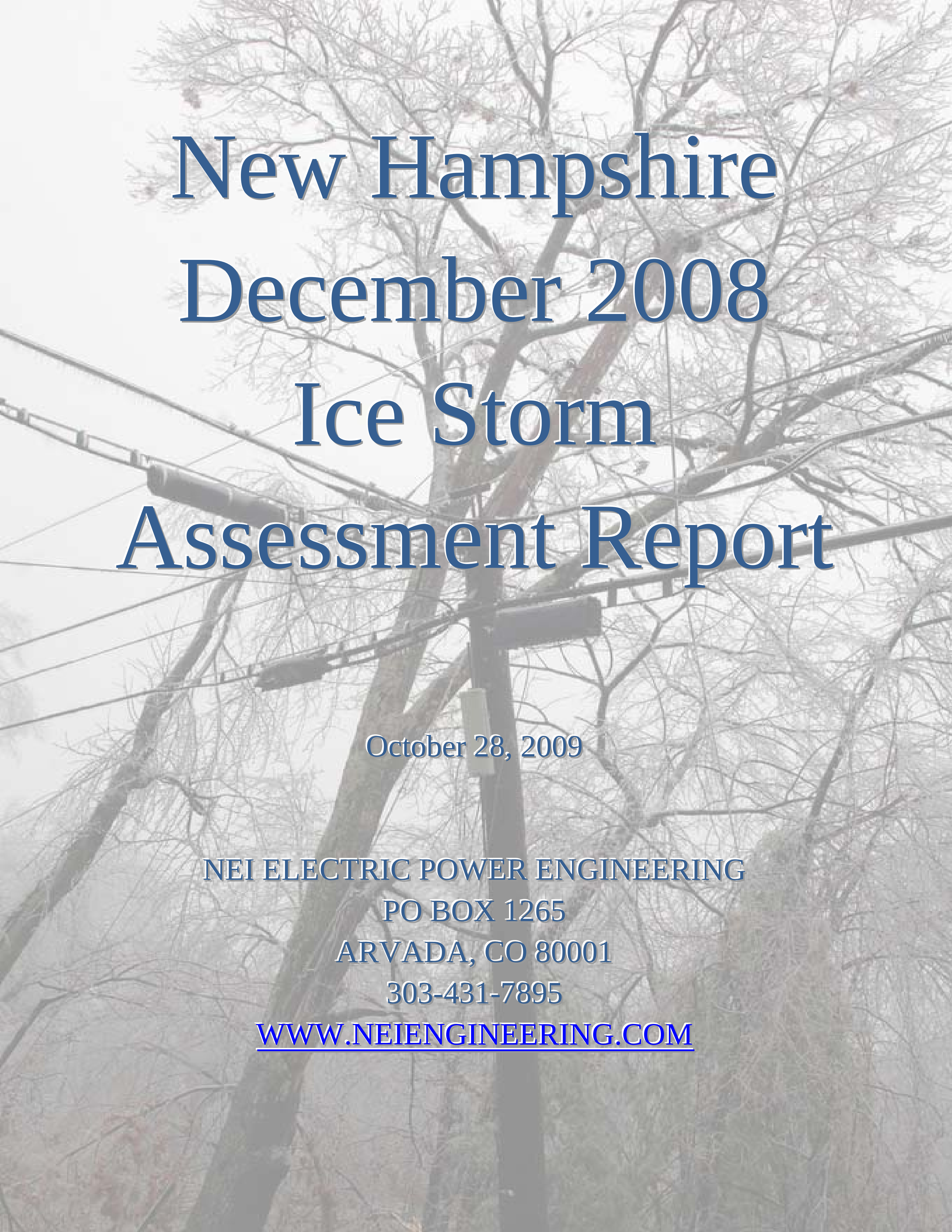

New Hampshire December 2008 Ice Storm Assessment Report

October 28, 2009

NEI ELECTRIC POWER ENGINEERING
PO BOX 1265
ARVADA, CO 80001
303-431-7895
WWW.NEIENGINEERING.COM

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ASSESSMENT TEAM MEMBERS

NEI TEAM MEMBERS

John P. Nelson	Engagement Director, CEO NEI
Michael Joyner	Project Manager, President Joyner & Associates
Mark Fowler	Sr. Management Consultant, President Fowler & Associates
Keith Malmedal	Sr. Technical Consultant, President NEI
Andrew Ackerman	Sr. Management Consultant, Engineering Manager NEI
Brian Beaty	Management Consultant, Arborist
James Satterfield	Management Consultant, Independent Consultant
Clifton Oertli	Technical Assistant, Electrical Engineer NEI
Rosa Gardine	Administrative Assistant, NEI

