Utah: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-12 | 2:56 PM | 06/12/2019 | 3:50 PM | California: Imperial County, Riverside County; | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Generation Inadequacy | 982 | 30907 | Generation Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2019-06-16 | 2:00 AM | 06/17/2019 | 11:59 PM | Texas: Dallas County, Tarrant County, Collin County, Denton County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 340000 | Weather |
| June | 2019-06-16 | 3:25 AM | Unknown | Unknown | Oklahoma: | SPP RE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | Unknown | Unknown | Weather |
| June | 2019-06-18 | 6:21 AM | 06/18/2019 | 6:40 AM | Washington: Grant County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| June | 2019-06-19 | 3:00 PM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-19 | 11:00 AM | 06/19/2019 | 11:01 AM | Oklahoma: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-19 | 10:30 PM | 06/20/2019 | 7:00 PM | Arkansas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 82045 | Weather |
| June | 2019-06-20 | 4:11 PM | 06/21/2019 | 12:45 PM | Virginia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 60000 | Weather |
| June | 2019-06-21 | 6:36 PM | 06/21/2019 | 7:27 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| June | 2019-06-21 | 10:00 AM | 06/21/2019 | 11:00 AM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2019-06-21 | 7:15 PM | Unknown | Unknown | Kentucky: Tennessee: | SERC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Severe Weather | Unknown | 50000 | Weather |
| June | 2019-06-22 | 8:46 PM | 06/23/2019 | 12:30 AM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 115 | 34637 | Weather |
| June | 2019-06-23 | 5:13 AM | 06/23/2019 | 10:58 AM | Arkansas: | SPP RE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 47 | 16199 | Transmission Interruption |
| June | 2019-06-23 | 10:00 PM | 06/25/2019 | 11:00 PM | Texas: Dallas County, Denton County, Ellis County, Collin County, Ellis County, Hood County, Johnson County, Kaufman County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 265000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2019-06-24 | 9:40 AM | 06/24/2019 | 3:17 PM | Oklahoma: Oklahoma County; | SPP RE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| June | 2019-06-24 | 5:30 AM | 06/24/2019 | 8:45 AM | Arkansas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 56451 | Weather |
| June | 2019-06-26 | 1:58 PM | 06/26/2019 | 2:03 PM | North Dakota: Williams County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 53 | 0 | Transmission Interruption |
| June | 2019-06-28 | 2:25 PM | Unknown | Unknown | Idaho: Nez Perce County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| June | 2019-06-30 | 3:15 PM | 06/30/2019 | 4:15 PM | New York: Nassau County, Suffolk County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 3189 | 52498 | Weather |
| June | 2019-06-30 | 3:30 PM | 06/30/2019 | 8:30 PM | Illinois: Cook County, DeKalb County, DuPage County, Grundy County, Iroquois County, Ford County, Lake County, Kendall County, Kankakee County, Kane County, Ogle County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 100000 | Weather |
| July | 2019-07-02 | 1:00 PM | 07/02/2019 | 1:22 PM | Idaho: Ada County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| July | 2019-07-06 | 10:00 PM | 07/07/2019 | 1:57 PM | Mississippi: Panola County; | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | Unknown | 3000 | Physical Attack |
| July | 2019-07-09 | 1:59 AM | 07/09/2019 | 3:50 PM | Texas: Louisiana: Arkansas: Mississippi: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| July | 2019-07-10 | 12:00 PM | 07/10/2019 | 12:15 PM | Utah: Salt Lake County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| July | 2019-07-10 | 12:10 PM | 07/12/2019 | 12:30 PM | Texas: Collin County, Dallas County, Denton County, Hood County, Johnson County, Tarrant County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 57000 | Weather |
| July | 2019-07-11 | 11:08 AM | 07/11/2019 | 11:13 AM | Texas: Lynn County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 26 | 2043 | Transmission Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2019-07-13 | 6:47 PM | 07/13/2019 | 11:37 PM | New York: New York County; | NPCC | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident | Transmission Interruption | 452 | 72669 | Transmission Interruption |
| July | 2019-07-13 | 11:55 PM | 07/14/2019 | 1:00 PM | Louisiana: Acadia Parish, Avoyelles Parish, Catahoula Parish, Evangeline Parish, Grant Parish, Iberia Parish, LaSalle Parish, Natchitoches Parish, Rapides Parish, Sabine Parish, St. Landry Parish, St. Martin Parish, St. Mary Parish, St. Tammany Parish, Allen Parish, Beauregard Parish, Calcasieu Parish, Vermilion Parish, De Soto Parish, Jefferson Davis Parish, Red River Parish, Tangipahoa Parish, Vernon Parish, Washington Parish; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 63000 | Weather |
| July | 2019-07-13 | 7:15 AM | 07/14/2019 | 5:00 PM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 55730 | Weather |
| July | 2019-07-17 | 2:12 PM | 07/17/2019 | 2:30 PM | Oklahoma: Oklahoma County; | SPP RE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2019-07-19 | 9:55 AM | 07/19/2019 | 1:00 PM | Wisconsin: Dane County; | MRO | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | Unknown | Unknown | Operations |
| July | 2019-07-19 | 7:00 PM | 07/21/2019 | 8:00 PM | Michigan: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 400000 | Weather |
| July | 2019-07-20 | 7:37 AM | 07/20/2019 | 9:20 AM | Missouri: Boone County; | SERC | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2019-07-20 | 11:55 AM | 07/23/2019 | 12:00 AM | Wisconsin: Michigan: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 200 | 50000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2019-07-20 | 3:00 AM | 07/22/2019 | 7:00 AM | Michigan: Kent County, Newaygo County, Mecosta County, Montcalm County, Isabella County, Ionia County, Allegan County, Barry County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 160000 | Weather |
| July | 2019-07-21 | 11:00 PM | 07/22/2019 | 8:54 PM | New York: Kings County, New York County, Queens County, Bronx County, Westchester County, Richmond County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 60 | 45000 | Weather |
| July | 2019-07-22 | 4:00 PM | 07/24/2019 | 11:00 PM | Pennsylvania: Bucks County, Delaware County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 165000 | Weather |
| July | 2019-07-22 | 5:50 PM | 07/25/2019 | 1:15 PM | New Jersey: Gloucester County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 49 | 95600 | Weather |
| July | 2019-07-23 | 3:22 AM | 07/23/2019 | 5:40 AM | California: Santa Cruz County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 25 | Physical Attack |
| July | 2019-07-23 | 11:55 PM | 07/23/2019 | 11:56 PM | Nebraska: | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| July | 2019-07-23 | 11:55 PM | 07/24/2019 | 5:22 AM | Nebraska: Scotts Bluff County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| July | 2019-07-23 | 3:39 PM | 07/23/2019 | 7:00 PM | Massachusetts: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 54 | 54535 | Weather |
| July | 2019-07-24 | 8:01 AM | 07/24/2019 | 12:49 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2019-07-24 | 1:30 PM | 07/24/2019 | 1:31 PM | Utah: Iron County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 1 | Physical Attack |
| July | 2019-07-28 | 6:48 PM | 07/28/2019 | 7:18 PM | Michigan: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2019-07-30 | 8:45 AM | 07/30/2019 | 9:45 AM | Louisiana: | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | Unknown | 13720 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2019-08-02 | 6:24 PM | 08/02/2019 | 7:28 PM | Washington: Clark County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-02 | 1:49 AM | 08/02/2019 | 1:55 AM | Minnesota: Chisago County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| August | 2019-08-05 | 5:23 PM | 08/06/2019 | 12:02 AM | Oregon: Umatilla County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 66 | Unknown | Transmission Interruption |
| August | 2019-08-07 | 9:30 AM | 08/07/2019 | 11:15 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-07 | 3:00 PM | 08/07/2019 | 3:30 PM | California: Kern County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2019-08-07 | 8:40 AM | Unknown | Unknown | Washington: Pierce County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| August | 2019-08-08 | 4:16 PM | 08/08/2019 | 10:41 PM | Ohio: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | Unknown | 5600 | Weather |
| August | 2019-08-09 | 9:53 AM | 08/09/2019 | 10:46 AM | Texas: Travis County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2019-08-10 | 4:11 PM | 08/10/2019 | 4:46 PM | Michigan: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-10 | 7:59 PM | 08/10/2019 | 9:04 PM | Michigan: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-13 | 10:00 AM | 08/13/2019 | 11:00 AM | California: Placer County; | WECC | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident. | Vandalism | 0 | 0 | Physical Attack |
| August | 2019-08-13 | 12:00 AM | Unknown | Unknown | North Dakota: Mercer County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | Unknown | Physical Attack |
| August | 2019-08-13 | 3:10 PM | 08/13/2019 | 5:30 PM | Texas: Williamson County; | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2019-08-15 | 11:03 PM | 08/16/2019 | 12:37 AM | California: Marin County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Distribution Interruption | 80 | 61318 | Distribution Interruption |
| August | 2019-08-15 | 8:30 AM | Unknown | Unknown | New York: Tompkins County; | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 150 | Unknown | Fuel Supply Deficiency |
| August | 2019-08-15 | 3:07 AM | 08/15/2019 | 3:56 AM | District of Columbia: Maryland: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-15 | 11:00 AM | 08/15/2019 | 3:30 PM | Kentucky: Ohio County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2019-08-15 | 3:11 PM | 08/15/2019 | 6:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| August | 2019-08-18 | 4:47 PM | 08/18/2018 | 11:00 PM | Texas: | TRE | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident | Distribution Interruption | 752 | 86373 | Distribution Interruption |
| August | 2019-08-18 | 4:30 PM | 08/18/2019 | 10:00 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Transmission Interruption/Distribution Interruption | 259 | 61000 | Transmission Interruption |
| August | 2019-08-18 | 3:59 PM | 08/18/2019 | 11:00 PM | Louisiana: Texas: | SPP RE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Transmission Interruption | 271 | 86373 | Transmission Interruption |
| August | 2019-08-21 | 7:56 AM | Unknown | Unknown | Ohio: | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 1397 | Physical Attack |
| August | 2019-08-21 | 3:30 PM | Unknown | Unknown | Massachusetts: Middlesex County[13]; | NPCC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| August | 2019-08-24 | 4:10 PM | 08/24/2019 | 7:28 PM | Washington: | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | Suspicious Activity | 0 | 0 | Cyber Attack |
| August | 2019-08-25 | 1:44 AM | 08/25/2019 | 2:20 AM | Washington: King County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2019-08-26 | 9:09 AM | 08/26/2019 | 1:34 PM | North Dakota: | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| August | 2019-08-26 | 7:00 PM | 08/27/2019 | 3:00 AM | Oklahoma: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | Unknown | 95000 | Weather |
| August | 2019-08-26 | 7:00 PM | 08/29/2019 | 1:00 PM | Oklahoma: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 103779 | Weather |
| August | 2019-08-29 | 11:30 PM | 08/30/2019 | 5:30 PM | Michigan: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2019-08-31 | 3:05 PM | 08/31/2019 | 3:46 PM | Pennsylvania: New Jersey: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2019-08-31 | 4:00 PM | 09/02/2019 | 6:00 AM | California: Calaveras County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| September | 2019-09-04 | 11:13 AM | 09/04/2019 | 11:57 AM | Maryland: District of Columbia: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-04 | 2:30 PM | 09/06/2019 | 6:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| September | 2019-09-05 | 10:08 AM | 09/05/2019 | 12:08 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-05 | 10:00 PM | 09/06/2019 | 12:00 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 3 | 2000 | Weather |
| September | 2019-09-05 | 10:36 PM | 09/06/2019 | 4:00 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 116000 | Weather |
| September | 2019-09-05 | 4:15 AM | 09/05/2019 | 3:17 PM | South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 172278 | Weather |
| September | 2019-09-06 | 8:20 AM | Unknown | Unknown | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 77000 | Weather |
| September | 2019-09-10 | 9:22 PM | 09/10/2019 | 9:23 PM | Wyoming: Sweetwater County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 885 | 0 | Transmission Interruption |
| September | 2019-09-11 | 10:35 PM | 09/11/2019 | 11:59 PM | Michigan: Ionia County, Kent County, Barry County, Montcalm County, Allegan County, Ottawa County, Newaygo County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 54000 | Weather |
| September | 2019-09-13 | 2:31 AM | 09/16/2019 | 5:00 PM | Tennessee: | SERC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-19 | 5:55 AM | 09/19/2019 | 2:30 PM | Arizona: Pima County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| September | 2019-09-19 | 6:40 PM | 09/19/2019 | 6:46 PM | Minnesota: Washington County; | MRO | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| September | 2019-09-20 | 12:21 AM | 09/20/2019 | 12:04 PM | Oklahoma: Oklahoma County; | SPP RE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-24 | 3:56 PM | 09/26/2019 | 7:25 PM | Washington: King County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2019-09-25 | 5:25 PM | 09/25/2019 | 6:16 PM | Wisconsin: Marathon County; | MRO | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2019-09-25 | 9:59 AM | 09/25/2019 | 10:00 AM | Texas: | TRE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | Unknown | Physical Attack |
| September | 2019-09-25 | 3:47 AM | 09/25/2019 | 3:40 PM | California: Napa County, Nevada County, Placer County, Plumas County, Sonoma County, Butte County, Yuba County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 25 | 69524 | Weather |
| September | 2019-09-26 | 2:31 PM | 09/26/2019 | 3:14 PM | Maryland: Baltimore County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-29 | 7:38 AM | Unknown | Unknown | California: Alameda County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Distribution Interruption | Unknown | 50072 | Distribution Interruption |
| September | 2019-09-30 | 5:35 AM | 09/30/2019 | 8:10 AM | Washington: King County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2019-09-30 | 12:17 PM | 09/30/2019 | 12:58 PM | Nevada: Clark County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Actual Physical Attack | 3736 | 0 | Physical Attack |
| September | 2019-09-30 | 10:53 AM | 09/30/2019 | 10:54 AM | Idaho: Bonneville County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| October | 2019-10-03 | 12:13 AM | 10/03/2019 | 4:00 AM | Missouri: Reynolds County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| October | 2019-10-04 | 5:15 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| October | 2019-10-06 | 5:15 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| October | 2019-10-06 | 2:50 PM | 10/06/2019 | 3:00 PM | Texas: Hidalgo County, Cameron County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| October | 2019-10-09 | 12:27 AM | Unknown | Unknown | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 2400 | 737808 | Weather |
| October | 2019-10-10 | 2:06 AM | 10/10/2019 | 5:05 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-10 | 12:22 AM | 10/10/2019 | 2:12 AM | Colorado: Jefferson County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2019-10-11 | 10:56 AM | 10/11/2019 | 11:46 AM | Michigan: Wayne County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-12 | 3:00 PM | 10/12/2019 | 4:21 PM | Texas: | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2019-10-15 | 7:57 PM | 10/15/2019 | 8:44 PM | Kansas: Shawnee County; | SPP RE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-15 | 3:19 AM | 10/15/2019 | 6:38 AM | Ohio: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2019-10-16 | 7:00 AM | Unknown | Unknown | Texas: Louisiana: Arkansas: Mississippi: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| October | 2019-10-17 | 12:45 AM | 10/19/2019 | 9:30 AM | Connecticut: Rhode Island: Massachusetts: Vermont: New Hampshire: Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 101683 | Weather |
| October | 2019-10-19 | 2:00 PM | 10/19/2019 | 9:07 PM | California: Imperial County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-19 | 5:57 AM | 10/19/2019 | 1:58 PM | South Dakota: Codington County; Nebraska: Scotts Bluff County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2019-10-20 | 10:15 PM | 10/25/2019 | 2:00 AM | Texas: Cass County, Cameron County, Collin County, Dallas County, Ellis County, Erath County, Hunt County, Kaufman County, Lamar County, Panola County, Rains County, Rockwall County, Rusk County, Tarrant County, Van Zandt County, Wood County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 400000 | Weather |
| October | 2019-10-23 | 12:49 AM | 10/23/2019 | 4:05 AM | New York: Monroe County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2019-10-23 | 12:49 AM | 10/23/2019 | 4:05 AM | New York: Broome County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-23 | 2:36 PM | Unknown | Unknown | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | Unknown | 50000 | Weather |
| October | 2019-10-24 | 5:15 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| October | 2019-10-24 | 5:02 PM | 10/24/2019 | 5:09 PM | Ohio: Lorain County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2019-10-25 | 2:53 AM | 10/25/2019 | 4:37 AM | South Carolina: Cherokee County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| October | 2019-10-26 | 8:07 AM | 10/26/2019 | 8:45 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-26 | 6:20 PM | 10/31/2019 | 1:27 AM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 3190 | 972000 | Weather |
| October | 2019-10-26 | 5:15 AM | 10/26/2019 | 5:31 PM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 82124 | Weather |
| October | 2019-10-26 | 6:00 PM | Unknown | Unknown | Tennessee: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 70000 | Weather |
| October | 2019-10-29 | 1:46 PM | 10/29/2019 | 2:49 PM | Wisconsin: Brown County, Manitowoc County, Calumet County, Winnebago County, Kewaunee County, Door County, Oconto County, Marinette County, Forest County, Langlade County, Oneida County, Vilas County, Lincoln County, Oneida County, Portage County; | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2019-10-30 | 6:32 AM | 11/01/2019 | 1:29 PM | California: Los Angeles County, Orange County, Riverside County, San Bernardino County, Ventura County, Kern County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | 285 | 114402 | Weather |
| October | 2019-10-31 | 10:00 PM | Unknown | Unknown | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | Unknown | 53943 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2019-11-01 | 11:45 PM | 11/02/2019 | 12:48 AM | New York: Broome County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2019-11-01 | 11:45 PM | 11/02/2019 | 12:48 AM | New York: Monroe County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2019-11-01 | 1:00 AM | 11/03/2019 | 1:00 PM | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 8000 | Weather |
| November | 2019-11-01 | 1:15 AM | 11/02/2019 | 9:30 PM | Connecticut: Maine: Massachusetts: Rhode Island: New Hampshire: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 80066 | Weather |
| November | 2019-11-01 | 2:41 AM | Unknown | Unknown | New York: Broome County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 66325 | Weather |
| November | 2019-11-03 | 10:17 PM | 11/04/2019 | 11:10 AM | Minnesota: Sherburne County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| November | 2019-11-05 | 8:30 AM | 11/05/2019 | 4:16 PM | Indiana: | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| November | 2019-11-05 | 3:40 PM | 11/05/2019 | 5:11 PM | Idaho: Elmore County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 131 | Physical Attack |
| November | 2019-11-05 | 8:56 AM | 11/05/2019 | 11:51 AM | Florida: Duval County; | FRCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 1500 | Unknown | Transmission Interruption |
| November | 2019-11-08 | 5:50 AM | 11/08/2019 | 6:10 AM | Utah: California: Oregon: Wyoming: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | System Operations | 72 | Unknown | Operations |
| November | 2019-11-16 | 4:11 PM | 11/16/2019 | 5:01 PM | Oregon: Lane County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| November | 2019-11-16 | 6:00 AM | 11/16/2019 | 5:45 PM | Texas: New York: Dutchess County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| November | 2019-11-20 | 4:55 PM | 11/20/2019 | 5:37 PM | California: Imperial County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2019-11-20 | 9:49 AM | 11/20/2019 | 3:20 PM | California: Colusa County, Lake County, Mendocino County, Napa County, Solano County, Sonoma County, Yolo County, Shasta County, Tehama County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 178 | 54000 | Weather |
| November | 2019-11-22 | 12:00 AM | 11/22/2019 | 1:10 AM | New York: Broome County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2019-11-22 | 12:00 AM | 11/22/2019 | 1:10 AM | New York: Monroe County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2019-11-26 | 6:07 PM | 11/27/2019 | 12:27 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 300 | 93000 | Weather |
| November | 2019-11-27 | 2:44 AM | 11/27/2019 | 4:00 PM | California: Santa Clara County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 35 | 2 | Physical Attack |
| November | 2019-11-27 | 12:00 PM | 11/30/2019 | 2:00 AM | Michigan: Tuscola County, Sanilac County, Huron County, St. Clair County, Macomb County, Oakland County, Wayne County, Livingston County, Washtenaw County, Monroe County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 30 | 107000 | Weather |
| November | 2019-11-29 | 12:00 AM | 12/01/2019 | 12:00 AM | Texas: Dawson County; | TRE | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a Bulk Electric System Emergency. | Actual Physical Attack | 0 | 0 | Physical Attack |
| December | 2019-12-03 | 7:16 PM | 12/03/2019 | 7:49 PM | Alabama: Covington County; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2019-12-03 | 6:55 AM | Unknown | Unknown | California: Fresno County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | Unknown | Physical Attack |
| December | 2019-12-05 | 4:48 PM | 12/09/2019 | 5:16 AM | Ohio: Kentucky: | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2019-12-05 | 12:00 AM | Unknown | Unknown | Washington: Chelan County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2019-12-07 | 6:10 AM | 12/08/2019 | 2:20 AM | Oklahoma: Stephens County; | SPP RE | Physical attack that causes major interruptions or impacts to critical infrastructure or to operations. | Actual Physical Attack | 2 | 400 | Physical Attack |
| December | 2019-12-08 | 1:40 PM | 12/08/2019 | 1:41 PM | Texas: Dallas County; | TRE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2019-12-11 | 1:22 PM | 12/11/2019 | 4:28 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2019-12-11 | 8:53 PM | 12/11/2019 | 9:33 PM | Oklahoma: Stephens County; | SPP RE | Physical attack that causes major interruptions or impacts to critical infrastructure or to operations. | Actual Physical Attack | 1 | 392 | Physical Attack |
| December | 2019-12-11 | 1:27 PM | 12/11/2019 | 1:51 PM | North Dakota: Burleigh County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 18 | 1 | Transmission Interruption |
| December | 2019-12-16 | 11:55 PM | 12/17/2019 | 1:47 AM | Texas: | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| December | 2019-12-18 | 2:30 PM | 12/18/2019 | 3:25 PM | Texas: Nueces County; | TRE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2019-12-19 | 2:58 AM | 12/19/2019 | 3:46 AM | Nebraska: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2019-12-24 | 3:30 PM | 12/24/2019 | 7:34 PM | Illinois: | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| December | 2019-12-31 | 12:00 PM | 12/31/2019 | 1:00 PM | Washington: | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| December | 2019-12-31 | 11:03 AM | 01/01/2020 | 10:59 AM | Texas: Nueces County; | TRE | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blocked out area or within the partial failure of an integrated electrical system. | Transmission Interruption | 25 | 0 | Transmission Interruption |
| January | 2020-01-09 | 11:07 PM | 1/9/2020 | 11:19 PM | Arkansas: Yell County; | SPP RE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 0 | 0 | Weather |
| January | 2020-01-09 | 8:45 PM | 1/10/2020 | 9:23 PM | Washington: King County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | Suspicious Activity | 0 | 0 | Cyber Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2020-01-09 | 7:40 AM | 1/9/2020 | 8:48 AM | Minnesota: North Dakota: Wisconsin: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| January | 2020-01-09 | 11:07 PM | 1/9/2020 | 11:18 PM | Arkansas: | SPP RE | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | System Operations | Unknown | Unknown | Operations |
| January | 2020-01-10 | 2:53 PM | Unknown | Unknown | Tennessee: Hamilton County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | Unknown | Unknown | Physical Attack |
| January | 2020-01-11 | 2:25 AM | 1/11/2020 | 7:56 AM | Arkansas: Cross County; | SPP RE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | 22 | 7541 | Weather |
| January | 2020-01-11 | 11:02 PM | 1/12/2020 | 2:01 AM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 66475 | Weather |
| January | 2020-01-11 | 3:30 AM | 1/11/2020 | 5:30 PM | Arkansas: Texas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 68138 | Weather |
| January | 2020-01-11 | 1:20 PM | Unknown | Unknown | Tennessee: | SERC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather | 4 | Unknown | Weather |
| January | 2020-01-11 | 12:50 PM | 1/12/2020 | 1:33 PM | Alabama: Georgia: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 219 | 30715 | Weather |
| January | 2020-01-12 | 11:15 AM | 1/12/2020 | 11:18 AM | Texas: Brazos County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| January | 2020-01-14 | 12:00 AM | 1/14/2020 | 1:00 AM | Florida: Alachua County; | FRCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| January | 2020-01-16 | 11:06 AM | 1/16/2020 | 11:36 AM | Texas: Harris County; | TRE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 2020-01-17 | 5:28 AM | 1/17/2020 | 10:13 AM | California: Humboldt County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather/Transmission Interruption | 87 | 67864 | Weather |
| January | 2020-01-20 | 6:30 AM | 1/20/2020 | 6:31 AM | California: Los Angeles County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| January | 2020-01-22 | 2:57 AM | 1/22/2020 | 3:17 AM | Nevada: Humboldt County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 7 | 3120 | Physical Attack |
| January | 2020-01-23 | 11:30 PM | 1/24/2020 | 12:39 AM | Florida: Manatee County; | FRCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| January | 2020-01-24 | 4:34 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| January | 2020-01-27 | 2:10 PM | 1/27/2020 | 6:58 PM | North Dakota: South Dakota: Montana: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 540 | 130000 | Operations |
| January | 2020-01-30 | 3:01 AM | 1/30/2020 | 4:36 AM | North Dakota: Burleigh County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 75 | 0 | Transmission Interruption |
| January | 2020-01-31 | 9:50 AM | 2/3/2020 | 10:00 AM | California: | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | Suspicious Activity | 0 | 0 | Cyber Attack |
| February | 2020-02-06 | 2:29 PM | 2/7/2020 | 12:44 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | Unknown | 284256 | Weather |
| February | 2020-02-06 | 1:30 PM | 2/7/2020 | 8:08 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | Unknown | 89500 | Weather |
| February | 2020-02-07 | 4:25 PM | 2/8/2020 | 12:00 PM | Connecticut: Maine: Massachusetts: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 123359 | Weather |
| February | 2020-02-07 | 2:42 PM | 2/10/2020 | 9:25 AM | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 7500 | Weather |
| February | 2020-02-07 | 11:00 AM | Unknown | Unknown | Pennsylvania: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | Unknown | 52000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2020-02-07 | 8:48 AM | Unknown | Unknown | Virginia: North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 87000 | Weather |
| February | 2020-02-08 | 1:56 PM | 2/8/2020 | 3:04 PM | California: | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| February | 2020-02-09 | 9:30 AM | 2/9/2020 | 9:40 PM | California: Alameda County, Contra Costa County, El Dorado County, Nevada County, Placer County, Sierra County, Santa Clara County, Napa County, Marin County, Santa Cruz County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 500 | 145000 | Weather |
| February | 2020-02-11 | 2:53 AM | 2/11/2020 | 1:30 PM | Texas: Sterling County; | TRE | Cyber event that could potentially impact electric power system adequacy or reliability. | System Operations | 0 | 0 | Cyber Attack |
| February | 2020-02-11 | 7:13 AM | 2/11/2020 | 4:00 PM | Oregon: Clackamas County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | 0 | Transmission Interruption |
| February | 2020-02-12 | 7:36 AM | 2/12/2020 | 8:53 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| February | 2020-02-13 | 8:01 AM | 2/13/2020 | 2:38 PM | Oregon: | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| February | 2020-02-17 | 9:47 AM | 2/17/2020 | 3:31 PM | Alabama: Chambers County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 97 | Unknown | Physical Attack |
| February | 2020-02-17 | 1:18 PM | 2/20/2020 | 9:51 AM | Michigan: Eaton County; | RF | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| February | 2020-02-17 | 4:00 AM | Unknown | Unknown | Northern and Central California; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 91 | 70000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| February | 2020-02-18 | 1:00 PM | 2/18/2020 | 2:00 PM | California: Kern County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| February | 2020-02-25 | 11:45 AM | 2/25/2020 | 1:00 PM | California: Los Angeles County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| February | 2020-02-26 | 4:30 PM | 2/26/2020 | 5:02 PM | Oklahoma: | SPP RE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| February | 2020-02-26 | 5:00 PM | 2/26/2020 | 6:05 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| February | 2020-02-26 | 11:29 AM | 2/26/2020 | 12:14 PM | South Dakota: Wyoming: Colorado: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| February | 2020-02-29 | 1:45 AM | 2/29/2020 | 2:30 AM | Nevada: Clark County, Washoe County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-01 | 11:27 AM | 03/01/2020 | 9:47 PM | Mississippi: Rankin County; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 19 | 3136 | Transmission Interruption |
| March | 2020-03-01 | 10:15 PM | Unknown | Unknown | New York: | NPCC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-01 | 8:00 AM | Unknown | Unknown | Western NY | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 675 | Unknown | Fuel Supply Deficiency |
| March | 2020-03-02 | 1:43 AM | 03/02/2020 | 2:43 AM | Nevada: Clark County, Washoe County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-03 | 2:30 PM | 03/03/2020 | 2:31 PM | Alabama: | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-08 | 10:10 PM | 03/09/2020 | 1:02 AM | Texas: Llano County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2020-03-12 | 1:03 AM | 03/12/2020 | 3:00 AM | Pennsylvania: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 40 | 15864 | Transmission Interruption |
| March | 2020-03-16 | 12:01 PM | 03/16/2020 | 1:10 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 165 | 110800 | Weather |
| March | 2020-03-16 | 8:00 AM | 03/16/2020 | 8:01 AM | California: Los Angeles County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-16 | 8:00 AM | 03/16/2020 | 8:01 AM | California: Los Angeles County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-17 | 10:30 AM | 03/17/2020 | 11:41 AM | Michigan: Washtenaw County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 6062 | 0 | Operations |
| March | 2020-03-18 | 7:09 AM | Unknown | Unknown | Utah: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Natural Disaster | 237 | 73000 | Natural Disaster |
| March | 2020-03-19 | 5:05 PM | 03/19/2020 | 5:43 PM | Minnesota: St. Louis County; | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-20 | 10:20 PM | 03/20/2020 | 11:30 PM | Connecticut: Massachusetts: Rhode Island: Maine: New Hampshire: Vermont: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-20 | 11:38 PM | 03/20/2020 | 11:59 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-20 | 11:45 PM | 03/21/2020 | 12:30 AM | Connecticut: Massachusetts: | NPCC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-23 | 12:15 AM | 03/25/2020 | 5:11 PM | Wisconsin: Columbia County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-23 | 2:15 PM | 03/23/2020 | 4:37 PM | Virginia: | SERC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Sabotage | Unknown | 1018 | Physical Attack |
| March | 2020-03-24 | 12:45 PM | 03/24/2020 | 2:00 PM | California: Nevada County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| March | 2020-03-24 | 2:55 AM | 03/24/2020 | 6:50 AM | Connecticut: Massachusetts: Maine: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 51026 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| March | 2020-03-25 | 10:31 AM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| March | 2020-03-26 | 9:29 PM | 03/26/2020 | 9:47 PM | Ohio: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 19 | 11964 | Transmission Interruption |
| March | 2020-03-27 | 1:06 PM | 03/27/2020 | 1:58 PM | Delaware: Kent County, New Castle County, Sussex County; Maryland: Cecil County, Harford County, Talbot County, Kent County, Queen Anne's County, Dorchester County, Wicomico County, Worcester County, Somerset County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-27 | 1:06 PM | 03/27/2020 | 1:58 PM | New Jersey: Atlantic County, Cape May County, Cumberland County, Gloucester County, Salem County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| March | 2020-03-29 | 8:27 PM | 03/29/2020 | 11:04 PM | Mississippi: Panola County; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 4 | 1558 | Transmission Interruption |
| March | 2020-03-31 | 11:45 AM | 03/31/2020 | 8:00 PM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 412 | 57744 | Weather |
| April | 2020-04-01 | 9:43 PM | 04/01/2020 | 10:18 PM | Illinois: Williamson County; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2020-04-02 | 6:41 PM | 04/02/2020 | 7:23 PM | Texas: Travis County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2020-04-02 | 1:37 PM | 04/02/2020 | 2:43 PM | Nebraska: York County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 5 | Unknown | Transmission Interruption |
| April | 2020-04-02 | 8:45 PM | Unknown | Unknown | Washington: Wallula | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | Unknown | Unknown | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2020-04-03 | 9:13 AM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-05 | 2:30 AM | 04/05/2020 | 3:01 AM | Texas: Cameron County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| April | 2020-04-05 | 3:46 PM | 04/05/2020 | 5:35 PM | California: Stanislaus County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather | 7 | 6814 | Weather |
| April | 2020-04-07 | 11:39 PM | 04/07/2020 | 11:46 PM | Washington: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2020-04-08 | 9:57 PM | 04/09/2020 | 8:59 AM | Ohio: Kentucky: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 78314 | Weather |
| April | 2020-04-08 | 10:03 PM | 04/09/2020 | 7:36 AM | Indiana: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 93000 | Weather |
| April | 2020-04-08 | 1:21 AM | 04/08/2020 | 3:56 AM | Ohio: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 82509 | Weather |
| April | 2020-04-09 | 7:25 PM | 04/10/2020 | 3:30 AM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 95000 | Weather |
| April | 2020-04-09 | 7:40 PM | 04/11/2020 | 10:00 PM | Maine: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 340000 | Weather |
| April | 2020-04-09 | 7:34 AM | 04/09/2020 | 5:40 PM | Wisconsin: Dane County; | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2020-04-10 | 10:00 AM | 04/10/2020 | 4:19 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| April | 2020-04-10 | 4:00 PM | Unknown | Unknown | Nevada: White Pine County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-11 | 11:24 AM | 04/11/2020 | 11:42 AM | Wyoming: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| April | 2020-04-11 | 5:40 PM | 04/11/2020 | 5:51 PM | Utah: Salt Lake City | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Suspicious Activity | Unknown | Unknown | Physical Attack |
| April | 2020-04-12 | 8:45 PM | Unknown | Unknown | Arkansas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 95318 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2020-04-12 | 1:00 PM | 04/12/2020 | 7:27 PM | Louisiana: Acadia Parish, Iberville Parish, Jefferson Davis Parish, Concordia Parish, Winn Parish, Catahoula Parish, Terrebonne Parish, St. Mary Parish; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | Severe Weather | 122 | 37991 | Weather |
| April | 2020-04-12 | 8:30 PM | 04/14/2020 | 9:00 AM | Arkansas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 51000 | Weather |
| April | 2020-04-12 | 9:28 PM | 04/15/2020 | 12:00 PM | Virginia: West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 104000 | Weather |
| April | 2020-04-12 | 5:00 PM | 04/14/2020 | 1:25 AM | Mississippi: Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 448 | 62828 | Weather |
| April | 2020-04-12 | 6:13 PM | 04/13/2020 | 3:23 PM | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 63289 | Weather |
| April | 2020-04-13 | 3:30 AM | 04/14/2020 | 6:18 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 216400 | Weather |
| April | 2020-04-13 | 12:45 AM | 04/13/2020 | 3:00 AM | Tennessee: Hamilton County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 120000 | Weather |
| April | 2020-04-13 | 8:08 AM | Unknown | Unknown | South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 72233 | Weather |
| April | 2020-04-13 | 10:25 AM | 04/13/2020 | 6:55 PM | North Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 95000 | Weather |
| April | 2020-04-13 | 1:05 PM | 04/14/2020 | 4:00 PM | Connecticut: Maine: Massachusetts: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 68476 | Weather |
| April | 2020-04-13 | 7:31 AM | 04/13/2020 | 2:00 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | Unknown | Weather |
| April | 2020-04-16 | 11:30 AM | 04/16/2020 | 3:45 PM | Georgia: | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-18 | 7:38 PM | Unknown | Unknown | Nevada: Washoe County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-19 | 1:14 AM | 04/20/2020 | 11:42 AM | North Dakota: Burleigh County; | MRO | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| April | 2020-04-20 | 12:42 PM | 04/20/2020 | 1:27 PM | South Dakota: Deuel County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-20 | 12:59 AM | 04/20/2020 | 8:40 AM | Alabama: Mississippi: Georgia: Florida: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 552 | 77341 | Weather |
| April | 2020-04-23 | 4:30 AM | 04/23/2020 | 7:00 AM | Mississippi: Arkansas: Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 55184 | Weather |
| April | 2020-04-23 | 8:00 AM | 04/23/2020 | 11:40 PM | Alabama: Georgia: Mississippi: Florida: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 375 | 52163 | Weather |
| April | 2020-04-24 | 10:00 PM | Unknown | Unknown | Nevada: White Pine County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| April | 2020-04-24 | 9:00 PM | 04/24/2020 | 9:33 PM | California: Placer County, Nevada County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | System Operations | 5 | 945 | Operations |
| April | 2020-04-25 | 9:25 PM | 04/25/2020 | 9:56 PM | Oregon: Multnomah County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| April | 2020-04-26 | 1:38 AM | Unknown | Unknown | Florida: | FRCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 49999 | Weather |
| April | 2020-04-28 | 8:01 PM | 04/28/2020 | 11:21 PM | Texas: Jefferson County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 14 | 1 | Transmission Interruption |
| April | 2020-04-29 | 6:00 AM | 04/29/2020 | 12:31 PM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 77933 | Weather |
| April | 2020-04-29 | 5:55 AM | 04/29/2020 | 7:00 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 146660 | Weather |
| April | 2020-04-30 | 3:00 PM | Unknown | Unknown | Pennsylvania: Bucks County, Chester County, Delaware County, Montgomery County, Philadelphia County, York County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 78007 | Weather |
| May | 2020-05-04 | 11:59 AM | 05/07/2020 | 8:00 PM | Tennessee: Davidson County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 500 | 130000 | Weather |
| May | 2020-05-08 | 1:45 PM | 05/08/2020 | 1:46 PM | Nevada: Nye County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-13 | 11:16 PM | 05/14/2020 | 1:52 PM | Indiana: Hendricks County; | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2020-05-13 | 5:12 AM | 05/13/2020 | 2:07 PM | Washington: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| May | 2020-05-14 | 11:23 AM | 05/14/2020 | 11:25 AM | Oregon: Jackson County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-15 | 5:55 PM | 05/17/2020 | 6:00 PM | New York: Saratoga County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 52 | Weather |
| May | 2020-05-16 | 12:00 AM | 05/16/2020 | 12:30 AM | Texas: Cameron County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | 2020-05-18 | 11:51 PM | 05/19/2020 | 4:37 AM | South Carolina: | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2020-05-18 | 9:27 AM | 05/18/2020 | 10:15 AM | Oregon: Clackamas County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| May | 2020-05-19 | 8:04 PM | 05/19/2020 | 10:00 PM | Alabama: Jefferson County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 8 | 6000 | Physical Attack |
| May | 2020-05-19 | 8:17 AM | 05/19/2020 | 8:18 AM | Idaho: Bonneville County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-19 | 1:45 PM | 05/19/2020 | 1:46 PM | Arkansas: | SPP RE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| May | 2020-05-20 | 11:41 AM | Unknown | Unknown | Nevada: Clark County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-22 | 4:35 PM | 05/23/2020 | 3:29 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 108190 | Weather |
| May | 2020-05-24 | 4:45 PM | Unknown | Unknown | Central Oklahoma | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 54000 | Weather |
