REPORT ON

Transmission Facility Outages During the Northeast Snowstorm of October 29–30, 2011

Causes and Recommendations

Prepared by the Staffs of the

Federal Energy Regulatory Commission *and the* North American Electric Reliability Corporation

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I. Introduction

On October 29-30, 2011, an unprecedented fall snowstorm hit the Northeastern United States, blanketing the region with up to two and a half feet of heavy, wet snow. Snowfall amounts broke all previous October records throughout the Mid-Atlantic and New England regions. The snowfall totals were most significant in New England, but parts of New York, New Jersey, and Pennsylvania also received well over a foot of snow. On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power.[1] Thousands were without power for more than a week, some for as long as eleven days. Estimates put storm costs between approximately $1 billion and $3 billion.

Although the vast majority of these customer outages were caused by damage to electric distribution lines,[2] seventy-four transmission lines[3] and forty-four transmission substations[4] also experienced outages of ten minutes or more. Twenty-four of the transmission facilities (twenty-three lines and one substation) that experienced outages are Bulk-Power System (BPS) elements.[5]

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[1] Over the course of the weekend, more than 4.3 million customers lost power at one point or another. U.S. DEPARTMENT OF ENERGY, ENERGY ASSURANCE DAILY 1 (Oct. 31, 2011), http://www.oe.netl.doe.gov/docs/eads/ead103111b.pdf (showing the non-concurrent, peak reported outages of twenty-two utilities).

[2] Distribution lines, which carry power from the interstate transmission system to retail customers, are typically operated under 100 kilovolts (kV) and are generally regulated by the states.

[3] Transmission lines, which carry power from electric generating facilities to substations connected to the distribution system, are typically operated over 100 kV and generally – but not universally – regulated by the Federal Energy Regulatory Commission (FERC or the Commission) as to rates and terms of transmission service. See Federal Power Act § 201(b)(1), 16 U.S.C. § 824(b)(1). As explained in footnote 5, the Commission also has jurisdiction, pursuant to Section 215 of the Federal Power Act, over the reliability of the bulk-power system. Although some facilities operated under 100 kV are considered to be "transmission facilities" in certain contexts, this report uses that term to refer only to facilities operated at or above 100 kV.

[4] A transmission substation is connected to one or more transmission lines and houses transformers used to step up or step down (increase or decrease) electric energy voltages. Substations also contain, among other equipment, breakers that allow lines to be connected or isolated in order to clear faults or perform maintenance. Transmission substations impacted by the storm are discussed further in Section IV.B.

[5] Section 215(a)(1) of the Federal Power Act defines the bulk-power System as "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." 16 U.S.C. § 824o(a)(1). With respect to electric reliability, the Commission has jurisdiction over all users, owners, and operators of the BPS. FERC approves mandatory and enforceable Reliability Standards that are developed by the Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), that apply to those BPS users, owners and operators registered by NERC. The Commission has adopted, at least for an initial period, NERC's definition of the term Bulk

In light of, among other things, the scope and seriousness of the October snowstorm event, the number of customers and states impacted, the duration of some of the outages, the storm's impact on entities subject to the Commission's jurisdiction, and the level of interest of the public and elected officials in the event, the Commission initiated an inquiry in November 2011 focused on the transmission- and BPS-related impacts of the storm. NERC also began an inquiry into the storm's effect on the BPS, and FERC and NERC combined their efforts into one joint inquiry. NPCC, which had been assisting NERC in its assessment of the storm event, also joined the inquiry team.

From the outset, this joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry has not been to investigate whether particular companies violated the Reliability Standards or other applicable statutes and regulations. NPCC, NERC, and FERC will follow their regular processes in identifying and pursuing any potential Reliability Standards violations. Nor has the purpose of this inquiry been to propose new or revised Reliability Standards or other regulations.

During the course of the inquiry, FERC, NERC, and NPCC staff obtained a significant amount of data from a variety of affected entities. Staff issued a first set of seven multi-part data requests to the thirty-six NERC-registered Transmission Owners and Transmission Operators[6] in the NPCC region, and sent a set of twenty-one multi-part data requests to those entities that reported experiencing transmission facility outages during the event. Staff conducted numerous follow-up calls and requested additional information from a number of entities. Staff also interviewed representatives of Northeast Utilities, the parent company of the three utilities that experienced the most

Electric System (BES) for application of the Reliability Standards. The current definition of the BES is: "as defined by the [Regional Entity,] 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 included in this definition." *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 75, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). The Northeast Power Coordinating Council (NPCC), the NERC-certified Regional Entity for the states affected by the October snowstorm, uses a performance-based test (rather than a voltage-based bright line) to determine which facilities in its region are subject to the Reliability Standards, and calls those facilities "Bulk Power System elements." *See* NPCC DOCUMENT A-10, CLASSIFICATION OF BULK POWER SYSTEM ELEMENTS (2007). Because the transmission facility outages caused by the October snowstorm occurred only in the NPCC region, this report uses NPCC's term "BPS elements."

[6] A Transmission Owner is an entity "that owns and maintains transmission facilities." A Transmission Operator is an entity that "is responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." NERC, *Glossary of Terms Used in Electric Reliability Standards* (Feb. 8, 2012), http://www.nerc.com/files/Glossary_of_Terms.pdf.

transmission facility outages. Staff visited approximately twenty transmission sites on a three-day visit to Connecticut, Massachusetts, and New Hampshire. Staff reviewed relevant reports issued by the affected utilities and independent entities.

A number of agencies in several states affected by transmission and distribution facility outages during the October snowstorm are conducting their own inquiries into utility performance before, during, and after the event. Staff consulted with many of these state agencies, monitored their public proceedings, and discussed with them the report's preliminary findings and recommendations. Staff held outreach meetings with the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the North American Transmission Forum, and also shared with them, on a non-public basis, the report's preliminary findings and recommendations. Feedback provided by state agencies and industry associations was considered in preparing this report.

This report: (1) presents staff's assessment of the October snowstorm event, including its impacts on transmission facilities and the BPS, and the causes of transmission facility outages; (2) discusses the applicability of the transmission vegetation management reliability standard to the event; and (3) provides a number of recommendations to industry that, if implemented, could improve utilities' performance and enhance transmission grid reliability during the next large snowstorm or similar event.

II. Executive Summary

The early autumn snowstorm that hit the Northeast on October 29-30, 2011, was unprecedented in the amount of snowfall it produced and particularly devastating because of the untimely combination of several factors. As much as two and a half feet of heavy, wet snow fell at a time when many trees still had their leaves, following a warm, rainy period that left the ground unfrozen, saturated, and soft. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights-of-way,[7] being uprooted and falling onto distribution and transmission lines.

The storm left a trail of destruction that primarily affected distribution systems. Distribution lines were damaged in an estimated 50,000 locations ("trouble spots") throughout the Northeast.[8] Millions of customers[9] served by more than two dozen utilities lost power. Tens of thousands of customers served by Connecticut Light & Power Company (CL&P) were without electricity for more than a week, and some customers served by CL&P were without service for eleven days.[10]

Most of the damage, and customer outages, was due to impacts to the distribution system, which is generally subject to state or local regulation. The transmission system, which is subject to the Commission's jurisdiction, was impacted as well, but it caused less than 5% of customer outages at the storm's peak. Seventy-four transmission lines and forty-four transmission substations experienced sustained outages.[11] Transmission line outages were responsible for approximately 130,000 customer outages around the storm's peak. Most of these outages lasted for less than two days, and none lasted for more than five days. Nearly three-quarters of all of the transmission outages were

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[7] Utilities rarely own the land on which they site transmission lines. Instead, utilities obtain rights, usually in the form of an easement, over portions of property owned by others. The easement allows the utility to construct, maintain, and operate transmission facilities and vegetation over a defined area of land, the "right-of-way."

[8] A "trouble spot" is a location where there is damage to a line requiring crew response to make conditions safe for the public, repair damage, and restore power.

[9] In the utility industry, the term "customer" generally refers to a single meter, whether at a residence, a retail store, or a factory; it does not refer to each person served at that meter.

[10] *See* WITT ASSOCIATES, CONNECTICUT OCTOBER 2011 SNOWSTORM POWER RESTORATION REPORT 11 (Dec. 1, 2011), *available at* http://www.wittassociates.com/assets/860/CTPowerRestorationReport20111201_FINAL_1_.pdf.

[11] For purposes of this report, facility outages lasting ten or more minutes are considered "sustained" outages.

caused when trees weighed down with heavy, wet snow fell onto transmission lines. Although most of the damage and outages were on the distribution system, this report addresses impacts on, and recommendations for, the FERC-jurisdictional transmission system.

Partly as a result of the August 14, 2003 blackout across the Northeast and Canada, which was caused in part by trees growing too close to transmission lines,[12] Congress passed legislation requiring the Commission to enact mandatory and enforceable Reliability Standards. One of those standards, FAC-003-1 (Transmission Vegetation Management Program), requires Transmission Owners to develop transmission vegetation management programs. These programs must include a schedule for vegetation inspections and specific vegetation clearance distances around transmission lines, have annual vegetation management work plans, and report certain vegetation-related outages.

This Standard's applicability to this event is limited in that FAC-003-1 only applies to transmission lines operated at voltages of 200 kV and above, plus any lower voltage lines identified by the applicable Regional Entity as critical to the reliability of the electric system in the region — and NPCC has not designated any lower-voltage facilities as critical for the purpose of applying FAC-003-1. In fact, FAC-003-1 applied to only one transmission facility forced out of service due to vegetation contact — a 345 kV transmission line in Connecticut — and that line outage did not cause any loss of service to customers. To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

In addition, the Standard's applicability to the October event is limited because it does not specifically address off-right-of-way vegetation management. Further, although FAC-003-1 requires each Transmission Owner to "prepare and keep current, a formal transmission vegetation management program" that must include the Transmission Owner's objectives, practices, approved procedures, and work specifications,"[13] beyond this, each Transmission Owner has flexibility on the specific content of its vegetation

[12] 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 139 (Apr. 2004), *available at* http://www.nerc.com/filez/blackout.html.

[13] Reliability Standard FAC-003-1, at Requirement R-1.

management program, including specific direction on how to address danger trees[14] outside of Clearance 1[15] but within the right-of-way.

This report makes several recommendations to help reduce the adverse impacts of future, similar weather events on the transmission system, including: (1) where appropriate, taking targeted steps to address off-right-of-way danger trees; (2) employing best practices in managing vegetation on full rights-of-way; (3) laying the foundation for effective vegetation management when establishing new rights-of-way; and (4) enhancing storm preparedness and response plans as needed. In addition, staff recommends increasing reporting of vegetation-caused outages and improving the content of required disturbance reports.

[14] A danger tree is any tree that, if it fell, could contact a transmission line. *See*, *e.g.*, Accredited Standards Comm. (ASC) A300, Tree Care Indus. Ass'n, American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Integrated Vegetation Management a. Electric Utility Rights-of-Way) 72.5 (2006) [hereinafter ANSI A300].

[15] Clearances are defined and discussed in more detail in Section VII.A.

III. The October 29–30, 2011 Nor'easter

An unprecedented early fall snowstorm blanketed the upper East Coast with up to two-and-a-half feet of snow in about a twenty-four hour period spanning October 29–30, 2011. Significant October snowstorms are rare, and the 2011 storm broke records throughout the Northeast. While the storm and its impacts on trees and power lines were not unanticipated, the severity of the storm exceeded forecasts, and its repercussions were wide-ranging and severe.

A. Forecasts and Utility Preparations

By early in the afternoon of Thursday, October 27, 2011, weather agencies had issued forecasts that an unusual October Nor'easter would hit the New England and the Mid-Atlantic states on Saturday, October 29.[16] Several inches of snow were predicted to fall across the Northeast, and that day's forecasts warned that the coming storm would bring down trees and power lines across the region.[17] Predictions of maximum total snowfall amounts increased rapidly from October 27 to October 29. By the morning of October 29, forecasters were predicting up to fifteen inches of snow in some areas.[18] The snow was expected to begin falling in the late afternoon or early evening of October 29.[19]

A number of utilities began preparations for the storm on Friday, October 28. In the lead-up to the storm, they held internal planning meetings, increased staff in

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[16] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 1:00 p.m. on October 27, 2011, which mentioned a storm arriving on October 29, 2011). A Nor'easter is a severe winter weather event that produces heavy snow or rain, severe winds, and significant waves. A Nor'easter gets its name from the strong northeasterly winds blowing in from the ocean ahead of the storm and over coastal areas. Nat'l Oceanic & Atmospheric Admin., *National Weather Service Glossary*, http://www.weather.gov/glossary/.

[17] *See*, *e.g.*, CL&P Resp. to Data Req. AG-03, Q-AG-117-SP01, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 18, 2011 (providing National Weather Service briefing slides used by CL&P to prepare for the storm).

[18] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 6:00 a.m. on October 29, 2011, which predicted up to fifteen inches of snow in western Massachusetts).

[19] Nat'l Oceanic & Atmospheric Admin., *Rare October Winter Storm in the Northeast* (Oct. 28, 2011), http://www.nnvl.noaa.gov/MediaDetail2.php?MediaID=874&MediaTypeID=1.

operations centers, and placed in-house and contract field crews on call.[20] Regional mutual aid groups, through which utilities can request line restoration assistance from other utilities, also held conference calls. However, due in part to the moderate snowfall amounts in weather predictions from that morning, few utilities requested assistance on October 28.[21] Nor did many utilities make mutual assistance requests on the morning of Saturday, October 29; at that point, there was a general understanding that utilities would be holding their crews in order to respond to the event in their own service territories.[22] However, snowfall amounts exceeded forecasts, and by Saturday afternoon, utilities began to see that more manpower would be required to address the rapidly increasing outages. Many utilities then began requesting aid from the mutual assistance groups.[23] But because the storm was so widespread — and demand was so great — there were few regional crews immediately available.[24] In addition, there generally was only limited pre-staging of crews (i.e., positioning field workers at locations around a utility's service territory before a weather event so that they will be on the scene to make repairs as soon as the storm is over).