Executive Summary

This report contains an assessment of the actions of the major electric and telecommunications utilities in New Hampshire resulting from the December 2008 ice storm. The utilities assessed included:

- New Hampshire Electric Cooperative (NHEC) - Electric
- Granite State Electric Company in New Hampshire d/b/a National Grid - Electric
- Public Service Company of New Hampshire (PSNH) - Electric
- Unitil Energy Systems, Inc - Electric
- FairPoint Communications - Telecommunications
- TDS Companies - Telecommunications

This assessment may be divided into the following categories:

- A detailed chronology and critique of the December 2008 Ice Storm
- The emergency response and preparedness of each utility
- Aspects of planning, design, and protection by the utilities as related to the results of the ice storm
- Aspects of operations, maintenance, and vegetation management as related to the results of the ice storm
- Post ice storm actions and processes
- Telecommunications
- Best utility practices
- Summary of recommendations, priorities and cost estimates

The December 2008 ice storm resulted in over $150 million of reported damages to property in the state. Close to 60% of this damage was experienced on the systems of the four electric and two telecommunications utilities studied in this report. Nearly 1/2 of all the damage reported in the state occurred on PSNH's system alone. The electric restoration efforts for the storm lasted approximately two weeks, beginning with the loss of power to the first customers late on December 11, 2008, and ending on December 24, 2008. The telecommunication restoration efforts lasted longer, finally ending on approximately January 3, 2009.

While the December 2008 ice storm created the greatest amount of property damage and longest duration of power and telecommunication outages in the recent history of New Hampshire, an ice storm of this magnitude should occur on average once every 10 years based on research done by the Army Corps of Engineers Cold Regions Research Engineering Laboratory. Past storms, such as the 1998 ice storm, were more severe than the 2008 ice storm in terms of ice accretion, but occurred farther north in less populated areas. It is quite probable that people who witnessed the December 2008 ice storm will still be living to see another storm of equal or greater severity.

To prevent similar damage from occurring, the State of New Hampshire will need to be better prepared.

This report concentrates on the electric utilities with some attention given to the telecommunications utilities. The areas of assessment covered in this report involve a number of technical aspects. Each chapter will provide a set of findings, conclusions, and recommendations. Key findings in the report include the following:

- All of the utilities underestimated the severity of the storm and the extent of damage it would cause. There were a number of lessons learned from the storm that could be used to improve the response to future storms.
- Communications between the utilities, the state EOC, public officials, and customers were often ineffective and uncoordinated. Lessons learned from this storm should be used to implement improved communication efforts with all in the future. It was also determined that better communications between the power and telecommunication companies could have reduced the outage duration for both groups.
- If a storm of similar or greater magnitude were to occur again, the damage to facilities and outage durations would in all likelihood be the same or very similar to those experienced during the December 2008 ice storm. However, if the recommendations of this report are implemented, less damage will occur, utility response will be faster, and the time needed to restore power will be reduced.
- The December 2008 ice storm was a multistate event. This meant that the utilities in multiple states competed for the manpower available to help in the restoration. This lack of manpower increased the duration of restoration. Applying the lessons learned from the December 2008 ice storm could mitigate this factor during a future multistate disaster.
- The possibility of converting the entire overhead transmission and distribution system in New Hampshire to an underground system was investigated. The results of the investigation revealed that the implementation of such a conversion could take as long as 50 years and the costs would be exorbitant. However, limited overhead to underground conversion on a case by case basis may be considered when costs are reasonable and reliability can be improved.
- This assessment revealed that the most significant cause of storm damage to the electric system was ice laden limbs and trees falling onto power lines. To minimize impacts of future storms, a more aggressive tree trimming and vegetation removal program needs to be implemented by the utilities and backed by local and state government.
- Electric and telecommunication companies have joint use pole agreements which allow them to share the ownership and maintenance of poles. There is a growing concern that the telecommunication companies may not be providing adequate pole inspection and

vegetation management, and the electric utilities may be required to bear a greater burden of the maintenance costs.