| May | 2020-05-25 | 10:58 AM | 05/25/2020 | 1:00 PM | Texas: Kerr County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 8 | 3745 | Transmission Interruption |
| May | 2020-05-27 | 5:15 PM | 05/29/2020 | 6:30 AM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 382000 | Weather |
| May | 2020-05-27 | 5:20 PM | Unknown | Unknown | Texas: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 273269 | Weather |
| May | 2020-05-29 | 5:01 PM | 05/29/2020 | 6:57 PM | Pennsylvania: Warren County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| May | 2020-05-29 | 5:30 PM | 05/31/2020 | 6:00 PM | Minnesota: Hennepin County; | MRO | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center. | System Operations | 0 | 0 | Physical Attack |
| May | 2020-05-29 | 9:37 PM | 05/30/2020 | 4:29 AM | Ohio: Franklin County; | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-30 | 10:20 PM | 05/30/2020 | 11:00 PM | Texas: Bexar County; | TRE | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | 2020-05-31 | 9:30 PM | 06/01/2020 | 1:00 AM | Alabama: Jefferson County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| May | 2020-05-31 | 12:15 AM | Unknown | Unknown | Pennsylvania: | RF | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center. | Vandalism | 0 | 0 | Physical Attack |
| June | 2020-06-02 | 2:36 PM | 06/02/2020 | 2:37 PM | Idaho: Blaine County, Jerome County, Minidoka County, Power County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | Unknown | 0 | Physical Attack |
| June | 2020-06-03 | 1:00 PM | 06/06/2020 | 4:30 PM | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 80 | 87000 | Weather |
| June | 2020-06-03 | 12:30 PM | 06/03/2020 | 6:00 PM | Pennsylvania: Bucks County, Chester County, Delaware County, Montgomery County, Philadelphia County, York County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 708000 | Weather |
| June | 2020-06-03 | 4:57 PM | 06/03/2020 | 5:29 PM | North Dakota: Minnesota: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| June | 2020-06-03 | 1:36 PM | 06/03/2020 | 4:30 PM | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 78079 | Weather |
| June | 2020-06-09 | 11:21 AM | 06/09/2020 | 12:01 PM | Washington: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| June | 2020-06-10 | 7:30 PM | Unknown | Unknown | Michigan: Oakland County, Macomb County, Wayne County, Sanilac County, Tuscola County, Huron County, Lapeer County, Livingston County, Monroe County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 237000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2020-06-10 | 12:22 PM | 06/10/2020 | 5:00 PM | Michigan: Gratiot County, Lake County, Missaukee County, Benzie County, Leelanau County, Manistee County, Wexford County, Montcalm County, Kent County, Ottawa County, Van Buren County, St. Joseph County, Arenac County, Saginaw County, Calhoun County, Branch County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 270000 | Weather |
| June | 2020-06-10 | 5:24 PM | 06/11/2020 | 6:00 PM | Ohio: Indiana: Kentucky: West Virginia: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 85822 | Weather |
| June | 2020-06-12 | 8:21 AM | 06/12/2020 | 8:22 AM | Michigan: Houghton County; | RF | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 0 | Physical Attack |
| June | 2020-06-18 | 12:11 PM | 06/22/2020 | 8:11 AM | Colorado: El Paso County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Actual Physical Attack | 0 | 0 | Physical Attack |
| June | 2020-06-18 | 8:32 PM | 06/18/2020 | 8:35 PM | Kentucky: Gallatin County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 0 | 0 | Physical Attack |
| June | 2020-06-21 | 1:16 AM | 06/21/2020 | 6:45 PM | Delaware: New Castle County; | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2020-06-22 | 11:44 AM | 06/22/2020 | 12:42 PM | Pennsylvania: Allegheny County, Beaver County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| June | 2020-06-25 | 9:40 AM | 06/25/2020 | 11:00 AM | Kentucky: Madison County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | Unknown | 0 | Physical Attack |
| June | 2020-06-26 | 4:20 PM | 06/29/2020 | 3:00 PM | North Dakota: Mountrail County; | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| June | 2020-06-26 | 12:47 PM | 06/26/2020 | 1:53 PM | Texas: Travis County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| June | 2020-06-27 | 4:00 PM | 06/28/2020 | 2:27 AM | Alabama: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 33480 | 78109 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| June | 2020-06-29 | 2:32 PM | 06/29/2020 | 4:35 PM | Arkansas: Garland County; | SPP RE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| June | 2020-06-30 | 10:28 AM | 06/30/2020 | 10:29 AM | Oregon: | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 0 | Physical Attack |
| July | 2020-07-01 | 7:26 PM | 07/01/2020 | 7:44 PM | Pennsylvania: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 32 | 2013 | Transmission Interruption |
| July | 2020-07-02 | 8:30 PM | Unknown | Unknown | California: Butte County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| July | 2020-07-06 | 12:26 PM | Unknown | Unknown | New York: Kings County; | NPCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2020-07-06 | 6:45 PM | 07/06/2020 | 7:42 PM | District of Columbia: Maryland: | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2020-07-07 | 11:38 AM | 07/07/2020 | 6:24 PM | California: Los Angeles County; | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| July | 2020-07-07 | 1:09 PM | 07/08/2020 | 8:17 AM | Colorado: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| July | 2020-07-07 | 7:17 PM | 07/07/2020 | 11:49 PM | West Virginia: Wyoming County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Severe Weather/Transmission Interruption | Unknown | Unknown | Weather |
| July | 2020-07-08 | 10:04 PM | Unknown | Unknown | Texas: | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Actual Physical Attack | 0 | 0 | Physical Attack |
| July | 2020-07-08 | 6:45 PM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2020-07-09 | 3:09 PM | Unknown | Unknown | Washington: Thurston County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2020-07-11 | 11:30 PM | 07/12/2020 | 6:30 AM | Oklahoma: Arkansas: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 68000 | Weather |
| July | 2020-07-11 | 9:30 PM | Unknown | Unknown | Oklahoma: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 94700 | Weather |
| July | 2020-07-11 | 4:55 AM | Unknown | Unknown | California: | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| July | 2020-07-12 | 4:30 AM | 07/13/2020 | 5:00 AM | Texas: Collin County, Dallas County, Denton County, Rockwall County, Tarrant County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 48000 | Physical Attack |
| July | 2020-07-12 | 2:08 PM | 07/12/2020 | 8:44 PM | Nevada: Washoe County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 36 | 10000 | Physical Attack |
| July | 2020-07-13 | 4:30 PM | 07/13/2020 | 4:31 PM | Kentucky: Madison County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2020-07-14 | 2:16 PM | 07/14/2020 | 2:53 PM | California: | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2020-07-15 | 11:00 AM | 07/15/2020 | 11:20 AM | Kentucky: Madison County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | Unknown | 0 | Physical Attack |
| July | 2020-07-16 | 8:49 AM | 07/16/2020 | 11:06 AM | North Dakota: Minnesota: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 475 | 0 | Operations |
| July | 2020-07-17 | 11:00 PM | 07/17/2020 | 11:30 PM | Oklahoma: | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| July | 2020-07-17 | 7:24 PM | Unknown | Unknown | New York: | NPCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2020-07-19 | 2:30 PM | 07/21/2020 | 6:48 PM | Michigan: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 158500 | Weather |
| July | 2020-07-19 | 10:30 AM | Unknown | Unknown | New York: Niagara County | NPCC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 675 | | Fuel Supply Deficiency |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| July | 2020-07-20 | 12:57 AM | 07/20/2020 | 2:34 AM | Texas: Travis County; | TRE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Suspicious Activity | 21 | 14096 | Physical Attack |
| July | 2020-07-21 | 11:53 AM | 07/21/2020 | 1:00 PM | Washington: Pierce County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 19 | 11000 | Physical Attack |
| July | 2020-07-22 | 11:30 AM | 07/22/2020 | 2:19 PM | West Virginia: Tucker County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| July | 2020-07-24 | 8:25 AM | Unknown | Unknown | New York: Bronx County; | NPCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| July | 2020-07-25 | 9:00 PM | 07/26/2020 | 4:00 PM | Texas: Hidalgo County, Cameron County, Starr County, Kenedy County, Willacy County, Brooks County, Jim Hogg County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 125 | 84000 | Weather |
| July | 2020-07-25 | 7:58 PM | 07/27/2020 | 7:00 PM | Texas: Nueces County, Kleberg County, Cameron County, Willacy County, Hidalgo County, Starr County, Kenedy County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 201208 | Weather |
| July | 2020-07-28 | 3:00 PM | 07/28/2020 | 11:00 PM | Michigan: Jackson County; | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| July | 2020-07-30 | 5:54 PM | 07/30/2020 | 8:18 PM | Nebraska: Scotts Bluff County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| August | 2020-08-01 | 11:14 AM | 08/10/2020 | 9:26 PM | Texas: Cameron County, Willacy County, Hidalgo County, Starr County; | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-01 | 8:16 AM | 08/01/2020 | 9:15 AM | California: San Diego County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-01 | 12:00 AM | 08/01/2020 | 12:01 AM | Texas: Cameron County, Hidalgo County, Starr County, Willacy County; | TRE | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a Bulk Electric System Emergency. | Severe Weather | Unknown | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-02 | 7:43 PM | 08/02/2020 | 10:27 PM | Illinois: Rock Island County; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| August | 2020-08-03 | 8:00 AM | 08/03/2020 | 1:00 PM | Texas: Ector County; | TRE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2020-08-03 | 11:15 PM | 08/06/2020 | 7:00 AM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 340000 | Weather |
| August | 2020-08-03 | 11:02 PM | Unknown | Unknown | North Carolina: | SERC | Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-04 | 12:00 PM | 08/07/2020 | 6:00 AM | New York: Rockland County, Orange County, Sullivan County; New Jersey: Bergen County, Passaic County, Sussex County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 160000 | Weather |
| August | 2020-08-04 | 1:00 PM | 08/04/2020 | 11:59 PM | New York: Nassau County, Suffolk County, Queens County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 3907 | 420000 | Weather |
| August | 2020-08-04 | 11:20 AM | 08/07/2020 | 10:55 AM | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 60 | 75000 | Weather |
| August | 2020-08-04 | 9:00 AM | 08/05/2020 | 6:00 PM | Delaware: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 100000 | Weather |
| August | 2020-08-04 | 2:00 PM | 08/08/2020 | 12:00 PM | New York: Dutchess County, Orange County, Ulster County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 116818 | Weather |
| August | 2020-08-04 | 4:41 AM | 08/05/2020 | 4:26 PM | Virginia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 508000 | Weather |
| August | 2020-08-04 | 12:18 PM | 08/08/2020 | 5:31 PM | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 788000 | Weather |
| August | 2020-08-04 | 2:35 PM | 08/10/2020 | 11:00 AM | New York: Broome County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 76120 | Weather |
| August | 2020-08-04 | 3:15 PM | 08/07/2020 | 10:27 AM | Connecticut: Massachusetts: New Hampshire: Maine: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 2000 | 1188247 | Weather |
| August | 2020-08-04 | 1:31 PM | Unknown | Unknown | New York: Bronx County, Richmond County, Queens County, Kings County, Westchester County, New York County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 271119 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-04 | 6:01 AM | 08/06/2020 | 3:30 PM | North Carolina: Brunswick County, Columbus County, Pender County, Duplin County, Onslow County, Jones County, Craven County, Jones County, Beaufort County, Bertie County, Chowan County, Gates County, Perquimans County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 311 | 125987 | Weather |
| August | 2020-08-04 | 12:00 PM | Unknown | Unknown | Pennsylvania: Bucks County, Chester County, Delaware County, Montgomery County, Philadelphia County, York County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 137103 | Weather |
| August | 2020-08-04 | 10:30 AM | Unknown | Unknown | New Jersey: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 70000 | Weather |
| August | 2020-08-04 | 2:35 PM | Unknown | Unknown | New York: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 76120 | Weather |
| August | 2020-08-05 | 5:58 PM | 08/05/2020 | 8:53 PM | Texas: Orange County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 89 | 19785 | Transmission Interruption |
| August | 2020-08-07 | 5:13 AM | Unknown | Unknown | New York: Queens County, New York County; | NPCC | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident. | Severe Weather | 500 | 187068 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-10 | 11:00 AM | 08/10/2020 | 4:00 PM | Iowa: Webster County, Greene County, Dallas County, Hamilton County, Boone County, Polk County, Hardin County, Story County, Jasper County, Grundy County, Marshall County, Tama County, Poweshiek County, Benton County, Iowa County, Linn County, Johnson County, Jones County, Cedar County, Muscatine County, Jackson County, Clinton County, Scott County; | MRO | Uncontrolled loss of 200 Megawatts or more of firm system loads for 15 minutes or more from a single incident for entities with previous year's peak demand less than or equal to 3,000 Megawatts. | Severe Weather | 550 | Unknown | Weather |
| August | 2020-08-10 | 4:00 PM | 08/13/2020 | 3:00 PM | Illinois: Missouri: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 135000 | Weather |
| August | 2020-08-10 | 12:49 PM | Unknown | Unknown | Iowa: | MRO | Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-10 | 10:39 PM | 08/13/2020 | 3:48 PM | Indiana: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 95300 | Weather |
| August | 2020-08-10 | 2:30 PM | Unknown | Unknown | Illinois: Cook County, Will County, DuPage County, Lake County, Kane County, Grundy County, LaSalle County, DeKalb County, McHenry County, Lee County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 856000 | Weather |
| August | 2020-08-10 | 10:25 PM | 08/10/2020 | 11:02 PM | New York: Onondaga County; | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-10 | 12:38 PM | Unknown | Unknown | Iowa: | MRO | Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident. | Severe Weather | 1400 | 250000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-10 | 10:00 AM | Unknown | Unknown | Iowa: Dallas County, Polk County, Warren County, Madison County, Johnson County, Scott County; Illinois: Rock Island County, Henry County, Mercer County; | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 950 | 300000 | Weather |
| August | 2020-08-13 | 1:51 PM | 08/13/2020 | 4:27 PM | Texas: El Paso County; | TRE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | System Operations | 218 | 57060 | Operations |
| August | 2020-08-14 | 6:36 PM | 08/14/2020 | 8:42 PM | California: | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | System Operations | 560 | 220000 | Operations |
| August | 2020-08-14 | 4:39 PM | 08/14/2020 | 5:42 PM | Louisiana: St. Charles Parish; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 101 | 12671 | Transmission Interruption |
| August | 2020-08-14 | 5:15 PM | 08/15/2020 | 9:00 PM | California: | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 1120 | Unknown | Weather |
| August | 2020-08-14 | 6:45 PM | 08/14/2020 | 9:12 PM | California: Kern County, Kings County, Los Angeles County, Orange County, Riverside County, San Bernardino County, Santa Barbara County, Tulare County, Ventura County; | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | System Operations | 1419 | 132000 | Operations |
| August | 2020-08-14 | 8:00 PM | 08/16/2020 | 5:00 PM | Minnesota: Anoka County, Hennepin County, Ramsey County, Washington County; | MRO | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 60000 | Weather |
| August | 2020-08-15 | 6:25 PM | 08/15/2020 | 7:44 PM | California: | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | System Operations | 459 | 220000 | Operations |
| August | 2020-08-15 | 2:53 PM | 08/15/2020 | 8:00 PM | California: | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 795 | Unknown | Weather |
| August | 2020-08-15 | 3:00 PM | 08/15/2020 | 7:45 PM | California: Inyo County, Kern County, Los Angeles County, Orange County, Riverside County, San Bernardino County, Tulare County, Ventura County; | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | System Operations | 200 | 70000 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-15 | 5:00 PM | Unknown | Unknown | Washington: Snohomish County; | WECC | Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems. | Vandalism | 0 | 8 | Physical Attack |
| August | 2020-08-15 | 5:41 PM | 08/15/2020 | 6:48 PM | Connecticut: New Haven County[13]; | NPCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2020-08-16 | 8:00 PM | 08/18/2020 | 9:00 PM | Texas: Collin County, Dallas County, Denton County, Tarrant County, Ellis County, Kaufman County, Johnson County, Anderson County, Angelina County, Grayson County, Smith County, Wichita County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 300000 | Weather |
| August | 2020-08-16 | 3:44 AM | 08/17/2020 | 2:18 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 409 | 124266 | Weather |
| August | 2020-08-16 | 5:30 PM | 08/16/2020 | 7:10 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 712 | Unknown | Weather |
| August | 2020-08-17 | 8:21 AM | 08/17/2020 | 9:01 AM | California: Yuba County; | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather | 2 | 2 | Weather |
| August | 2020-08-17 | 3:05 PM | 08/17/2020 | 9:24 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 829 | Unknown | Weather |
| August | 2020-08-18 | 7:00 PM | 08/18/2020 | 7:30 PM | California: Kings County; | WECC | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center. | Potential Physical Attack | 0 | 0 | Physical Attack |
| August | 2020-08-18 | 2:00 PM | 08/18/2020 | 9:00 PM | Nevada: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 7800 | 1400000 | Weather |
| August | 2020-08-18 | 9:55 PM | 08/18/2020 | 10:10 PM | California: Imperial County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-18 | 1:30 PM | 08/18/2020 | 8:30 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 917 | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-18 | 2:44 PM | 08/18/2020 | 3:14 PM | Texas: Culberson County, Reeves County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 205 | 238 | Transmission Interruption |
| August | 2020-08-18 | 2:30 PM | Unknown | Unknown | Arizona: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 0 | Unknown | Weather |
| August | 2020-08-19 | 1:27 AM | 08/19/2020 | 3:03 AM | Ohio: Trumbull County; | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 22 | 16107 | Transmission Interruption |
| August | 2020-08-19 | 2:00 PM | 08/19/2020 | 9:00 PM | Arizona: Maricopa County; | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 1200 | 0 | Weather |
| August | 2020-08-19 | 2:00 PM | 08/19/2020 | 9:00 PM | Nevada: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 7500 | 1400000 | Weather |
| August | 2020-08-19 | 12:00 PM | 08/19/2020 | 9:00 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-20 | 12:03 AM | 08/20/2020 | 2:05 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-20 | 9:17 AM | 08/20/2020 | 1:42 PM | Mississippi: Jasper County; | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| August | 2020-08-20 | 3:29 PM | 08/20/2020 | 3:39 PM | Nebraska: Custer County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 60 | Unknown | Transmission Interruption |
| August | 2020-08-23 | 10:12 PM | 08/23/2020 | 10:15 PM | West Virginia: Putnam County; | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Suspicious Activity | 0 | 0 | Physical Attack |
| August | 2020-08-23 | 10:30 AM | Unknown | Unknown | Texas panhandle, SE NM | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-24 | 11:00 PM | 08/24/2020 | 11:59 PM | Texas: Denton County; | TRE | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Potential Physical Attack | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-25 | 2:43 AM | 08/25/2020 | 7:43 AM | Colorado: Jefferson County; | WECC | Physical threat to its Bulk Electric System control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. Or suspicious device or activity at its Bulk Electric System control center. | Vandalism | 0 | 0 | Physical Attack |
| August | 2020-08-27 | 5:00 AM | 09/03/2020 | 12:00 PM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 200 | 50000 | Weather |
| August | 2020-08-27 | 7:00 AM | 08/30/2020 | 7:00 PM | Louisiana: Rapides Parish; | SERC | Complete operational failure or shut-down of the transmission and/or distribution of electrical system. | Severe Weather | 48 | Unknown | Weather |
| August | 2020-08-27 | 12:44 PM | 08/27/2020 | 11:00 PM | Texas: | TRE | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-27 | 12:06 PM | 08/27/2020 | 10:49 PM | Texas: | TRE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 581 | Unknown | Weather |
| August | 2020-08-27 | 7:40 AM | 08/31/2020 | 7:40 AM | Louisiana: Texas: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 130000 | Weather |
| August | 2020-08-27 | 1:15 AM | Unknown | Unknown | Texas: Louisiana: | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 615992 | Weather |
| August | 2020-08-27 | 7:40 AM | 08/31/2020 | 3:33 AM | Louisiana: Texas: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 47927 | Weather |
| August | 2020-08-27 | 12:02 PM | 08/27/2020 | 10:54 PM | Texas: | TRE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 573 | Unknown | Weather |
| August | 2020-08-27 | 12:29 PM | 08/27/2020 | 12:59 PM | Nebraska: Douglas County, Burt County, Washington County, Dodge County, Colfax County, Saunders County, Sarpy County, Cass County, Otoe County, Johnson County, Nemaha County, Pawnee County, Richardson County; | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-27 | 5:11 PM | 08/28/2020 | 10:00 AM | Connecticut: Massachusetts: New Hampshire: Maine: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 100 | 60687 | Weather |
| August | 2020-08-27 | 1:24 PM | Unknown | Unknown | Texas: Montgomery County, Liberty County; | TRE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 208 | Unknown | Weather |
| August | 2020-08-27 | 12:06 PM | Unknown | Unknown | Texas: | TRE | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 350 | Unknown | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| August | 2020-08-27 | 6:00 AM | 08/27/2020 | 6:05 AM | West Virginia: Putnam County; | RF | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 2900 | Unknown | Physical Attack |
| August | 2020-08-27 | 3:14 AM | Unknown | Unknown | Louisiana: Calcasieu Parish, Beauregard Parish, Iberia Parish, Acadia Parish, Evangeline Parish, Rapides Parish, St. Landry Parish, Vernon Parish; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-28 | 4:27 PM | 08/28/2020 | 7:26 PM | Washington: Oregon: | WECC | Total generation loss, within one minute of: greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection. | Severe Weather | 0 | 0 | Weather |
| August | 2020-08-28 | 12:25 AM | 08/28/2020 | 1:00 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| August | 2020-08-29 | 3:35 AM | 08/29/2020 | 5:45 AM | Texas: | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | Severe Weather | Unknown | Unknown | Weather |
| August | 2020-08-31 | 9:00 AM | 08/31/2020 | 3:53 PM | Washington: | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| September | 2020-09-01 | 1:04 PM | 09/01/2020 | 1:05 PM | California: Los Angeles County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2020-09-03 | 1:46 PM | 09/03/2020 | 10:47 PM | Washington: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| September | 2020-09-04 | 1:07 AM | 09/04/2020 | 1:37 AM | Florida: Pinellas County; | FRCC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2020-09-05 | 5:20 PM | 09/05/2020 | 8:37 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 986 | Unknown | Weather |
| September | 2020-09-05 | 5:25 PM | 09/05/2020 | 8:55 PM | California: Imperial County; | WECC | Firm load shedding of 100 Megawatts or more implemented under emergency operational policy. | Severe Weather | 100 | 20000 | Weather |
| September | 2020-09-06 | 4:00 PM | 09/06/2020 | 9:00 PM | Nevada: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | Severe Weather | 8180 | 1400000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2020-09-06 | 4:30 PM | 09/06/2020 | 9:05 PM | California: | WECC | Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System. | System Operations | 1071 | Unknown | Public Appeal |
| September | 2020-09-06 | 5:36 PM | 09/06/2020 | 7:27 PM | Washington: Oregon: California: | WECC | Total generation loss, within one minute of: greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection. | System Operations | 0 | 0 | Operations |
| September | 2020-09-06 | 5:00 PM | 09/07/2020 | 3:00 AM | California: Los Angeles County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 72000 | Weather |
| September | 2020-09-07 | 10:40 PM | 09/09/2020 | 5:24 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Transmission Interruption | 610 | 172000 | Transmission Interruption |
| September | 2020-09-07 | 6:00 PM | 09/08/2020 | 6:00 PM | Washington: Kitsap County, King County, Pierce County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 71500 | Weather |
| September | 2020-09-07 | 9:13 AM | 09/08/2020 | 6:00 AM | Washington: | WECC | Complete operational failure or shut-down of the transmission and/or distribution of electrical system. | Natural Disaster | 80 | 21000 | Natural Disaster |
| September | 2020-09-07 | 7:05 PM | 09/08/2020 | 10:00 PM | Oregon: Multnomah County, Washington County, Clackamas County, Marion County, Yamhill County, Polk County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 2859 | 103000 | Weather |
| September | 2020-09-08 | 9:50 AM | 09/08/2020 | 10:56 AM | Michigan: Ingham County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 265 | 0 | Operations |
| September | 2020-09-09 | 10:16 PM | 09/11/2020 | 8:17 AM | Minnesota: Sherburne County; | MRO | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| September | 2020-09-09 | 11:22 AM | 09/09/2020 | 1:04 PM | Idaho: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Natural Disaster | 0 | 0 | Natural Disaster |
| September | 2020-09-15 | 10:00 PM | 09/20/2020 | 3:00 PM | Alabama: Florida: Georgia: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Transmission Interruption | 236 | 34096 | Weather |
| September | 2020-09-15 | 3:04 PM | 09/15/2020 | 3:37 PM | North Dakota: South Dakota: Montana: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2020-09-16 | 7:00 AM | 09/18/2020 | 6:00 AM | Florida: Escambia County; | FRCC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| September | 2020-09-16 | 3:00 AM | 09/21/2020 | 8:00 AM | Alabama: Baldwin County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 0 | 77600 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| September | 2020-09-16 | 2:09 AM | 09/16/2020 | 2:20 AM | Maine: Oxford County; | NPCC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| September | 2020-09-20 | 8:01 PM | 09/21/2020 | 3:44 PM | Oklahoma: Canadian County; | SPP RE | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Actual Physical Attack | 0 | Unknown | Physical Attack |
| September | 2020-09-22 | 10:02 AM | 09/22/2020 | 12:58 PM | California: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | System Operations | 8 | 4350 | Operations |
| September | 2020-09-23 | 12:00 PM | 09/23/2020 | 1:00 PM | New Jersey: | RF | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| September | 2020-09-26 | 5:17 AM | 09/26/2020 | 5:41 AM | Nevada: Clark County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Actual Physical Attack | 26 | 13000 | Physical Attack |
| September | 2020-09-27 | 6:27 PM | 09/28/2020 | 3:17 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Natural Disaster | 337 | 102267 | Natural Disaster |
| September | 2020-09-30 | 5:55 AM | 09/30/2020 | 11:30 PM | Connecticut: Maine: Rhode Island: Massachusetts: New Hampshire: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 155000 | Weather |
| October | 2020-10-02 | 7:30 PM | 10/04/2020 | 6:30 AM | Virginia: Hanover County; | SERC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| October | 2020-10-07 | 1:45 PM | 10/07/2020 | 1:59 PM | Louisiana: Orleans Parish; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 183 | 39089 | Transmission Interruption |
| October | 2020-10-07 | 4:00 PM | Unknown | Unknown | New York: Onondaga County; | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 7500 | Weather |
| October | 2020-10-07 | 6:50 PM | 10/09/2020 | 3:00 PM | Connecticut: Massachusetts: Maine: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 186600 | Weather |
| October | 2020-10-09 | 10:44 AM | 10/09/2020 | 10:25 PM | Colorado: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2020-10-09 | 8:00 PM | 10/15/2020 | 7:00 AM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 200 | 50000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2020-10-09 | 7:50 PM | 10/11/2020 | 3:09 PM | Louisiana: Acadia Parish, Beauregard Parish, Calcasieu Parish, Evangeline Parish, Iberia Parish, Rapides Parish, Vernon Parish, Avoyelles Parish, Grant Parish, Natchitoches Parish, St. Landry Parish, St. Mary Parish, St. Tammany Parish; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 132200 | Weather |
| October | 2020-10-09 | 5:30 PM | 10/10/2020 | 6:00 PM | Louisiana: Texas: Arkansas: Mississippi: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 477966 | Weather |
| October | 2020-10-09 | 8:00 PM | 10/10/2020 | 6:00 AM | Louisiana: Lafayette Parish; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 50000 | Weather |
| October | 2020-10-10 | 11:10 PM | 10/10/2020 | 11:15 PM | Washington: Oregon: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2020-10-10 | 8:05 AM | 10/10/2020 | 12:00 PM | Oregon: Clackamas County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2020-10-10 | 2:22 AM | 10/10/2020 | 5:00 AM | Louisiana: Lafayette Parish; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | Severe Weather | Unknown | Unknown | Weather |
| October | 2020-10-12 | 4:06 AM | 10/12/2020 | 4:07 AM | Florida: Polk County; | FRCC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2020-10-13 | 1:14 PM | 10/14/2020 | 2:00 PM | Washington: Whatcom County, King County, Pierce County, Thurston County, Kittitas County, Kitsap County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 76000 | Weather |
| October | 2020-10-14 | 6:26 PM | 10/15/2020 | 1:11 PM | Texas: Pecos County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 18 | Unknown | Transmission Interruption |
| October | 2020-10-15 | 11:43 PM | Unknown | Unknown | Washington: Walla Walla County; | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| October | 2020-10-15 | 4:50 PM | Unknown | Unknown | Michigan: | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2020-10-16 | 2:00 PM | 10/16/2020 | 4:00 PM | Kentucky: | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 62 | 0 | Physical Attack |
| October | 2020-10-20 | 6:48 PM | 10/20/2020 | 6:49 PM | Illinois: Massac County; | SERC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| October | 2020-10-22 | 8:00 AM | 10/22/2020 | 8:01 AM | Idaho: | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| October | 2020-10-22 | 10:48 PM | 10/22/2020 | 11:34 PM | Florida: Pinellas County; | FRCC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2020-10-23 | 3:42 PM | 10/23/2020 | 11:11 PM | Ohio: | RF | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| October | 2020-10-23 | 3:46 PM | 10/23/2020 | 11:03 PM | Texas: Harris County; | TRE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 55506 | Weather |
| October | 2020-10-24 | 8:13 PM | 10/24/2020 | 10:52 PM | Minnesota: Hennepin County; | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 1 | 4 | Transmission Interruption |
| October | 2020-10-25 | 2:32 PM | 10/27/2020 | 6:00 PM | California: | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 1218 | 370000 | Weather |
| October | 2020-10-25 | 3:25 AM | 10/25/2020 | 3:45 AM | Wisconsin: Milwaukee County; Michigan: | MRO | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Suspicious Activity | 0 | 0 | Physical Attack |
| October | 2020-10-26 | 1:00 PM | 11/07/2020 | 7:00 PM | Oklahoma: Oklahoma County, Canadian County, Logan County, Cleveland County, Pottawatomie County; | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 447000 | Weather |
| October | 2020-10-26 | 11:24 AM | 10/27/2020 | 4:43 PM | California: Los Angeles County, Riverside County, San Bernardino County, Orange County, Kern County, Ventura County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 136833 | Weather |
| October | 2020-10-26 | 9:28 AM | 10/26/2020 | 12:20 PM | Colorado: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 75 | 13000 | Transmission Interruption |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| October | 2020-10-26 | 10:00 AM | 10/26/2020 | 10:15 AM | Kentucky: | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 64 | 0 | Physical Attack |
| October | 2020-10-27 | 5:50 PM | Unknown | Unknown | Oklahoma: | SPP RE | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 235000 | Weather |
| October | 2020-10-28 | 9:37 PM | 11/02/2020 | 7:30 PM | Alabama: Florida: Mississippi: Georgia: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 253 | 35478 | Weather |
| October | 2020-10-28 | 6:00 PM | 10/29/2020 | 1:15 AM | Louisiana: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 481268 | Weather |
| October | 2020-10-28 | 11:53 AM | 10/28/2020 | 3:26 PM | Texas: | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| October | 2020-10-28 | 10:28 AM | 10/28/2020 | 10:29 AM | Texas: | TRE | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather | Unknown | Unknown | Weather |
| October | 2020-10-28 | 5:12 PM | 10/29/2020 | 4:30 PM | Louisiana: St. Tammany Parish, St. Mary Parish; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 72707 | Weather |
| October | 2020-10-29 | 8:15 AM | 10/31/2020 | 6:45 PM | North Carolina: South Carolina: | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 461580 | Weather |
| October | 2020-10-29 | 11:58 AM | 10/29/2020 | 1:10 PM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| October | 2020-10-29 | 2:00 AM | 10/31/2020 | 9:00 AM | Alabama: Baldwin County, Butler County, Clarke County, Conecuh County, Escambia County, Lee County, Lowndes County, Macon County, Montgomery County, Pike County, Russell County, Tallapoosa County, Talladega County, Washington County, Monroe County; Florida: Escambia County, Okaloosa County, Walton County, Santa Rosa County; | SERC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 0 | 90000 | Weather |
| November | 2020-11-01 | 6:00 PM | 11/01/2020 | 6:09 PM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 85677 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2020-11-01 | 12:31 PM | 11/01/2020 | 12:35 PM | California: Placer County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| November | 2020-11-02 | 11:12 AM | 11/02/2020 | 11:21 AM | Florida: | FRCC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| November | 2020-11-07 | 5:40 PM | 11/07/2020 | 10:10 PM | Colorado: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| November | 2020-11-09 | 12:00 PM | 11/10/2020 | 9:45 AM | New Hampshire: Coos County; | NPCC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| November | 2020-11-10 | 10:42 AM | 11/10/2020 | 12:45 PM | Arizona: Maricopa County; | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2020-11-13 | 12:20 AM | 11/13/2020 | 8:00 AM | Washington: Snohomish County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | System Operations | 0 | 0 | Operations |
| November | 2020-11-14 | 7:40 AM | Unknown | Unknown | California: San Bernardino County; | WECC | Fuel supply emergencies that could impact electric power system adequacy or reliability. | Fuel Supply Deficiency | 0 | 0 | Fuel Supply Deficiency |
| November | 2020-11-15 | 3:08 PM | 11/15/2020 | 10:30 PM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 123361 | Weather |
| November | 2020-11-15 | 2:52 PM | 11/16/2020 | 5:59 AM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 96809 | Weather |
| November | 2020-11-15 | 12:30 PM | 11/18/2020 | 9:44 AM | Michigan: Huron County, Livingston County, Macomb County, Monroe County, Wayne County, Washtenaw County, Tuscola County, St. Clair County, Lapeer County, Oakland County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 150000 | Weather |
| November | 2020-11-15 | 3:37 PM | 11/17/2020 | 12:15 PM | Michigan: Iosco County, Oscoda County, Ogemaw County, Livingston County, Ionia County, Barry County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 57327 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 2020-11-15 | 11:05 PM | 11/16/2020 | 5:00 AM | Connecticut: Massachusetts: Maine: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 62408 | Weather |
| November | 2020-11-15 | 11:30 AM | 11/16/2020 | 3:25 AM | Ohio: West Virginia: Virginia: Indiana: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 75000 | Weather |
| November | 2020-11-18 | 8:30 AM | 11/18/2020 | 10:50 AM | Missouri: Jackson County; | SERC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2020-11-18 | 10:20 AM | 11/18/2020 | 11:18 AM | Maine: | NPCC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2020-11-20 | 9:10 AM | 11/20/2020 | 9:22 AM | Texas: Kentucky: Arizona: New Mexico: Oregon: Washington: | TRE | Cyber event that causes interruptions of electrical system operations. | System Operations | 0 | Unknown | Cyber Attack |
| November | 2020-11-21 | 11:59 AM | 11/21/2020 | 12:59 PM | Nevada: Clark County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Actual Physical Attack | 21 | 577 | Physical Attack |
| November | 2020-11-23 | 5:50 AM | 11/23/2020 | 7:27 AM | Wisconsin: Dane County; | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| November | 2020-11-30 | 2:33 PM | 11/30/2020 | 5:20 PM | Texas: El Paso County; | TRE | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 0 | 0 | Transmission Interruption |
| November | 2020-11-30 | 4:24 PM | 12/01/2020 | 2:25 PM | Massachusetts: Maine: Connecticut: Rhode Island: Vermont: New Hampshire: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 116000 | Weather |
| December | 2020-12-01 | 12:32 PM | 12/01/2020 | 10:50 PM | Ohio: | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 170190 | Weather |
| December | 2020-12-03 | 9:01 AM | 12/03/2020 | 9:03 AM | Colorado: | WECC | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | 89 | 0 | Transmission Interruption |
| December | 2020-12-03 | 12:44 AM | 12/05/2020 | 11:03 AM | California: San Diego County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 93 | 73000 | Weather |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2020-12-03 | 10:57 AM | 12/04/2020 | 3:02 PM | California: Kern County, Los Angeles County, Orange County, Riverside County, San Bernardino County, San Diego County, Tulare County, Ventura County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 132 | 51686 | Weather |
| December | 2020-12-05 | 4:40 PM | Unknown | Unknown | Connecticut: Massachusetts: Maine: New Hampshire: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 271231 | Weather |
| December | 2020-12-06 | 9:45 AM | 12/06/2020 | 5:00 PM | Pennsylvania: | RF | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-07 | 6:10 PM | 12/08/2020 | 9:09 PM | California: Kern County, Los Angeles County, Orange County, Riverside County, San Bernardino County, Ventura County, Tulare County; | WECC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | 286 | 76234 | Weather |
| December | 2020-12-08 | 9:43 AM | 12/08/2020 | 10:33 AM | Michigan: Wayne County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-09 | 1:20 PM | 12/09/2020 | 2:30 PM | Missouri: Kansas: | MRO | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-10 | 4:30 PM | 12/12/2020 | 5:00 AM | Washington: King County; | WECC | Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-11 | 10:51 PM | 12/11/2020 | 11:57 PM | Texas: Harris County; | TRE | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-13 | 6:47 AM | 12/13/2020 | 7:36 AM | California: | WECC | Uncontrolled loss of 200 Megawatts or more of firm system loads for 15 minutes or more from a single incident for entities with previous year's peak demand less than or equal to 3,000 Megawatts. | System Operations | 298 | 159239 | Operations |
| December | 2020-12-14 | 11:00 AM | Unknown | Unknown | Idaho: Oregon: | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | Cyber Event | 0 | 0 | Cyber Attack |
| December | 2020-12-14 | 5:01 PM | 12/14/2020 | 5:34 PM | California: | WECC | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2020-12-14 | 1:30 AM | Unknown | Unknown | New Jersey: Pennsylvania: Maryland: Illinois: Delaware: District of Columbia: | RF | Cyber event that could potentially impact electric power system adequacy or reliability. | Cyber Event | 0 | 0 | Cyber Attack |
| December | 2020-12-16 | 11:20 PM | 12/17/2020 | 7:20 AM | Oklahoma: | MRO | Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing). | Transmission Interruption | Unknown | Unknown | Transmission Interruption |
| December | 2020-12-17 | 8:07 AM | 12/17/2020 | 8:32 AM | California: | WECC | Electrical System Separation (Islanding) where part or parts of power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system. | Severe Weather | 35 | 17000 | Weather |
| December | 2020-12-17 | 4:19 PM | 12/17/2020 | 4:57 PM | Michigan: Wayne County; | RF | Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more. | System Operations | 0 | 0 | Operations |
| December | 2020-12-18 | 6:34 AM | 12/18/2020 | 9:51 AM | Oregon: Clackamas County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |
| December | 2020-12-20 | 5:06 AM | 12/20/2020 | 5:22 AM | California: Los Angeles County; | WECC | Cyber event that could potentially impact electric power system adequacy or reliability. | Cyber Event | 0 | 0 | Cyber Attack |
| December | 2020-12-22 | 2:20 AM | 12/22/2020 | 2:21 AM | Washington: Pierce County; | WECC | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Vandalism | 0 | 2000 | Physical Attack |
| December | 2020-12-24 | 11:40 PM | Unknown | Unknown | Pennsylvania: Bucks County, Chester County, Delaware County, Montgomery County, Philadelphia County, York County; | RF | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather/Distribution Interruption | Unknown | 68114 | Weather |
| December | 2020-12-25 | 3:51 AM | 12/25/2020 | 3:52 AM | California: | WECC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |
| December | 2020-12-25 | 6:51 PM | 12/25/2020 | 7:24 PM | Ohio: Kentucky: | RF | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. Or suspicious device or activity at its Facility. | Suspicious Activity | 0 | 0 | Physical Attack |