Some utilities — in particular, CL&P — have faced criticism at the state level for inadequate storm preparation, including failing to request mutual assistance earlier or to pre-stage field crews in order to speed response times.[25] Utility emergency preparation and response is almost entirely outside of the Commission's jurisdiction.[26] However, as discussed below, staff's review of the impact of utility preparation and response on transmission restoration found no indication that inadequate preparation materially

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[20] *See*, *e.g.*, Davies Consulting, Final Report: Connecticut Light and Power's Emergency Preparedness and Response to Storm Irene and the October Nor'easter 19 (Feb. 27, 2012), *available at* http://media2.wtnh.com/docs/Storm-Review-Final-Report.pdf

[21] *See*, *e.g.*, Witt Associates, *supra* note 10; Central Hudson gas & Electric Corp., 16 NYCRR — Part105 Compliance Filing: Report and Evaluation of October 2011 Snowstorm, October 29–November 4, 2011, at 22-23 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={23000E96-EBCF-45C1-BB29-387EF9943C33}; Davies Consulting, *supra* note 20, at 19.

[22] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note10, at 21.

[23] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[24] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[25] *See, e.g.*, JOE MCGEE ET AL., REPORT OF THE TWO STORM PANEL, PRESENTED TO: GOVERNOR DANNEL P. MALLOY 10–11 (Jan. 9, 2012), *available at* http://www.governor.ct.gov/malloy/lib/malloy/two_storm_panel_final_report.pdf; WITT ASSOCIATES, *supra* note 10, at 2-3.

[26] Although several Emergency Operations Reliability Standards deal with registered entities' responses to emergency situations, those Standards are focused on BPS operation issues, and not more conventional preparation and response issues like employee training, staffing levels, or field crew response.

hindered restoration of transmission facilities, as opposed to the more serious preparation and restoration problems reported on the distribution side.

B. Storm Produces Record Amounts of October Snowfall

Not long after the storm began, it became clear that snowfall totals would exceed projections. Wet snow began falling in the late morning of October 29.[27] Snowfall was heavy by mid-day, and it fell quickly: up to three inches per hour for sustained periods.[28] Within about twenty-four hours, some areas had received two-and-a-half feet of snow. The highest amounts of total snowfall were in Massachusetts, where Peru recorded 32 inches, and in New Hampshire, where Jaffrey recorded 31.4 inches.[29] The storm set records for October snowfall across the region. On October 29 alone, Hartford, Connecticut, received 12.3 inches of snow, far surpassing the previous October record of 1.7 inches.[30] That same day, Concord, New Hampshire, received a record 13.6 inches of snow, and Worcester, Massachusetts, received a record 11.4 inches.[31] The previous records were 3.0 inches and 7.5 inches, respectively.[32]

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27 Nat'l Weather Serv., *October 29th Historic Early Season Snowstorm*, http://www.erh.noaa.gov/okx/StormEvents/10292011/index.html; DAVIES CONSULTING, *supra* note 20, at 18.

28 Nat'l Weather Serv. Forecast Office, Boston, Mass., *Review of Snow-tober 2011*, http://www.erh.noaa.gov/box/sigevents/Snowtober_2011/

29 Nat'l Weather Serv., *Significant Weather Event: Oct. 29–30, 2011*, http://www.erh.noaa.gov/box/displayEvent.php?event=Oct_29-30_2011&element=snow.

30 Nat'l Climatic Data Ctr., *CT Daily Snowfall Records Set in October 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/00?sts[]=CT#records_look_up.

31 Nat'l Climatic Data Ctr., *MA Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=MA#records_look_up (providing daily snowfall records for cities in Massachusetts on October 29, 2011); Nat'l Climatic Data Ctr., *NH Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=NH#records_look_up (providing daily snowfall records for cities in New Hampshire on October 29, 2011).

32 Nat'l Weather Serv., *Concord Climate Data For the Year 2011* (Jan. 18, 2012), http://www.srh.noaa.gov/data/GYX/CLACON; Nat'l Climatic Data Serv.; *MA Monthly Snowfall Records Set in 2011*, http://ncdc.noaa.gov/extremes/records/monthly/snow/2011/10/00?sts[]=MA#records_look_up.

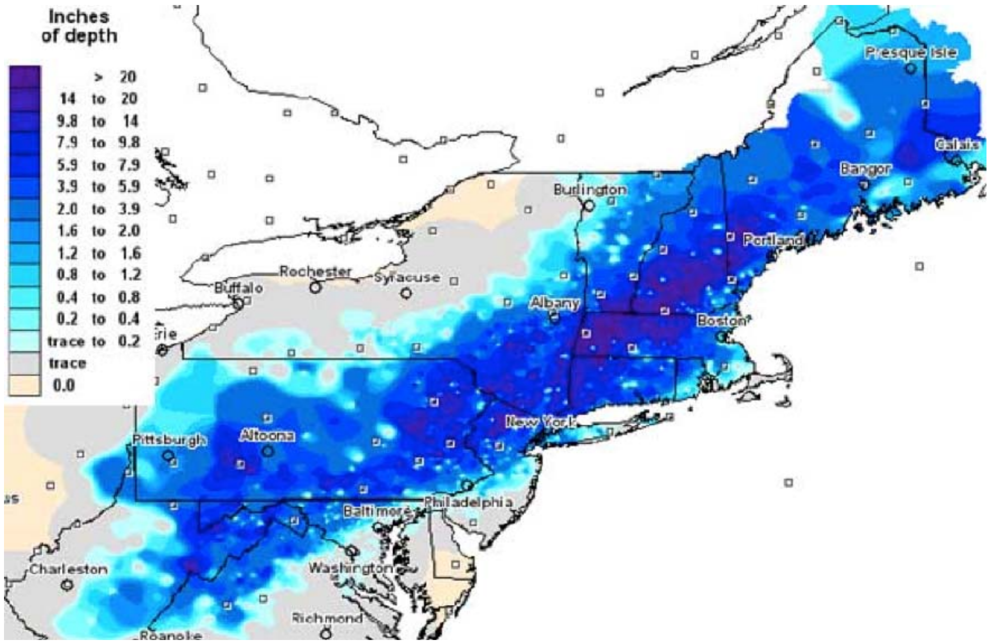

Figure 1: Snowfall Totals Across the Northeast on October 30, 2011

Source: NOAA, nohrsc.noaa.gov/interactive

The National Weather Service called the October Snowstorm a "rare and historic October Nor'easter"[33] and rated it as the strongest fall storm on record for the Northeast region.[34] Connecticut Governor Dan Malloy said that "a review of state records dating back to 1650 indicates that this storm is the most severe October Nor'easter in Connecticut history."[35] The only other notable October snowstorm in New England in the last one hundred and fifty years, which occurred on October 4, 1987, was far less destructive. That storm produced between six and twenty inches of snowfall from Albany, New York, to the Western Berkshires in Massachusetts, and caused only about 300,000 customer outages,[36] compared to the more than 3 million outages caused by the October 2011 storm.

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[33] Nat'l Weather Serv., *Winter Storm Summary for October 29, 2011 Event*, http://www.erh.noaa.gov/phi/show_wss.php.

[34] Email from NOAA staff to FERC staff (Mar. 15, 2012) (on file with OE staff). The October snowstorm is the only October storm to be ranked by NOAA among the 45 highest-impact snowstorms that have affected the Northeast urban corridor. Nat'l Climatic Data Ctr., *The Northeast Snowfall Impact Scale*, NOAA, http://www.ncdc.noaa.gov/snow-and-ice/rsi/nesis.

[35] Letter from Dannel P. Malloy, Conn. Governor, to Barack Obama, President (Nov. 11, 2011) [hereinafter Malloy Letter].

[36] Robert D. McFadden, *Early Snowstorm Covers Northeast*, N.Y. TIMES (Oct. 5, 1987), http://www.nytimes.com/1987/10/05/us/early-snowstorm-covers-northeast.html?pagewanted=all&src=pm.

C. Leafy Trees and Prior Rainfall Compound the Impact of the Snowstorm

The effects of record amounts of heavy, wet snow were particularly severe because the snow fell across densely wooded areas where deciduous trees had not yet lost many of their leaves. Due to an unusually warm and wet September and October, leaf drop was significantly lower than normal for late October. For example, before the October storm, most of Massachusetts and Connecticut had only experienced "Moderate" — rather than the typically "High" — leaf drop.[37] The weight of snow on the leaves put significant strain on trees, causing limbs to snap and entire healthy trees to fall.

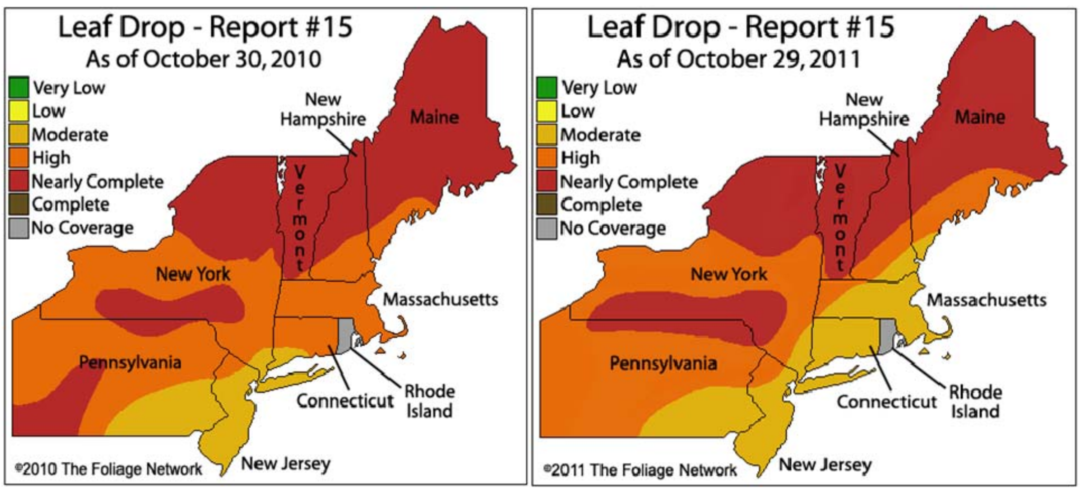

Figure 2: Leaf Drop Reports, October 2010 vs. October 2011
Source: The Foliage Network

Moreover, the ground throughout much of the Northeast was saturated due to an abnormally wet year — including significant August rainfall from Tropical Storm Irene. In fact, August 2011 was the wettest month on record in the Northeast since recording began in 1895.[38] Because the saturated ground had not yet frozen, the weight of the

[37] *See Report #15 – Oct. 29, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=333:ne-foliage-report-15-2011&catid=34:northeast-us&Itemid=68; *Report #15 – Oct. 30, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=275:ne-foliage-report-10302010&catid=62:northeast-us&Itemid=85.

[38] In August 2011 an average of 8.53 inches of precipitation was recorded in the Northeast, while the 20th century regional average is only 3.85 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings August 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?parameter=pcp&state=101&div=0&periods[]=1&month=8&year=2011. The year 2011 was also the wettest year on record for the Northeast since 1895: an average of 56.04 inches of precipitation was recorded, while the 20th century average is only 41.08 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings December 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?periods%5B%5D=12&parameter=pcp&year=2011&month=12&state=101&div=0.

heavy, wet snow on leafy trees caused many healthy trees across the region to uproot. On November 1, 2011, the Connecticut Department of Transportation estimated there were 24,000 trees downed on Connecticut roads alone. As explained by Governor Malloy: [39]

> "*The combination of heavy wet snow and near freezing air caused adherences of the snow to all objects including trees, which had not yet lost their seasonal foliage. The weight of the snow on trees and power lines, combined with very wet soils as a result of Tropical Storm Irene and the remnants of Tropical Storm Lee, quickly overwhelmed the ability of trees to remain upright under the added weight. This added weight de-limbed hundreds of thousands of trees and uprooted tens of thousands of additional trees in just 12 hours.*"

The October snowstorm crippled much of the Northeast. As noted above, more than 3 million customers lost electric power. Activity in the affected states ground to a halt: many roads were impassable and scores of schools and businesses closed.[40] States of emergency were declared in many states, including Connecticut,[41] Massachusetts,[42] New Hampshire,[43] and parts of New York.[44] News reports identified at least twenty-two storm-related deaths.[45] The National Oceanic and Atmospheric Administration estimates the costs of the storm to be between $850 and $900 million, and one unofficial estimate puts the costs at more than $3 billion.[46]

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[39] *See* Malloy Letter, *supra* note 35.

[40] *See* Lauren Keiper, *Millions Without Power After US Northeast Snowstorm*, Reuters (Oct. 31, 2011), http://www.reuters.com/article/2011/10/31/uk-weather-northeast-idUSLNE79U02Y20111031.

[41] Press Release, Gov. Malloy Declares State of Emergency (Oct. 29, 2011), *available at* http://www.governor.ct.gov/malloy/cwp/view.asp?A=4010&Q=.

[42] Press Release, Governor Lynch Requests FEMA's Reconsideration of Emergency Disaster Declaration (Nov. 2, 2011), *available at* http://www.governor.nh.gov/media/news/2011/110211-emergency.htm.

[43] Press Release, Governor Patrick Meets with Utility Company Officials on Storm and Power Recovery Efforts (Oct. 31, 2011), *available at* http://www.mass.gov/governor/pressoffice/pressreleases/2011/111031-storm-power-recovery.html.