- Based upon team member's experiences throughout the utility industry, a set of best practices was developed. These practices should be reviewed by each utility, used as a self assessment tool, and when practical, implemented to improve performance.

The report includes a total of 38 recommendations. Chapter IX summarizes these recommendations, and ranks them according to priority and cost.

CHAPTER I

Introduction

Chapter Structure

A. BACKGROUND

Late on Thursday, December 11, 2008, a major ice storm struck New England and Upstate New York. The storm continued into Friday, December 12, wreaking havoc along its path. Figure I-1 displays the geographical footprint of the damage caused by the storm. Thousands of trees were damaged when their branches became laden with ice as shown in Figure I-2, resulting in tree limbs breaking and entire trees uprooting. Many of the damaged trees and limbs fell onto houses, cars, or across roads, and others fell onto telecommunication and power lines. The mechanical shock caused by falling limbs and trees resulted in a tremendous amount of damage to the overhead electric power system infrastructure.

Power outages in New Hampshire began late on Thursday, December 11 (Day 1), and power was not restored to all customers until Wednesday, December 24 (Day 14), a full two weeks after the storm occurred. This ice storm, one of the worst natural disasters to occur in New Hampshire within the last two decades, resulted in over sixty percent of New Hampshire electric customers losing power. As described in Chapter II, the storm caused over $150 million in reported property damage in New Hampshire alone.

The restoration of power was a long and difficult process due to the record amount of damage to the power system. In addition, ice and tree covered roads, as seen in Figure I-3, made the initial damage assessments difficult and time consuming, and hampered repair crews trying to enter damaged areas. The ice storm was followed by two snow events 4 days and 7 days later during the restoration period that further hampered the restoration of power outages. At the peak of the outage there were nearly a half-million customers without power in New Hampshire.[1] The storm

[1] For a full discussion of outage numbers please refer to Chapter II.

resulted in severe economic loss to the state, made even worse due to its occurrence during the holiday shopping season.

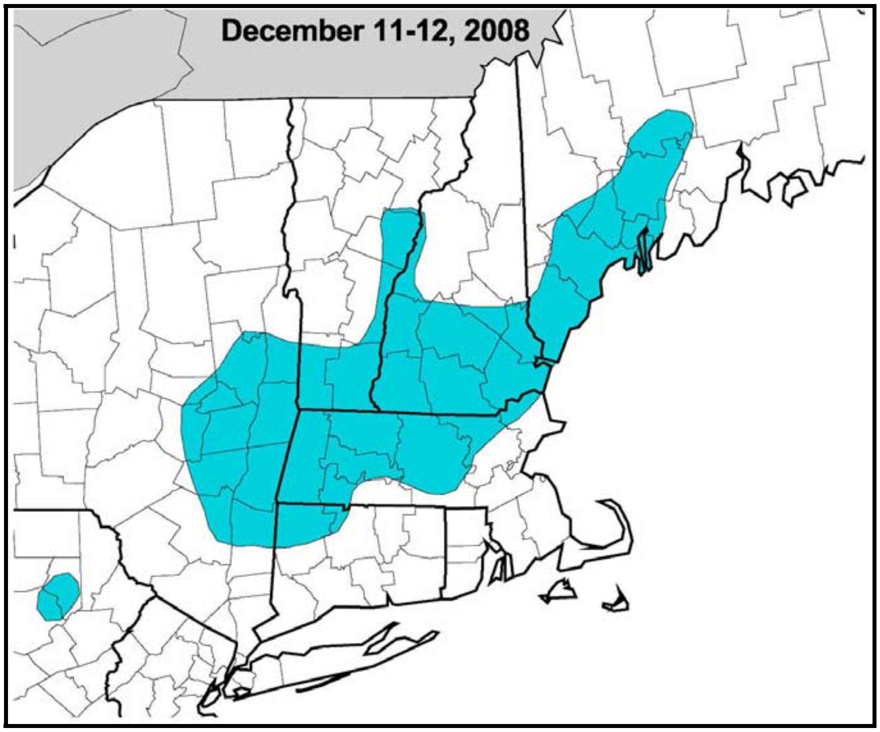

Figure I-1 – Map of the ice storm damage footprint.[2]

[2] Jones, K.F. (July 28, 2009). The December 2008 Ice Storm in New Hampshire. U.S. Army Corps of Engineers Cold Regions Research Engineering Laboratory, Hanover, New Hampshire.