| Data | Date Event Began | Time Event Began | Date of Restoration | Time of Restoration | Area Affected | NERC Region | Alert Criteria | Event Type | Demand Loss (MW) | Number of Customers Affected | Category |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December | 2020-12-25 | 7:55 AM | 12/25/2020 | 4:45 PM | Connecticut: Maine: New Hampshire: Massachusetts: Rhode Island: Vermont: | NPCC | Loss of electric service to more than 50,000 customers for 1 hour or more. | Severe Weather | Unknown | 19000 | Weather |
| December | 2020-12-28 | 5:31 PM | 12/29/2020 | 1:31 PM | Virginia: | SERC | Damage or destruction of its Facility that results from actual or suspected intentional human action. | Vandalism | 0 | 0 | Physical Attack |

# Exhibit B

**Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Complaint of Michael Mabee** | **)** | |
| **Related to Mandatory Reliability Standards** | **)** | **Docket No. EL21-54-000** |
| **in the Texas Grid Collapse of 2021** | **)** | |

**<u>Motion of Complainant Requesting FERC Take Official Notice</u>**

Submitted to FERC on March 14, 2021

I am a private citizen who conducts public interest research on the security of the electric grid. I am also the Complainant in this docket.

I request that the Commission take official notice of Government Accountability Office (GAO) report GAO-21-346 (March 5, 2021) which is relevant to this docket. The report, entitled: "Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions" is attached as Exhibit A.

The GAO recommended:

> The Chairman of FERC should direct staff to take steps to identify and assess climate related risks to the electricity grid, and plan a response, including identifying actions to address the risks and enhance the resilience of the grid to climate change. (Recommendation 2)

GAO's recommendation would be at least partially addressed by the Commission granting the relief requested by the Complaint in this docket.

Respectfully submitted,

Michael Mabee

# Exhibit A

**Motion of Complainant Requesting FERC Take Official Notice**
**Submitted to FERC on March 14, 2021**

United States Government Accountability Office

Report to Congressional Requesters

March 2021

# ELECTRICITY GRID RESILIENCE

## Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions

**This Report Is Temporarily Restricted Pending Official Public Release.**

A Century of Non-Partisan Fact-Based Work

GAO-21-346

GAO@100 Highlights

Highlights of GAO-21-346, a report to congressional requesters

## Why GAO Did This Study

According to the U.S. Global Change Research Program, changes in the earth's climate are under way and expected to increase, posing risks to the electricity grid that may affect the nation's economic and national security. Annual costs of weather-related power outages total billions of dollars and may increase with climate change, although resilience investments could help address potential effects, according to the research program. Private companies own most of the electricity grid, but the federal government plays a significant role in promoting grid resilience—the ability to adapt to changing conditions; withstand potentially disruptive events; and, if disrupted, to rapidly recover. DOE, the lead agency for grid resilience efforts, conducts research and provides information and technical assistance to industry. FERC reviews mandatory grid reliability standards.

GAO was asked to examine U.S. energy infrastructure resilience. This report describes: (1) potential climate change effects on the electricity grid; and (2) actions DOE and FERC have taken since 2014 to enhance electricity grid resilience to climate change effects, and additional actions these agencies could take. GAO reviewed reports and interviewed agency officials and 55 relevant stakeholders.

## What GAO Recommends

GAO is making two recommendations: (1) DOE should develop a department-wide strategy to enhance grid resilience to climate change, and (2) FERC should identify and assess climate change risks to the grid and plan a response. DOE and FERC neither agreed nor disagreed with GAO's recommendations.

View GAO-21-346. For more information, contact Frank Rusco at (202) 512-3841 or RuscoF@gao.gov.

March 2021

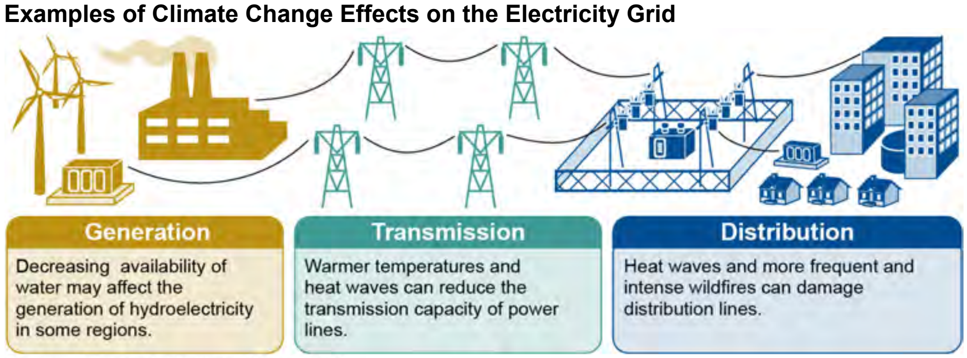
# ELECTRICITY GRID RESILIENCE

## Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions

## What GAO Found

Climate change is expected to have far-reaching effects on the electricity grid that could cost billions and could affect every aspect of the grid from generation, transmission, and distribution to demand for electricity, according to several reports GAO reviewed. The type and extent of these effects on the grid will vary by geographic location and other factors. For example, reports GAO reviewed stated that more frequent droughts and changing rainfall patterns may adversely affect hydroelectricity generation in Alaska and the Northwest and Southwest regions of the United States. Further, transmission capacity may be reduced or distribution lines damaged during increasing wildfire activity in some regions due to warmer temperatures and drier conditions. Moreover, climate change effects on the grid could cost utilities and customers billions, including the costs of power outages and infrastructure damage.

**Examples of Climate Change Effects on the Electricity Grid**




Source: GAO analysis of reports. | GAO-21-346

Since 2014, the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have taken actions to enhance the resilience of the grid. For example, in 2015, DOE established a partnership with 18 utilities to plan for climate change. In 2018, FERC collected information from grid operators on grid resilience and their risks to hazards such as extreme weather. Nevertheless, opportunities exist for DOE and FERC to take additional actions to enhance grid resilience to climate change. For example, DOE identified climate change as a risk to energy infrastructure, including the grid, but it does not have an overall strategy to guide its efforts. GAO's Disaster Resilience Framework states that federal efforts can focus on risk reduction by creating resilience goals and linking those goals to an overarching strategy. Developing and implementing a department-wide strategy that defines goals and measures progress could help prioritize DOE's climate resilience efforts to ensure that resources are targeted effectively. Regarding FERC, it has not taken steps to identify or assess climate change risks to the grid and, therefore, is not well positioned to determine the actions needed to enhance resilience. Risk management involves identifying and assessing risks to understand the likelihood of impacts and their associated consequences. By doing so, FERC could then plan and implement appropriate actions to respond to the risks and achieve its objective of promoting resilience.