[44] Press Release, Governor Cuomo Declares State of Emergency for Counties Hit Hard by Winter Storm (Oct. 29, 2011), *available at* http://www.governor.ny.gov/press/10292011stateofemergency.

[45] CNN Wire Staff, *Freak Snowstorm Blamed for at Least 22 Deaths*, CNN (Nov. 3, 2011), http://articles.cnn.com/2011-11-03/us/us_east-coast-storm_1_carbon-monoxide-poisoning-cl-p-power-outages?_s=PM:US.

[46] AON Benfield, October 2011 Monthly Cat Recap – Impact Forecasting 2 (Nov. 3, 2011), *available at* http://thoughtleadership.aonbenfield.com/ThoughtLeadership/Documents/201111_if_monthly_cat_recap_october.pdf; Mary O'Leary, *Gov. Malloy: "What We Need is Action" on Connecticut Power Crisis*, New Haven Register (Nov. 2, 2011), http://www.governor.ct.gov/malloy/cwp/view.asp?A=11&Q=489996 (quoting Governor Malloy as anticipating

IV. Significant and Widespread Damage to Electric Delivery Infrastructure

The October storm's historic snowfall and resulting tree damage devastated the system of high and low voltage wires that distribute power across the Northeast, leaving approximately 3.2 million customers from Pennsylvania to Maine without power near the end of the storm. The vast majority of the damage to electric delivery infrastructure was to the distribution system. However, the storm's impact on transmission facilities was also significant. Seventy-four transmission lines in a half-dozen states experienced sustained outages.

A. Distribution Facility Damage and Customer Impact

Exact measures of the total physical damage to distribution systems are hard to determine, but there were an estimated 50,000 separate locations across the Northeast where utility crews were required to remove trees from or physically repair distribution lines ("trouble spots"). This serious and widespread damage to distribution facilities caused more than 95% of customer outages. The map on the next page overlays a snapshot of several utilities' customer outages on a map showing snowfall totals across the Northeast.

storm costs would exceed $3 billion); Email from NOAA staff to FERC staff (Mar. 29, 2012) (estimating costs at between $850 million and $900 million) (on file with OE Staff).

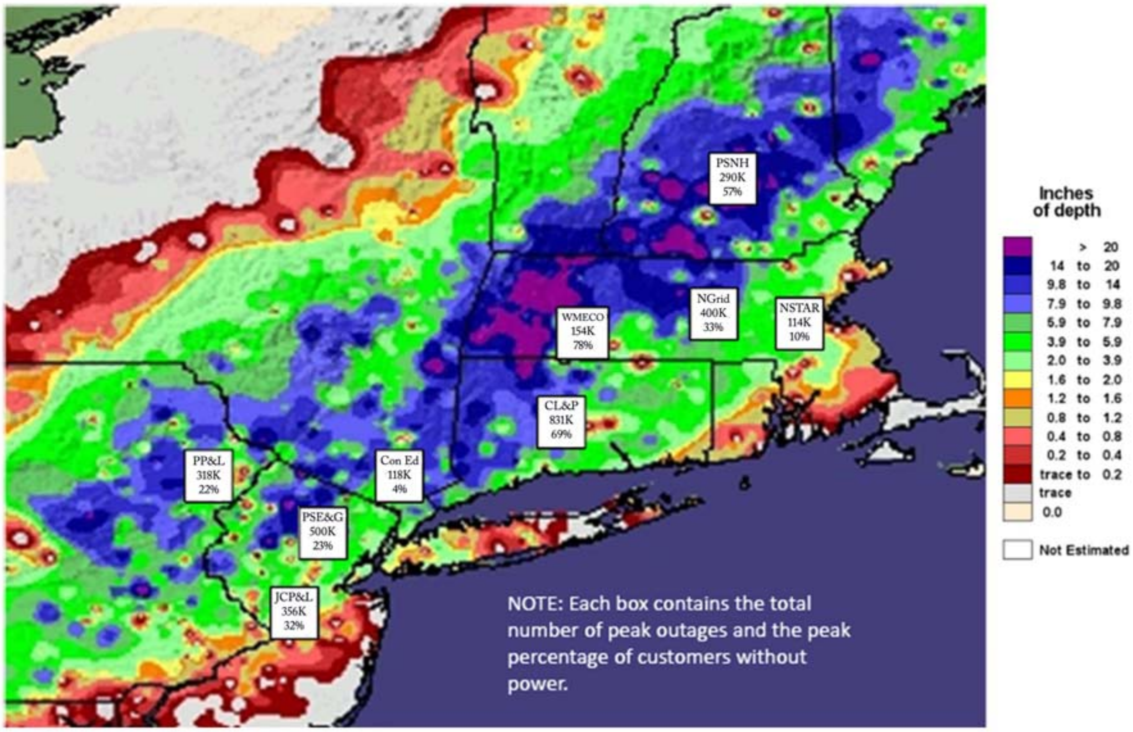

Figure 3: Snowfall Amounts and Customers That Lost Power

Source: NOAA, National Operational Hydrologic Remote Sensing Center, Interactive Snow Information[47] *and U.S. Department of Energy, Energy Assurance Daily.*[48]

There was significantly more damage to distribution facilities than transmission facilities for a number of reasons, including the fact that in some areas there are approximately twenty times more miles of distribution lines than transmission lines.[49] In addition, under typical industry practices, vegetation is generally allowed to grow much closer to distribution lines than transmission lines because there is less risk of flashover[50] between low-voltage distribution lines and nearby trees.

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[47] *Available at* http://www.nohrsc.nws.gov/interactive/html/map.html?ql=station&zoom=&loc=Latitude%2CLongitude%3B+City%2CST%3B+or+Station+ID&var=snowfall_72_h&dy=2011&dm=10&dd=30&dh=0&incr=+%2B+&snap=1&o9=1&lbl=m&mode=pan&extents=us&min_x=-76.041666666669&min_y=33.741666666667&max_x=-63.450000000002&max_y=43.816666666667&coord_x=-69.745833333336&coord_y=38.779166666667&zbox_n=&zbox_s=&zbox_e=&zbox_w=&metric=0&bgvar=dem&shdvar=shading&palette=1&width=1000&height=800&nw=1000&nh=800&h_o=2&font=0&js=1&uc=0

[48] U.S. Department of Energy, supra note 1.

[49] See About NU, Northeast Utilities, http://www.nu.com/aboutnu/nufacts.asp (listing 4,500 circuit miles of transmission lines and 72,000 pole miles of distribution lines).

[50] Flashover is the spontaneous arcing of electricity from a line to a grounded object like a tree.

A number of state utility commissions and other state government agencies have initiated inquiries into the distribution-level customer outages caused by the storm.[51] In addition, several utilities (and some independent entities) have produced reports on the event that focus on distribution system impacts.[52]

B. Transmission Facility Damage and Customer Impact

Although its impact was not as extensive as the damage to the distribution system, the October snowstorm impacted many transmission facilities. Near the end of the storm, about 130,000 customers across six states lost power as a result of transmission line outages.

1. Transmission Outages

Of the seventy-four transmission lines forced out of service for a sustained period during to the storm, the vast majority (seventy) were 115 kV facilities. One 138 kV and three 345 kV lines also experienced outages.

[51] The Connecticut Public Utilities Regulatory Authority (Docket No. 11-09-09), the Massachusetts Department of Public Utilities (Docket No. 11-119), the New Hampshire Public Utilities Commission, and the New York State Public Service Commission (Case No. 11-M-0595) are all conducting inquiries.

[52] *See*, *e.g.*, Central Hudson Gas & Electric Corp., *supra* note 21; Consolidated Edison Company of New York, Inc., Report on Preparation and System Restoration Performance: Nor'easter October 29 through November 3, 2011 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={512EF4A0-EC4C-4204-A527-B047022B6FC3}; Davies Consulting, *supra* note 20; McGee, *supra* note 25; Public Service of New Hampshire, Amp Up and Power On: October Nor'easter 2011 (Nov. 2011), *available at* http://www.hollisnh.org/announce/2011OctoberNor'easterReport.pdf; Western Massachusetts Electric Company's Report to the Department of Public Utilities on Expectations for Electric Distribution Company Performance Regarding Emergency Events (Dec. 20, 2011), *available at* http://www.env.state.ma.us/dpu/docs/electric/11-119/12202011-tech-session.pdf.

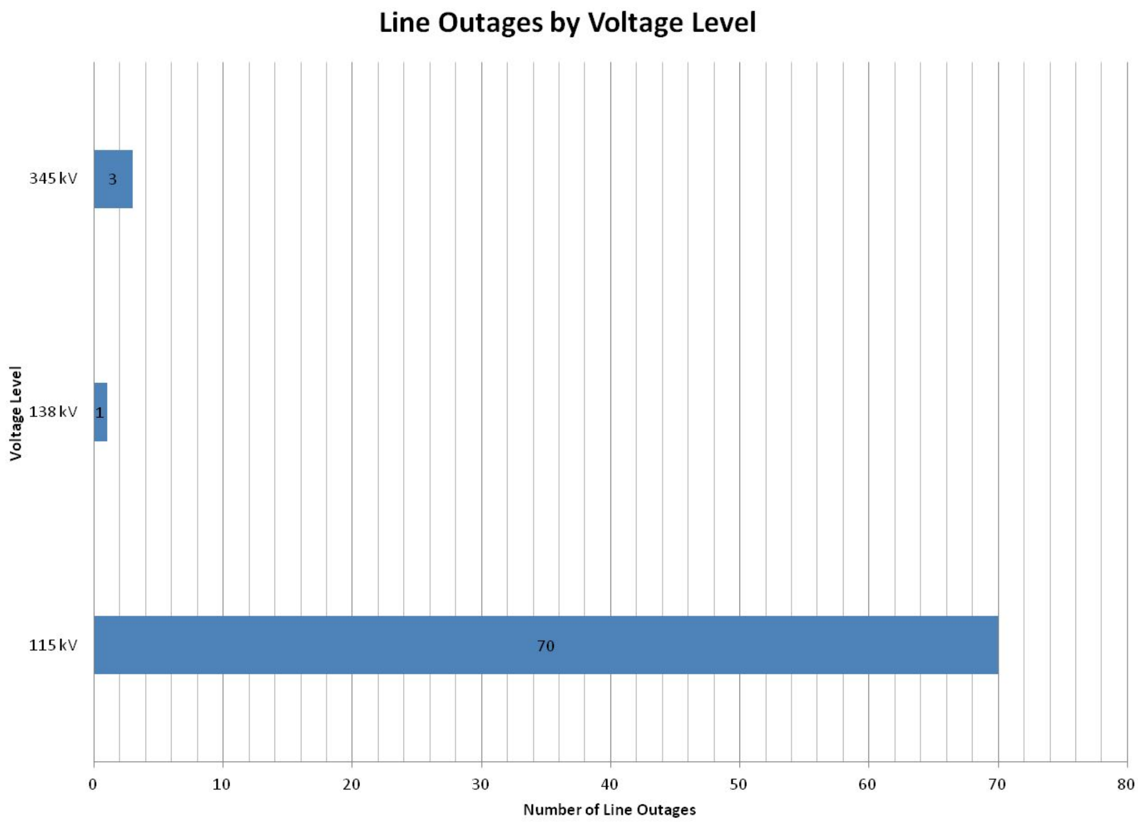

Figure 4: Transmission Line Outages by Voltage Level

There were also seven brief — between one and nine minute — line trips, four of which were caused by relay misoperations.[53]

Twenty-three of these seventy-four line outages occurred on NPCC-designated BPS elements. As explained in footnote 5, NPCC uses a performance-based test to designate facilities as BPS elements.[54]

[53] Relay misoperations occur when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. Failure of a relay to operate when it should is also considered a misoperation. The one relay misoperation that resulted in a transmission line outage of ten or more minutes is discussed in Section V.C.

[54] NERC has filed, for Commission consideration, a revised definition of BES that would impose a bright-line threshold of 100 kV, such that if approved, all facilities over 100 kV would be part of the Bulk Electric System and subject to most Reliability Standards unless a specific exception was granted or generic inclusion was made. *See N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM 12-06-000 (filed Jan. 25, 2012). This report takes no position on the BES definition filing.

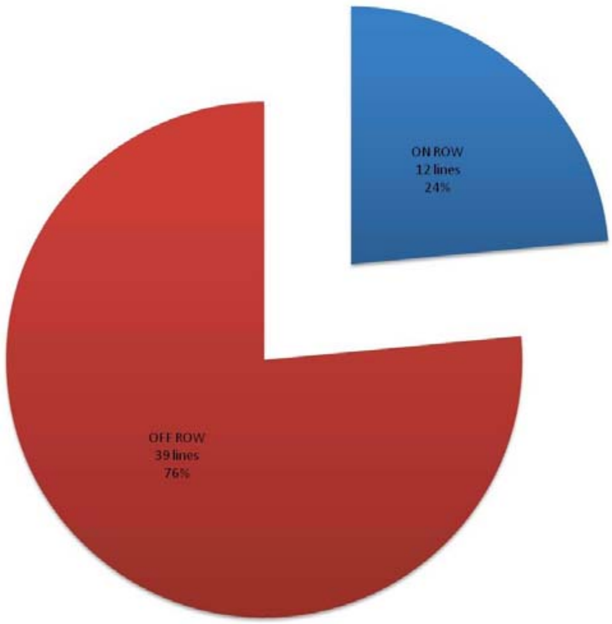

Figure 5: Total Outages: BPS vs. Non-BPS Elements

Because transmission lines conduct power from generating facilities to substations, transmission line outages can cause substation outages.[55] During the October snowstorm, transmission line outages forced forty-four transmission substations out of service, including one NPCC designated as a BPS element. Loss of power to transmission substations is significant for two main reasons. First, many transmission substations provide power to distribution systems, so that the loss of power to a transmission substation can result in thousands of customer outages. Second, transmission substations contain relays and breaker controls that operate to protect individual transmission lines and stabilize the power grid as a whole. When a substation's power source is lost, substation battery banks provide backup power to control equipment and breakers, but those batteries only last for a limited period of time, at which point the equipment can no longer perform its functions. These forty-four transmission substation outages, combined with seventy-four transmission line outages, constituted a significant transmission event.