Figure I-2 – Damage in PSNH distribution line corridor.
(Photo courtesy of PSNH. Exact location unknown.)

Figure I-3 - Impassable roads due to ice damage in Londonderry, NH
(Photo courtesy of PSNH)

As a result of the storm, the governors of New York, Massachusetts, New Hampshire, and Maine declared states of emergency in their jurisdictions. On December 12, at 9:20 a.m. Governor John Lynch declared a state of emergency. In New Hampshire, 500 National Guardsmen were deployed for 13 days to help with traffic control, delivery of supplies to local emergency centers, wellness checks of residential properties, support for the state emergency center, and tree clearing efforts. National Guard armories in Concord, Manchester, Peterborough, and a hangar at Pease Air Force Base in Portsmouth were converted into shelters for residents and staging areas for use by electric utilities.[3] The State's Emergency Operations Center (EOC) operated throughout the entire emergency to provide situational information, support in terms of goods and services for local emergency centers, problem solving when needed, and coordination, command, and control of specific tasks related to the ice storm. A record number (81) of local emergency operations centers as well as a record number (51) of shelters were opened during the ice storm. Over 448 schools were closed due to loss of power or because they were serving as shelters for local communities. Over 350 segments of state and local roads were affected by downed wires or fallen trees. Businesses that lost power during the storm remained closed for several days. Some businesses that had power experienced a temporary increase in sales of food, accommodations, supplies, and other items in demand during lengthy power outages.

Many utilities in New Hampshire were criticized for restoring power too slowly and for poor communications with customers. They were also criticized for not communicating the extent of the damage and for being unspecific or inaccurate when estimating restoration times.

The New Hampshire Public Utilities Commission (NHPUC) requested assistance from a consultant in reviewing the efforts of the four electric utilities and the two largest incumbent telecommunications utilities in New Hampshire prior to, during, and after the storm. This review was undertaken by NEI Electric Power Engineering (NEI), resulting in this report. The six utilities reviewed are listed in Table I-1 below.

Table I-1 – New Hampshire utilities included in the December 2008 ice storm assessment.

New Hampshire Utility	Type
Public Service Company of New Hampshire (PSNH)	Electric
Unitil Energy System, Inc. (Unitil)	Electric
Granite State Electric Company d/b/a National Grid (National Grid)	Electric
New Hampshire Electric Cooperative, Inc. (NHEC)	Electric
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications-NNE (FairPoint)	Telecommunications
Hollis Telephone Company, Kearsarge Telephone Company, Merrimack County Telephone Company and Wilton Telephone Company d/b/a TDS Telecom (jointly referenced as TDS Companies)	Telecommunications

[3] Champa, H. Program Assistant, Business office of the Adjutant General, New Hampshire National Guard. Interview by Malmedal, K. August 14, 2009.

The four electric utilities are very different in terms of service territory, organizational structure, and numbers of customers they serve in New Hampshire. These differences are important when considering their response to emergencies and the types of emergency organizations they use. The differences were also important in the recommendations reached by this report. The map in Figure I-4, supplied by the NHPUC, shows the areas of New Hampshire served by each of the four electric utilities. Figure I-5 shows the number of customers each of the utilities serves.