# Contents

**Abbreviations List**

| | |
|---|---|
| DOE | U.S. Department of Energy |
| EGCC | Energy Sector Government Coordinating Council |
| ESCC | Electricity Subsector Coordinating Council |
| FEMA | Federal Emergency Management Agency |
| FERC | Federal Energy Regulatory Commission |
| GMLC | Grid Modernization Laboratory Consortium |
| ICE calculator | Interruption Cost Estimate calculator |
| ISO | independent system operator |
| LBNL | Lawrence Berkeley National Laboratory (of the U.S. Department of Energy) |
| NASA | National Aeronautics and Space Administration |
| National Academies | National Academies of Sciences, Engineering, and Medicine |
| NERC | North American Electric Reliability Corporation |
| NOAA | National Oceanic and Atmospheric Administration |
| QER | Quadrennial Energy Review |
| RTO | regional transmission organization |
| USGCRP | U.S. Global Change Research Program |

GAO@100 U.S. GOVERNMENT ACCOUNTABILITY OFFICE
A Century of Non-Partisan Fact-Based Work
**441 G St. N.W.
Washington, DC 20548**

March 5, 2021

The Honorable Tom Carper
Chairman
Committee on Environment and Public Works
United States Senate

The Honorable Joe Manchin
Chairman
Committee on Energy and Natural Resources
United States Senate

Climate change poses risks to the electricity grid—the power generation, transmission, and distribution system—that can potentially affect the nation's economic and national security. In 2013, we identified the federal government's management of climate change risks as a high-risk area due to the fiscal exposure it represents.[1] According to the U.S. Global Change Research Program (USGCRP), changes in the earth's climate are underway, and many extreme weather and climate-related events are expected to become more frequent and intense.[2] Extreme weather events have been the principal contributors to an increase in the frequency and duration of power outages in the United States.[3] As we reported in 2014,

[1]The rising number of natural disasters and increasing reliance on the federal government for assistance is a key source of federal fiscal exposure. The costliness of disasters is projected to increase as extreme weather events become more frequent and intense due to climate change. See GAO, *High-Risk Series: An Update,* GAO-13-283 (Washington, D.C.: Feb. 14, 2013).

[2]Greenhouse gases already in the atmosphere are expected to continue to alter the climate in the future, regardless of efforts to control emissions, according to USGCRP and the National Academies of Sciences, Engineering, and Medicine (National Academies). Nevertheless, according to the Fourth National Climate Assessment, more immediate and substantial global greenhouse gas emission reductions, as well as regional adaptation efforts are needed to avoid the most severe consequences of climate change in the long-term. USGCRP, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment*, vol. II (Washington, D.C.: 2018).

[3]According to the Quadrennial Energy Review and the USGCRP's Fourth National Climate Assessment, the leading cause of power outages in the United States is extreme weather. Quadrennial Energy Review (QER) Task Force, *Transforming the Nation's Electricity System: The Second Installment of the QER* (January 2017). Extreme weather includes high winds, thunderstorms, hurricanes, heat waves, intense cold periods, intense snow events and ice storms, and extreme rainfall. Such events can interrupt energy generation, damage energy resources and infrastructure, and interfere with fuel production and distribution systems, causing fuel and electricity shortages or price spikes.

most of our nation's energy infrastructure was engineered and built for our past or current climate and may not be resilient to continued changes.[4] Recent weather events—such as extreme heat and associated wildfires in California, extreme cold in Texas, and Hurricane Isaias on the East Coast—have adversely affected millions of electric utility customers. While it is not possible to say that climate change caused an individual weather event, these events are illustrative of the potential climate-related vulnerabilities facing the United States. Moreover, power disruptions during extreme weather events illustrate the need to plan for climate change risks and invest in climate resilience.[5]

Private companies own most of the electricity grid in the United States, but the federal government plays a significant role in promoting grid resilience—the ability to adapt to changing conditions; withstand potentially disruptive events, such as the loss of power lines; and if disrupted, to rapidly recover.[6] According to the National Academies of Sciences, Engineering, and Medicine (National Academies), no single entity is responsible for, or has the authority to implement, a comprehensive approach to grid resilience.[7] However, the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) play an important role in shaping electric industry decisions to adopt grid resilience measures. DOE is the lead agency for federal grid resilience efforts, conducts research and development on relevant technologies, and provides industry and other stakeholders with information and technical assistance. FERC regulates wholesale electricity markets and the transmission of electric energy in interstate commerce, reviews and approves mandatory grid reliability standards, and issues licenses for the construction of new hydropower projects, among other things.

[4]GAO, *Climate Change: Energy Infrastructure Risks and Adaptation Efforts,* GAO-14-74 (Washington, D.C.: Jan. 31, 2014).

[5]GAO, *Extreme Weather Events: Limiting Federal Fiscal Exposure and Increasing the Nation's Resilience,* GAO-14-364T (Washington, D.C.: Feb. 12, 2014).

[6]For purposes of this report, we use the definition of "resilience" in Presidential Policy Directive 21, which establishes national policy for critical infrastructure security and resilience. Specifically, Presidential Policy Directive 21 defines resilience as the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including naturally occurring threats or incidents.

[7]National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System* (July 2017).

You asked us to examine efforts to enhance U.S. energy infrastructure resilience. This report describes: (1) the potential effects of climate change on the electricity grid; and (2) actions DOE and FERC have taken since 2014 to enhance the resilience of the electricity grid to climate change effects, and additional actions the agencies could take to further enhance resilience.

To address both objectives, we reviewed relevant laws as well as agency guidance and documents, including the DOE Quadrennial Energy Review (QER) Task Force's Second Installment of the QER, the DOE and U.S. Department of Homeland Security's *Energy Sector-Specific Plan, 2015,* and FERC's *Strategic Plan, Fiscal Years 2018-2022*.[8] We interviewed DOE and FERC staff and representatives from the North American Electric Reliability Corporation (NERC)—the federally designated U.S. electric reliability organization.[9] We also conducted semi-structured interviews with 55 stakeholders who are knowledgeable about grid operations, climate change, and resilience measures.[10] We generally asked the same questions during each interview, including asking for recommendations for other stakeholders and organizations we should interview. These stakeholders include groups or individuals from academia; state government (e.g., an association representing state energy offices and another representing public utility commissions); industry (e.g., investor-owned utilities, public utilities, and electric cooperatives; regional and independent transmission organizations; and industry groups and associations); research organizations; environmental

[8]Quadrennial Energy Review Task Force, *Transforming the Nation's Electricity System.* U.S. DOE and U.S. Department of Homeland Security, *Energy Sector-Specific Plan, 2015* (Washington, D.C.: 2015), and Federal Energy Regulatory Commission. Strategic Plan, Fiscal Years 2018-2022 (Washington, D.C.: September 2018).

[9]We interviewed officials from several DOE offices, including the Office of Electricity, the Office of International Affairs, and the Office of Policy. We also received written responses from the Advanced Research Projects Agency-Energy, the Office of Cybersecurity, Energy Security, and Emergency Response and the Office of Energy Efficiency and Renewable Energy. FERC offices include: the Office of Electric Reliability, the Office of Energy Infrastructure Security, the Office of Energy Market Regulation, the Office of Energy Policy and Innovation, and the Office of the Executive Director.

[10]We did not interview but received written responses from a stakeholder group representing public utilities.

organizations; and staff from six DOE National Laboratories.[11] We also interviewed an energy consultant and a former FERC commissioner.

We identified these stakeholders through a review of prior GAO work and relevant reports (e.g., stakeholder involvement in related federal efforts such as the Fourth National Climate Assessment), and through recommendations from stakeholders and DOE and FERC staff. We selected stakeholders who were knowledgeable about electricity, climate change, and resilience. Specifically, for stakeholders from academia, we selected individuals who had authored a study on electricity grid resilience, climate change, or related topic; testified before the U.S. Congress on relevant topics; served on a relevant panel or advisory group (i.e., member of a relevant federal advisory committee, such as DOE's Electricity Advisory Committee, or the National Academies); or were recommended by one or more stakeholders we interviewed. We also selected research groups with knowledge of electricity and climate change data and models. We selected stakeholders from state government and industry (e.g., utilities and grid operators) from different regions of the United States, including Alaska and Hawaii, since climate change effects vary by region. Findings from our selected stakeholders cannot be generalized to those we did not speak with or include in our review; rather, our interviews provide insights into how selected stakeholders viewed the various topics.

To describe what is known about the potential effects of climate change on the electricity grid, we reviewed 30 reports, such as the USGCRP's Fourth National Climate Assessment and reports issued through DOE's Partnership for Energy Sector Climate Resilience.[12] To identify these reports, we reviewed prior GAO work and asked for recommendations from stakeholders we interviewed. To understand the potential costs of climate change on the electricity grid, we conducted a literature search for

[11]The number of stakeholders by category is as follows: six from academia; nine from state government including associations representing state energy offices, state public service commissioners, and state utility consumer advocates; 24 from industry (including three federal utilities: the Tennessee Valley Authority, the Bonneville Power Administration and the Western Area Power Administration); five research organizations including the research arm of one credit agency that has published work on climate change effects on utilities' credit ratings; three environmental organizations and staff from six DOE National Laboratories: Argonne National Laboratory; Pacific Northwest National Laboratory; Lawrence Berkeley National Laboratory; Sandia National Laboratory; National Renewable Energy Laboratory; and Oak Ridge National Laboratory.

[12]We use the term "report" to refer to federal agency program reports; journal articles; and publications by associations, nonprofit organizations, consultants, and think tanks.

reports published since 2012. We searched sources such as Scopus. We reviewed 19 reports and identified one that quantified the climate change impacts on transmission and distribution infrastructure. To understand the potential costs of power outages, we conducted a literature search for reports published since 2012. We searched sources including Scopus and ProQuest, among others, and asked for report recommendations from stakeholders we interviewed. We focused on reports that addressed three issues: (1) estimates of annual average costs of weather-related outages in the United States; (2) estimates of the costs of outages due to specific severe weather events; and (3) the types of costs—direct and indirect—that are included or excluded in these estimates. We identified three reports that estimated the annual costs of power outages in the United States specifically related to weather. We reviewed the methodologies of these reports and determined that the estimates were sufficiently reliable for our purposes of describing estimates of the annual average cost of weather-related outages.

To identify actions DOE and FERC have taken to enhance the resilience of the electricity grid to climate change since 2014, we reviewed federal agency reports, such as DOE's 2016 Climate Change Adaptation Plan[13] and budget documents; reports from federal entities such as the Congressional Research Service and DOE National Laboratories; and other documents including FERC proposed and final rules, and meeting transcripts. To identify further actions the agencies could take to enhance grid resilience, we reviewed 24 reports from DOE National Laboratories, academia, industry, consultants, research institutions, and environmental groups. This includes reviewing recommendations on grid resilience included in reports by the National Academies, the Electricity Advisory Committee, the House Select Committee on the Climate Crisis, and the

[13]U.S. Department of Energy, Sustainable Performance Office, *Climate Change Adaptation Plan, 2016 Interim Update* (Washington, D.C: December 2016).

National Commission on Grid Resilience.[14] To identify these reports, we searched industry news sources, reviewed prior GAO work, and asked for report recommendations from stakeholders we interviewed. We reviewed reports based on their relevance to how DOE and FERC could enhance the resilience of the electricity grid to climate change effects.[15] We also reviewed our prior work on risk management, climate change, and climate resilience; and assessed agency actions using agency planning documents and GAO's Disaster Resilience Framework and enterprise risk management framework.[16]

We also reviewed documents such as comments to FERC regarding grid resilience from regional and independent transmission organizations,[17] utilities, and organizations, such as the Center for Climate and Energy

[14]National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System;* and The Electricity Advisory Committee, *Policy and Research Opportunities for Grid Resilience: Recommendations for the U.S. Department of Energy* (March 2019). The Electricity Advisory Committee is a federal advisory committee composed of 35 members from state governments, regional planning entities, utility companies, cybersecurity and national security firms, the natural gas sector, equipment manufacturers, construction and architectural companies, nongovernmental organizations, and other electricity-related organizations. See also The House Select Committee on the Climate Crisis, Majority Staff Report*: Solving the Climate Crisis: The Congressional Action Plan for a Clean Energy Economy and a Healthy, Resilient, and Just America* (Washington, D.C.: June 2020). National Commission on Grid Resilience, *Grid Resilience: Priorities for the Next Administration* (August 2020). The National Commission on Grid Resilience is a bipartisan group chartered and supported by Woodstar Labs, a nonprofit technology and analysis firm owned by Associated Universities Inc.

[15]We reviewed information on grid resilience to climate change and not on mitigation or lowering emissions. We discuss mitigation to the extent that documents we reviewed and stakeholders identified mitigation as a strategy for enhancing the resilience of the grid.

[16]GAO, *Disaster Resilience Framework: Principles for Analyzing Federal Efforts to Facilitate and Promote Resilience to Natural Disasters,* GAO-20-100SP (Washington, D.C.: Oct. 23, 2019); and GAO, *Enterprise Risk Management: Selected Agencies' Experiences Illustrate Good Practices in Managing Risk,* GAO-17-63 (Washington, D.C.: Dec. 1, 2016).

[17]Different regions of the country use different approaches to ensure adequate electricity supplies. In some regions, entities called regional transmission organizations (RTOs) manage the system of electricity lines that comprise the grid and help ensure enough electricity is available to meet customers' electricity needs in the future. While major sections of the country operate under more traditional market structures, two-thirds of the nation's electricity is served in RTO regions. Independent operators of the transmission system can be referred to as RTOs or independent system operators (ISO). For the purposes of this report, we use the term "RTOs" to refer to both RTOs and ISOs. FERC does not regulate wholesale sales of electricity in the ISO market in Texas (which is known as the Electric Reliability Council of Texas) which is separate from the rest of the U.S. grid.

Solutions and Columbia University's Sabin Center for Climate Change Law.[18] We analyzed the information and identified themes from both interviews and reports. Throughout the report, we use the following categories to quantify statements identified by reports or stakeholders: "some," which we define as two to five reports or stakeholders collectively; "several," which we define as six to 10 reports or stakeholders collectively; and "many," which we define as more than 10 reports or stakeholders collectively. Given our methodology, we may not have identified every action DOE and FERC could take to enhance the resilience of the grid to climate change effects, but we provide key examples of actions these agencies could take.

We conducted this performance audit from November 2019 to March 2021, in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

## Background

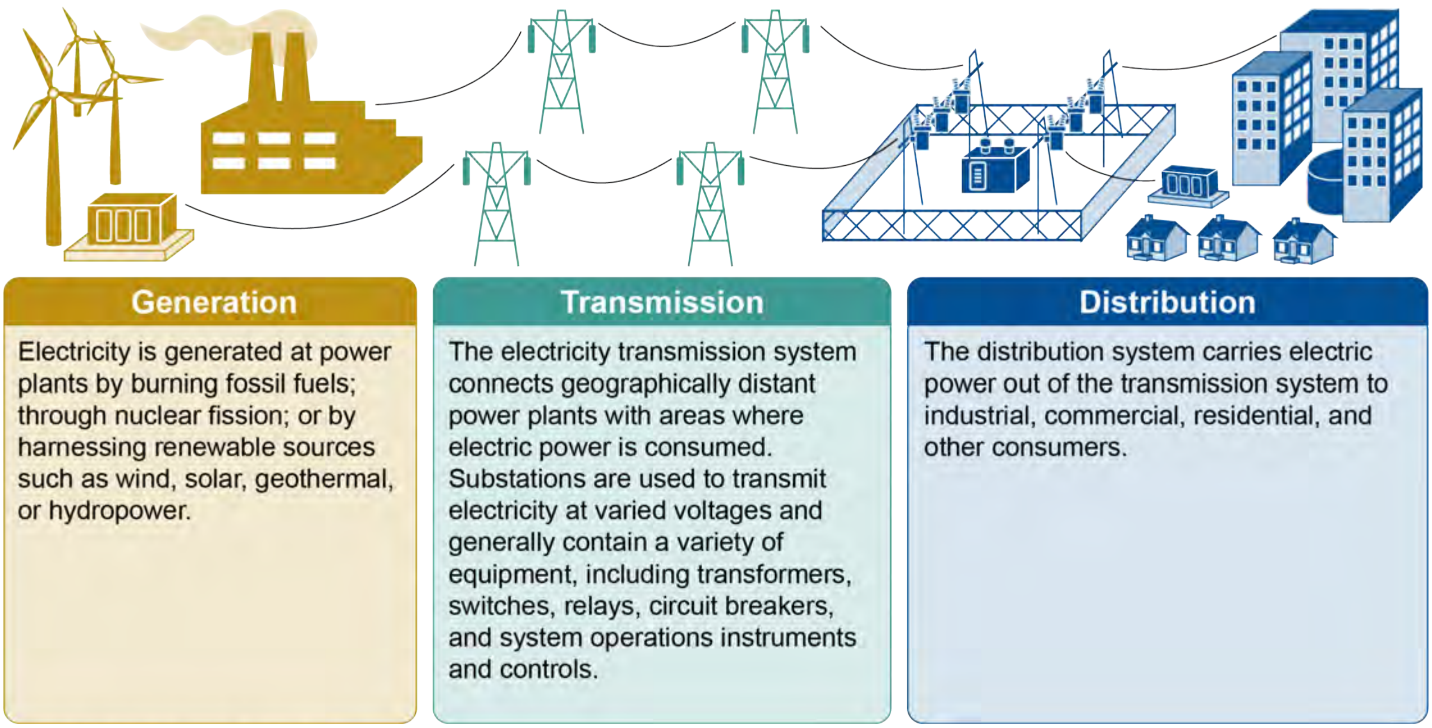
This section describes (1) the electricity grid, (2) oversight of the electricity industry, (3) the federal government's role in ensuring grid resilience to climate change, and (4) risk management and GAO's Disaster Resilience Framework.

### The Electricity Grid

The electricity grid involves three main functions: generation, transmission, and distribution (see fig. 1).

[18]FERC Docket AD18-7-000, *Grid Resilience in Regional Transmission Organizations and Independent System Operators* (Jan. 8, 2018).

**Figure 1: The Electricity Grid**




Source: GAO analysis of reports. | GAO-21-346

Throughout the process of generating and delivering electricity to customers, grid operators, such as local utilities, must constantly seek a balance between the generation and consumption of electricity. To do so, grid operators monitor electricity consumption from a centralized location, using information systems, and send minute-by-minute signals to power plants to adjust their output to match changes in the demand for electricity.

The United States has over 10,000 power plants, more than 642,000 miles of high-voltage transmission lines, and 6.3 million more miles of distribution lines. Grid operators in the United States are investing in an aging grid with a growing segment of the infrastructure that needs replacement or modernization. For example, about 70 percent of the electricity grid's transmission lines and power transformers are at least 25 years old, and the average age of power plants is at least 30 years old. According to the American Society of Civil Engineers, most of our nation's electricity transmission system was built in the 1950s and 1960s and was expected to last 50 years.[19] The electricity sector is experiencing complex transformations and challenges, including aging infrastructure; a changing mix of power generation; growing penetration of variable generation, such as wind and solar; climate change; increased physical and cybersecurity risks; and, in some regions, widespread adoption of distributed energy resources.[20] Moreover, the traditional model of large centralized generators is evolving as retiring generators are replaced with variable wind and solar generators;[21] smaller and more flexible natural gas generators; and nontraditional resources, such as demand-response and distributed generation.[22]

New technologies provide utilities with additional options for meeting demand and providing reliable service. These options include variable energy resources, smart grid technologies, and energy storage.[23] Many of these options are relatively inexpensive and fast to deploy, especially compared with constructing large, conventional power plants. New technologies will also alter the traditional, real-time requirements for grid operations and the nature of production, transmission, and distribution. In addition, new technologies within the system are increasingly available for use by customers and can enable more flexible operations.

Grid operators conduct planning to assess the ability of the existing grid infrastructure to meet the demand for electricity and evaluate the cost and

[19]American Society of Civil Engineers, *Failure to Act: Electric Infrastructure Investment Gaps in a Rapidly Changing Environment* (Reston, VA: 2020).

[20]A distributed energy resource is any resource located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.

[21]Due to their variable output, these new technologies are different from traditional generation resources. Wind and solar units are only available to generate electricity when the wind is blowing or the sun is shining and, for this reason, they are often referred to as “variable generation” resources and do not fit the traditional paradigm of building capacity to meet baseload, intermediate, or peaking needs.

[22]Demand response activities encourage consumers to reduce demand when the cost to generate electricity is high, which can reduce the costs of producing electricity, improve market functions, and enhance reliability.

[23]Smart grid technologies include information and communications systems to automate actions with the aim of improving the electric grid’s reliability and efficiency, as well as facilitating the use of alternative energy sources. Smart grid technologies include new devices, such as smart meters and appliances that allow for the use of rate structures, and other mechanisms to more cost effectively balance the demand and supply of electricity.

effectiveness of potential solutions to meet demand. Utilities have various options to meet the demand for electricity, including constructing new plants, upgrading existing plants, purchasing power from other utilities, building new transmission and distribution lines, and providing incentives to customers to reduce their demand for electricity. Utilities deal with uncertainties, such as future supply and user demand for electricity, partly by producing a range of forecasts and using models to help determine the least-costly way to meet demand. If their forecasts and models are incorrect, a utility could end up with more or less generating capacity than it needs to meet user demand for electricity, or with a resource portfolio that is not cost effective. These outcomes can affect electricity rates that customers pay, as well as the utility's financial situation.

There are three types of electric utilities: investor-owned utilities are large public companies that issue stock owned by shareholders; publicly owned utilities are operated by federal, state, or municipal governments; and electric cooperatives are member-owned not-for-profits. Investor-owned utilities are required to disclose, through annual and other periodic filings with the Securities and Exchange Commission, information about known trends, events, and uncertainties that are reasonably likely to have a material effect on the company's financial condition or operating performance.[24] These disclosures may include information on climate-related risks.

## Oversight of the Electricity Industry

Responsibility for regulating the electricity industry is divided between the states and the federal government. Most electricity customers are served by electric utilities that are regulated by the states, generally through state public utility commissions or equivalent organizations. As the primary regulator of electricity, state public utility commissions have a variety of responsibilities, such as approving utility investments in generation and distribution assets, the rates customers pay, and how those rates are

[24]GAO, *Climate Related Risks: SEC Has Taken Steps to Clarify Disclosure Requirements,* GAO-18-188 (Washington, D.C.: Feb. 20, 2018). Almost three-quarters of utility customers get their electricity from investor-owned utilities.

set.[25] Before electricity is sold to end-use customers, it may be traded in wholesale electricity markets that the federal government oversees through FERC.[26] FERC regulates the interstate transmission of electricity and is responsible for overseeing regional transmission organizations' (RTO) development and operation of markets to ensure that wholesale electric rates are "just and reasonable" and not "unduly discriminatory or preferential."[27] To do so, FERC reviews and approves RTO market rules and monitors the competitiveness of RTO markets. RTOs serve as grid operators by managing regional networks of electric transmission lines and also operate wholesale electricity markets to buy and sell services to maintain a reliable grid. In regions of the country without RTOs, electric utilities generally serve in the role of grid operator. Utilities in these regions may build and operate power plants to provide electricity to serve their customers. These utilities may also buy electricity from other power plant owners.

## The Federal Government's Role in Ensuring Grid Resilience to Climate Change

National policies and federal preparedness efforts have highlighted the importance of enhancing the resilience of the nation's critical infrastructure, including the electricity grid. Presidential Policy Directive 21, issued in February 2013, established national policy on critical infrastructure security and resilience. The directive expanded the nation's focus from protecting critical infrastructure against terrorism to protecting critical infrastructure and increasing its resilience against all hazards,

[25]State regulators approve utility investments either in advance of construction or afterwards, when the utility seeks to recover costs in the rates it charges customers. Some states have integrated resource planning processes to determine what facilities should be built. The purpose of integrated resource planning is to meet future power demand by identifying the need for generating capacity and determining the best mix of resources to meet the need on a least-cost, system-wide basis. The integrated approach considers a broad range of feasible supply-side and demand-side options and assesses them with respect to financial, economic, and environmental impacts.

[26]FERC is to be composed of five commissioners, who are appointed by the President of the United States with the advice and consent of the Senate. FERC needs a quorum of three commissioners to conduct business. Commissioners serve 5-year terms and have an equal vote on regulatory matters.

[27]This authority is granted under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d-824e. According to FERC staff, FERC does not have an explicit statutory mandate under the Federal Power Act to initiate rates with respect to climate change considerations. However, under the Federal Power Act, if a public utility seeks to recover in its jurisdictional rates costs incurred related to climate change issues, FERC would review the proposed rates to determine whether they are just and reasonable given the inclusion of such costs, according to these officials.

including natural disasters, terrorism, and cyber incidents.[28] In addition, the directive recognizes that proactive and coordinated efforts are necessary to strengthen and maintain critical infrastructure that is secure and resilient. It also identifies 16 critical infrastructure sectors, including the energy sector—which encompasses the electricity grid—and designates lead federal agencies to coordinate and prioritize security and resilience activities in each sector. *The Energy Sector-Specific Plan, 2015,* describes federal efforts to improve the security and resilience of the energy sector's critical infrastructure, including the electricity grid, and identifies federal priorities for enhancing the security and resilience of the grid and addressing potential risks, such as climate change.[29]

- **DOE:** Designated as the lead sector-specific agency for the energy sector, DOE is responsible for coordinating with other relevant federal agencies, such as the Department of Homeland Security, and for collaborating with critical infrastructure owners and operators to prioritize and coordinate federal resilience efforts. In 2015, DOE led the update to *Energy Sector-Specific Plan, 2015*. DOE also funds research and provides information and technical assistance to utilities and states and partners with other federal agencies on these efforts. DOE is a member of the USGCRP —which coordinates and integrates the activities of 13 federal agencies that research changes in the global environment and their implications for society and prepares the National Climate Assessment.
- **FERC.** In addition to overseeing RTO operation of markets, FERC reviews and approves standards that NERC develops to provide for the reliable operation of the bulk power system. NERC is the federally designated U.S. electric reliability organization and is responsible for conducting reliability assessments and developing and enforcing mandatory standards to provide for the reliable operation of the bulk power system.[30] FERC conducts inquiries, audits, and investigations of major blackouts and other grid-related events to determine whether

[28]*Presidential Policy Directive-21*, Critical Infrastructure Security and Resilience (Feb. 12, 2013).

[29]DOE and U.S. Department of Homeland Security, *Energy Sector-Specific Plan, 2015.*

[30]The bulk power system includes the facilities and control systems necessary for operating the interconnected electricity transmission network and the electric energy from certain generation facilities needed for reliability. NERC has developed reliability standards for the bulk power system, including standards on cybersecurity and physical security. FERC can approve or disapprove NERC-proposed reliability standards, and can remand them back to NERC for further consideration, but it cannot author or unilaterally modify reliability standards.

the standards were violated and whether adjustments to the standards are needed to help prevent future blackouts.

## Risk Management and GAO's Disaster Resilience Framework

According to USGCRP's Fourth National Climate Assessment, enhancing climate resilience entails a continuing risk management process through which individuals and organizations become aware of and assess risks and vulnerabilities from climate and other drivers of change, take actions to reduce those risks, and learn over time. In December 2016, we found that enterprise risk management can assist federal leaders in anticipating and managing risks. Enterprise risk management includes first identifying and assessing risks to understand the likelihood of impacts and their consequences, and then planning risk responses and making decisions.[31]

In October 2019, we issued the Disaster Resilience Framework to serve as a guide for analysis of federal action to facilitate and promote resilience to natural disasters.[32] The principles in this framework can help identify opportunities to enhance federal efforts to promote disaster resilience, including building resilience to climate change. As shown in figure 2, the framework is organized around three broad, overlapping principles to enhance federal efforts to promote disaster resilience.

[31] GAO-17-63.

[32] GAO-20-100SP.

**Figure 2: GAO's Disaster Resilience Framework**

## Principle:

### Information

Accessing information that is authoritative and understandable can help decision makers to identify current and future risk and the impact of risk-reduction strategies.

**Provide reliable and authoritative information about current and future risk**

To what extent could federal efforts:
- Enhance the validity and reliability of the disaster risk information produced?
- Generate and share additional information that would help decision makers understand their disaster risk?
- Reduce the complexity of and translate risk information for non-technical audiences?
- Help leverage and synthesize disaster risk information from other partners across agencies, governments, and sectors?
- Promote consensus around the reliability of the sources and methods that produce disaster risk information?

**Improve the ability to assess alternatives to address risk**

To what extent could federal efforts:
- Help decision makers identify and select among disaster risk-reduction alternatives?
- Provide technical assistance to help build capacity of nonfederal partners?
- Contribute to an understanding of approaches for estimating returns on investment?
- Help decision makers identify and combine available funding sources and innovative methods for meeting disaster risk-reduction needs?

**Strengthen the ability to assess status and report progress**

To what extent could federal efforts:
- Advance methodologies or processes to measure the current state of nationwide resilience?
- Promote monitoring of progress toward resilience on a programmatic basis?

### Integration

Integrated analysis and planning can help decision makers take coherent and coordinated resilience actions.