[55] Sometimes only one transmission line feeds power to a substation. If that single source line experiences an outage, the entire substation will be out of service. Generally, multiple transmission lines provide power to a substation; in that case, the substation will go out of service because of transmission line outages only if all of the transmission lines serving that substation are out of service.

2. Affected States and Utilities

A half-dozen states — Connecticut, Maine, Massachusetts, New Hampshire, New York, and Rhode Island — and ten utilities experienced transmission outages on lines they own, or co-own and maintain. Half of those outages occurred in just one state, Connecticut.[56] The chart below shows the number of outages by state.

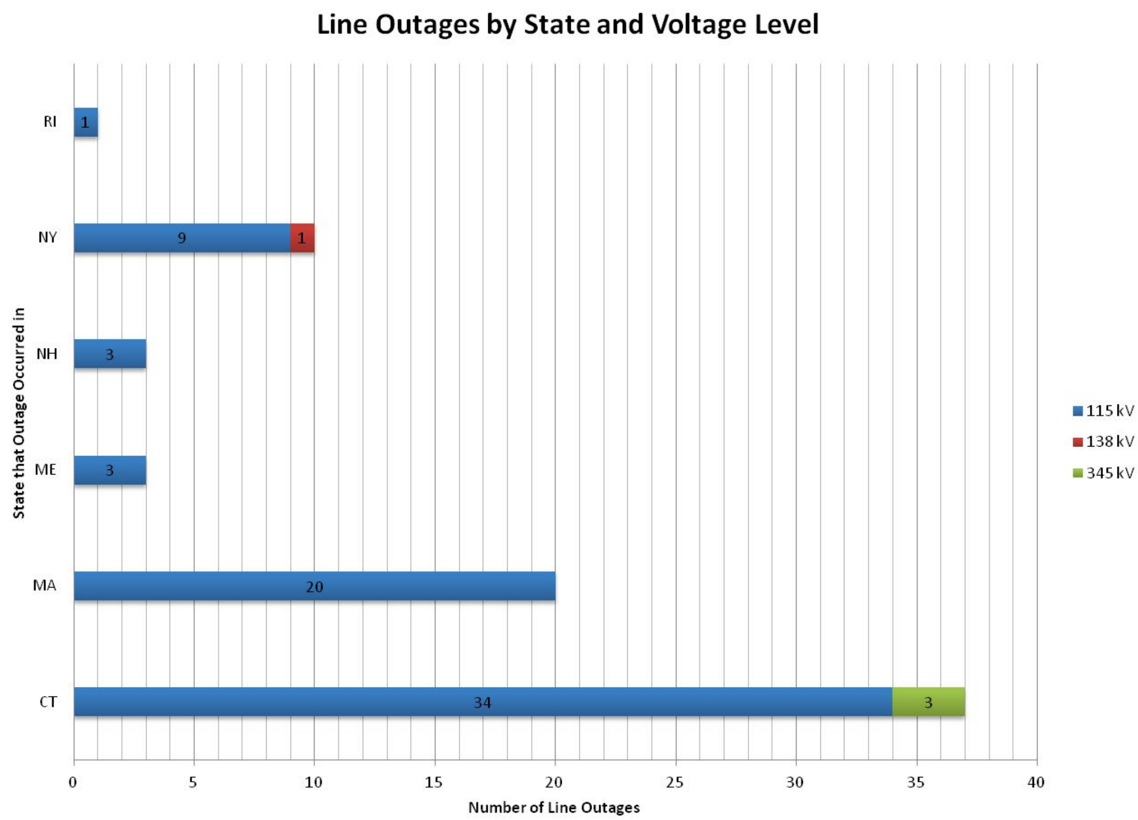

Figure 6: Transmission Line Outages by State and Voltage Level

As the following map shows, transmission line outages were concentrated in the Connecticut River Valley area, through Connecticut and into Massachusetts.

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56 Other states, such as Pennsylvania and New Jersey, experienced significant snowfall and distribution facility outages, but no transmission facility outages.

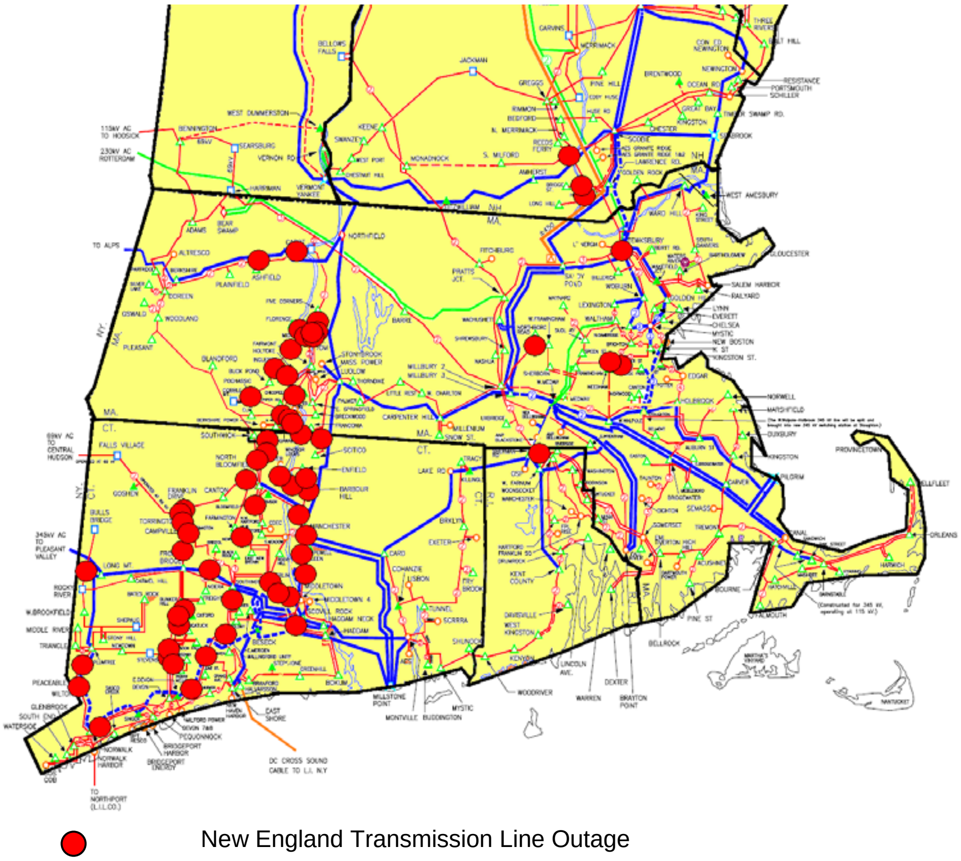

Figure 7: ISO-NE Transmission Line Outages During the October Snowstorm

Source: ISO-New England

The service territories of CL&P and Western Massachusetts Electric Company (WMECO), two subsidiaries of Northeast Utilities (NU), largely cover this area. As shown in the chart below, these two companies had the most transmission line outages. A third NU subsidiary, Public Service of New Hampshire (PSNH), had an additional three transmission line outages. Overall, outages of facilities owned — or co-owned, operated, and maintained — by NU subsidiaries[57] accounted for fifty-four of the October storm's seventy-four transmission line outages (approximately 74%).

[57] NU and NSTAR merged on April 10, 2012, and NSTAR is now a subsidiary of NU. Because the merger occurred after the October snowstorm, this report does not include NSTAR as an NU subsidiary.

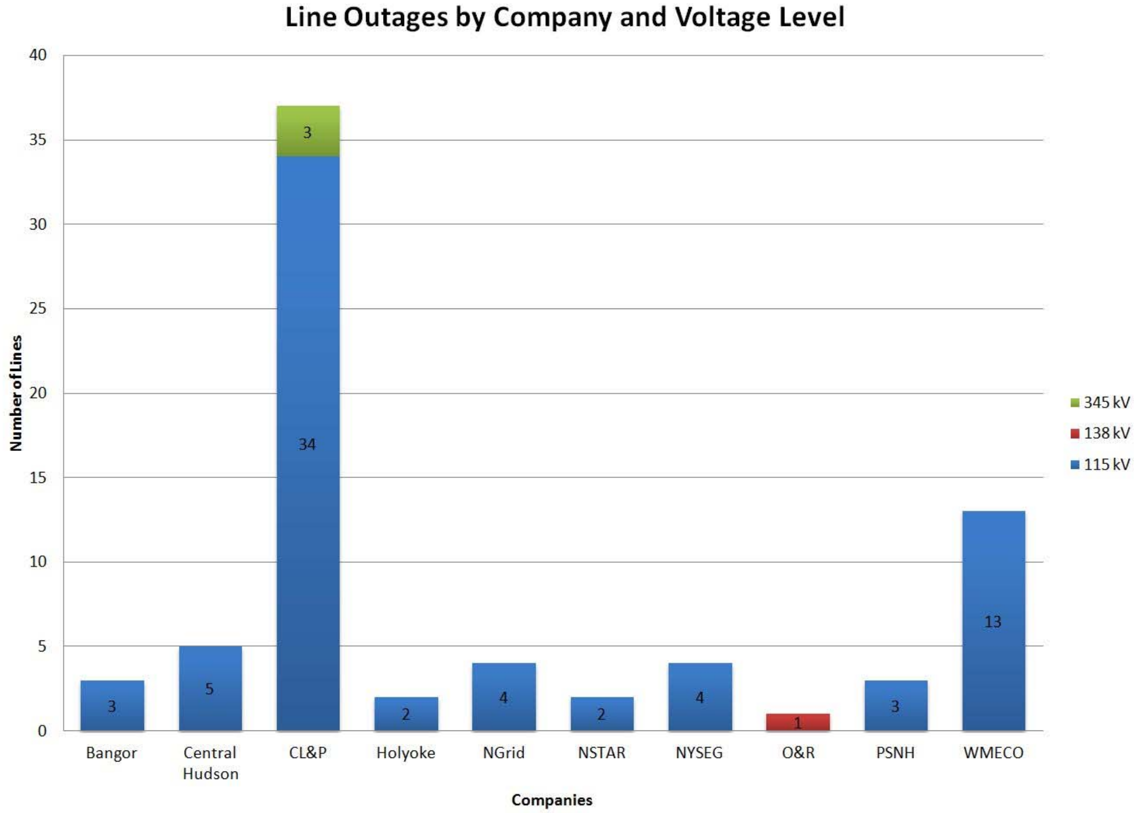

Figure 8: Line Outages by Company and Voltage Level[58]

3. Transmission Facility Outages Had Relatively Limited Impacts on Customers and Were Restored Quickly

Although seventy-four transmission line outages is a significant transmission event, these outages impacted far fewer customers than the distribution facility outages. At the storm's peak, damage to the transmission system caused approximately 130,000 homes and businesses to lose power, less than 5% of all of the storm-related customer outages. In addition, the peak number of transmission-caused customer outages (which rose above 100,000 customers for only about two hours) was relatively small compared to distribution-caused outages. While many customers impacted by distribution facility outages were without service for more than five days – and some for eleven – service was restored to all customers that lost power due to transmission outages in less than five

[58] The full names of the utility companies included in this chart are: Bangor Hydro Electric Co.; Central Hudson Gas & Electric Corp.; Connecticut Light & Power Co.; Holyoke Gas & Electric Department; National Grid USA; NSTAR Electric & Gas Co.; New York State Electric & Gas Co.; Orange & Rockland Utilities, Inc.; Public Service of New Hampshire; and Western Massachusetts Electric Co. Where a line is co-owned by more than one utility, this report attributes the outage to the company with the responsibility for maintaining the line where the outage occurred.

days. In fact, service was restored to the majority (77% percent) of such customers in less than forty-eight hours.