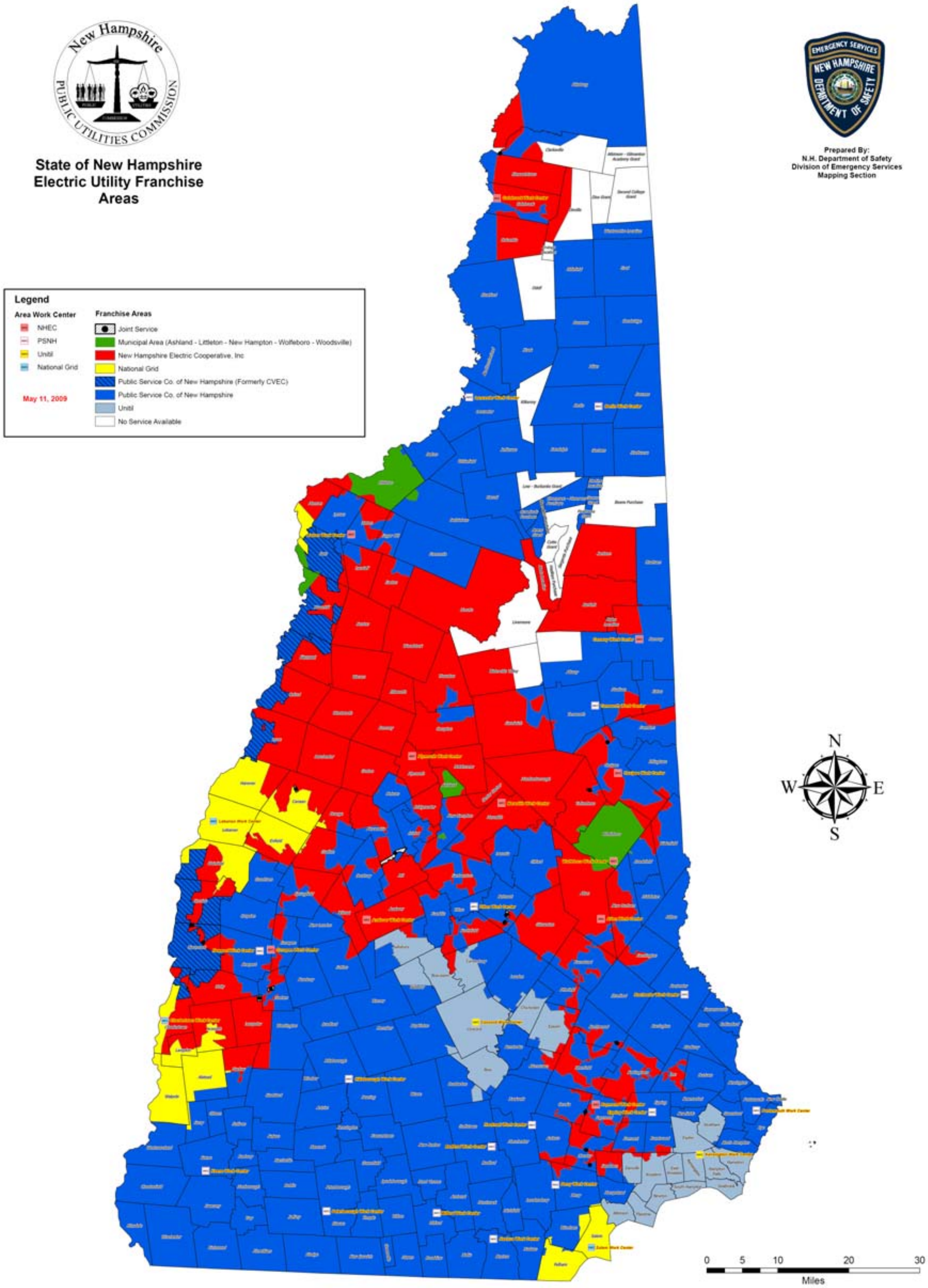

Figure I-4 – Map of New Hampshire electric utility service territories.