**Build an overarching strategic vision and goals**

To what extent could federal efforts:
- Help to establish overarching strategies that guide national resilience efforts?
- Ensure that resilience goals are incorporated into relevant national strategies?
- Prioritize resilience goals that reflect the most pressing resilience challenges?

**Promote coordination across missions and sectors**

To what extent could federal efforts:
- Ensure consistent and complementary policies, procedures, and timing across relevant federal funding mechanisms?
- Convene stakeholders with different perspectives and interests to create whole systems solutions?
- Encourage governance mechanisms that foster coordination and integrated decision making within and across levels of government?
- Engage non-government partners in disaster risk reduction?

**Recognize relationships among infrastructure and ecosystems**

To what extent could federal efforts:
- Promote better understanding and awareness of the interactions among infrastructure components and ecosystems in disaster resilience actions?
- Assist decision makers in determining what combination of ecosystem and built infrastructure solutions will best suit their needs within their constraints?
- Assist in ensuring that projects undertaken under different programs and by different actors do not conflict?
- Facilitate planning across jurisdictions and sectors to avoid or respond to cascading failure?

### Incentives

Incentives can help to make long-term, forward-looking risk-reduction investments more viable and attractive among competing priorities.

**Provide financial and nonfinancial incentives**

To what extent could federal efforts:
- Make risk-reduction measures more viable and attractive?
- Incorporate disaster risk-reduction measures in infrastructure and ecosystem management financial assistance?
- Require disaster risk-reduction measures for government-owned or -operated infrastructure and for federally funded projects?

**Reduce disincentives**

To what extent could federal efforts:
- Alleviate unnecessary administrative burden?
- Streamline review processes?
- Improve program design to motivate risk-reduction actions?

Source: GAO, Disaster Resilience Framework: Principles for Analyzing Federal Efforts to Facilitate and Promote Resilience to Natural Disasters, GAO-20-100SP (Washington, D.C.: Oct. 23, 2019). | GAO-21-346

## Climate Change Is Expected to Have Far-reaching Effects on the Electricity Grid That Could Cost Billions

Climate change is expected to have far-reaching effects on the electricity grid that could cost billions and affect every aspect of the electricity grid, from generation, transmission, and distribution to end-user demand, according to several reports we reviewed. The types and extent of the effects that climate change will have on the grid will vary by geographic location and other factors, according to reports we reviewed.

### Climate Change Is Expected to Affect Every Aspect of the Electricity Grid

Climate change is expected to affect all aspects of the electricity grid, from generation, transmission, and distribution to end-user demand, according to several reports we reviewed.[33] The type and extent of the effects of climate change on the grid will vary by geographic location, energy source, condition of grid infrastructure, and other factors, according to several stakeholders we interviewed and reports we reviewed. According to the Fourth National Climate Assessment, many regions will experience more than one climate-related effect. For example, a region may see more extreme rainfall combined with coastal flooding, or extreme heat coupled with drought. However, warmer temperatures and more heat waves could affect all regions in the United States and could decrease the efficiency of electricity generation, transmission, and distribution systems, according to reports we reviewed.

- *Generation:* The effects of climate change could impact the efficiency of power plant operations and the ability to generate power. For example, storms can disrupt operations; extreme heat can affect the efficiency of power plant operations; and changes in the availability of resources needed to generate electricity, such as water, can affect the ability to generate power. Climate change is expected to increase the frequency and intensity of hurricanes. Paired with greater rainfall, rising sea levels, and larger storm surges, future hurricanes may increase the risk of coastal flooding. Power plants along the Atlantic and Gulf Coasts are especially vulnerable to flooding. In addition, wind turbines in close proximity to the Gulf of Mexico may be vulnerable to wind damage from more intense hurricanes.[34] According

[33]DOE National Laboratories (Argonne National Laboratory, Brookhaven National Laboratory, Los Alamos National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, and Sandia National Laboratory), *Resilience of the U.S. Electricity System: a Multi-Hazard Perspective* (August 2016).

[34]DOE, *Climate Change and the U.S. Energy Sector: Regional Vulnerabilities and Resilience Solutions* (Washington, D.C.: October 2015).

to the Fourth National Climate Assessment, hundreds of electricity facilities along the Gulf and Atlantic Coasts are threatened by Category 5 hurricanes, which have the potential to cause catastrophic damage. Electricity generation in these regions serves other parts of the country, and regional disruptions can have national implications.

In addition, more frequent droughts and changing rainfall patterns in some regions may affect the ability to generate electricity, such as water shortages affecting nuclear plants or hydroelectricity. For example, earlier snowmelt or more frequent droughts in regions that use hydroelectricity as a source of electricity generation—such as Alaska, the Northwest, and the Southwest—could face changes in hydroelectricity generation patterns. According to a 2015 DOE report, in Alaska—where hydroelectricity generates about 25 percent of the state's electricity—declining snowpack and earlier snowmelt, among other factors, may shift peak streamflow timing, reduce water availability, and limit hydroelectricity generation in the summer. Moreover, utilities in the western United States have also reported that earlier snowmelt and runoff due to higher temperatures have reduced the amount of water in reservoirs that are available for the warmer months of the year. Droughts can also reduce the amount of water available for the cooling of electricity-generating units, causing these units to go offline. In addition, high temperatures can trigger environmental requirements that force a power plant to shut down. For example, in 2007, 2010, and 2011, the Tennessee Valley Authority had to reduce power output from its Browns Ferry Nuclear Plant in Alabama because the temperature of the river was too high to receive discharge water without raising ecological risks.[35]

- *Transmission:* Climate change could also affect the ability of grid operators to transmit electricity. For example, warmer temperatures in the Southwest are estimated to decrease transmission line capacity by between 1.5 and 2.5 percent, according to a DOE report. Moreover, higher temperatures cause the expansion of transmission line materials, and sagging lines can cause permanent damage to the lines, increasing the likelihood of power outages when the lines make contact with other lines, trees, or the ground. Additionally, warmer temperatures and drier conditions associated with climate change are projected to increase wildfire activity in the Northern Great Plains, Northwest, and Southwest regions of the United States. Increasing wildfires threaten critical transmission infrastructure, including

[35]To prevent hot water from harming fish and other wildlife, power plants typically are not allowed to discharge cooling water above a certain temperature. When power plants reach those limits, they can be forced to reduce power production or shut down.

transmission towers, and some utility operators conduct public safety power shutoffs because of wildfire risks.

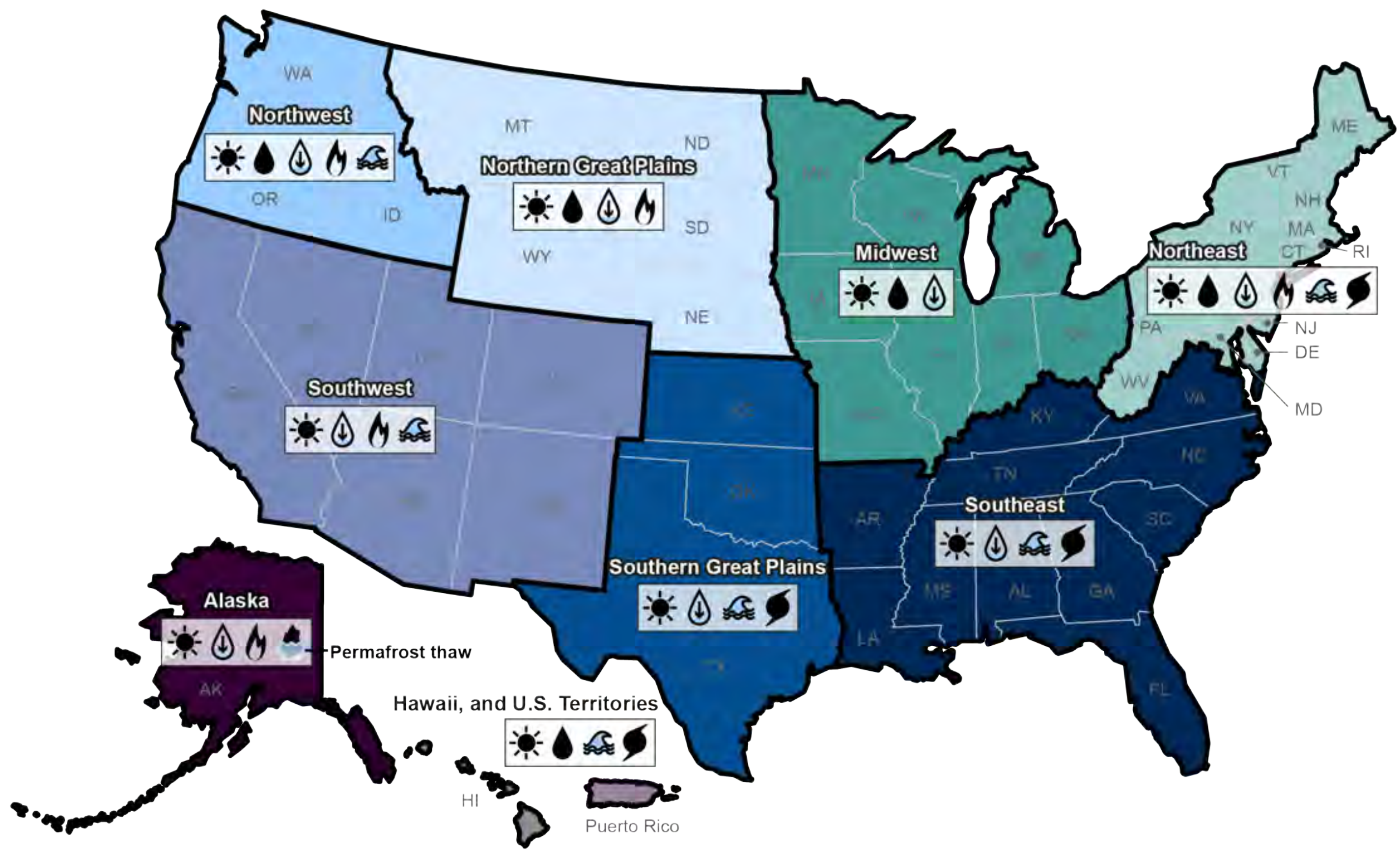
- *Distribution.* Climate change could affect the ability of utilities to distribute electricity to customers. For example, higher temperatures could increase the likelihood of damage to power transformers on hot days, when electricity demand is at its highest.[36] According to a 2015 DOE report, prolonged exposure to higher temperatures can damage power transformers, and operators may be forced to reduce the supply of electricity to operate air conditioning systems to cool buildings and homes. In addition, areas in the Northeast United States are likely to experience more extreme weather, including more frequent and intense hurricanes that can threaten grid infrastructure and distribution capacity.[37]

Additionally, according to the Fourth National Climate Assessment, climate change is expected to affect the demand for electricity. For example, warmer temperatures and more heat waves could increase demand for electricity. According to the Fourth National Climate Assessment, in 2015 and 2016, Honolulu experienced 24 days of record-setting heat. As a result, the local utility issued emergency public service announcements asking residents to reduce their use of air conditioning because the increased demand for electricity threatened the grid. Figure 3 highlights examples of climate change effects on the electricity grid in different regions of the United States.

[36]A transformer changes the voltage of electricity in a conductor or power line. Transformers increase (step up) or reduce (step down) voltages as electricity moves from power plants to homes and businesses.

[37]According to the U.S. Energy Information Administration (EIA), in 2018, in the five states with the longest total annual power interruptions per customer, major weather events such as winter storms and hurricanes caused significant disruptions to service. North Carolina was hit by both Hurricane Florence and Hurricane Michael in 2018, resulting in lengthy outages. Maine, Vermont, Massachusetts, and West Virginia are heavily forested states where power interruptions resulting from falling tree branches are common, especially as a result of winter ice and snowstorms that weigh down tree limbs and power lines. EIA is a statistical administration within the U.S. Department of Energy that collects, analyzes, and disseminates independent information on energy issues.

**Figure 3: Potential Climate Change Effects by Region and Examples of Climate-Related Events on the Electricity Grid**




**Key potential climate change effects examples:**

| Warmer temperatures and more heat waves: | Increasing precipitation or heavy downpours: | Decreasing water availability: | Increasing wildfires: | Increasing sea-level rise and storm surge: | Increasing frequency and intensity of hurricanes: |
|---|---|---|---|---|---|
| Warmer temperatures and more heat waves can reduce the transmission capacity of power lines. This reduced capacity, combined with an increased demand for electricity for cooling, can contribute to power outages. For example, a 2019 heat wave affected the Northeast, resulting in 100,000 customers in New York City losing power. | Increasing frequency and severity of heavy precipitation will increase heavy runoff and the risk of flooding. Floods can threaten low-lying grid structures. For example, in 2011, Missouri River floodwaters surrounded Nebraska's Fort Calhoun nuclear power plant, causing the reactor to remain closed during the summer because of flood waters. | Decreasing water availability may reduce downstream hydropower production. For example, in the summer of 2015, below-average precipitation, combined with above-average temperatures in the Northwest, resulted in lower-than-average runoff in the Columbia River Basin, which affected hydropower generation. | Increasing wildfires may damage critical transmission infrastructure and disrupt power supply. Warmer and drier conditions are projected to increase the risk of wildfires and lengthen the fire season. Based on increasing wildfire risk, a utility in California conducted public safety power shutoffs that affected more than 1 million customers in 2019. | Increasing sea-level rise and storm surge threatens low-lying coastal power plants in California. Rising sea-levels accelerate erosion and can increase flood risk during high tides and storm surges. | Increasing frequency and intensity of Category 4 and 5 hurricanes may increase the risk of physical damage to grid transmission and distribution infrastructure near the coasts. For example, in August 2020, Category 4 Hurricane Laura damaged low-lying grid infrastructure and caused outages for 616,000 customers in Arkansas, Louisiana, Mississippi, and Texas. |

Sources: GAO review of Department of Energy reports, Fourth National Climate Assessment and other documents; Map Resources (map). | GAO-21-346

## The Effects of Climate Change on the Grid Could Cost Billions

The effects of climate change could cost billions, including the costs of power outages to utility customers and costs from storm damage, among others.[38] Specifically, three reports we reviewed estimated that the average annual costs of severe weather-related outages to utility customers in the United States totaled billions each year.[39] In the absence of measures to enhance resilience, more frequent and severe weather associated with climate change is likely to increase the cost of outages, according to these reports. According to one report, the total annual cost of outages to utility customers is estimated to increase from roughly $55 billion over the 2006-2019 period to over roughly $480 billion during the 2080-2099 period in 2019 dollar values, absent aggressive grid resilience mitigation measures.[40] Power outages affect residential, commercial, industrial, and other customers' ability to use electricity for lighting, heating, cooling, and refrigeration; and for operating appliances, computers, electronics, machinery, and public transportation systems.

---

[38]As we reported in 2017, information on the economic effects of climate change is developing and imprecise, but it can convey insights into the nation's regions and sectors that could be most affected. Decision makers need more comprehensive information on economic effects to better understand the potential costs of climate change to society and begin to develop an understanding of the benefits and costs of different adaptation options, according to a 2010 National Academies report, literature reviewed, and experts GAO interviewed for that report. GAO, *Climate Change: Information on Potential Economic Effects Could Help Guide Federal Efforts to Reduce Fiscal Exposure,* GAO-17-720 (Washington, D.C.: Sept. 28, 2017).

[39]Three reports we reviewed included estimates of the average annual cost of weather-related outages in the United States, which range from about $2 billion to about $77 billion (2019 dollar values). Congressional Research Service, *Weather-Related Power Outages and Electric System Resiliency* (Aug. 28, 2012); Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* (August 2013); and Peter H. Larsen et al., *Projecting Future Costs to U.S. Electric Utility Customers from Power Interruptions* (2017). These estimates cover periods ranging from the mid-1980s through 2012. The three reports differed with respect to the types of costs that they estimated and the data and methods underlying the report. The estimates are based on surveys of customers' willingness to pay to avoid outages or the estimated losses they would incur as a result of an outage, but the estimates do not account for all costs, including indirect costs on individuals, businesses, and local or regional economies. The large range—from $2 billion to $77 billion—reflects differences in what is counted and in methodologies. For example, the $2 billion estimate accounts for outages that are due to severe weather, while the $77 billion estimate includes outages that lasted over 5 minutes that were attributed to weather.

[40]Larsen et al., *Projecting Future Costs to U.S. Electric Utility Customers.* This report projected the future customer costs of power outages through 2099, using climate change scenarios as one of the cost drivers in its model, and estimated changes in future severe weather metrics under 10 scenarios—including two climate change scenarios. The report did not include Hawaii or Alaska nor did it include any indirect (i.e., spillover) effects to the broader economy from power outages.

Moreover, power outages can disproportionately affect vulnerable populations that rely on continued electricity service to address certain health conditions.[41] In addition, low-income groups are more vulnerable to events such as heat waves, given their limited ability to meet higher energy costs and invest in measures to minimize the impact of outages, such as backup generators. Power outages can also have significant cascading effects on critical sectors such as health, transportation, and telecommunications.[42] See table 1 for examples of the effects and costs of power outages.

[41]For example, after Hurricanes Maria and Irma caused widespread power outages in Puerto Rico and the U.S. Virgin Islands, we reported that the chronically ill often did not have access to electricity to power their medical devices, such as ventilators. GAO, *Disaster Response: HHS Should Address Deficiencies Highlighted by Recent Hurricanes in the U.S. Virgin Islands and Puerto Rico*, GAO-19-592 (Washington, D.C.: Sept. 20, 2019). According to the Fourth National Climate Assessment, poor or marginalized populations often face a higher risk from climate change because they live in areas with higher exposure, are more sensitive to climate impacts, or lack the capacity to respond to climate hazards.

[42]Critical sectors rely on electricity, but the reliable operation of the grid also depends on the performance of multiple supporting infrastructures. Power outages can be caused by disruptions to other sectors, such as telecommunications, natural gas, and transportation, among other critical infrastructures.

**Table 1: Examples of the Costs and Effects of Power Outages**

| Type of cost or effect | Examples |
|---|---|
| Residential customer losses | • spoilage of items dependent on refrigeration<br>• inability to use elevators, appliances, fans, and lighting<br>• inability to heat and cool homes (HVAC and boilers) and associated health impacts<br>• inability to use ATM machines<br>• inability to refuel at gas stations<br>• public safety (street and traffic lights) |
| Commercial and industrial sector losses | • diminished or halted production of goods and services<br>• spoilage of inventory dependent on refrigeration |
| Critical infrastructure disruptions[a] | • drinking water and wastewater<br>• telecommunications<br>• transportation (failure of road and rail traffic signals)<br>• hospitals/health care (loss of power to medical machinery and instrumentation, such as ventilators and dialysis machines)<br>• emergency services<br>• energy sector[b] |
| Supply chain disruption | • Impact on businesses that did not lose power, but were negatively affected because they rely on businesses that lost power |

Source: GAO analysis of reports and documents that describe the range of effects of power outages. I GAO-21-346

[a]Critical infrastructure generally has backup power generation but these work only for limited periods, and in some cases, fuel disruptions because of refinery and transport disruptions result in fuel shortages that affect backup power.

[b]According to the U.S. Department of Energy (DOE), electric service disruptions also significantly affect the reliability of other parts of the energy sector. These losses are of special concern because outages caused by climate effects can be widespread and affect large geographic areas at once, according to DOE. Failure of electrical equipment (e.g., electrical lines, pumps) can shut down steam boilers, cooling towers, pumps, and electrically operated safety control mechanisms in oil and gas refineries, pumping stations, terminals, and other facilities. Besides the lost revenue and other costs associated with equipment damage in these sectors, disruptions can lead to disruption in fuel deliveries, worsening the effects of power outages for consumers. For example, following Hurricane Sandy in 2012, power outages caused widespread gasoline shortages in New Jersey and New York, limiting the ability of consumers to run generators.

In recent years, power outages resulting from extreme weather events have affected millions of customers. For example,

- In February 2021, extreme cold weather from the Canadian border as far south as Texas resulted in record winter power demand and left about 4.5 million customers in Texas without power, along with about 376,000 customers in Louisiana and Oklahoma.
- In 2019, dry and windy conditions in California that increased the risk of wildfires resulted in public safety power shutoff events that affected

more than 1 million customers with an estimated economic cost of $2 billion.[43]

- In July 2019, a heat wave in the Northeast contributed to two power outages and resulted in over 100,000 customers in New York City losing power. The outages disrupted commercial activities, transportation systems, and traffic control operations.
- In September 2017, Hurricanes Irma and Maria damaged Puerto Rico's electricity grid, causing the longest blackout in U.S. history.
- In August 2017, Hurricane Harvey left over 300,000 customers in Texas without power after the storm damaged electricity generation and transmission lines. The power outages affected critical infrastructure, such as hospitals, water and wastewater treatment plants, and refineries, and contributed to an increase in gasoline prices, regionally and nationally.
- In October 2012, Hurricane Sandy disrupted power service to over 8 million customers in the Northeast as the result of damage to generation, transmission, and distribution equipment. The most severely affected areas saw record winds and storm surge, including a 14-foot storm surge in Manhattan.

In addition to the costs of power outages to utility customers, extreme weather associated with climate change can increase the financial risk to utilities by contributing to sharp increases or declines in demand for electricity, according to one report.[44] Specifically, extreme weather conditions require more backup generation, which increases costs and can heighten the risk of system stress and service interruptions, according to this report. This may raise electricity prices as utilities add capacity to meet demand, thereby increasing costs to customers. For example, according to the Fourth National Climate Assessment, if greenhouse gas emissions continue unabated, the effects of climate

[43]Rocky Mountain Institute, *Reimagining Grid Resilience* (2020). Three utilities in California are authorized to perform public safety power shutoffs in fire-prone areas to prevent wildfires caused by energized transmission and distribution lines. In October 2019, one California utility announced that it would issue $86 million in credits to its customers for one of these public safety power shutoffs.

[44]Moody's Analytics, *Regulated Electric Utilities in the United States: Intensifying Climate Hazards to Heighten Focus on Infrastructure Investments* (January 2020). Sharp volatility in demand could affect liquidity because utilities will need to buy or sell power or natural gas as demand fluctuates.

change could require new generation capacity costing utility customers an estimated $30 billion per year by midcentury.

In addition, utilities and other entities, such as the federal government, also incur costs from storm damage resulting from severe weather. These costs could increase as the frequency and intensity of weather events increase in the future. According to one report, total annual expenditures for transmission and distribution infrastructure in the contiguous United States were found to increase with climate change by as much as 25 percent (or about $25 billion) in 2090 as compared with annual expenditures in 2015.[45]

To minimize the occurrence of power outages and enhance the resilience of grid infrastructure to the effects of climate change, utilities and government entities are investing in resilience measures.[46] For example:

- Following Hurricane Sandy, Con Edison, the utility that serves New York City, planned to invest $1 billion to make the grid more resilient to the potential effects of climate change. Con Edison reported damage to five transmission substations and the loss of about 1,000 utility poles, and more than 900 transformers. Power restoration following the storm required crews from over 100 companies in 34 states to help conduct repairs to the grid. According to utility

[45]Charles Fant et al., *Climate Change Impacts and Costs to U.S. Electricity Transmission and Distribution Infrastructure* (January 2020). According to the report, total annual increase in expenditures on transmission and distribution infrastructure due to climate change could range from $6 billion to about $25 billion with climate change by 2090 as compared with annual expenditures in 2015, but expected costs are estimated to decrease by half if resilience measures are adopted. The report estimates these costs using two emission scenarios and three response cases—(1) no adaptation, (2) reactive adaptation, and (3) proactive adaptation. The $6 billion increase estimate is associated with a proactive adaptation strategy under a climate scenario where greenhouse gas emissions have been "significantly" reduced, while the $25 billion increase estimate is associated with a substantial warming scenario due to high emissions and with no adaptation strategy. It considers temperature, precipitation, lightning, wildfires, and vegetation growth but does not consider floods, high winds (including hurricanes), or ice storms. All figures reported here have been converted to 2019 dollar values.

[46]Some stakeholders we interviewed told us that there is a need to lower emissions and invest in resilience. Lowering emissions could enhance resilience because doing so would lessen the effects of climate change on grid infrastructure, according to one stakeholder. According to the Fourth National Climate Assessment, neither global efforts to mitigate climate change causes nor regional resilience efforts currently approach the scale needed to avoid substantial damage to the U.S. economy, environment, and human health over the coming decades.

documents, Con Edison has spent $847 million on resilience measures, including floodwalls, submersible transformers, and flood proofing at substations and generating stations.

- To protect its nuclear power plants from damage, the Tennessee Valley Authority has spent $153 million on modifications and improvements related to extreme flooding preparedness, and expects to spend an additional $27 million to complete the modifications, according to Tennessee Valley Authority financial filings.
- Following Hurricanes Irma and Maria, federal agencies provided about $3.9 billion to help restore electricity service in Puerto Rico, including temporary or partial repairs, such as attaching electricity lines to damaged poles.[47] More recently, the Federal Emergency Management Agency (FEMA) has committed $10 billion to fund longer-term grid improvements in Puerto Rico.[48]

Figure 4 provides examples of measures that could enhance grid resilience to potential climate change effects.

[47]GAO, *Puerto Rico Electricity: FEMA and HUD Have Not Approved Long-Term Projects and Need to Implement Recommendations to Address Uncertainties and Enhance Resilience,* GAO-21-54 (Washington, D.C.: Nov. 17, 2020).

[48]GAO-21-54.

**Figure 4: Examples of Resilience Measures**


Sources: GAO analysis of reports and documents, CenterPoint Energy; Jamie Hooper, and Wirestock/stock.adobe.com. | GAO-21-346

Note: For additional information on measures adopted by utilities to improve grid resilience and minimize damage from flooding, storm surges, and high winds, see GAO, *Electricity Grid: Opportunities Exist for DOE to Better Support Utilities in Improving Resilience to Hurricanes*, GAO-21-274 (Washington, D.C.: Mar. 5, 2021). In addition to the flood protection examples in the figure, utilities have also installed network protectors that contain flood monitoring sensors that detect when there is an abnormal water level near an electrical facility, such as a substation. Network protectors also insulate electrical facility equipment from flooding, thereby enabling the equipment to function when submerged in water. Utilities have also adopted technologies that enhance operational capacity and can help provide quick restoration of service. For example, some automated technologies provide enhanced communication capabilities; monitor electrical systems to detect, locate, and repair sources of service disruptions; and continue service through part of the grid when the central grid experiences a service disruption.

Investments in measures to enhance resilience can be expensive and it can be difficult for utilities to calculate the return on such investments because the benefit typically is realized only when a major event threatens the reliability of service. As a result, these investments can be difficult to justify, and utilities must balance the need to enhance resilience with the associated costs, which could result in increases to the rates charged to customers.[49] Further, increases in rates could disproportionately affect low-income populations that spend a greater portion of their income on energy expenses. It is important for utilities and other stakeholders to take vulnerable and disadvantaged populations into account when planning for and investing in resilience because many customers cannot afford rate increases to pay for resilience investments, according to several stakeholders and reports we reviewed.

## DOE and FERC Have Taken Actions to Enhance Grid Resilience and Have Opportunities to Further Address Climate Change

DOE and FERC have taken some actions since 2014 to enhance the resilience of the electricity grid. According to stakeholders we interviewed and reports we reviewed, opportunities exist for DOE and FERC to take additional actions to further enhance the resilience of the grid to climate change.

### DOE Has Taken Actions to Enhance Grid Resilience to Potential Climate Change Effects since 2014

Since 2014, DOE has provided information and technical assistance, supported research through its Grid Modernization Initiative and other

[49]In our March 2021 report, we found that most utilities recover the cost of resilience measures through rates paid by the utilities' customers. Utilities face challenges justifying investments and obtaining regulatory approval, and some utilities have limited resources to pursue resilience enhancements, such as researching grid resilience technologies. GAO, *Electricity Grid: Opportunities Exist for DOE to Better Support Utilities in Improving Resilience to Hurricanes*, GAO-21-274 (Washington, D.C.: Mar. 5, 2021).

efforts, and developed resilience tools.[50] While not all of these actions directly address climate change risks, they could yield climate resilience benefits.

- **DOE provided information and technical assistance.** DOE has provided information and technical assistance to utilities and states, and has partnered with other federal agencies on these efforts.[51] For example, in 2015, DOE established the Partnership for Energy Sector Climate Resilience with utility owners and operators to help them plan for climate change. Through the partnership, DOE collaborated with 18 utilities, published several reports and guidance documents, facilitated webinars to help members develop climate change vulnerability assessments, and provided other technical assistance to utilities.[52] DOE also facilitated the sharing of climate science information by other federal agencies, such as the National Aeronautics and Space Administration (NASA) and the National Oceanic and Atmospheric Administration (NOAA), to support the

[50]According to DOE documents, the Grid Modernization Initiative works across DOE to help create a modern grid of the future. According to DOE officials, DOE's Grid Modernization Initiative has invested over $30 million in developing Resilient Distribution Systems through a solicitation with the Grid Modernization Laboratory Consortium (GMLC). The GMLC is a strategic partnership between DOE's headquarters and 13 DOE National Laboratories. According to DOE, the GMLC brings together leading experts and resources to collaborate on national grid modernization goals.