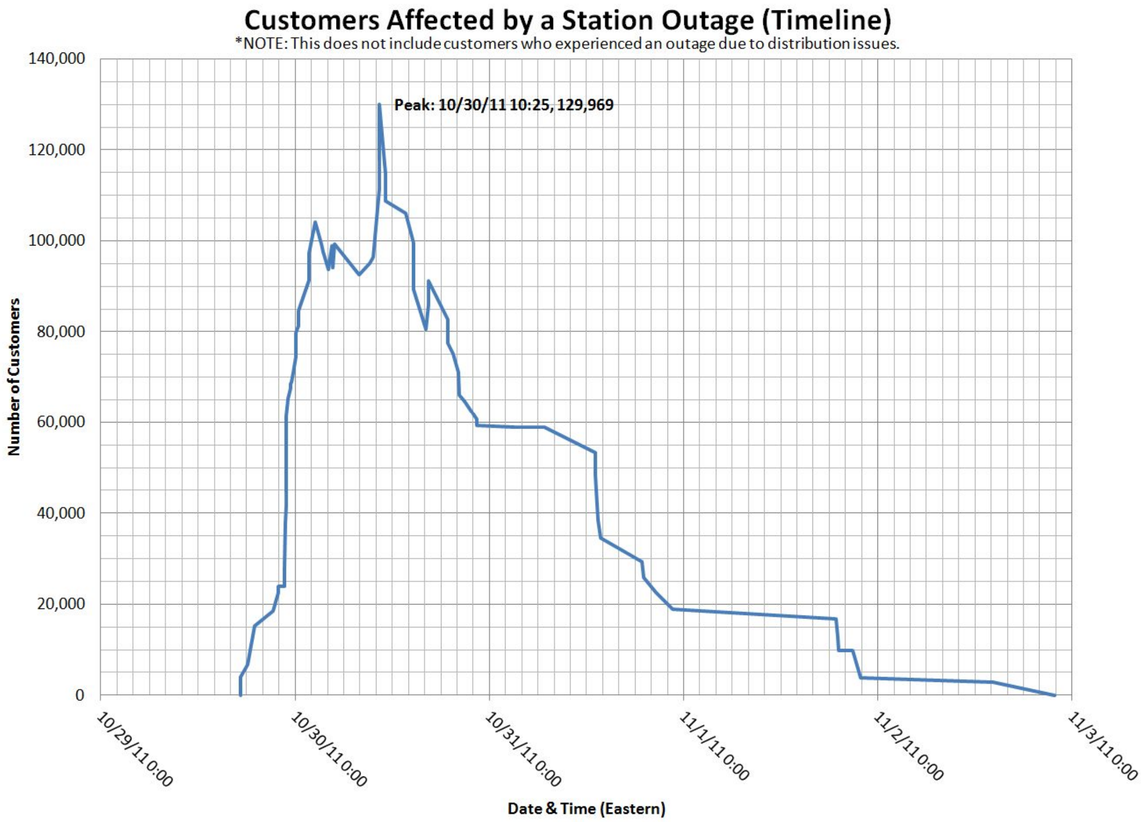

Figure 9: Timeline of Customers Affected by a Transmission Station Outage

While most transmission facilities were restored relatively quickly, four were out of service for nearly a week, and an additional three remained out of service between seven and eight days. However, none of these seven transmission line outages resulted in customer outages or were, at that time, necessary for BPS stability. The following chart illustrates the duration of transmission line outages.

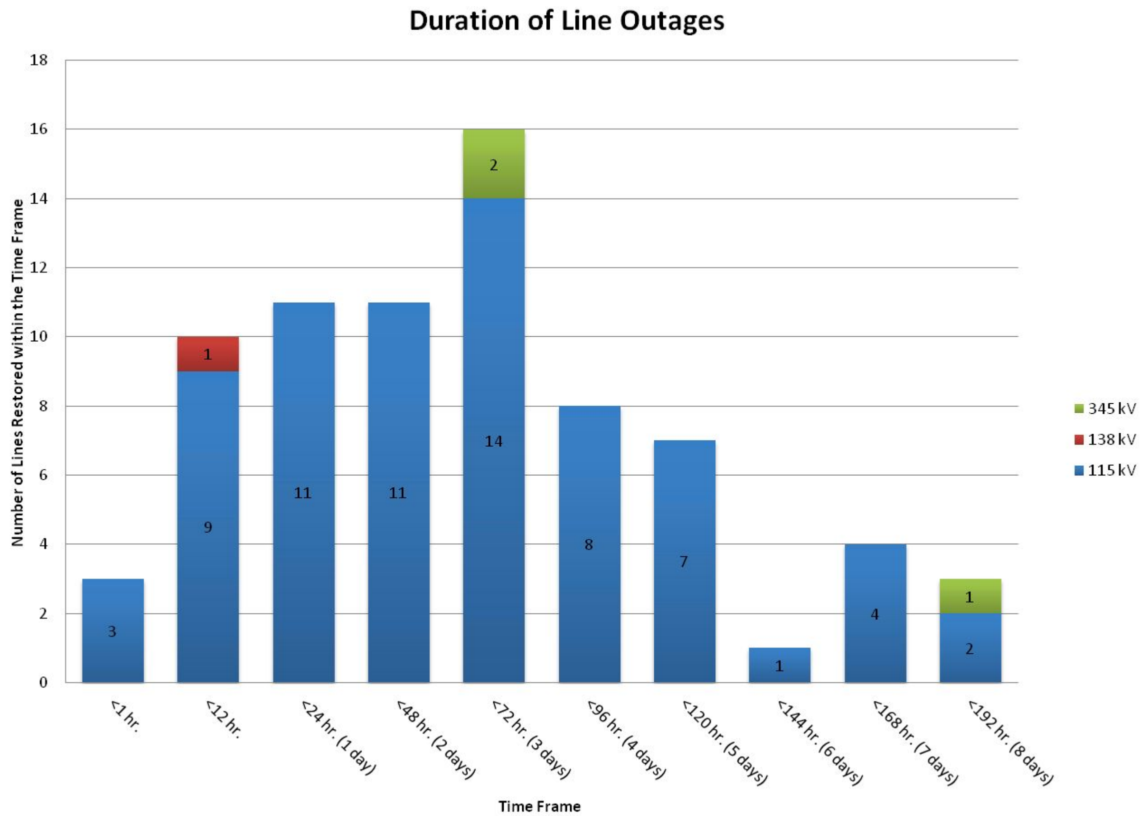

Figure 10: Duration of Transmission Line Outages

Utilities faced several physical obstacles in restoring the seven transmission lines that were out of service for six to eight days. Each of these lines or its supporting structures had significant structural damage that required rebuilding. For example, on five of these seven lines, falling trees snapped insulators, cross-arms, and various support structures. In addition, the site of the damage to the 345 kV line that was out of service for nearly eight days was particularly difficult to access. Again, no retail customers were without service due to these seven line outages.

One of the reasons for fast restoration of many transmission lines that caused customer outages is that, in setting priorities for transmission line restoration, utilities focus on restoration of lines that impact customers and are important for grid stability. For example, NU's restoration priorities for the storm event were: (1) transmission lines that would restore more than one substation; (2) transmission lines that impacted one substation; (3) 345 kV lines; (4) lines that served substations with only one live-line feeding them, such that if the live-line went out of service, the substation — and customers served by it — would experience an outage (i.e., single contingency load loss situations); and (5) all other transmission lines.

Staff concludes that restoration of transmission lines was not materially hampered by inadequate utility preparation or response.[59] For example, staff finds that, overall, additional staffing or field crew pre-staging would not have significantly enhanced transmission facility restoration. However, staff — and utilities themselves — recognize that there is room for improvement in storm preparedness. NU informed staff that its restoration of transmission facilities would have happened somewhat faster, albeit minimally, if the company had obtained more outside assistance in advance of the storm, pre-staged some crews, and had access to additional damage assessment equipment (specifically, helicopters and infrared cameras). Therefore, although utility preparation did not pose significant problems for restoration of transmission facilities during this event, staff recommends in Section IX.4 several steps utilities can take to improve preparation for future severe storm events.

[59] Staff recognizes that a number of states are looking into the impact of utility preparation and response on the distribution system as part of their ongoing proceedings relating to the storm's impacts on customers in their state. This report makes no findings regarding impacts of utility preparation and response on restoration of distribution facilities.

V. Causes of Transmission Facility Outages

As could be expected from a major snowstorm, the vast majority of transmission line outages during the October event were caused by tree contact or the accumulation of ice and heavy, wet snow on transmission conductors.[60] Other causes included losses of source[61] and relay misoperation.

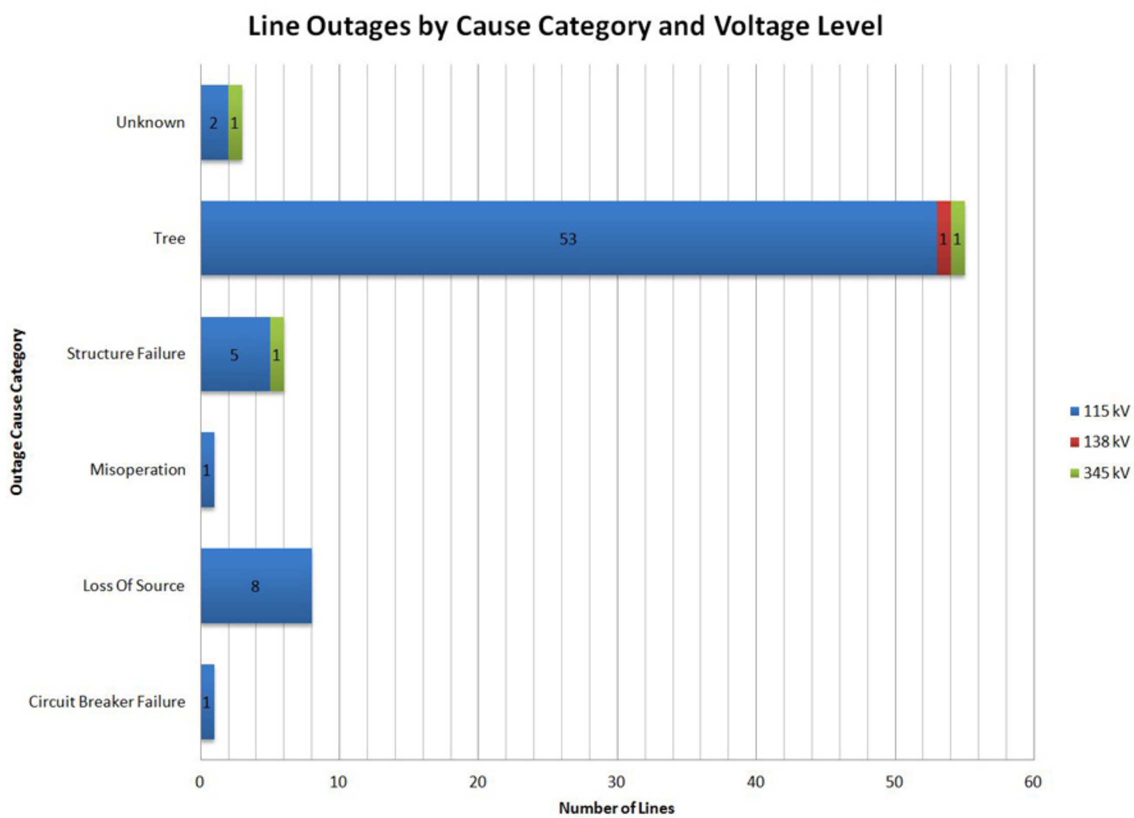

Figure 11: Line Outages by Cause Category and Voltage Level

[60] Transmission lines, the wires that carry electricity, are also called conductors.

[61] "Loss of source" outages occur when a connected line, or series of lines, trip and no longer feed an interconnected transmission line, meaning the interconnected line no longer has a source of electrical energy.

A. Tree Contact

The vast majority of transmission line outages — fifty-five out of seventy-four, or nearly 80% — were caused when snow-weighted leafy trees contacted transmission lines.[62] All but two of these trees were healthy. Twenty-five percent of these trees were located within the utility's right-of-way, and therefore, were likely within the utilities' rights to maintain.

Specifically, thirty-nine transmission line outages resulted from off-right-of-way trees falling onto transmission lines, resulting in loss of power to approximately 84,000 customers. An additional twelve transmission line outages, resulting in 13,000 customer outages, occurred when trees located *inside* a utility's full right-of-way[63] fell into transmission lines. The only tree-caused 345 kV line outage occurred when a sixty-five-foot tall tree located within a full right-of-way (forty-six feet from the nearest transmission line) fell. All of the trees that fell into lines from within the utility's full right-of-way were located outside the area in which the utility performs vegetation management (known as the "maintained right-of-way").[64]

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[62] Utilities attributed four of those fifty-five outages to tree contact, but post-storm field inspections by the utilities could not definitively confirm that explanation. Based on review of the data, staff accepts the utilities' attribution of these four outages to tree contact.

[63] For purposes of this report, "full right-of-way" means the portion of land for which a utility has documented legal rights to build and maintain transmission facilities.

[64] As explained in Section VII.B, no Reliability Standard requires that utilities manage vegetation on the entire width of their full rights-of-way. In fact, managing a narrower maintained right-of-way, rather than the full right-of-way, is a relatively common industry practice, though not a best practice.

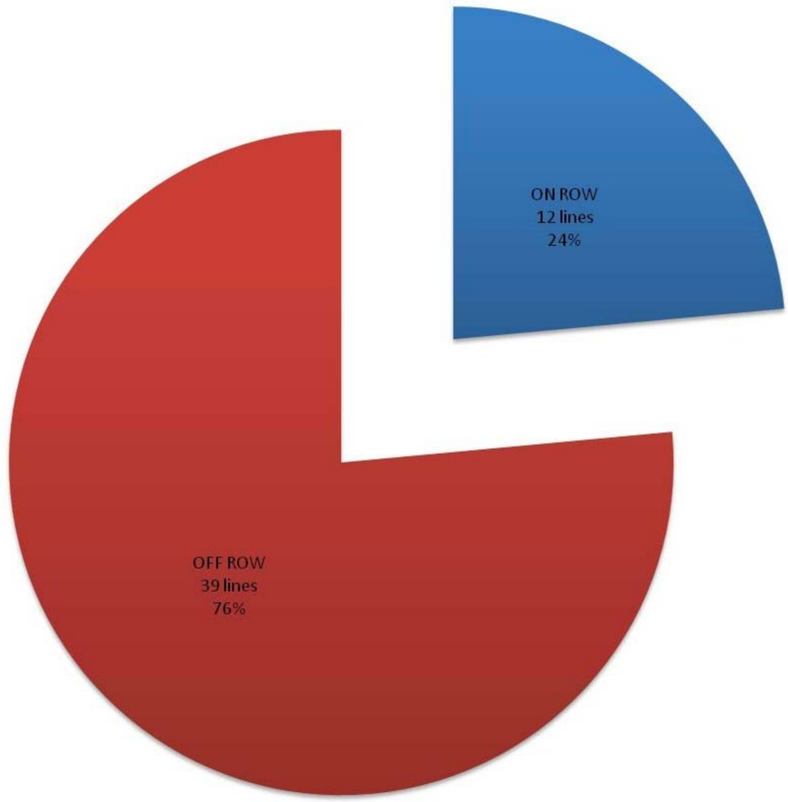

Figure 12: Fallen Trees Located on Rights-of-Way and Off-Rights-of-Way

The 115 kV line in the photograph below was forced out of service when several trees, each over sixty feet tall and located twenty to thirty feet outside of the utility's full right-of-way, uprooted and fell onto three separate spans of the line. Transmission lines are not always located in the middle of a right-of-way, but instead often are closer to an edge of the right-of-way. Thus, as is the case here, a tree may be outside the boundaries of a 130 foot wide right-of-way but still less than sixty-five feet from a conductor.