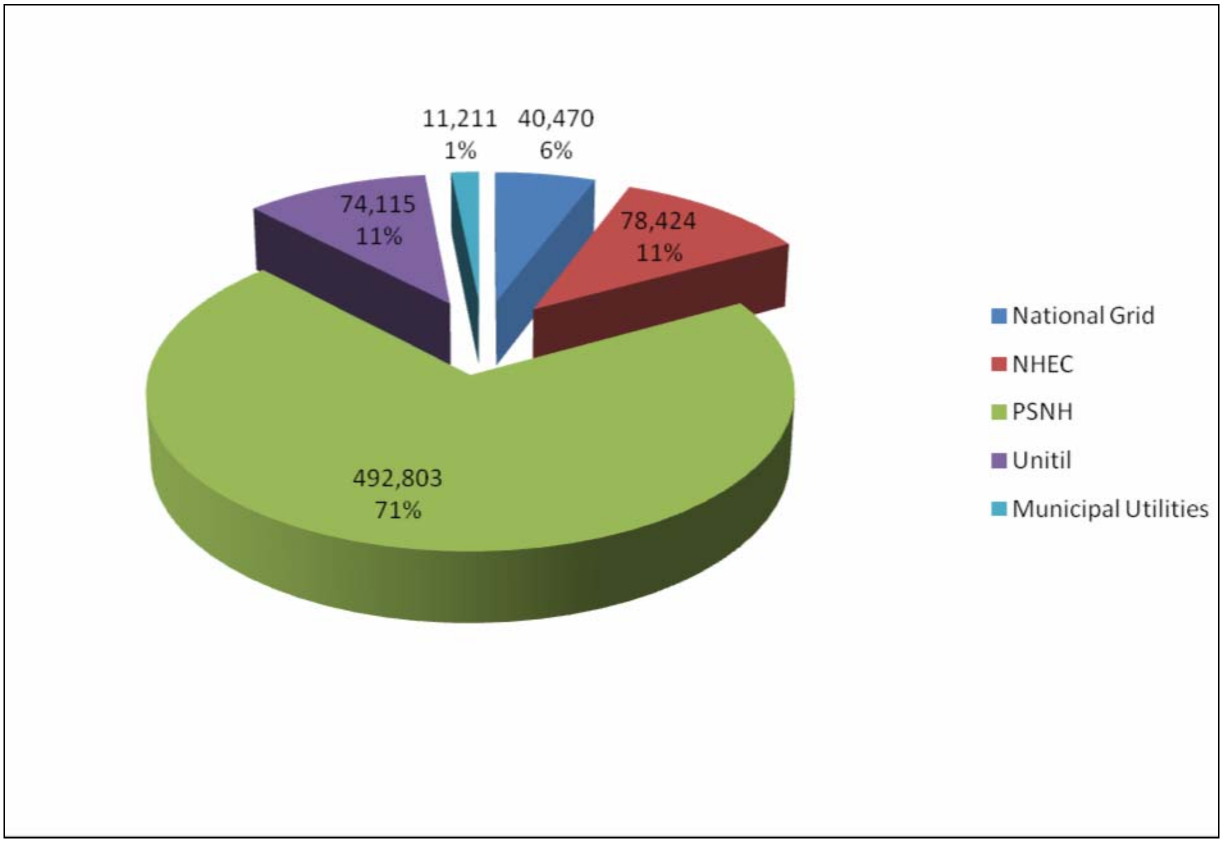

Figure I-5 – Relative sizes of New Hampshire electric utilities based on the number of customer meters. [4] [5]

PSNH

Public Service Company of New Hampshire (PSNH) is a wholly owned subsidiary of Northeast Utilities, whose other electric utility subsidiaries include Connecticut Light & Power and Western Massachusetts Electric Company. Altogether they serve approximately 1.7 million electric customers in New Hampshire, Massachusetts and Connecticut.

PSNH supplies power to a larger area and to more customers in New Hampshire than any other New Hampshire electric utility. It serves approximately 500,000, customers including 70 percent of the retail customers in the state. Its service area includes 211 communities, 13 of the 15 largest cities in New Hampshire, and rural and urban areas throughout the state. PSNH manages emergencies at the state level and has a corporate level emergency operations organization to provide logistical and managerial support when requested. PSNH has a large contingent of workers in New Hampshire, consistent with the size of its customer base, and can

[4] Getz, T. Knepper, R. and Frantz, T. (Jan. 14, 2009). Brief Legislative Overview of Dec 2008 Ice Storm Impacts [PowerPoint]. Concord, New Hampshire.
[5] National Grid Response to Data Request NEI 11-1 – (July 8, 2009 E-mail from P O'Brien to JPN)

draw upon a large contingent of affiliate company workers in Massachusetts and Connecticut in an emergency.