[51]This is consistent with the Disaster Resilience Framework, which states that federal efforts should improve the availability of authoritative, understandable, and comprehensive information on disaster risks and risk reduction strategies in order to help entities effectively assess their climate risks, determine what viable alternatives are available to increase resilience to those risks, and better understand and measure the impact of resilience strategies. Furthermore, bringing together the disparate missions and resources that support disaster risk reduction can help build national resilience to natural hazards. See GAO-20-100SP.

[52]Utilities that joined the partnership committed to identifying vulnerabilities to energy infrastructure assets and operations from extreme weather and climate change effects. DOE, Office of Energy Policy and Systems Analysis, *A Review of Climate Change Vulnerability Assessments: Current Practices and Lessons Learned from DOE's Partnership for Energy Sector Climate Resilience* (Washington, D.C.: May 2016); DOE, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning* (Washington, D.C.: September 2016); and DOE, *Climate Change and The Electricity Sector: Guide for Assessing Vulnerabilities and Developing Resilience Solutions to Sea Level Rise* (Washington, D.C.: July 2016).

development of the vulnerability assessments.[53] DOE officials we interviewed told us that the agency, in collaboration with members of the partnership, developed several draft reports addressing methods for conducting a cost-benefit analysis of energy resilience investments, attributes of resilience, and a compendium of federal programs that provide funding assistance for resilience investments.[54] Some members we interviewed said that DOE's partnership provided a forum to share best practices with member utilities and found the partnership valuable. DOE was assessing whether to continue actions related to the partnership as of January 2021.[55] DOE also facilitates communication between the government and the private sector, including holding meetings with the Electricity Subsector Coordinating Council (ESCC).[56] These efforts are not focused on climate change,

[53]According to DOE officials we interviewed, climate change information is generated by other federal agencies, such as NOAA and NASA. These agencies work to identify and provide tools, methods, and down-scaled extreme weather information (e.g., temperature, precipitation, drought, wildfire, sea level rise, etc.) for utility resilience planning, according to these officials.

[54]Craig Zamuda et al., *Resilience Management Practices for Utilities and Extreme Weather* (November 2019); Craig Zamuda et al., *Monetization Methods for Evaluating Investments in Electricity System Resilience to Extreme Weather and Climate Change* (November 2019); Craig Zamuda and Anne Ressler, *Federal Adaptation and Mitigation Programs Supporting Community Investment in Electricity Resilience to Extreme Weather* (October 2020).

[55]According to DOE officials, as part of this assessment, DOE worked with members to identify priority gaps and needs in the summer of 2020. For example, members identified a need to increase awareness of available climate information and technical assistance from DOE, NOAA, and NASA; and federal resilience funding opportunities. Members also identified a need for guidance on how to assess the benefits and effectiveness of resilience measures, information on how to work with vulnerable or disadvantaged communities, and how to develop an enhanced understanding of various natural hazards.

[56]The ESCC includes chief executive officers and executives from electric companies, public power utilities, and rural electric cooperatives, as well as their trade association leaders. According to its charter, the purpose of the ESCC includes coordinating activities and initiatives designed to improve the reliability and resilience of the electricity subsector, including the electricity grid, and serving as the principal liaison between the council's membership and the Energy Sector Government Coordinating Council (EGCC). DOE co-chairs the EGCC—the government counterpart to the ESCC—in coordination with the U.S. Department of Homeland Security. According to its charter, the EGCC serves as a single point of contact to facilitate communication between the government and the private sector when preparing for and responding to issues and threats resulting from physical, cybersecurity, or weather-related disasters of national significance impacting the energy sector. The EGCC includes representatives from various levels of government (federal, state, local, territorial, and tribal).

but the ESCC recently partnered with government leaders to address wildfire risks.

DOE also provided information and technical assistance to states. For example, according to a DOE report and agency officials we interviewed, in 2016, DOE collaborated with state and regional organizations through the State Energy Risk Assessment Initiative to raise state officials' awareness of the risks to their energy infrastructure. DOE worked with states to help them make decisions on resilience solutions, energy system and infrastructure investments, energy assurance planning, and asset management.[57] While this effort has not continued, DOE's Office of Cybersecurity, Energy Security, and Emergency Response is currently updating the Energy Risk Profiles that examine the relative magnitude of risks at a state and regional level, according to DOE officials.[58] In addition, according to DOE documents, DOE works with state and local governments through the State Energy Assurance Plan Assistance program to develop information and tools and to conduct forums, training sessions, and tabletop exercises for energy officials, emergency managers, policy makers, and industry asset owners and operators. Furthermore, DOE officials told us that they developed a Distribution Resilience Decision Framework—a multiyear project on this topic—in consultation with states and utilities to help them and utility regulators make better decisions about utilities' resilience investments.[59]

DOE also partnered with other federal agencies to provide climate information and technical assistance, according to DOE officials we interviewed. For example, DOE participates in the Climate Data Initiative and contributes to the Climate Resilience Toolkit to provide information, data, and tools that the public and private sectors can use to increase

[57]DOE, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning*.

[58]DOE's State and Regional Energy Risk Profiles can be found here: https://www.energy.gov/ceser/state-and-regional-energy-risk-profiles [last visited Jan. 27, 2021].

[59]According to DOE officials we interviewed, DOE's Office of Electricity developed a strategy and implementation planning guidebook for state regulators and communities. The reference document includes considerations for distribution resilience planning and decision making resulting from research of the multiyear project. See DOE *Modern Distribution Grid (DSPx) Strategy and Implementation Planning Guidebook, vol. iv* (Washington, D.C.: June 2020).

climate change preparedness and resilience.[60] In addition, according to a 2016 DOE report, DOE collaborates with other federal agencies to advance climate change understanding in the following areas: wildfire management (U.S. Forest Service); storm water modeling (U.S. Geological Survey); and climate science (U.S. Department of Homeland Security, U.S. Environmental Protection Agency, and NASA).[61]

- **DOE conducted research.** DOE conducts fundamental energy science and energy technology research and development, and climate change is an ongoing part of this research.[62] DOE program offices support a range of research and development activities related to climate change. For example, DOE's Office of Science supports several climate change projects at the National Laboratories. According to DOE officials, one project—the Integrated Multi Scale Sector Modeling Project—evaluates the impact of climate change on the grid, looking at direct and indirect impacts on other sectors or

[60]The Climate Data Initiative is a web portal that provides access to federal climate-related statistics and information to help companies, communities, and citizens understand and prepare for the impacts of climate change, such as coastal flooding and sea-level rise. The Climate Resilience Toolkit is a website designed to help people find and use tools, information, and subject matter expertise to build climate resilience. This interagency initiative operates under the auspices of the U.S. Global Change Research Program. The site is managed by the National Oceanic and Atmospheric Administration's Climate Program Office and is hosted by the agency's National Centers for Environmental Information. U.S. federal government, "U.S. Climate Resilience Toolkit," last accessed on Feb. 2, 2021, https://toolkit.climate.gov/. DOE officials told us that the resulting information generated through its Partnership for Energy Sector Climate Resilience can be accessed through the Climate Resilience Toolkit. See: https://toolkit.climate.gov/topics/energy-supply-and-use.

[61]DOE was a member of the Interagency Climate Change Adaptation Task Force—established in 2009 and co-chaired by the Council on Environmental Quality, the Office of Science and Technology Policy, and the National Oceanic and Atmospheric Administration. It included representatives from more than 20 federal agencies, including DOE. In addition, DOE was a member of the Council on Climate Preparedness and Resilience, established by Executive Order 13653 to, among other things (1) coordinate interagency efforts on priority federal government actions related to climate preparedness and resilience and (2) facilitate the integration of climate science in policies and planning of government agencies and the private sector. Executive Order 13653, *Preparing the United States for the Impacts of Climate Change* (Washington, D.C.: Nov. 1, 2013; revoked in March 2017 by Executive Order 13783).

[62]This is consistent with the Disaster Resilience Framework, which states that the federal government should provide reliable and authoritative information about current and future risk, and promote consensus around the reliability of the sources and methods that produce disaster risk information. See GAO-20-100SP.

activities.[63] Another project—the Integrated Coastal Modeling project—provides deeper understanding of coastal processes, hazards to critical infrastructure, and integrated responses in the context of climate change, hurricanes, and urbanization in coastal areas, according to officials. In addition, DOE's Office of Energy Efficiency and Renewable Energy funds a range of research, development, and deployment activities related to renewable power, sustainable transportation, energy efficiency, and combined heat and power, which have the potential to improve resilience and mitigate the impacts of extreme weather events.[64]

DOE has also funded laboratory research through its Grid Modernization Initiative and Grid Modernization Lab Consortium (GMLC). Under the GMLC, DOE funded the Midwest Interconnection Seams Study to analyze scenarios facilitating regional transfers of electricity.[65] Several stakeholders we interviewed told us that an interconnected grid that facilitates transfers of electricity across the three main interconnections could have several benefits, including enhancing the resilience of the grid

[63]The long-term goals of this project are to develop flexible modeling capabilities that capture the dynamic multiscale interactions among climate, energy, water, land, socioeconomics, critical infrastructure, and other sectors and to use these capabilities to study the vulnerability and resilience of coupled human and natural systems from local to continental scales under scenarios that include short-term shocks, long-term stresses, and feedbacks associated with human decision-making.

[64]DOE was directed by a 2009 law to submit a report to committees of Congress on each effect of, and risk resulting from, global climate change with respect to: (1) water supplies used for hydroelectric power generation and (2) power supplies marketed by each Federal Power Marketing Administration. Omnibus Public Land Management Act of 2009, Pub. L. No. 111-1, § 9505(c), 123 Stat. 991, 1337.

[65]At the highest level, the U.S. power system is made up of three main interconnections, which operate largely independently from each other with limited transfers of electricity between them. These three main interconnections are the Eastern Interconnection, which encompasses the area east of the Rocky Mountains and a portion of the Texas panhandle; the Western Interconnection, which encompasses the area from the Rockies to the west; and the Electric Reliability Council of Texas, which covers most of Texas. These interconnections extend into parts of Canada and Mexico. The network structure of the interconnections helps maintain the reliability of the grid by providing multiple routes for power to flow and allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service to customers.

to climate change.[66] For example, one stakeholder said that if there is more interconnection, regions can exchange energy and, if local infrastructure goes down, these regions can rely on other regions for power. An interconnected grid could also accelerate the growth of renewable energy, such as wind energy, and help lower emissions, according to another stakeholder. However, DOE officials we interviewed told us that after reviewing early results from the study, the agency decided not to pursue the project further because of other priorities. DOE officials told us that an interconnected grid is unquestionably feasible in engineering terms but that it has yet to be demonstrated whether an interconnected grid would provide substantial economic and other benefits. These questions could be answered conclusively only through a large-scale, multi-million-dollar project requiring collaboration and coordination among many government agencies and private companies, according to DOE officials.

- **DOE supported development of resilience metrics and tools.** DOE has funded efforts to develop metrics for grid resilience.[67] DOE

[66]In June 2020, the House Select Committee on the Climate Crisis recommended that the federal government designate National Interest Electric Transmission Corridors, building on the Interconnection Seam Study conducted by the National Renewable Energy Laboratory. The report stated that a better-connected national grid would enable the country to maximize the use of the lowest-cost sources of renewable energy, which may be located far from population centers. According to the report, federal financial support through loan guarantees or access to the tax credits could facilitate project development. House Select Committee on the Climate Crisis, Majority Staff Report*: Solving the Climate Crisis*. In June 2020, FERC issued a report on barriers and opportunities for high voltage transmission that discussed the benefits of high voltage transmission, including the ability for utilities to share generating resources, enhance the stability of the existing transmission system and help with restoration and recovery after an event. The report also discussed barriers and limitations such as permitting and planning challenges. See Federal Energy Regulatory Commission, *Report on Barriers and Opportunities for High Voltage Transmission*: *A Report to the Committees on Appropriations of Both Houses of Congress Pursuant to the 2020 Further Consolidated Appropriations Act* (Washington, D.C.: June 2020).

[67]Examples of metrics for grid operations and resilience include time and cost to recover from an outage, or critical services (e.g., healthcare, public safety) without power. The objective of the resilience metrics project is to define, develop, and validate a set of metrics that can be used to measure progress toward grid modernization. The metrics DOE is developing are not climate change specific metrics but could yield climate resilience benefits. DOE officials we interviewed told us that DOE is working with the Department of Defense on a joint project to characterize energy-related threats at selected military facilities and develop metrics that would reveal which threats would significantly impair a facility’s ability to perform its essential functions. These same metrics could then be used to gauge the effectiveness of alternative investments in terms of reducing the facility’s vulnerability to specified threats, according to these officials.

officials we interviewed told us that there is a need for resilience metrics and that DOE and the National Laboratories are working with states, utilities, and other stakeholders to develop such metrics. DOE officials said that progress has been made but that work remains to develop resilience metrics. In our March 2021 report, we stated that officials from several utilities and some National Laboratories said that the lack of resilience metrics, as well as difficulties quantifying the benefits of resilience, has made it challenging for utilities to justify the costs of adopting resilience measures to their regulators.[68] Specifically, in that report, we stated that without a way to demonstrate the value of such investments, these utilities face challenges justifying investments and obtaining regulatory approvals to increase rates.

In addition, in 2018, DOE's Lawrence Berkeley National Laboratory (LBNL) and an industry partner updated a tool—the Interruption Cost Estimate (ICE) calculator—that LBNL originally released to the public in 2011. The tool aims to help utilities and others estimate short-duration outage costs to customers. The analysis and models used in the ICE calculator are designed to estimate the cost to customers of short-duration outages that do not exceed 1 day. However, utilities can use the tool to estimate some of the benefits of resilience improvements to justify investments.[69] DOE officials told us that, in addition to supporting the development and continued availability of the ICE calculator, the agency has also collected information from industry on cost-effective ways to enhance grid resilience to severe weather events to help identify best practices. According to DOE officials we interviewed, DOE plans to publish a summary of this information but there is no timeline for doing so.

In addition, DOE National Laboratories have developed various tools that can help utilities prepare for and respond to weather-related events. For

[68] GAO-21-274.

[69] According to a DOE report, some utilities have used the ICE calculator to demonstrate how it can help estimate the benefits of resilience measures. For example, EBP [formerly known as the Electric Power Board of Chattanooga] used funding from DOE's Smart Grid Investment Grant to deploy 1,200 automatic circuit switchers and sensors to improve reliability. The ICE calculator estimated the benefits of these improvements to consumers at about $26.8 million annually, in the form of avoided customer interruption costs. See DOE*, Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning.* In March 2019, the Electricity Advisory Committee recommended that DOE consider creating and publicizing broad training webinars on resilience-related tools such as the ICE calculator, and inviting state utility commission staff to these webinars. See Electricity Advisory Committee, *Policy and Research Opportunities for Grid Resilience.*

example, Argonne National Laboratory developed the Hurricane Electric Assessment Damage Outage tool, designed to estimate the likely effects of hurricanes on the electricity sector, including restoration needs and number of customers affected. DOE officials also told us that they supported the development of another tool—the Transmission Resilience Maturity Model—developed jointly by the North American Transmission Forum, the Pacific Northwest National Laboratory, and the Electric Power Research Institute. The tool is designed to help utilities prioritize actions and investments to improve the resilience of their systems.[70] DOE officials said that the tool has been validated and refined through pilot tests with several utilities and is now available for general use. The tool was designed to address all hazards, but utilities can apply the tool to evaluate their preparedness for any combination of risks that could threaten the resilience of their transmission system, and help prioritize needed investments, according to DOE officials.

DOE is also working with several National Laboratories to develop an all-hazards risk management tool—the North American Energy Resilience Model—that aims to identify interdependencies with other sectors such as natural gas, and vulnerabilities to the electricity grid. The tool also aims to address the impacts of both natural (e.g., hurricanes, flooding) and man-made threats (e.g., cyber-attacks, electromagnetic pulses).[71] Some stakeholders, including DOE National Laboratory staff we interviewed, told us that as DOE continues to develop the North American Energy Resilience Model, the agency could consider incorporating climate change scenarios and sharing the tool with potential users—such as utilities and grid operators—to help them identify and manage climate

[70]In August 2020, the National Commission on Grid Resilience recommended that the President issue a Presidential Decision Directive initiating climate impact modeling of a range of future scenarios to identify where it will be safe to site new and upgraded bulk electric transmission. According to the commission report, these planning scenarios should take into account sites critical to national infrastructure, areas threatened by environmental impacts (including sea-level rise, extreme heat, and climate-driven population migration), impacts to the national economy, and enhancements that could be made by public-private partnerships. National Commission on Grid Resilience, *Grid Resilience: Priorities for the Next Administration* (August 2020).

[71]For example, the North American Energy Resilience Model aims to integrate other models such as the Hurricane Electric Assessment Damage Outage model developed eight National Laboratories. According to DOE, the North American Energy Resilience Model can and does provide the modeling to show the best use of taxpayer dollars for infrastructure investment (where to install renewable energy and energy storage). In addition, the real-time situational awareness layers are to assess the impact of immediate threats from physical equipment and/or weather, according to DOE.

change risks. According to DOE, the agency has completed the basic North American Energy Resilience Model modeling and analytics tool including the data sets with interdependency cases on natural gas.

## Opportunities Exist for DOE to Take Additional Actions to Enhance Grid Resilience to Climate Change

According to many stakeholders we interviewed and reports we reviewed, opportunities exist for DOE to take additional actions to further enhance grid resilience to climate change, including sharing tools and information to evaluate resilience measures and plan for climate change, and providing incentives, such as grants, to invest in resilience measures.

- **Share tools and information to help evaluate resilience measures and plan for climate change.** DOE could provide information to help entities evaluate investments in resilience by identifying a set of metrics and providing information on the cost of long-term power outages.[72] According to a 2017 National Academies report, establishing a set of resilience metrics and building consensus around these metrics is an important prerequisite for comparing resilience measures and for assessing their costs and benefits. According to another report we reviewed, energy providers face challenges evaluating investments in resilience because of an absence of climate resilience metrics and analytical frameworks.[73] Many stakeholders and DOE officials we interviewed told us that there is a need for a vetted set of resilience metrics that utilities and others can use. DOE is supporting efforts to develop resilience metrics through the GMLC but has not identified a set of agreed-upon metrics that utilities and

[72]According GAO's Disaster Resilience Framework, the federal government could help improve the ability to assess alternatives to address risk. For example, the federal government could contribute to an understanding of approaches for estimating returns on investment, according to the framework. See GAO-20-100SP. In our March 2021 report, we recommended that the Secretary of Energy take steps to better leverage the National Laboratories' emerging grid resilience efforts and technologies by developing a formal mechanism to share this information with utilities. GAO-21-274.

[73]Pacific Gas and Electric Company, *Climate Change Vulnerability Assessment and Resilience Strategies* (November 2016).

others can use.[74] In addition, in our March 2021 report, we stated that DOE has funded some case studies to explore these metrics.[75]

DOE could also help entities evaluate investments in measures to enhance resilience by providing information on the cost of long-term power outages. According to many stakeholders we interviewed and reports we reviewed, information on the cost of long-term power outages is needed to help utilities understand the benefits of measures that could enhance resilience and justify investments.[76] Specifically, according to the reports we reviewed and stakeholders we interviewed, the ICE calculator is limited because it only estimates the cost to customers from outages lasting less than a day, and there is a need for a tool to calculate the cost of longer-term power outages. Moreover, in March 2019, the Electricity Advisory Committee recommended that DOE direct LBNL to modify the ICE calculator to evaluate costs of power outages beyond 24 hours and support efforts to evaluate investments in resilience measures. However, in DOE's response to the recommendation, the agency stated that expanding the calculator would cost more than $10 million and require extensive support and collaboration from state regulators, utilities, and other relevant groups. DOE officials told us that the agency recognizes the importance of understanding the potential costs of long-term outages, but said that it is difficult to analyze because of the many uncertainties that could affect these costs. According to DOE officials we interviewed, the agency is taking other actions to help utilities understand and measure the impact of resilience strategies, such as supporting the continued public availability of the ICE calculator.

In our March 2021 report, we stated that developing tools that support planning for grid resilience would help utilities evaluate investments in grid resilience.[77] DOE has efforts underway to develop tools for

[74]According to DOE officials, the Grid Modernization Initiative has done some work developing resilience metrics. In April 2020, the Grid Modernization Lab Consortium issued a report on resilience metrics. According to the report, research results will help regional decision makers prioritize resilience investments. Grid Modernization Lab Consortium, *Grid Modernization: Metrics Analysis (GMLC1.1)—Resilience,* PNNL-28567 (April 2020).

[75]GAO-21-274.

[76]Legislation introduced in the 116th Congress would have directed DOE to develop a report that provides recommendations on how to minimize the need for, effects of, and duration of planned electric power outages that are due to extreme weather conditions. Utility Resilience and Reliability Act, H.R. 7186, 116th Cong. § 4 (2020).

[77]GAO-21-274.

resilience planning but DOE did not have a plan to fully develop these tools.[78] In our report, we recommended that DOE establish a plan to guide the agency's efforts to develop tools for resilience planning, such as performance measures for resilience, a framework for resilience planning, and additional information on the cost of long-term outages.

- **Provide incentives.** According to several stakeholders we interviewed, the federal government has an opportunity to promote resilience by providing financial and other incentives as well as addressing disincentives.[79] DOE can provide financial assistance to further its mission and goals in the form of formula and competitive grants, cooperative agreements, and prizes (i.e., competitions).[80] DOE officials told us that they plan to release a funding opportunity announcement in fiscal year 2021 to support energy resilience initiatives. According to these officials, the funding is intended to enhance resilience of critical energy infrastructure to mitigate against malicious and natural threats, including extreme weather events resulting from climate change. Officials also told us that DOE is working with the Department of Housing and Urban Development and FEMA to identify resources available to mitigate possible threats to the electricity grid. Several reports we reviewed and stakeholders we interviewed said that a grant program to enhance the resilience of the grid to climate change effects should be targeted to regions in most

[78]GAO-21-274.

[79]This is consistent with GAO's Disaster Resilience Framework, which states that incentives can lower the costs or increase the benefits of risk-reduction measures, which can help stimulate investment by state, local, and tribal governments, individuals, and the private sector. Because much of the nation's infrastructure is not owned and operated by the federal government, many resilience-related decisions ultimately are made by nonfederal actors, and those decision makers face competing priorities, according to the framework. Disincentives, such as confusing or overly complex practices and administrative burden, can discourage participation in resilience programs. See GAO-20-100SP.

[80]Legislation that was introduced in the 116th Congress would have directed DOE to award grants for research and development on technologies and capabilities to help withstand current and projected impacts of a changing climate on electricity grid infrastructure, including extreme weather events and other natural disasters. Grid Modernization Research and Development Act of 2020, H.R.5428, 116th Cong. §4. Another bill from the 116th Congress would have required the Secretary of Energy to establish a grant program to provide grants to states, local governments, and Indian tribe economic development entities to improve preparedness and restoration time to mitigate power disturbances resulting from severe weather and climate change, among other threats. Leading Infrastructure for Tomorrow's America Act, H.R.2741, 116th Cong. § 31101(b)(2) (2019).

need and to utilities with fewer resources.[81] As mentioned previously, when planning for and investing in resilience measures, it is important to take vulnerable and disadvantaged populations into account, as several stakeholders told us. For example, one stakeholder said that creating a program to help pay for resilience investments through a cost-sharing mechanism, such as a federal grant, would help mitigate the need to raise electricity rates to fund resilience investments, or make it easier for regulators to approve investments if partially funded through other mechanisms.[82]

In considering the specific actions cited that stakeholders cited, DOE would benefit from having an overall strategy to enhance grid resilience to climate change. According to GAO's Disaster Resilience Framework, such a strategy and the associated planning can help decision makers take coherent and coordinated resilience actions.[83] The framework states that federal efforts can focus on disaster risk reduction by creating resilience goals in all relevant national strategies and by linking those goals to an overarching strategy.

DOE has taken some actions consistent with principles described in our Disaster Resilience Framework. For example, it identified climate change as a risk to energy infrastructure, including the electricity grid, in its *Energy Sector-Specific Plan, 2015,* and in the Second Installment of the Quadrennial Energy Review.

However, DOE does not have a strategy to guide its efforts to enhance the resilience of the grid to climate change. In addition, it has not established goals, objectives, or performance measures for its climate change resilience efforts. DOE officials told us that it has not developed a strategy because the agency currently regards other threats, such as cyber intrusions and electromagnetic pulse, as greater risks to the grid

[81]According to the Quadrennial Energy Review, the combination of large service territories, minimal staffing, limited budgets, lack of access to tax incentives, and low customer density presents challenges to small utilities addressing new and evolving threats. See *Quadrennial Energy Review (QER) Task Force, Transforming the Nation's Electricity System.*

[82]This is consistent with GAO's Disaster Resilience Framework, which states that the federal government can also provide matching funding to help stimulate partner investment. See GAO-20-100SP.

[83]GAO-20-100SP.

that are of higher priority than weather-related risks.[84] However, the severity of the risks identified by numerous climate change forecasts demonstrates that weather-related events and effects could also be deemed a high priority.

A department-wide strategy could improve DOE's ability to address risks to the grid and enhance grid resilience. Developing and implementing a grid strategy for climate change that defines specific goals and measures progress could help guide DOE's agency-wide grid climate resilience efforts and help the agency prioritize actions to ensure that resources are targeted effectively. For example, such a strategy could describe and prioritize DOE efforts to coordinate with industry and other federal agencies; conduct research and development through the National Laboratories; and identify incentives, such as existing grant programs.

## FERC Has Taken Some Actions to Enhance Grid Resilience

Since 2014, FERC has taken several actions to enhance the resilience of the grid. Specifically:

- **FERC collected and shared information.** In 2018, FERC requested information from grid operators and other interested entities on resilience.[85] In 2019, FERC held a technical conference on the reliability of the grid where stakeholders discussed how NERC should address risks including climate change.[86] In addition, on February 22, 2021, FERC announced that it would open a new proceeding to

---

[84]DOE has similar strategies for potential cyber incidents and electromagnetic pulse events. DOE officials told us that they recently began working on establishing a coordinated DOE Defense Critical Electric Infrastructure capability strategy against all-hazards including natural and weather related disasters but this effort does not explicitly consider climate change effects as they pertain to extreme weather events. Subsection 215A(a)(4) of the Federal Power Act defines Defense Critical Electric Infrastructure as "any electric infrastructure located in any of the 48 contiguous States or the District of Columbia that serves a facility designated by the Secretary [of Energy] pursuant to subsection [215A(c) of the Federal Power Act], but is not owned or operated by the owner or operator of such facility."

[85]FERC Docket AD18-7-000. On February 18, 2021 FERC terminated the proceeding and stated that FERC did not believe that any generic action was appropriate. Instead, FERC stated that resilience concerns would be best addressed on a case-by-case and region-by-region basis.

[86]Climate change was not the focus of the technical conference but stakeholders discussed extreme weather and what NERC could do to help prepare for events such as wildfires in the West, hurricanes in the Southeast and extreme cold and blizzards in the Northeast. See: FERC Docket AD19-13-000: 2019 *Reliability Technical Conference Regarding the Bulk-Power System* (June 27, 2019).

examine the threat that climate change and extreme weather events pose to electric reliability.[87] NERC also holds webinars and meetings with grid operators to discuss a variety of topics, some of which address climate-related risks.

- **FERC assessed grid vulnerabilities.** FERC, working with NERC, also has assessed grid vulnerabilities through ad hoc efforts that include some potential climate change effects. For example, NERC conducts seasonal assessments of grid reliability and assessments following extreme weather events. In November 2019, NERC's Reliability Issues Steering Committee published a report on reliability risk priorities and identified extreme natural events, such as storms and wildfires, as risks.[88] The committee recommended that NERC and the six regional entities conduct special assessments of extreme natural event impacts including infrastructure interdependencies and analytical data and insights regarding resilience under severe weather conditions. In addition, in 2019, FERC and NERC issued a report on an extreme cold weather event that caused power outages in the South Central United States.[89] The report included several recommendations to enhance grid resilience, including developing a mandatory reliability standard on cold weather preparedness for generators. In February 2021, FERC and NERC announced a joint inquiry into the operations of the bulk-power system during extreme winter weather conditions in the Midwest and South Central states that contributed to power outages affecting millions of electricity customers throughout the region.
- **FERC approved reliability standards.** NERC officials we interviewed told us that existing standards could help address effects

---

[87]FERC announced that the new proceeding will examine how grid operators prepare for and respond to extreme weather events, including, but not limited to droughts, extreme cold, wildfires, hurricanes, and prolonged heat waves.