Figure 13: Trees Fallen on 115kV Line in Connecticut

Source: Northeast Utilities

The line in the photograph below is a 115 kV line in Massachusetts that went out of service when a seventy-five foot tall tree located outside of the 100 foot wide maintained right-of-way, but inside the 200 foot wide full right-of-way, fell onto the line. Because the transmission line was not centered on the right-of-way, the base of the tree, while outside the maintained right-of-way, was only about 30 feet from the nearest conductor.

Figure 14: Tall Tree Fallen on an 115kV line in Massachusetts

Source: Northeast Utilities

As noted above, data obtained during the inquiry indicates that some of the affected utilities only manage vegetation on narrower maintained rights-of-way rather than their full rights-of-way. For example, one utility's maintained right-of-way widths for 115 kV lines range from 68 feet to 280 feet despite having easements of 88 feet to 325 feet. One 345 kV line is located on a 340-foot wide easement, but only 280 feet of the right-of-way is maintained. Staff finds that the removal of danger trees from full rights-of-way could have prevented the twelve 115 kV transmission line outages (six of which were NPCC-designated BPS elements) that resulted from on-right-of-way tree contact during the October Nor'easter. Preventing those line outages would have avoided approximately 13,000 customer outages.[65] Based on the findings outlined above, staff makes several recommendations regarding right-of-way management in Section IX.

[65] Further complicating right-of-way management is the fact that, for a variety of reasons, some utilities find it difficult to locate the exact edges of many rights-of-way in the field.

B. Transmission Structure Failures

Extreme weather conditions caused several transmission facilities to break, resulting in transmission line outages. Temperatures during the snowstorm hovered around 32 degrees, which is conducive to the accumulation of ice and snow on transmission lines. The weight of the accumulated ice and snow on conductors, and, in one case, high wind conditions, caused a number of structures — including static wires,[66] conductors, insulators,[67] and cross-arms[68] — to break, resulting in six transmission line outages and approximately 32,000 customer outages. Although a number of the transmission structures that failed were several decades (or even more than fifty years) old, it does not appear, based on data obtained during the inquiry, that these structures were in need of repair before the storm. Data reviewed by staff also indicates that the affected structures had been maintained according to utility plans, which staff finds are consistent with typical utility practice.

Figure 15: Structure Failure on a 345kV Line in Connecticut

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[66] Static wire (also known as shield wire) is grounded wire that is strung above conductors to protect them from lightning strikes. The static wire is connected to the grounded tower structure and provides a path for lightning to discharge into the earth.

[67] Transmission line insulators are devices used to contain, separate, or support electrical conductors on high-voltage electricity supply networks. Their purpose is to prevent electricity from arcing between conductors or from conductors to the ground.

[68] Cross-arms are the structures located near the top of transmission poles or metal towers that support conductors.

The 345 kV line shown in the photograph above was forced out of service when the weight of ice and heavy, wet snow on conductors damaged a structure and broke a conductor, static wire, cross-arms, guy-wires,[69] and insulators. This photograph shows (in the background) a wood pole where cross-arms and guy-wires have broken and the conductor has fallen to the ground.

C. Other, or Unknown, Causes

Several transmission line outages were the result of various other, or unknown, causes.

- Eight lines experienced outages as a result of other transmission line failures (i.e., losses of source); these lines were each energized by only one other transmission line, so that when that feeder transmission line failed, the adjacent line also experienced an outage. These loss-of-source transmission line outages caused approximately 16,000 customers to lose power.

- A relay misoperation caused one 115 kV line to be out of service for approximately five hours. As described in footnote 53, a relay misoperation occurs when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. In this case, a relay incorrectly detected a problem on the line and forced it out of service. The misoperation did not result in loss of service to any customers.

- One 115 kV line was forced out of service when a circuit breaker component became stuck. The stuck component prevented the breaker from isolating a line that had experienced a fault, resulting in the interconnected 115 kV line losing power. This stuck breaker condition caused about 4,900 customers to lose power for approximately one-and-a-half hours.

- Utility inspections of one 345 kV and two 115 kV transmission lines that experienced outages did not reveal any damage to transmission structures or nearby vegetation, and there is no indication of equipment misoperations. Therefore, the causes of these outages could not be determined by the utility. No customers lost power because of the 345 kV line outage. Approximately 3,800 customers lost service for approximately four to twelve hours as a result of the two 115 kV line outages. Possible causes of those two line outages are undetected tree contacts or arcing across an insulator due to accumulated snow and ice.

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[69] A guy-wire is a tensioned cable designed to add stability to structures like utility poles. One end of the cable is attached to the structure and the other is anchored to the ground at a distance from the structure's base.

VI. Transmission Outages Did Not Destabilize the BPS or Regional Systems

Despite the number — and, in some cases, the duration — of the transmission facility outages caused by the storm, the stability of the BPS and the operations of the transmission systems operated by ISO-New England (ISO-NE) and the New York Independent System Operator (NYISO) were never impaired. This was the result of two main factors: a significant decrease in load resulting from distribution facility damage and, to a lesser extent, preventative measures taken by ISO-NE.

A. Bulk Power System Impacts

The loss of seventy-four transmission lines — including twenty-three BPS elements — during the October snowstorm did not strain the BPS. There were no Special Protection System[70] operations. System operators were not required to shed load or take other mitigating measures to maintain reliability. All transmission substations that went out of service were restored before their batteries were depleted; thus, the stability and control of the BPS was not threatened due to those substation outages. In short, the transmission system held up well. An important reason for this, however, is that the damaged distribution system significantly reduced the demands placed on the transmission system. The dramatic drop in power usage (also known as "loss of load") that occurred when millions of customers lost power due to distribution facility damage eased the burden on transmission facilities across the Northeast. Under normal load conditions, seventy-four transmission facility outages could have caused swings in voltage and changes in flows requiring system operators to take emergency actions, possibly including load shedding, in order to prevent cascading outages.[71]

Of course, utilities and regulators strive to prevent loss of load, the effects of which can cause significant harm to customers and the economy. Efforts are currently under way in many Northeastern states to prevent significant damage to distribution systems

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[70] Special Protection Systems are systems designed to automatically detect abnormal conditions on a transmission system and to take corrective action. *See* NERC, *supra* note 6.

[71] A cascading outage is a sequence of events where an initial event, or set of events, triggers a series of other outages. Cascading outages can result in widespread power outages, such as those that occurred during the 2003 Blackout. However, in some cases, outages can be halted before the sequence results in a major interruption of electricity service.

in future storms in order to minimize customer outages.[72] If these efforts succeed, then load loss resulting from distribution facility damage during severe weather will diminish, which could then increase the demands on transmission lines during and immediately after storm events. Therefore, while it has always been important that utilities take steps to minimize weather-caused transmission line outages, it becomes especially important to do so as efforts are underway to minimize load loss caused by distribution facility damage.[73]

Although the transmission line outages caused by the October snowstorm did not significantly impact the BPS, future storms could cause greater harm to the BPS, and there are valuable lessons that can be learned from this event. Therefore, staff recommends in Section IX that utilities consider targeted actions to better protect transmission facilities. In particular, as discussed below, staff recommends that, where appropriate, utilities take steps to improve maintenance of their rights-of-way and take a targeted approach to enhance management of off-right-of-way danger trees, focusing on protecting lines rated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

B. Regional System Impacts

Transmission facility outages during the storm also had no detrimental impact on the ISO-NE or NYISO operations. The ten transmission line outages in the NYISO74 region did not impact the reliability or operation of the NYISO system: no system operating limits were exceeded, no generation was lost, and all applicable reserve margins were maintained. There was no need for NYISO to implement any emergency procedures or alerts.

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[72] For example, the Connecticut legislature recently passed a bill that, among other things, requires the state Public Utilities Regulatory Authority to establish standards for electric utilities in preventing outages, restoring power, trimming trees, and for emergency planning, staffing, mutual aid policies, and power restoration coordination efforts with telecommunication companies. SB 23, Reg. Sess. (Conn. 2012).

[73] As during the October snowstorm, future severe storms events that damage transmission lines will also likely damage distribution lines for the simple reason that large-scale tree failures will not occur only, or even primarily, near transmission lines.

[74] NYISO is the independent, non-profit organization that operates New York State's transmission network, administers its wholesale electricity markets, and serves as the state's NERC-certified Reliability Coordinator. A Reliability Coordinator is "[t]he entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System [in a defined area], has the Wide Area view of the Bulk Electric 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." NERC, *supra* note 6.

Nearly all transmission facility outages — sixty-four — occurred on the ISO-NE[75] system, but they caused no significant operating impacts. ISO-NE implemented limited procedures to ensure the reliability of the region's transmission system before, during, and after the snowstorm. In anticipation of the snowstorm, ISO-NE implemented an Abnormal Conditions Alert (Master/Local Control Center Procedure 2 (M/LCC-2)) at 1:00 p.m. Eastern Daylight Time (EDT) on Saturday, October 29. This alert protects the stability of the transmission system by requiring market participants to postpone scheduled maintenance, construction, or testing activities in order to maintain reliability in the face of unplanned outages or similar conditions. ISO-NE cancelled the Abnormal Conditions Alert at 11:15 a.m. EDT on Monday, November 7, 2011.

The storm's most significant impact on ISO-NE operations was the significant loss of load caused by the damage to distribution and, to a lesser extent, transmission lines. As a result of the dramatically decreased demand, by Sunday, October 30, ISO-NE had more generation scheduled to run than it needed. In order to reduce the planned power output and keep the system in balance on October 30, ISO-NE twice implemented a Minimum Generation Emergency. This declaration allowed ISO-NE to require generators to operate below the minimum level at which it is economic to run.

Finally, approximately 1,500 MW of generation capacity in ISO-NE went offline during the storm.[76] However, ISO-NE maintained its required reserve margins at all times.[77] All but one of these generation outages were resolved by 9:00 a.m. EDT on October 31. The remaining generator was restored on November 2. The loss of generation capacity had no impact on the stability of the ISO-NE system or the BPS because load levels dropped so significantly during and after the storm that the power the facilities could have produced was not needed.

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[75] ISO-NE is a private, non-profit organization that operates the transmission grid, administers the energy markets, and serves as the NERC-certified Reliability Coordinator for Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[76] Twenty-one small units in total were offline; twelve were offline due to loss of transmission lines serving those facilities, seven due to loss of communications for remote start capability, and two due to generator step-up transformer trips.

[77] A generation reserve margin is the amount of generation capacity required to be available at any given time in excess of the amount of generation that is anticipated to be needed to meet actual demand. Reserve margins ensure that there will be enough generation available to meet demand that exceeds projections or to compensate for unanticipated losses of other sources of generation. *See* NERC, *Reliability Indicators: Planning Reserve Margin*, http://www.nerc.com/page.php?cid=4%7C331%7C373.

VII. Applicability of the Transmission Vegetation Management Reliability Standard

As discussed above, the majority of transmission facility outages and related loss of load that occurred during the October snowstorm were the result of vegetation contact with transmission lines. Therefore, the FERC-approved Reliability Standard most relevant to this event is FAC-003-1 (Transmission Vegetation Management Programs). However, its applicability to the October snowstorm event is limited.

A. Overview of Reliability Standard FAC-003-1

Reliability Standard FAC-003-1[78] was developed by the industry with the purpose of preventing outages from vegetation located in transmission rights-of-way and minimizing outages from vegetation adjacent to the right-of-way.[79] The standard requires Transmission Owners to document a transmission vegetation management program (TVMP) that defines a schedule for right-of-way vegetation inspections based on anticipated vegetation growth and other relevant factors.[80] TVMPs must identify two minimum clearances around transmission lines: a "Clearance 2," the minimum distance around transmission lines to be maintained at all times in order to prevent flashover between the lines and vegetation;[81] and a "Clearance 1," the distance around transmission lines utilities will clear to when performing periodic maintenance so as to prevent vegetation from growing into the Clearance 2 space during maintenance intervals.[82] The TVMP also must specify a schedule for, and methods of, vegetation

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[78] Reliability Standard FAC-003-1 was approved by FERC on March 16, 2007, in Order No. 693, FERC Stats. & Regs. ¶ 31,242, and became mandatory and enforceable on June 18, 2007.

[79] Reliability Standard FAC-003-1 (Transmission Vegetation Management Program), at A.3.

[80] *Id.*, at Requirement R1.1.

[81] *Id.*, at Requirement R1.2.2. Clearance 2 distances must be at least as great as the clearances set forth in IEEE Standard 516-2003, which range from 0.75 to 6.24 meters (2.45 to 22.44 feet) between conductors and grounded objects like vegetation, depending on the conductor's rating. INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS GUIDE FOR MAINTENANCE METHODS ON ENERGIZED POWER LINES 20, 94 (2003).

[82] Reliability Standard FAC-003-1, at Requirement R1.2. As the Commission explained in Order No. 693, FAC-003-1's clearance requirements mandate that Transmission Owners establish "sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 729. The Commission noted that "all applicable conditions" does not include the extraordinary circumstances specified in Requirement R3.2, which excludes "natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the [right-of-way]." *Id.*

inspections.[83] In addition, utilities are required to develop annual plans for vegetation management work to ensure reliability, taking into account various factors, such as anticipated vegetation growth.[84] Finally, Transmission Owners must report certain vegetation-related outages to the relevant Regional Entity.[85]

Unlike the vast majority of Reliability Standards, which apply to all BES facilities (i.e., generally, those operated at or above 100 kV, or otherwise as determined by the Regional Entity), FAC-003-1 applies only to BPS "transmission lines operated at 200 kV and above and to any lower voltage lines designated by the [Regional Entity] as critical to the reliability of the electric system."[86] This means that the Standard does not apply to lines operated at voltages under 200 kV in the NPCC region unless NPCC has designated those lines as "critical" under the Standard. NPCC has not designated any transmission lines rated under 200 kV as "critical" for the purposes of applying FAC-003-1.

When approving FAC-003-1, the Commission acknowledged that, although the proposed Standard gave Regional Entities discretion to designate lines under 200 kV to which the Standard would be applicable, no Regional Entity had actually designated any lower-voltage lines as critical for that purpose.[87] The Commission expressed the concern that a bright-line 200 kV threshold for application of the Standard would "exclude a significant number of transmission lines that could impact Bulk Power System reliability."[88] However, in response to industry concerns that, among other things, the costs of expanded applicability to sub-200 kV facilities could outweigh the benefits, the Commission did not require NERC to revise FAC-003-1 immediately. Instead, it directed NERC to "revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard."[89]

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83 Reliability Standard FAC-003-1, at Requirement R1.

84 *Id.*, at Requirement R2.

85 *Id.*, at Requirement R3.

86 *Id.*, at A.4.

87 Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 706.

88 *Id.*

89 *See id.* P 710.

Because NPCC does not apply FAC-003-1 to any sub-200 kV BPS elements, FAC-003-1 only applied to one line — a 345 kV line in Connecticut — that was forced out of service due to tree contact during the October snowstorm.[90] That line's outage did not result in any customer outages. Thus, although the October snowstorm outages were almost entirely caused by vegetation contact, the Transmission Vegetation Management Reliability Standard applied to only *one* of the fifty-five transmission lines forced out of service by tree contact (and applied to none of the distribution lines damaged in the storm).[91] To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV[92] and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

B. FAC-003-1's Scope

If FAC-003-1 had applied to all of the transmission facilities impacted by tree contact during the October snowstorm, compliance with the Standard with respect to those lines may not have prevented the storm's vegetation-caused transmission line outages. This is because: (a) the majority of outages were caused by trees that fell onto transmission lines from outside the utility's right-of-way, and FAC-003-1 does not specifically address off-right-of-way vegetation management; and (b) FAC-003-1 does not dictate specific right-of-way management practices, including how utilities should manage on-right-of-way danger trees.

First, FAC-003-1 does not specifically address management of vegetation located outside a utility's right-of-way. Thus, even if the Standard had applied to all

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90 Two other lines that experienced outages during the October snowstorm are operated at over 200 kV, and therefore subject to FAC-003-1, but those outages were not caused by vegetation contact.

91 On December 21, 2011, NERC filed with FERC a proposal to replace FAC-003-1 with a new standard, FAC-003-2. Among other things, FAC-003-2 would revise the Standard so that it would be applicable to all transmission lines operated at or above 200 kV and any line that is an element of an Interconnection Reliability Operating Limit (IROL) or a Western Electric Coordinating Council (WECC) Transfer Path. N. Am. Elec. Reliability Corp., Petition, Docket No. RM12-4-000 (filed Dec. 21, 2011). However, this expanded applicability would not have significantly increased the Standard's impact on lines forced out of service by tree contact during the October snowstorm because only eight of those 115 kV or 138 kV lines are IROL elements (none are WECC Transfer Paths). Moreover, the proposed FAC-003-2's requirement that no vegetation come into contact with lines governed by the Standard does not apply when the vegetation contact is caused by major storms. This report does not offer any views on proposed FAC-003-2, which is currently under review by the Commission.

92 *See, e.g.*, N.Y. Comp. Codes R. & Regs. Title. 16 §§ 84.2, 84.3; Cal. Gen. Order 95, Rule 35.

transmission lines impacted by vegetation during the October storm, it would not have addressed the condition — tall trees growing outside of utilities' rights-of-way — that caused over half of all storm-related outages. One reason FAC-003-1 does not explicitly address off-right-of-way vegetation management is that land adjacent to rights-of-way is typically not owned by the utility, and state laws usually limit utilities' ability to prune or remove trees on property they do not own. Although state laws differ, generally speaking, a utility may not remove a tree (including a danger tree) located outside of its right-of-way without the property owner's consent.[93] Moreover, obtaining permission to remove off-right-of-way trees can be complicated and difficult.

When utilities and state agencies set policies and make decisions regarding removal of danger trees outside the right-of-way, they must consider a number of factors. Reliability of the transmission system, and, in particular, preserving the stability of the BPS, is a central concern. However, environmental issues, property rights, viewsheds, and cost also play an important role. In heavily forested regions like New England, even if possible, the reliability benefits of removing all danger trees from outside utilities' rights-of-way often would not outweigh the costs of doing so.[94] For example, Northeast Utilities provided staff with an estimate that there are some 800,000 danger trees along the edges of its rights-of-way, and that removing them would cost approximately $400 million.[95] Notwithstanding competing policy concerns, off-right-of-way tree fall-ins were the leading cause of transmission line outages during the October snowstorm, and, in general, some off-right-of-way danger trees can pose a threat to reliability. Therefore, staff makes a recommendation in Section IX that utilities should re-evaluate, and work to enhance, their off-right-of-way vegetation management.

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[93] *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(I) (electric utilities must obtain consent of the landowner to prune trees outside of the right-of-way); *see also Tree Trimming FAQs*, PUBLIC SERVICE OF NEW HAMPSHIRE, http://www.psnh.com/CustomerSupport/Home/Tree-Trimming-FAQs.aspx (explaining procedures for obtaining consent of tree owners before performing trimming maintenance). In some circumstances, if a utility provides notice of its intent to remove a tree and the landowner does not object, the utility may proceed without specific permission. *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(II)(b) (stating that the utility may perform the work without permission if the tree owner does not request personal consultation after receiving notice). In some states, there are expedited procedures for obtaining permission to remove "hazard trees" — trees that present an imminent danger to transmission lines because they are damaged or diseased. *See, e.g.*, Mass. Gen. Laws Ann. ch. 87 § 14(b), (c) (permitting electric utilities to file hazard tree removal plans for approval by the tree warden to avoid otherwise applicable restrictions on tree removal).

[94] As ISO-NE has stated, "[t]he political, social and environmental expectations placed on utilities in New England prevent the clearing required to guarantee total system protection from falling trees. In severe weather events (hurricanes, micro bursts, tornadoes and ice storms) trees may fail and fall into lines." ISO-NE, OPERATING PROCEDURE 3 Appendix C (2005).

[95] Of course, the monetary and non-monetary costs of danger tree removal must be weighed against, among other things, the often high costs of transmission outages.

Second, while FAC-003-1 does require utilities to maintain plans and procedures to address vegetation to meet its Clearance 1 requirements, and utilities have considerable flexibility in designing transmission vegetation management programs as long as utilities are compliant with the FAC-003-1 requirements, the Standard does not specifically dictate how utilities should manage danger trees that are outside of Clearance 1 but within the right-of-way. Thus, utilities may maintain vegetation clearances on less than the full right-of-way, which can increase the number of danger trees within the right-of-way. [96]

FAC-003-1 does recognize that the American National Standard Institute's (ANSI) Standard A300, which provides guidelines for integrated vegetation management on electric utility rights-of-way,[97] is an industry best practice.[98] ANSI A300 does not specifically prohibit growth of danger trees on a right-of-way, but it does explain that the "wire zone-border zone" vegetation management method, where the full right-of-way is managed in order to prevent the growth of danger trees, "is a proven method that ensures the reliability of electric supply lines."[99] The wire zone-border zone method allows very low-growing vegetation such as grasses and other groundcover species in the area under and immediately around transmission structures (the "wire zone") and permits short-growing vegetation like shrubs and short trees from the outer edge of the wire zone to the edge of the utility's full right-of-way (the "border zone").[100] The following drawing illustrates the wire zone-border zone concept.

[96] Staff notes that no registered entity has been charged with a violation of FAC-003-1 as the result of a healthy tree falling onto (as opposed to growing into) a transmission line.

[97] Integrated vegetation management (IVM) is "[a] system of managing plant communities in which compatible and incompatible vegetation is identified, action thresholds are considered, control methods are evaluated, and selected control(s) are implemented to achieve a specific objective." ANSI A300, *supra* note 14 at 72.

[98] Reliability Standard FAC-003-1, at Requirement R1 n.1.

[99] ANSI A300, *supra* note 14 at 75.2, Annex A.

[100] ANSI A300, *supra* note 14; RANDALL H. MILLER, BEST MANAGEMENT PRACTICES: INTEGRATED VEGETATION MANAGEMENT 17 (2007) (companion publication to ANSI A300).

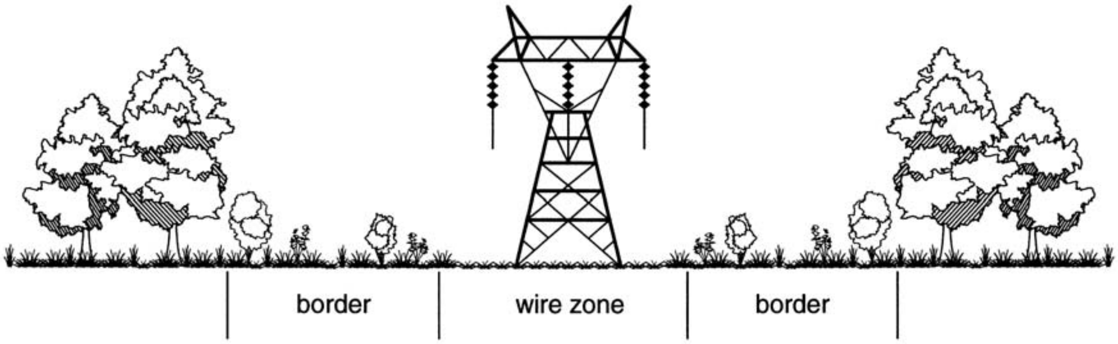

Figure 16: Wire Zone-Border Zone Illustration

Source: UVM Final Report, infra note 109

FAC-003-1's focus on maintaining clearances through a specific method like the recognized wire zone-border zone best practice reflects an emphasis on preventing vegetation from growing or swaying into conductors (or conductors swaying or sagging into vegetation) rather than vegetation breaking and falling into conductors, especially during severe storms.[101] Thus, to minimize the damage caused by similar events in the future vegetation management requirements would need to include a requirement to address at least those danger trees growing within the right-of-way.

[101] Indeed, the genesis of FAC-003-1 was the major blackout that occurred on August 14, 2003, which was caused in significant part by unmanaged vegetation that, due to growth and line sag, contacted several 345 kV lines and precipitated cascading outages throughout the eastern United States and Canada. *See* U.S.-CANADA POWER SYSTEM OUTAGE TASK FORCE, *supra* note 12. Proposed FAC-003-2 requires that Transmission Owners manage vegetation in order to prevent *any* vegetation from making contact with transmission lines – including fall-ins. *N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM12-4-000, at Proposed Standard FAC-003-2, R1, R2 (filed Dec. 21, 2011). However, as stated in note 91, the proposed standard would *not* apply to vegetation contact in "circumstances that are beyond the control of a Transmission Owner," including natural disasters such as "major storms as defined either by the Transmission Owner or an applicable regulatory body . . . ." *Id.*, at R1 n.2. As previously noted, this report takes no position on proposed FAC-003-2.

VIII. Outage Reporting Provides Limited Information

During and after the storm, two Reliability Standards – FAC-003-1 and EOP-004-1 – required that entities report some information about their outages to either NERC or NPCC. However, those requirements, and the responses provided by most affected utilities, resulted in FERC and NERC initially receiving limited information about the event. Based on the findings in this Section, staff makes recommendations in Section IX for improved or enhanced reporting of certain outage information.[102]

Standard FAC-003-1 requires Transmission Owners to report on a quarterly basis to Regional Entities such as NPCC sustained vegetation-caused outages on lines subject to that Standard,[103] and NPCC guidance also instructs transmission owners to report vegetation-caused outages on any BPS elements operated under 200 kV.[104] However, outages caused by off-right-of-way tree contacts during natural disasters, including major storms, do not have to be reported under FAC-003-1.[105] While NERC obtains certain data about outages through other reporting mechanisms, there are no data reporting requirements in place that mandate the reporting of all the transmission facility outages that occurred in the October storm. Nor were all such outages, in fact, reported to NERC. Thus, utilities were not required by FAC-003-1 to submit information on the October storm's BPS element outages caused by off-right-of-way tree fall-ins.

Staff gathered substantial information about these outages during the inquiry, but is concerned that information about off-right-of-way tree fall-ins during other weather

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[102] This report's findings and recommendations regarding reporting address only issues related to reporting outage information to FERC, NERC, or the Department of Energy (DOE). We do not address issues related to reporting distribution facility or customer outages to state regulators. However, staff notes that there have been calls to improve the consistency of distribution facility outage reporting. *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *The Future of the Electric Grid*, 9 (2011), *available at* http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml ("Most outages occur within distribution systems, but only 35 U.S. states require utilities to report data on the impact of all outages on consumers, and reporting standards and practices differ. It is accordingly impossible to make comprehensive comparisons across space or over time.").