[88]North American Electric Reliability Corporation, Reliability Issues Steering Committee, *2019 ERO Reliability Risk Priorities Report* (Atlanta, GA: November 2019). According to the report, extreme natural events and their potential effects on the reliability of the bulk power system should be monitored and addressed to maintain reliability and improve resiliency.

[89]In January 2018, regional operators in the Midwest and South Central United States called for voluntary reductions in electricity use due to abnormally cold temperatures and higher-than-forecast demand. See 2019 NERC and FERC Staff Report: *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019).

from severe weather.[90] Furthermore, according to several stakeholders we interviewed, existing reliability standards could help address potential climate change effects. For example, these stakeholders told us that an existing transmission planning standard—TPL-001-4 Transmission System Planning Performance Requirements—calls for grid operators to plan for extreme weather events, such as those associated with climate change.[91] Specifically, the standard requires grid operators to conduct studies to assess the impact of extreme events including severe weather. However, the standards are based on historical data, and several stakeholders told us that historical weather patterns may not reflect future conditions given climate change. Therefore, they may not directly address all future climate change effects.

- **FERC issued market rules.** FERC has issued market rules that could affect grid resilience. For example, in March 2020, it proposed revising its transmission incentives policy to encourage development of transmission facilities.[92] The proposed revisions include encouraging grid operators to participate in regional transmission planning organizations and to consider transmission projects that provide resilience and reliability benefits—including hardening

[90]These NERC officials also noted that NERC's emergency preparedness and operations standards support mitigation of operating emergencies, provide for system restoration, and require event reporting.

[91]TPL-001-4 Transmission System Planning Performance Requirements.

[92]According to FERC documents, since the last formal review of FERC's transmission incentives policy, the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. These changes include an evolution in the resource mix, an increase in the number of new resources seeking transmission service, and FERC's implementation of Order No. 1000, which, according to FERC staff, directed the development of regional transmission planning processes to consider transmission needs driven by reliability, economic, and public policy considerations. In 2011, FERC issued Order No. 1000, which requires that public utility transmission providers participate in a regional transmission planning process and develop a regional transmission plan. See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35). Order No. 1000 also requires public utility transmission providers to consider alternatives to transmission—such as energy efficiency, demand response, energy storage, distributed generation, and combined heat and power systems sited close to load—in the regional transmission planning process. As a result, the order could also promote energy efficiency and demand response, two strategies that some stakeholders we interviewed told us could help enhance the resilience of the grid.

transmission assets against adverse weather events.[93] According to FERC staff we interviewed, the proposed revisions include offering public utilities incentives for transmission projects that provide significant and demonstrable reliability benefits. Generally, increased investment in transmission facilities should lead to a more robust grid that promotes resilience by being better able to respond to disruptive events, according to FERC staff. [94] This matter is pending before the Commission.

Some stakeholders we interviewed said that incentivizing distributed energy resources and energy storage could enhance the resilience of the grid.[95] According to FERC staff we interviewed, FERC has taken steps to ensure access of evolving technologies to markets through recent rulemaking orders, such as orders on storage and distributed energy sources. For example, in February 2018, FERC issued Order No. 841, which aims to address barriers to integrating storage into

[93]Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, 85 Fed. Reg. 18,784 (Apr. 2, 2020).

[94]In reference to the electric transmission incentives rule, one stakeholder told us that prudent investments should be recoverable in rates without incentives and that there is little reason to think that transmission providers and developers would need incentives to undertake these projects.

[95]As we reported in 2018, storage can provide services that support resilience by helping the grid adapt to changing conditions and potentially disruptive events and, if a disruptive event occurs, to rapidly recover. Specifically, in the event of an outage during which power sources or power lines become unavailable, storage can respond quickly to provide backup power or black start services—the provision of the power necessary to restore a generation plant when power from the grid is unavailable during a major outage. In addition, storage can also support microgrids—systems that can connect and disconnect from the grid depending on operating conditions—that could maintain power for a small area independent of the grid. See GAO, *Energy Storage: Information on Challenges to Deployment for Electricity Grid Operations and Efforts to Address Them,* GAO-18-402 (Washington, D.C.: May 24, 2018). FERC staff we interviewed told us that, if designed correctly, charging batteries prior to power outages or the pairing of local resources, such as solar rooftops with behind-the-meter storage, can allow customers to continue to use electricity during power outages. Storage can also be operated or dispatched to charge during periods of over-generation and then discharged later to reduce reliance on other types of generation according to these officials.

organized wholesale markets.[96] In September 2020, FERC issued Order No. 2222, which aims to address barriers to participation of distributed energy resources in wholesale markets.[97] According to FERC staff we interviewed, both Order No. 841 and Order No. 2222 may increase the amount of storage and other resources located closer to load—an end-use device or customer that receives power from the electric system. To the extent that more storage and distributed energy resources interconnect with the grid, the grid would be better able to react to disruptive events, according to FERC staff. This is because locating resources closer to load may allow customers, communities, distribution utilities, and others to operate independently of the grid, if there is a loss of power, according to FERC staff.

## Opportunities Exist for FERC to Take Actions Focused on Climate Change

Opportunities exist for FERC to take specific actions to further enhance grid resilience to climate change, according to several stakeholders we interviewed and documents we reviewed. The actions stakeholders identified include developing climate resilience standards and guidance; identifying statutory changes needed to address climate change risks; and examining whether and how the Commission should consider climate change risks when reviewing and approving projects, such as hydropower facilities. Some stakeholders we interviewed suggested that convening a technical conference would facilitate the sharing of information that could

[96]The rule requires that RTOs establish participation models consisting of market rules that recognize the physical and operational characteristics of electric storage resources to facilitate their participation in the RTO markets. Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 83 Fed. Reg. 9,580 (Mar. 6, 2018) (codified at 18 C.F.R. pt. 35). In prior years, FERC issued several orders—such as FERC Order Nos. 755 and 792—that also aimed to address barriers to storage participation in organized wholesale electric markets.

[97]Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 85, Fed. Reg. 67,094 (Oct. 21, 2020) (codified at 18 C.F.R. pt. 35). According to FERC, this rule enables distributed energy resources to participate alongside traditional resources in the regional organized wholesale markets through aggregations, opening U.S.-organized wholesale markets to new sources of energy and grid services and could yield several benefits, such as lower costs for consumers through enhanced competition, more grid flexibility and resilience, and more innovation within the electric power industry. According to FERC staff, as of March 2, 2021, a rehearing for Order No. 2222 was pending.

assist FERC in making decisions about specific actions FERC could take to enhance the resilience of the grid to climate change.[98]

- **Climate resilience standards.** Some stakeholders told us that FERC could require NERC to update reliability standards to specifically address climate change.[99] In addition, in 2017, the Quadrennial Energy Review recommended that the federal government take formal steps to update reliability standards and planning requirements to increase resilience to emerging and rapidly evolving hazards, such as climate change.[100] One stakeholder said that FERC, in collaboration with grid operators, should require relevant stakeholders to periodically "take the pulse" of the grid with a focus on climate change. This stakeholder said that this would provide the federal government with the basis to develop standards and regulations that could significantly affect the grid's ability to respond to future climate change effects. However, some stakeholders told us that national standards may not make sense, given that climate change effects will vary by region.[101] One stakeholder said that national resilience standards could be beneficial, but they should not be too specific;

[98]Some stakeholders we interviewed told us that FERC has an opportunity to convene stakeholders from different sectors and entities who do not typically work together at a technical conference on climate change risks. Another stakeholder suggested that FERC establish a state energy policy advisory function at FERC, where state entities would routinely provide input and advice to FERC staff and commissioners. According to this stakeholder, involving the states is essential to address the risks presented by climate and other threats. According to our Disaster Resilience Framework, the federal government has an opportunity to act as a trusted clearinghouse and integrator of federal and nonfederal information in a way that enhances its reach and value. Furthermore, federal efforts can leverage the expertise and resources of other partners across agencies, governments, and industry sectors, bringing together the disparate missions and resources that support disaster risk reduction to help build national resilience to natural hazards. See GAO-20-100SP.

[99]In addition, legislation introduced in the 116th Congress would have directed NERC to develop a resilience standard. Utility Resilience and Reliability Act, H.R. 7186, 116th Cong. § 2 (2020).

[100]Quadrennial Energy Review (QER) Task Force, *Transforming the Nation's Electricity System.*

[101]In June 2020, the House Select Committee on the Climate Crisis also recommended developing resilience standards for components of the bulk electric system for hazards such as wildfires; floods; extreme heat; and extreme weather events, such as hurricanes. According to the committee, these standards could be tailored to local conditions but provide consistency across the nation and help drive down costs in developing resilient power systems. House Select Committee on the Climate Crisis, Majority Staff Report, *Solving the Climate Crisis*.

rather, they should be broad enough to allow grid operators to determine how to best enhance the resilience of the grid.

- **Statutory changes.** FERC could also take steps to determine whether statutory changes are needed to adequately address climate change risks to the grid. Section 215 of the Federal Power Act provides for FERC's oversight of grid reliability, but there is no specific requirement that FERC consider climate change in doing so. According to some stakeholders and a report we reviewed, FERC has not addressed climate change risks due to lack of specific direction in the Federal Power Act. One stakeholder we interviewed stated that Congress could specifically require that FERC, NERC, or grid operators study how climate change will affect the grid and develop a plan for managing any adverse effects. This stakeholder said that this could be done by amending the Federal Power Act or new legislation. FERC staff we interviewed told us that legislative action to modify the Federal Power Act to expressly define FERC's role in incentivizing grid resilience may be helpful to clarify actions that FERC could take in this regard.
- **Project review and authorization.** FERC could examine whether and how FERC should consider climate change risks when reviewing and authorizing projects, such as hydropower facilities. According to some stakeholders we interviewed, FERC could require that operators of these facilities account for climate change effects when designing or relicensing facilities. Specifically, these stakeholders told us that FERC could develop or update criteria such as engineering guidelines for electricity generation facilities to ensure that facilities are designed to withstand climate change effects. FERC staff told us that FERC considers climate change impacts to specific projects in its environmental reviews. In its review of hydropower proposals, FERC considers historical and recent hydrological data and stream flow information, which would include any alterations due to climate change, and often includes monitoring and provisions that allow FERC to alter license requirements, should environmental conditions change in the future, according to FERC staff. For natural gas projects, FERC analyzes physical design considerations that allow facilities, especially coastal liquefied natural gas terminals, to have accounted for potential hurricanes and storm surges, according to FERC staff we interviewed. However, in both cases, FERC has not found any scientifically accepted methods for determining project area specific forecasts of climate change effects, according to staff. According to FERC staff, the Commission recently reopened a review to explore methods to consider climate change impacts in its natural

gas pipeline work, which may be useful in assessing climate change impacts to the electricity grid and hydroelectric projects.[102]

In considering these suggestions from stakeholders—developing climate resilience standards and guidance, identifying statutory changes that could help address climate change risks, and examining whether and how the Commission should consider climate change risks when reviewing and approving projects—FERC could take a risk-based approach in determining appropriate actions to take in addressing climate change and resilience. As we have previously reported, risk management should involve identifying and assessing risks to understand the likelihood of impacts and their associated consequences. This assessment enables the organization to plan and implement actions responsive to the highest-priority risks.

FERC has not identified and assessed risks posed to the grid by climate change or planned a response. As previously mentioned, in 2018, FERC requested and collected information on grid resilience.[103] The information FERC collected about grid resilience included information on the potential effects of climate change on the electricity grid and indicated a need to plan for climate change risks.[104] However, while FERC staff told us that they reviewed the record for this proceeding, the Commission has not taken further action on this collection effort or on identifying and

[102]In February 2021, FERC asked for new information and additional perspectives that would assist the Commission with a review of the 1999 Policy Statement on the Certification of New Interstate Natural Gas Facilities. See Certification of New Interstate Natural Gas Facilities, 86 Fed. Reg. 11,268 (Feb. 24, 2021).

[103]FERC Docket AD18-7-000.

[104]Several utilities and entities from academia and nonprofits responded to FERC's request and indicated a need to plan for climate change. According to FERC staff, in terminating the proceeding in Docket No. AD18-7-000, the Commission stated that it will continue to work closely with RTOs, ISOs and other public utilities to address grid resilience and take all the appropriate actions to ensure that the electricity grid remains stable.

assessing specific risks.[105] As mentioned previously, FERC announced that it would open a proceeding to examine the threat that climate change and extreme weather events pose on electric reliability, but FERC has not issued a formal notice for this proceeding. According to FERC's strategic plan, one of FERC's core functions includes protecting and improving the reliable and secure operation of the bulk-power system by identifying reliability and security risks; overseeing the development, implementation, and enforcement of mandatory reliability standards; and promoting the resilience, reliability, and security of the bulk-power system.[106] However, according to FERC staff, FERC has not taken steps to identify or assess climate change risks to the grid or planned a response because the Commission has not directed staff to do so. By taking steps to identify and assess climate-related risks and plan a response, including identifying the actions needed to enhance the resilience of the grid to climate change, FERC could better manage such risks and achieve its objective of promoting resilience.

## Conclusions

Key stakeholders cite changes in the earth's climate that are expected to result in more frequent and intense extreme weather and climate-related events. These changes pose risks to the electricity grid—the power generation, transmission, and distribution system—that can potentially affect the nation's economic and national security. DOE and FERC have taken actions to enhance the resilience of the electricity grid, and they have opportunities to further enhance grid resilience to climate change. DOE has not prioritized climate change resilience and does not have a department-wide strategy to coordinate its efforts to enhance the resilience of the grid to climate change. Developing and implementing a department-wide strategy for climate change, consistent with GAO's Disaster Resilience Framework, that defines goals and measures

[105]FERC staff told us that FERC generally does not require reporting on climate-related risks to the electricity grid. However, according to FERC staff, FERC has authority under sections 304 and 307 of the Federal Power Act to require reporting of information necessary for FERC's oversight of the rates and operations of jurisdictional electric utilities, including financial risk disclosures, if FERC finds it necessary. FERC staff noted that this issue is currently being considered by the Securities and Exchange Commission, and if the Securities and Exchange Commission requires additional disclosure requirements, those disclosures would be available for any future use deemed appropriate by FERC.

[106]FERC's strategic plan states that multiple internal and external factors–including threats from extreme weather and natural disasters–are creating challenges and opportunities to maintain and improve reliability, security, and resilience. Federal Energy Regulatory Commission, *Strategic Plan, Fiscal Years 2018-2022.*

progress, could help guide and prioritize DOE's efforts and ensure that resources are targeted effectively.

Opportunities also exist for FERC to take actions focused on climate change. While the new proceeding might pose opportunities to do so, FERC has not taken steps to identify and assess climate change risks to the grid and, therefore, is not well positioned to determine the actions needed to enhance resilience. Risk management involves identifying and assessing risks to understand the likelihood of impacts and their associated consequences. By taking steps to identify and assess climate-related risks and plan a response, FERC could better manage such risks to achieve its objective of promoting resilience.

## Recommendations for Executive Action

We are making two recommendations, one to DOE and one to FERC.

The Secretary of Energy should develop and implement a department-wide strategy to coordinate its efforts that defines goals and measures progress to enhance the resilience of the electricity grid to the risks of climate change. **(Recommendation 1)**

The Chairman of FERC should direct staff to take steps to identify and assess climate related risks to the electricity grid, and plan a response, including identifying actions to address the risks and enhance the resilience of the grid to climate change. **(Recommendation 2)**

## Agency Comments

We provided a draft of this report to the U.S. Department of Energy and the Federal Energy Regulatory Commission for review and comment. We received comments from DOE, which have been reproduced in appendix I. We received comments from FERC staff via email. In addition, DOE and FERC provided technical comments which we incorporated as appropriate.

In its comments, DOE neither agreed nor disagreed with our recommendation. The comment letter states that DOE remains committed to working with FERC and other partners, as appropriate, to strengthen resilience. We continue to believe that developing and implementing a department-wide strategy to coordinate DOE's efforts that defines goals and measures progress to enhance the resilience of the grid to the risks of climate change could improve DOE's ability to address risks to the grid and enhance grid resilience.

In its email, FERC staff stated that they did not have significant concerns with the specific recommendation in the draft report. FERC staff note, and our report acknowledges, that the FERC Chairman has recently announced a new proceeding to examine the threat that climate change and extreme weather events pose to reliability. We believe that the new proceeding that FERC announced might pose opportunities to identify and assess risks posed to the grid by climate change. We continue to believe that taking steps to identify and assess climate related risks to the electricity grid, and plan a response, could better position FERC to determine the actions needed to enhance the resilience of the electricity grid and manage such risks.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 5 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of the U.S. Department of Energy and the Executive Director of the Federal Energy Regulatory Commission, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix II.

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

# Appendix I: Comments from the U.S. Department of Energy

**Department of Energy**
Washington, DC 20585

March 2, 2021

Mr. Frank Rusco
Director
Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

The U.S. Department of Energy (DOE or Department) appreciates the analysis provided by the Government Accountability Office (GAO) in the draft report titled, *ELECTRICITY GRID RESILIENCE: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions (GAO-21-346)*.

DOE remains committed to working with FERC and other partners, as appropriate, to strengthen grid resilience. Given the short period of time provided for responding to this report, DOE will perform a full assessment of GAO's report and provide a complete response to GAO's recommendation when it provides its management decision letter to Congressional committees, as required by 31 U.S.C. § 720. Technical comments on GAO's report are provided in an attachment to this letter.

GAO should direct any questions to Charles Kosak, Deputy Assistant Secretary for Energy Resilience, at Charles.kosak@hq.doe.gov.

Sincerely,

Patricia A. Hoffman
Digitally signed by Patricia A. Hoffman
Date: 2021.03.02 10:59:27 -05'00'

Patricia A. Hoffman
Acting Assistant Secretary
Office of Electricity

# Appendix II: GAO Contact and Staff Acknowledgments

## GAO Contact

Frank Rusco at (202) 512-3841 or ruscof@gao.gov

## Staff Acknowledgments

In addition to the contact named above, the following individuals made key contributions to this report: Janice Ceperich (Assistant Director), Celia Rosario Mendive (Analyst-in-Charge), Austin Barvin, and Kelsey Sagawa. Also contributing to this report were Antoinette Capaccio, Tara Congdon, John Delicath, Jaci Evans, Philip Farah, Cindy Gilbert, Paige Gilbreath, Kathryn Godfrey, Leslie Gordon, Susan Irving, Madhav Panwar, Sara Sullivan, J.D. Thompson, and Meg Tulloch.

## GAO's Mission

The Government Accountability Office, the audit, evaluation, and investigative arm of Congress, exists to support Congress in meeting its constitutional responsibilities and to help improve the performance and accountability of the federal government for the American people. GAO examines the use of public funds; evaluates federal programs and policies; and provides analyses, recommendations, and other assistance to help Congress make informed oversight, policy, and funding decisions. GAO's commitment to good government is reflected in its core values of accountability, integrity, and reliability.

## Obtaining Copies of GAO Reports and Testimony

The fastest and easiest way to obtain copies of GAO documents at no cost is through our website. Each weekday afternoon, GAO posts on its website newly released reports, testimony, and correspondence. You can also subscribe to GAO's email updates to receive notification of newly posted products.

## Order by Phone

The price of each GAO publication reflects GAO's actual cost of production and distribution and depends on the number of pages in the publication and whether the publication is printed in color or black and white. Pricing and ordering information is posted on GAO's website, https://www.gao.gov/ordering.htm.

Place orders by calling (202) 512-6000, toll free (866) 801-7077, or TDD (202) 512-2537.

Orders may be paid for using American Express, Discover Card, MasterCard, Visa, check, or money order. Call for additional information.

## Connect with GAO

Connect with GAO on Facebook, Flickr, Twitter, and YouTube.
Subscribe to our RSS Feeds or Email Updates. Listen to our Podcasts.
Visit GAO on the web at https://www.gao.gov.

## To Report Fraud, Waste, and Abuse in Federal Programs

Contact FraudNet:

Website: https://www.gao.gov/fraudnet/fraudnet.htm

Automated answering system: (800) 424-5454 or (202) 512-7700

## Congressional Relations

Orice Williams Brown, Managing Director, WilliamsO@gao.gov, (202) 512-4400, U.S. Government Accountability Office, 441 G Street NW, Room 7125, Washington, DC 20548

## Public Affairs

Chuck Young, Managing Director, youngc1@gao.gov, (202) 512-4800
U.S. Government Accountability Office, 441 G Street NW, Room 7149
Washington, DC 20548

## Strategic Planning and External Liaison

Stephen J. Sanford, Acting Managing Director, spel@gao.gov, (202) 512-4707
U.S. Government Accountability Office, 441 G Street NW, Room 7814,
Washington, DC 20548

# Exhibit C

**Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Complaint of Michael Mabee** | **)** | |
| **Related to Mandatory Reliability Standards** | **)** | **Docket No. EL21-54-000** |
| **in the Texas Grid Collapse of 2021** | **)** | |

## Motion of Complainant Requesting FERC Take Official Notice

Submitted to FERC on March 31, 2021

I am a private citizen who conducts public interest research on the security of the electric grid. I am also the Complainant in this docket.

I request that the Commission take official notice of a report of the Texas Department of State Health Services (DSHS), published on March 25, 2021 which is relevant to this docket. The report, entitled: "Winter Storm-Related Deaths" is attached as Exhibit A (starting on page 3).

Texas DSHS is now reporting 111 deaths related to the winter storm in Texas and notes:

> DSHS disaster epidemiologists continue to reconcile information about causes of death. The majority of verified deaths were associated with hypothermia. There have also been multiple deaths caused by motor vehicle accidents, carbon monoxide poisoning, medical equipment failure, exacerbation of chronic illness, lack of home oxygen, falls, and fire. Confirmed deaths occurred between Feb. 11 and March 5.

Most of the major causes of death reported, such as hypothermia, carbon monoxide poisoning, medical equipment failure, exacerbation of chronic illness, lack of home oxygen, and fire may be inferred as being the result of the failure of the electric grid in Texas. These data show the compelling human toll of the ineffective and/or unenforced mandatory reliability standards which are the subject of this complaint.

These deaths are an unacceptable outcome of a preventable disaster. The Commission must act to improve the enforcement of the mandatory reliability standards and improve the standards themselves.

Respectfully submitted,

Michael Mabee

# Exhibit A

**Motion of Complainant Requesting FERC Take Official Notice**
**Submitted to FERC on March 31, 2021**

TEXAS Health and Human Services | Texas Department of State Health Services

# News Updates

*Current news topics:*

en español Subscribe



## COVID-19

The Texas Department of State Health Services tracks COVID-19 cases, testing, hospitalizations, vaccine allocations and uptake, and more.

**COVID-19 data dashboards can be accessed from the menu options to the right.**
***Accessible version* (Excel)** | **Texas COVID-19 Data *Additional Datasets***
**All data are provisional and subject to change.**

DSHS has additional information on COVID-19 for the public, health care professionals, health departments and labs at **dshs.texas.gov/coronavirus**.

News releases on COVID-19

Case Counts
*Accessible version* (Excel)
Test and Hospital Data
County Trends
Vaccine Data
Public Schools
Additional Data

▲ Top

## COVID-19 Vaccine Distribution – March 26, 2021

More than **1 million first doses of COVID-19 vaccine will be shipped** to providers across Texas next week. The Texas Department of State Health Services is allocating 818,410 doses to 779 providers in 202 counties. More than 200,000 additional first doses are expected to be available to pharmacy locations and federally-qualified health centers directly from the federal government.

**Texas COVID-19 Vaccine Information**

**COVID-19 Vaccine Allocations**

**Texas COVID-19 Vaccination Plan**

**Texas Vaccine Data**

**Vaccine Provider Locations**

▲ Top

## COVID-19 Vaccine Doses Wasted Report – March 26, 2021

Providers are required to self-report the reason why any vaccine doses that they received were unable to be used to vaccinate a person. The number of doses reported to have been discarded in Texas is 0.07% of the doses shipped to providers.

Reasons vaccine might not be used include:

- Storage refrigerator/freezer too warm
- Mechanical failure of the refrigerator/freezer
- Broken vials or syringes
- Spoiled vaccine – vaccine that couldn't be used within required timeframe

DSHS does outreach to providers reporting discarded doses to ensure that they follow proper storage and handling procedures and to allow them to correct any data entry errors.

A cumulative report will be posted weekly.

[Texas COVID-19 Doses Wasted Report]

▲ Top

## COVID-19 Variants – March 24, 2021

DSHS is tracking cases of COVID-19 variants of concern in Texas.

Because viruses constantly change through mutation, new variants of the virus that causes COVID-19 are expected to occur. Multiple variants have been documented in Texas and the United States that may spread more easily or cause more serious illness. Current scientific evidence indicates that available vaccines are effective at protecting people from severe illness caused by these variants. Public health officials at the federal, state and local levels continue to study them, monitor their spread, develop strategies to slow their spread and test how variants may respond to existing therapies, vaccines and testing.

**Summary Table: COVID-19 Variant of Concern Cases Reported to Texas DSHS, by trauma service area and variant.**

| TSA | B.1.1.7 UK | B.1.351 South Africa | B.1.429 Hawaii | P.1 Brazil | B.1.427 California | Total |
|---|---|---|---|---|---|---|
| B | 0 | 1 | 0 | 0 | 0 | 1 |
| E | 90 | 1 | 2 | 0 | 0 | 93 |
| G | 1 | 0 | 0 | 0 | 0 | 1 |
| H | 1 | 0 | 0 | 0 | 0 | 1 |
| I | 5 | 0 | 0 | 0 | 0 | 5 |
| J | 4 | 0 | 0 | 0 | 0 | 4 |
| L | 4 | 0 | 0 | 0 | 0 | 4 |
| M | 5 | 0 | 0 | 0 | 0 | 5 |
| N | 14 | 0 | 1 | 0 | 1 | 16 |
| O | 57 | 0 | 0 | 0 | 0 | 57 |
| P | 18 | 0 | 0 | 0 | 0 | 18 |
| Q | 207 | 2 | 6 | 2 | 0 | 217 |
| R | 61 | 0 | 2 | 0 | 0 | 63 |
| U | 6 | 0 | 0 | 0 | 0 | 6 |
| V | 11 | 0 | 0 | 0 | 0 | 11 |
| **Grand Total** | **484** | **4** | **11** | **2** | **1** | **502** |

[Centers for Disease Control and Prevention – Variants of the Virus that Causes COVID-19]
[Texas Trauma Service Areas Map]

▲ Top

## Multisystem Inflammatory Syndrome in Children (MIS-C) – March 15, 2021

DSHS has confirmed 97 cases of Multisystem Inflammatory Syndrome in Children. MIS-C is a rare but serious complication associated with COVID-19. The condition causes different body parts to become inflamed, including the heart, lungs, kidneys, brain, skin, eyes or gastrointestinal organs. Children with MIS-C may have fever and various symptoms, including abdominal pain, vomiting, diarrhea, neck pain, rash, bloodshot eyes, or feeling extra tired. The cause of MIS-C has not been determined. However, many children with MIS-C had the virus that causes COVID-19 or had been around someone with COVID-19.

Parents and caregivers should contact their child's health care provider if a child shows symptoms of MIS-C. Providers should report suspected cases to their public health department.

While the cause of MIS-C has not been identified, the best way to protect your children against the condition is to take precautions to prevent anyone in your household from getting COVID-19.

**MIS-C at a glance:**

- *Age range*: 9 months-18 years old (median: 9 years old)
- *Sex*: 59 Male (61%), 38 Female (39%)
- *Race/Ethnicity*: 51 Hispanic (53%), 25 Black (26%), 11 White (11%), 3 Asian (3%), 7 Unknown (7%)
- *Onset date range (fever)*: 4/22/20 – 1/1/21
- *Hospital and ICU admission*: 97 Hospitalized (100%), 69 ICU admission (71%)
- *Outcome*: 88 Discharged (91%), 1 Died (1%), 8 Unknown/Lost to Follow-Up (8%)

**Multisystem Inflammatory Syndrome in Children (MIS-C)**

| Public Health Region | Number of Cases |
|---|---|
| 1 (Panhandle) | 1 |
| 2/3 (North Texas) | 27 |
| 4/5N (East Texas) | 2 |
| 6/5S (Southeast Texas) | 45 |
| 7 (Central Texas) | 15 |
| 8 (South Texas) | 6 |
| 11 (Rio Grande Valley) | 1 |
| **Total** | 97 |

▲ Top

## Winter Storm-Related Deaths – March 25, 2021

DSHS is tracking deaths related to the February winter storms that affected Texas and posting data that is preliminary and subject to change.