[103] Reliability Standard FAC-003-1, at Requirement R3.

[104] NPCC, COMPLIANCE GUIDANCE STATEMENT ON REPORTING OF TRANSMISSION OUTAGE RELATED TO VEGETATION CONTACT (rev. Oct. 3, 2008), *available at* https://www.npcc.org/Compliance/Compliance%20Guidance%20Statements/Forms/Public%20List.aspx.

[105] Reliability Standard FAC-003-1, at Requirement R3.2.

events may not be reported. The weather exception prevents regulators from obtaining a key source of information about the extent and severity of these types of outages. Better information would allow policymakers to understand the scope and impacts of weather-caused off-right-of-way tree fall-ins, and to assess whether regulations or guidance should be formulated to address those outages.

Second, staff finds that, during and after the October snowstorm, affected entities did not always provide thorough information in the disturbance reports they were required to file with NERC under Reliability Standard EOP-004-1. That Standard mandates that registered entities submit completed disturbance report forms — either the DOE Electric Emergency Incident and Disturbance Report (Form OE-417) or NERC's Interconnection Reliability Operating Limit and Preliminary Disturbance Report — after certain events, including those where there is significant loss of load.[106] Initial Form OE-417s must be submitted to DOE and NERC within an hour of the disruption, and, at the time of the October storm, final reports providing complete disruption information were required to be filed within 48 hours of the event.[107] However, the majority of the OE-417 forms submitted by utilities during and after the October snowstorm did not provide enough information to allow for a useful initial analysis of the event. For example, many final reports did not include full narrative descriptions of events, or include the voltage of transmission lines that experienced outages. This lack of thoroughness, particularly in the final reports, made it difficult for FERC and NERC staff to ascertain the exact nature of the impact of the storm on the affected systems.[108]

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[106] Reliability Standard EOP-004-1 (Disturbance Reporting), at Requirement R3.

[107] *Id.*, Attachment 2. As of January 1, 2012, the forty-eight-hour reporting requirement for final reports was extended to seventy-two hours.

[108] The inconsistency and incompleteness of information regarding BPS outages was also noted in the MIT report on the future of the electric grid: "At the bulk power level, data on major disturbances and unusual occurrences have been reported to the U.S. Department of Energy (DOE) since the 1970s and to the North American Electric Reliability Corporation (NERC), which has responsibility for the reliability of the bulk power system, since 1984. However, these data are not consistent, complete, or necessarily accurate, and they cannot reliably be used to assess changes in the reliability of the bulk power system over time." *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *supra* note 102, at 9.

IX. Recommendations

The October 2011 Nor'easter was a rare storm that, due to a number of circumstances — record amounts of heavy wet snow, trees that had not lost most of their leaves, and unusually saturated ground — had severe and widespread impacts on the electricity infrastructure in the Northeast. Staff recognizes the unusual aspects of this weather event. Nonetheless, based on information gathered and findings made during the inquiry, staff concludes there are a number of "lessons learned" that, if implemented, could improve reliability during future storms and similar weather events. Accordingly, staff makes the following recommendations with regard to transmission facilities.

• ***Vegetation Management Recommendations***[109]

By far, the leading cause of transmission line outages during the October snowstorm was trees or tree branches falling onto power lines from outside and inside utilities' rights-of-way.[110] Staff therefore recommends that utilities take the following targeted steps to enhance their management of danger trees both on and off their rights-of-way in order to reduce these types of outages.[111]

1. Where Appropriate, Utilities Should Take Targeted Steps to Address Off-Right-of-Way Danger Trees

As noted above, off-right-of-way tree fall-ins accounted for about half of the storm's transmission line outages, and nearly 75% of all confirmed vegetation-caused outages. Off-right-of-way danger trees are a particular threat to reliability in New England, where there may be hundreds of danger trees along one span of a transmission line. Staff

[109] In response to the 2003 Blackout, FERC commissioned a separate vegetation management report to support the federal investigation into that event. The result was the Utility Vegetation Management Final Report, completed by CN Utility Consulting, LLC and published in 2004. Stephen R. Cieslewicz & Robert R. Novembri, Utility Vegetation Management Final Report (March 2004) [hereinafter "UVM Final Report"], *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/uvm-final-report.pdf. The recommendations related to vegetation management in this report are similar to several of the vegetation management recommendations made in the UVM Final Report.

[110] In fact, the majority of vegetation-related outages in the United States are caused by trees or portions of trees falling into lines from distances outside of normal clearing zones (i.e., Clearance 1 or Clearance 2 distances). *See* NERC, *Vegetation Management Reports*, http://www.nerc.com/page.php?cid=3|26.

[111] Staff recognizes the sensitivity of vegetation management issues and the difficulty of expanding rights-of-way and more effectively maintaining them. However, these difficulties must be balanced against the reliability and safety benefits of improved right-of-way management.

recognizes that in most cases utilities are not free to unilaterally remove off-right-of-way trees, that the process for obtaining permission to do so is frequently difficult and costly, and that tree removal often faces significant landowner and public opposition. Moreover, the costs of indiscriminate, widespread removal of off-right-of-way danger trees may outweigh the reliability benefits of doing so.

Taking all these factors into consideration, staff recommends that, where appropriate, utilities follow a targeted approach to enhancing their off-right-of-way danger tree management, focusing on protecting lines operated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System. Utilities should analyze their transmission systems in order to identify danger trees — particularly those species of trees that have a tendency to fail — that could impact critical transmission lines. After performing this analysis, utilities should work with affected property owners, state regulators, and local communities to develop a strategy for managing those trees that pose the greatest threat to those facilities. In addition, if state laws or policies significantly impact utilities' ability to manage off-right-of-way danger trees that could impact these critical facilities, utilities should work with stakeholders and state and local governments to develop solutions that reduce risk to those lines.

2. Utilities Should Employ Recognized Best Practices in Managing Rights-of-Way Where Feasible

Staff found in Section V.A that roughly 25% of the confirmed vegetation-related transmission line outages during the October event were caused by trees that fell into transmission lines from inside a utility's full right-of-way. These on-right-of-way trees were all located outside the utility's maintained right-of-way. Based on this finding, staff recommends that, where possible and practical, utilities implement the industry best practice of ensuring that danger trees are not present within their full rights-of-way.[112] In particular, to the extent a utility manages vegetation only on maintained rights-of-way rather than full rights-of-way, it should work toward reclaiming the full right-of-way width where feasible.[113]

[112] Staff recognizes that there are a number of ways to achieve this result. The wire zone-border zone right-of-way maintenance method, discussed in Section VI, is recognized as highly effective in protecting against on-right-of-way tree contact and generally maintaining reliability. Selection of the most appropriate maintenance method for any given right-of-way should be made by qualified vegetation management personnel.

[113] Maintaining narrower areas within a full right-of-way is not an uncommon practice in the industry and occurs for a variety of reasons, some of which are outside the control of the utility. However, it is not a best practice.

Two key components of reclaiming and maintaining full rights-of-way are (1) knowing the exact boundaries of that area and (2) being able to identify those boundaries in the field. This is not always easy, given that traditional markers (such as wooden stakes or iron plates) can deteriorate or get lost during four-plus year vegetation management cycles. However, technologies such as Light Detection and Ranging (LiDAR) and Global Positioning Systems (GPS) can help utilities accurately and more permanently identify right-of-way boundaries on the ground. Staff recommends that, over time, utilities work toward employing technologies that will allow them to track the exact boundaries of all of their transmission rights-of-way and locate those boundaries in the field.

Staff recognizes there are a number of circumstances where utilities may be unable to completely prevent the presence of danger trees within full, or even maintained, rights-of-way through implementation of the wire zone-border zone management or other, similar techniques, and that utilities have been, and must continue to be mindful, of these circumstances.[114] For example, utilities may be prohibited by state law from removing certain vegetation on their rights-of-way in environmentally sensitive areas, or may be required to maintain on-right-of-way vegetation in order to partially shield power lines from view.[115] Removal of danger trees also may not be possible where the easement establishing the utility's right-of-way explicitly limits, or does not clearly permit, vegetation management in the full easement area. Even where the easement gives a utility rights to manage vegetation across the entire right-of-way, past practices (for example, years of permitting landowners to grow tall trees inside the right-of-way), landowner objections, or public sentiment opposing the maintenance of wide rights-of-way may make it difficult to employ the wire zone-border zone method or otherwise to remove danger trees. Staff also recognizes that reclaiming rights-of-way that are not currently being fully managed can be expensive, time consuming, and difficult. However, staff finds that consistently maintaining the full right-of-way would reduce the number of danger trees near transmission lines.[116]

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[114] *See, e.g.,* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 21 (recognizing that there are locations where implementing the wire zone-border zone model is not practical); MILLER, *supra* note 100, at 18-19 (same).

[115] *See generally*, CIESLEWICZ & NOVEMBRI, *supra* note 109, at 15-16.

[116] Staff recognizes that, in some instances, removing certain tall-growing trees from the interior edge of the full-right-of-way may expose weaker, top-heavy danger trees on the exterior edge, posing more of a risk of a tree falling into the transmission facilities.

Utilities should, of course, take these circumstances into account when evaluating their right-of-way management policies to specifically address danger trees. Staff recommends that utilities: (a) identify the areas where elimination of danger trees inside the full right-of-way is possible given site-specific circumstances and (b) evaluate whether danger tree removal/right-of-way reclamation would increase reliability and be feasible. Once rights-of-way that are appropriate for removing danger trees are identified, utilities should prioritize their efforts, focusing first on rights-of-way surrounding lines that are rated at or above 200 kV, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

In sum, in order to improve reliability during future major storms, staff recommends that, where possible, utilities develop and implement plans to ensure that danger trees are not located within their full rights-of-way.[117]

3. Utilities Should Lay the Foundation for Effective Vegetation Management When Establishing New Rights-of-Way

Preventing fall-ins from both inside and outside the right-of-way is easier if utilities consider vegetation management needs when siting new transmission lines and acquiring new easements. Therefore, staff recommends that utilities carefully assess vegetation and growth rates in the area of planned lines in order to establish the appropriate right-of-way width. For example, if native trees have a mature height of 100 feet, the easement should cover an area wide enough to ensure that existing and future trees outside of the right-of-way will not fall into the facilities.[118]

In addition, utilities should ensure that easement documents protect the utility's ability to ensure safe and reliable transmission of electricity. New easements should clearly provide the utility with rights to manage the full easement in order to prevent the presence of danger trees inside the right-of-way. In addition and where possible, new easements should give the utility the ability to remove danger trees outside of the right-of-way.

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[117] To be clear, preventing the presence of danger trees within the right-of-way does *not* mean that full rights-of-way need to be (or should be) clear-cut. This recommendation is focused on ensuring that, where feasible, danger trees – those trees that could fall into a transmission line or structure – are not present within rights-of-way because they can threaten reliability. Many types of trees growing within rights-of-way do not constitute danger trees.

[118] *See* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 71.

• Other Recommendations

4. Utilities Should Evaluate and, As Needed, Enhance Their Storm Preparedness and Response Plans

As explained in Section III, the October snowstorm exceeded forecasts, and many utilities scrambled — often at the last minute — to assemble adequate response personnel, especially field crews. Although these manpower and related issues did not significantly hinder restoration of transmission line outages or unduly prolong transmission-caused customer outages, the event revealed potential areas of improvement in preparation for future storms. Thus, staff recommends that utilities evaluate their severe storm preparation and response plans to ensure they are flexible and scalable enough to quickly respond to events that are more severe than predicted. For example, utilities should: (a) clearly define how and when they will request outside assistance, through mutual aid or outside contractors; (b) be prepared for regional mutual assistance crews to be unavailable when a weather event is predicted to impact many states, either by requesting mutual aid from other regions early on or retaining additional local contractors to make up for the lack of immediately available mutual assistance; (c) have a policy in place regarding if, when, and where pre-staging will occur; (d) have the ability to, and procedures regarding, reservation of equipment, such as helicopters and infrared cameras, in advance of major storms in order to ensure prompt assessment of transmission system damage; and (e) in regions where extreme weather events occur, and especially where they are becoming more common, retain experienced weather personnel with the responsibility to predict likely impacts of weather events, taking into account service-territory-specific conditions.

5. Utilities Should Report All Vegetation-Caused BES Facility Outages to NERC

As discussed in Section VIII, even though off-right-of-way tree contact during severe storms is a frequent cause of transmission line outages, FAC-003-1 does not require utilities to report those outages to Regional Entities or NERC. Moreover, the Standard does not require the reporting of vegetation-caused sustained outages on BES transmission lines not subject to FAC-003-1 (i.e., those operated at voltages below 200 kV or lower-voltage lines not designated as critical by a Regional Entity). To ensure that regulators have sufficient information to allow them to make informed policy decisions about these types of outages, staff recommends that all tree contact-caused BES facility outages be reported to NERC.

6. Disturbance Reports Should Be Clear and Complete

Section VIII finds that although a number of entities were required by Reliability Standard EOP-004-1 to file preliminary and final disturbance reports related to the October snowstorm outages, many of the filed forms were not completed thoroughly. This lack of thoroughness made it difficult to quickly ascertain the impact of the storm on the affected systems. Staff recommends that, where possible, all entities required to file disturbance reports under EOP-004-1 promptly provide thorough, descriptive, high-quality information in the initial reports as it becomes available to them. With regard to the final disturbance reports, utilities should ensure their responses are comprehensive, providing all the relevant information in their possession.