There are three main ways DSHS is notified of disaster-related deaths:

- Medical certifiers submit a DSHS form specifying that a particular death was related to a disaster.
- Medical certifiers flag a death record as disaster related.
- DSHS epidemiologists match public reports of disaster-related deaths to death certificates.

DSHS disaster epidemiologists continue to reconcile information about causes of death. The majority of verified deaths were associated with hypothermia. There have also been multiple deaths caused by motor vehicle accidents, carbon monoxide poisoning, medical equipment failure, exacerbation of chronic illness, lack of home oxygen, falls, and fire. Confirmed deaths occurred between Feb. 11 and March 5.

This information will be updated weekly.

**Winter Storm-Related Deaths**
by county of occurrence
*Data is preliminary and subject to change as additional information is gathered and additional deaths are verified*

| County | Number of Deaths |
|---|---|
| Aransas | 1 |

| County | Number of Deaths |
|---|---|
| Armstrong | 1 |
| Bandera | 1 |
| Bexar | 4 |
| Brazoria | 1 |
| Cass | 1 |
| Clay | 1 |
| Coleman | 2 |
| Collin | 2 |
| Dallas | 3 |
| Ector | 1 |
| Ellis | 2 |
| Fayette | 1 |
| Fort Bend | 3 |
| Freestone | 1 |
| Frio | 1 |
| Galveston | 6 |
| Grayson | 1 |
| Hale | 1 |
| Harris | 31 |
| Henderson | 2 |
| Hill | 2 |
| Hopkins | 1 |
| Hunt | 1 |
| Kaufman | 1 |
| Kendall | 1 |
| Kerr | 1 |
| Lamar | 1 |
| Lavaca | 2 |
| Lee | 1 |
| Leon | 1 |
| Limestone | 1 |
| McLennan | 1 |
| Montgomery | 2 |
| Pecos | 1 |

| County | Number of Deaths |
|---|---|
| Rusk | 1 |
| San Saba | 1 |
| Schleicher | 1 |
| Sutton | 1 |
| Taylor | 6 |
| Travis | 9 |
| Trinity | 1 |
| Uvalde | 1 |
| Webb | 1 |
| Wharton | 1 |
| Wichita | 2 |
| Williamson | 2 |
| **Total** | **111** |

▲ Top

*Last updated March 27, 2021*

Document Content(s)

# Exhibit D

**Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| Complaint of Michael Mabee Related to Reliability Standards | ) ) ) | Docket No. EL21-54-000 |

**PROTEST OF**
**THE AMERICAN PUBLIC POWER ASSOCIATION,**
**THE EDISON ELECTRIC INSTITUTE,**
**THE LARGE PUBLIC POWER COUNCIL, AND**
**THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION**

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC") and the Commission's March 4, 2021 notice in the above-captioned proceeding, the American Public Power Association, the Edison Electric Institute, the Large Public Power Council, and the National Rural Electric Cooperative Association (collectively, the "Joint Trade Associations") submit this protest in response to the March 1, 2021 complaint filed by Michael Mabee ("Complaint").[1] As discussed below, the Commission should dismiss the Complaint.

## I. INTRODUCTION

Pointing to the impacts on the operation of the electric grid in Texas from the extreme cold weather during the week of February 15, 2021, the Complaint argues that either the mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by the Commission were not followed, or the mandatory standards were ineffective.[2] The Complaint asks, pursuant to sections 215(e)(3)[3] and 215(d)(5)[4] of the Federal Power Act

---

[1] Each of the Joint Trade Associations is filing a doc-less motion to intervene in this proceeding.

[2] Complaint at 1.

[3] 16 U.S.C. § 824o(e)(3).

[4] 16 U.S.C. § 824o(d)(5).

("FPA") that the Commission "investigate this Complaint and issue an appropriate order to the Electric Reliability Organization ('ERO') to correct deficiencies."[5] Specifically, the Complaint asks the Commission to direct NERC and Texas Reliability Entity, Inc. ("Texas RE") "to conduct a comprehensive investigation into whether reliability standards were followed by all entities registered with Texas RE who had any involvement in the Texas grid collapse of February 15, 2021."[6] Further, the Complaint requests that, if NERC and Texas RE "determine that violations of reliability standards did not contribute to the Texas grid collapse of February 15, 2021," the Commission should direct NERC "to improve the reliability standards to prevent catastrophic power outages such as this from occurring in the future."[7] On March 15, 2021, Mr. Mabee filed a motion in this docket asking the Commission to take official notice of a March 2021 report by the U.S. Government Accountability Office addressing electricity grid resilience, and on April 1, 2021 Mr. Mabee filed a motion asking the Commission to take official notice of a report issued by the Texas Department of State Health Services.

## II. PROTEST

Each of the Joint Trade Associations has members in Texas that were affected by the extreme winter weather and related impacts during the week of February 15, 2021, and we fully appreciate the need to examine the circumstances that led to the outages in order to prevent similar events from occurring in the future. However, the investigation requested in the Complaint is not the appropriate forum for such an examination.

---

[5] Complaint at 1.

[6] *Id.* at 12.

[7] *Id.*

The Commission and NERC have already announced that they will conduct a joint inquiry into the operations of the bulk-power system during the cold weather event.[8] The Commission and NERC explained that the inquiry "will work with other federal agencies, states, regional entities and utilities to identify problems with the performance of the bulk-power system and, where appropriate, solutions for addressing those issues."[9] The investigation requested by the Complaint is duplicative of the FERC-NERC joint inquiry, and would result in an inefficient use of Commission and NERC resources.[10] The Commission should dismiss the Complaint on this basis.

Dismissal of the Complaint is also warranted to the extent it seeks an investigation of reliability standards violations under FPA section 215(e)(3). That section "addresses specific instances of noncompliance by registered entities,"[11] yet the Complaint does not cite any evidence that any particular registered entity violated any NERC reliability standard during the course of the extreme winter weather event. In this respect, the Complaint fails to comply with Commission Rule 206, which requires, *inter alia*, that a complaint "[c]learly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements;"[12] and "[e]xplain how the action or inaction violates applicable statutory standards or regulatory requirements."[13] The Complaint does neither; instead, it inappropriately rests on mere speculation

---

[8] *See* News Release, "FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations" (Feb. 16, 2021), available at: https://www.ferc.gov/news-events/news/ferc-nerc-open-joint-inquiry-2021-cold-weather-grid-operations.

[9] *Id.*

[10] *See, e.g.*, *Complaint of Michael Mabee, Related to Critical Infrastructure, Reliability Standards*, 173 FERC ¶ 61,010, at P 15 (denying complaint "because the relief sought therein is either unsupported or premature given current proceedings before the Commission and projects within NERC"); *Cf. CITGO Petrol. Corp. v. Colonial Pipeline Co.*, 167 FERC ¶ 61,266, at PP 29-30 (2019) (dismissing duplicative complaint that would "result in an inefficient use of Commission and participant resources.").

[11] *Complaint of Michael Mabee, Related to Critical Infrastructure, Reliability Standard*, 171 FERC ¶ 61,205, at P 20 n.30 (2020).

[12] 18 C.F.R. § 385.206(b)(1) (2021).

[13] 18 C.F.R. § 385.206(b)(2) (2021).

that mandatory reliability standards may have been violated. Such speculation is insufficient to sustain a complaint under Rule 206.[14] And here again, to the extent the ongoing FERC-NERC joint inquiry turns up any evidence of a standards violation, action may then be taken. The Complaint's further request that the Commission direct NERC "to improve the reliability standards" is contingent on the outcome of the requested investigation,[15] so there is no basis to consider such a directive to NERC in this proceeding.

## III. CONCLUSION

Joint Trade Associations respectfully ask the Commission to dismiss the Complaint, as it is duplicative of the ongoing FERC-NERC joint inquiry into the February cold weather event and fails to satisfy the Commission's regulations governing complaints.

Respectfully submitted,

**American Public Power Association**

*<u>/s/ John E. McCaffrey</u>*
John E. McCaffrey
Senior Regulatory Counsel
Jack Cashin
Director, Policy Analysis & Reliability Standards
American Public Power Association
2451 Crystal Drive
Suite 1000
Arlington, VA 22202
202-467-2900
jmccaffrey@publicpower.org
jcashin@publicpower.org

**Edison Electric Institute**

*<u>/s/ Bob Stroh</u>*
Andrea Koch
Senior Director, Reliability Policy
Bob Stroh
Associate General Counsel, Reliability & Security
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, D.C. 20004
(202) 508-5000
akoch@eei.org
rstroh@eei.org

*Additional signatures on the next page*

[14] *See, e.g.*, *CAlifornians for Renewable Energy, Michael E. Boyd v. Cal. Indep. Sys. Operator Corp.*, 174 FERC ¶ 61,204, at P 32 (2021).

[15] *See* Complaint at 12.

**National Rural Electric Cooperative Association**

*/s/ Mary Ann Ralls*
Mary Ann Ralls
Senior Director, Regulatory Counsel
National Rural Electric Cooperative Association
4301 Wilson Blvd.
Arlington, VA 22203
(703) 907-5837
maryann.ralls@nreca.coop

**Large Public Power Council**

*/s/ Jonathan D. Schneider*
Jonathan D. Schneider
Jonathan P. Trotta
Stinson LLP
1775 Pennsylvania Avenue NW
Suite 800
Washington, DC 20006
(202) 728-3034
jonathan.schneider@stinson.com
jtrotta@stinson.com

April 5, 2021

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Arlington, Virginia, this 5th day of April, 2021.

*/s/ John E. McCaffrey*

John E. McCaffrey
2451 Crystal Drive
Suite 1000
Arlington, VA 22202
(202) 467-2900
jmccaffrey@publicpower.org

Document Content(s)

# Exhibit E

**Testimony of Michael Mabee on SB 1606 – All Hazards Grid Security**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Complaint of Michael Mabee Related to Reliability Standards** | ) ) ) ) ) ) | **Docket No. EL21-54-000** |

# MOTION TO INTERVENE AND COMMENT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND TEXAS RELIABILITY ENTITY, INC.

Derrick Davis
General Counsel & Corporate Secretary
Texas Reliability Entity, Inc.
805 Las Cimas Parkway, Suite 200
Austin, TX 78746
(512) 583-4900
derrick.davis@texasre.org

*Counsel for Texas Reliability Entity, Inc.*

Edwin G. Kichline
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
ed.kichline@nerc.net
marisa.hecht@nerc.net

*Counsel for the North American Electric Reliability Corporation*

April 5, 2021

# TABLE OF CONTENTS

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Complaint of Michael Mabee Related to Reliability Standards** | ) ) ) ) ) ) | **Docket No. EL21-54-000** |

## MOTION TO INTERVENE AND COMMENT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND TEXAS RELIABILITY ENTITY, INC.

Pursuant to Rules 206, 212, and 214 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure[1] and the Commission's Notice of Complaint,[2] the North American Electric Reliability Corporation ("NERC") and Texas Reliability Entity, Inc. ("Texas RE") move to intervene and comment on the Complaint filed by Michael Mabee ("Complainant") on March 1, 2021 in the above-captioned docket ("Complaint").

The Complaint claims that the recent cold weather event[3] in Texas that led to power outages demonstrates that either: (i) "[t]he mandatory [R]eliability [S]tandards were not followed";[4] or (ii) "[t]he mandatory [R]eliability [S]tandards were ineffective."[5] The Complaint requests the Commission (i) issue a public notice of the Complaint; (ii) direct NERC and Texas RE to conduct an investigation into whether Reliability Standards were followed by all entities

---

[1] 18 C.F.R. §§ 385.206, 385.212, and 385.214 (2021).
[2] Notice of Complaint, Docket No. EL21-54-000 (Mar. 4, 2021).
[3] The cold weather event refers to the extreme arctic weather that affected the central part of the United States during the second week of February 2021, leading to power outages.
[4] Complaint at 1.
[5] *Id.*

registered with Texas RE who had involvement in the power outages; and (iii) if NERC and Texas RE determine violations did not contribute to the power outages, then FERC should direct NERC to revise the Reliability Standards to prevent such power outages resulting from cold weather events.

NERC and Texas RE appreciate the impact caused by the recent cold weather event. Accordingly, NERC and Texas RE have pursued both an inquiry into the cold weather event and Reliability Standards development, as more fully described below. In light of these actions, NERC and Texas RE request leave to intervene and comment in response to the Complainant's assertions and recommendations and request that the Commission dismiss the Complaint. The Commission should not engage in a complaint proceeding at this time as it would be duplicative and potentially hamper the efforts already underway. This is especially true because the complaint, as filed, lacks the necessary specificity as required under Section 206 of the Federal Power Act.

## I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[6]

Derrick Davis*
General Counsel & Corporate Secretary
Texas Reliability Entity, Inc.
805 Las Cimas Parkway, Suite 200
Austin, TX 78746
(512) 583-4900
derrick.davis@texasre.org

Edwin G. Kichline*
Senior Counsel
Marisa Hecht*
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
ed.kichline@nerc.net
marisa.hecht@nerc.net

6 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

## II. SUMMARY OF COMPLAINT

The Complainant alleges that the cold weather event in Texas demonstrated that the Reliability Standards were not followed or were ineffective.[7] The Complainant recommends that the Commission:

i. Issue public notice of the complaint;[8]

ii. Direct NERC and Texas RE to conduct an investigation into whether Reliability Standards were followed by all entities registered with Texas RE "who had any involvement in the Texas grid collapse of February 15, 2021";[9] and

iii. Direct NERC to modify the Reliability Standards to prevent future outages if NERC and Texas RE determine that violations of the Reliability Standards did not contribute to the cold weather event in Texas.

On March 14, 2021, the Complainant also filed a motion requesting the Commission take official notice of a Government Accountability Office report.[10] On March 31, 2021, the Complainant file another motion requesting the Commission take official notice of a Texas Department of State Health Services website tracking deaths related to the cold weather.[11]

## III. MOTION TO INTERVENE

NERC and Texas RE have a substantial interest in this proceeding as the Complainant seeks to have the Commission direct NERC and Texas RE to conduct an investigation or revise

---

7 NERC and Texas RE note that the Complainant, as a private citizen, is not subject to the NERC Reliability Standards, including the CIP Reliability Standards. Complaint at 1.

8 Complaint at 1.

9 Complaint at 12.

10 Government Accountability Office, *Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions*, GAO-21-346 (Mar. 2021), https://www.gao.gov/assets/gao-21-346.pdf.

11 The website is available at https://dshs.texas.gov/news/updates.shtm.

Reliability Standards.[12] By enacting the Energy Policy Act of 2005,[13] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. The Commission certified NERC as the ERO in 2006.[14] Texas RE carries out certain ERO activities as a Regional Entity defined in Section 215(a)(7) of the FPA.[15]

As the ERO, NERC's mission is to improve the reliability and security of the Bulk-Power System in North America. Similarly, Texas RE supports this goal as a Regional Entity. Under its FERC-approved Rules of Procedure, NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of the NERC Rules of Procedure ("ROP") and the NERC Standard Processes Manual ("SPM").[16] NERC and the Regional Entities, including Texas RE, are responsible for monitoring, assessing, and enforcing compliance with Reliability Standards in the United States in accordance with Section 400 (Compliance Enforcement) of the ROP and the NERC Compliance Monitoring and Enforcement Program.[17]

---

12 Complaint at 12.

13 16 U.S.C. § 824o (2018).

14 *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

15 16 U.S.C. § 824o(a)(7) and (e)(4). *See also N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,060 (2006), *order on reh'g*, 120 FERC ¶ 61,260 (2007) (accepting a delegation agreement between NERC and Texas RE in order to designate Texas RE as a Regional Entity pursuant to Section 215(e)(4) of the FPA). The Commission approved the currently effective delegation agreement in 2020 in Docket No. RR20-5-000. *See N. Am. Elec. Reliability Corp.*, 173 FERC ¶ 61,277 (2020) (conditionally approving revised delegation agreements to be effective January 1, 2021 and directing modifications and a compliance filing).

16 The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-ofProcedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

17 *Id*. The NERC Compliance Monitoring and Enforcement Program is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4C_CMEP_06082018.pdf.

No other party can adequately represent NERC's or Texas RE's interests to respond to the Complainant's allegations. Therefore, it is in the public interest to permit this intervention.

## IV. COMMENTS

NERC and Texas RE take seriously their responsibility to support the reliability of the Bulk-Power System. NERC and Texas RE understand the human and economic impacts caused by lack of electricity service, as evidenced by the cold weather event in Texas, and focus on their mission to help ensure a reliable Bulk-Power System in North America. As described in more detail below, NERC, Texas RE, and FERC are pursuing several actions right now to address the cold weather event. On February 16, 2021, NERC and FERC announced a joint inquiry into the cold weather event. This inquiry will "identify problems with the performance of the [Bulk-Power System]"[18] and develop solutions as appropriate. Furthermore, NERC already is developing cold weather Reliability Standards as described below. As a result, the Complaint's requested relief of an investigation and standards revisions would duplicate current activities addressing the cold weather event and potentially hamper these efforts.

Furthermore, the Commission should dismiss the Complaint because it fails to meet the minimum requirements applicable to complaints under the Commission's Rules of Practice and Procedure.[19] Specifically, the Complaint failed to state the provision of the Reliability Standard allegedly violated, as is required of complaints alleging violations of Reliability Standards.[20]

---

18 *FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations*, News Release (Feb. 16, 2021), https://www.nerc.com/news/Pages/FERC,-NERC-to-Open-Joint-Inquiry-into-2021-Cold-Weather-Grid-Operations.aspx.

19 *See* 18 C.F.R. § 385.206.

20 *Citizens Energy Task Force v. Midwest Reliability Org., et al.*, 144 FERC ¶ 61,006 at P 39 (2013).

In sum, the Complaint fails to (i) meet the minimum requirements of Commission Rules of Practice and Procedure Section 206; and (ii) provide for remedies that are not already underway. For these reasons, the Commission should dismiss the Complaint.

**A. The Complaint should be dismissed because the Complaint fails to meet the minimum requirements of the FPA and the Commission's regulations.**

The Complaint asserts that the cold weather event in Texas demonstrates that the "mandatory [R]eliability [S]tandards were not followed…"[21] and that "[v]iolators of [R]eliability [S]tandards must be held accountable."[22] Because the Complainant has failed to support its assertions, as required by the Commission's rules and regulations, the Complaint should be dismissed.

To facilitate proceedings, the Commission sets forth procedural rules that dictate requirements for the content of complaints.[23] The purpose of these requirements is to help ensure respondents understand the specific allegations made in the complaint. Rule 203, for example, requires pleadings to set forth the basis in fact and law for the positions taken.[24] Rule 206 provides that complaints must, among other elements: (i) clearly identify the action or inaction alleged to violate applicable statutory or regulatory requirements; (ii) explain how the action or inaction violates applicable statutory standards or regulatory requirements; and (iii) state the specific relief or remedy requested and the basis for that relief.

Long-standing Commission precedent provides that "rather than bald allegations, [a complainant] must make an adequate proffer of evidence including pertinent information and

---

21 Complaint at 1.
22 *Id*. at 10.
23 18 C.F.R. § 385.
24 *Id.* § 385.203(a)(7).

analysis to support its claims."[25] Further, the Commission has previously held that, in cases alleging a violation of a Reliability Standard, the complaint must set forth the specific Reliability Standard at issue and explain how the alleged action or inaction caused the violation. In *Citizens Energy Task Force v. Midwest Reliability Org., et al.*, the Commission held:

> If a complaint regarding an alleged violation of a Reliability Standard is to meet the threshold requirements of Rule 206, then the complaint must, at a minimum, set forth the specific provision of the Reliability Standard that is at issue and provide some explanation as to how the Respondent's alleged action or inaction caused the violation.[26]

The Complaint failed to meet the necessary elements of Rule 206 and should therefore be dismissed. The Complainant did not set forth any Reliability Standards, let alone a specific provision of those Reliability Standards, that were allegedly violated. The Complainant describes impacts the cold weather had on the electric system[27] and on customers but did not state how the actions or inactions of utilities violated applicable Reliability Standards. Load shedding often can be an acceptable, although last resort, action to mitigate further damage to the grid.[28] The

---

[25] *Ill. Muni. Elec. Agency v. Cent. Ill. Pub. Serv. Co.*, Order Dismissing Complaint Without Prejudice, 76 FERC ¶ 61,084 at 4 (1996); *CAlifornians for Renewable Energy, Inc., (CARE) and Barbara Durkin v. Nat'l Grid, Cape Wind, and the Mass. Dep't of Pub. Util.*, Order Dismissing Complaint, 137 FERC ¶ 61,113, at PP 2, 31-32 (2011); *CAlifornians for Renewable Energy, Inc., Michael E. Boyd, and Robert M. Sarvey v. Pac. Gas and Elec. Co.*, Order Dismissing Complaint, 143 FERC ¶ 61,005 at P 2 (2013); and *Citizens Energy Task Force and Save Our Unique Lands v. Midwest Reliability Org., et al.*, Order Dismissing Complaint, 144 FERC ¶ 61,006 at P 38 (2013).

[26] *Citizens Energy Task Force v. Midwest Reliability Org., et al.*, 144 FERC ¶ 61,006 at P 39 (2013). The Commission more recently dismissed a complaint for failing to state a specific provision of a Reliability Standard in *Californians for Green Nuclear Power, Inc. v. NERC, et al.*, 174 FERC ¶ 61,203 at PP 49-50 (2021).

[27] The Complainant repeatedly refers to a "collapse" of the Texas electric system. While the consequences of the event were severe, the electric system was subject to controlled load shedding to preserve the reliability of the system and avoid the cascading outages that would represent a "collapse" of the system.

[28] NERC Chief Executive Officer James B. Robb testified before the United States Senate Committee on Energy and Natural Resources on this issue, stating, "To be clear, load shedding is an unwelcome last resort measure to avoid uncontrolled cascading outages across an entire interconnection. Faced with untenable choices during an emergency event when decisions must be made within minutes, actions taken by grid operators helped prevent even more widespread suffering. Data presented by [the Electric Reliability Council of Texas] show the entire electric system was within minutes of frequency and voltage collapse, necessitating the dramatic action they took." *Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events*, Testimony of James B. Robb, NERC CEO, United States Senate Committee on Energy

information available at present is not sufficient to determine whether violations of Reliability Standards occurred or contributed to the event. Moreover, the request to investigate whether Reliability Standards were violated undercuts the basis upon which the Complainant's allegations partially rely – that the Reliability Standards were not followed. As discussed below, a joint inquiry to examine the causes of the event is currently underway. The Commission should therefore dismiss this complaint as not only insufficient under the Commission's regulations but also premature.

**B. The Complaint should be dismissed because the requested relief is already underway.**

The Complaint requests that the Commission: (i) direct NERC and Texas RE to conduct an investigation into whether Reliability Standards were followed; and (ii) direct NERC to modify the Reliability Standards to prevent future outages if NERC and Texas RE determine that violations of the Reliability Standards did not contribute to the Texas cold weather event.[29] The requested relief is moot and duplicative given the current efforts underway among NERC, Texas RE, FERC, and other stakeholders.

The Commission has dismissed complaints when current proceedings or projects render the requested relief premature. In *Complaint of Michael Mabee, Related to Critical Infrastructure, Reliability Standards*, the Commission denied a complaint regarding Reliability Standard CIP-013-1 because of existing FERC proceedings and NERC standards development projects

and Natural Resources (Mar. 11, 2021), https://www.nerc.com/news/Headlines%20DL/NERC%20Reliability%20Hearing%20Testimony%203-11-21%20-%20Final.pdf [hereinafter Robb Testimony].

[29] Complaint at 12.

underway.[30] Likewise, the Commission should dismiss the current Complaint based on the following activities.

First, on February 16, 2021, FERC and NERC announced a joint inquiry into the operations of the Bulk-Power System during the extreme winter weather conditions.[31] Regional Entities, including Texas RE, and the Department of Energy are also on the inquiry team. This inquiry will focus on three areas: (1) a comprehensive, detailed analysis of the event, including root causes; (2) commonalities with other cold weather events; and (3) findings and recommendations for further action.[32] At the Commission's February 2021 open meeting, FERC Commissioners indicated their intent to pursue action based on the outcome of this inquiry. Chairman Glick stated, "I am prepared, if necessary, to support the imposition of new mandatory standards to make sure that electric generators and others are better prepared when weather strikes the next time."[33] Similarly, Commissioner Clements stated:

> Understanding and preventing the cause of the outages should be done in a thorough, deliberate fashion after we get the official data released. The causes of these outages are not fully understood, and it is prudent to wait until we have comprehensive data to shed light on the specific causes.[34]

These statements demonstrate FERC Commissioners are determined to take action but need more data to ascertain next steps. As such, the Commission should not engage in a complaint

---

30 *Complaint of Michael Mabee, Related to Critical Infrastructure, Reliability Standards*, Order Denying Complaint, 173 FERC ¶ 61,010 at P 15 (2020).

31 *FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations*, News Release (Feb. 16, 2021), https://www.nerc.com/news/Pages/FERC,-NERC-to-Open-Joint-Inquiry-into-2021-Cold-Weather-Grid-Operations.aspx.

32 Robb Testimony at 3.

33 *Federal Energy Regulatory Commission*, 1075th Commission Meeting Telephonic Conference, Transcript at 7 (Feb. 18, 2021), https://www.ferc.gov/sites/default/files/2021-03/transcript.pdf.

34 *Id.* at 37.

proceeding that requests relief that would duplicate and hinder this important inquiry that will inform next steps for regulators.

Second, NERC already initiated a project in the fall of 2019 to develop cold weather Reliability Standards. Project 2019-06 – Cold Weather[35] is developing revised Reliability Standards to address the recommendations in the NERC and FERC staff report titled *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*.[36] Recognizing that the "continued reliability of the Bulk-Power System depends on the prompt development and implementation of Reliability Standards to address cold weather preparedness," the NERC Board of Trustees formally directed that the development on this project be completed by June 2021.[37]

Third, the Commission has announced a technical conference and enforcement review that will help to advance discussion of the cold weather event. The Commission will hold a technical conference that examines the threat that climate change and extreme weather events pose to electric reliability, inviting comments on the matter.[38] In addition, the Commission's Office of Enforcement is examining jurisdictional markets to determine whether market participants

---

[35] The Project 2019-06 web page is available at https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx.

[36] FERC and NERC staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/sites/default/files/2020-04/07-18-19-ferc-nerc-report.pdf.

[37] NERC Board of Trustees, Action without a Meeting (Mar. 22, 2021), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/AWOM_Memo_2019-06%20Cold%20Weather%20Deadline_Executed.pdf.

[38] *FERC to Examine Electric Reliability in the Face of Climate Change*, News Release, Docket No. AD21-13-000 (Feb. 22, 2021), https://www.ferc.gov/news-events/news/ferc-examine-electric-reliability-face-climate-change.

engaged in market manipulation or other violations of market rules or tariffs during the cold weather event.[39]

NERC and Texas RE understand and share the Complainant's concerns about the human and economic toll of the February cold weather event. Nevertheless, given all the activities by subject matter experts focused on the Texas cold weather and cold weather preparedness generally, as described above, undergoing Complainant's proposed proceeding would be duplicative and would exhaust resources needed for these other activities. The Complaint does not even mention these activities or assert that they are insufficient. As such, the Commission should dismiss the Complaint because the requested relief is already underway.

## V. CONCLUSION

WHEREFORE, for the reasons stated above, NERC respectfully requests that the Commission grant this motion to intervene, accept the comments herein, and dismiss the Complaint.

[39] *FERC to Examine Potential Wrongdoing in Markets During Recent Cold Snap*, News Release (Feb. 22, 2021), https://www.ferc.gov/news-events/news/ferc-examine-potential-wrongdoing-markets-during-recent-cold-snap.

Respectfully submitted,

/s/ Marisa Hecht

Edwin G. Kichline
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
ed.kichline@nerc.net
marisa.hecht@nerc.net

*Counsel for the North American Electric Reliability Corporation*

Derrick Davis
General Counsel & Corporate Secretary
Texas Reliability Entity, Inc.
805 Las Cimas Parkway, Suite 200
Austin, TX 78746
(512) 583-4900
derrick.davis@texasre.org

*Counsel for the Texas Reliability Entity, Inc.*

Date: April 5, 2021

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C., this 5th day of April, 2021.

*/s/ Marisa Hecht*
Marisa Hecht
*Counsel for the North American Electric Reliability Corporation*

Document Content(s)