Unitil

Unitil Corporation provides electric distribution services to approximately 74,000 customers in two distinct areas within New Hampshire. The Seacoast area consists of approximately 15 communities and 44,000 customers and the Capital area consists of approximately 13 communities and 29,000 customers. Unitil provides only electric distribution services. It relies on PSNH for transmission and the supply interfaces to its system at 7 transfer (metering) locations. Unitil also provides electric service to customers in Massachusetts and natural gas to customers in Maine, New Hampshire, and Massachusetts. Although its electric territories in New Hampshire and Massachusetts are not contiguous, they are in close proximity to each other. Unitil's two operations centers in New Hampshire — Concord, NH and Kensington, NH — are less than 50 miles from the company's operations center in Fitchburg, Massachusetts. As a result of the December 2008 ice storm, the System Emergency Operations Center for all of Unitil's electric service is located in Hampton, New NH. This center includes both operations and staff support functions.

National Grid

National Grid operates in a relatively small geographic area of New Hampshire and serves approximately 40,000 customers in 21 New Hampshire communities. Its territory consists of two discrete areas: a densely populated area along the northeast New Hampshire-Massachusetts border, and a more sparsely populated area along the New Hampshire-Vermont border in the Upper Valley region. Of significance for emergency response is the fact that National Grid's New Hampshire operations are a very small part of a much larger international organization with correspondingly large resources. In the United States, National Grid serves approximately 3.3 million electric customers in Massachusetts, New Hampshire, New York, and Rhode Island, and manages the electricity network on Long Island under an agreement with the Long Island Power Authority. Due to its relatively large size, National Grid can draw upon extensive contract and support personnel from within the company during emergencies before having to go outside to find additional resources. This supply of personnel and other resources gives National Grid an advantage relative to other New Hampshire electric utilities in an emergency situation.

National Grid has a corporate emergency response organization located in Waltham, Massachusetts[6]. This organization is responsible for emergency plan development and designing drills and exercises, but does not have any operational responsibility for actual storm restoration. Storm restoration is managed entirely within the company's operations organization, which

[6] National Grid was in the process of moving from Westborough, Massachusetts to Waltham, Massachusetts during this assessment.

transitions into storm response mode during emergency events. This creates a division between personnel dedicated to planning and preparing for emergencies and those who execute the plan.

NHEC

New Hampshire Electric Cooperative (NHEC) serves approximately 78,000 customers in 115 cities and towns scattered throughout 9 of the 10 New Hampshire counties. Typical of cooperatives nationwide, NHEC's service territory varies from low population density to extremely rural. Of particular importance for this review is the fact that the cooperative operates with a very small management staff and is independent of the investor owned utility (IOU) mutual aid agreements (explained in Chapter II). NHEC provides only electric distribution services and relies on PSNH for transmission and supply interfaces for 32 of its 33 incoming electric transfer (metering) locations and on National Grid for 1 of its 33 interfaces.

Telecommunications Companies

The service territories of the telecommunications companies serving New Hampshire residents are shown in Figure I-6. The two largest incumbent companies are FairPoint Communications and TDS, who together constitute just over 60% of the market, as seen in Figure I-7.

FairPoint Communications is new to the state of New Hampshire. After acquiring Verizon's existing infrastructure in March 2008, FairPoint became the primary provider of telecommunications services in New Hampshire. It serves more customers and a larger area than any other telecommunications company in New Hampshire and provides service to 210 towns across the state.[7] During the December ice storm, FairPoint was still operating under an agreement with Verizon that relied upon Verizon's systems prior to an impending multi-computer systems cut over.

TDS Communications is a wholly owned subsidiary of Telephone and Data Systems, Inc. In the State of New Hampshire, TDS is comprised of Hollis Telephone Company, Kearsarge Telephone Company, Merrimack County Telephone Company, and Wilton Telephone Company. It provides service mainly in the central portion of the state and serves 24 towns in New Hampshire.

[7] FairPoint Communications FAQ. "What are the basics of the transaction with Verizon?" 2009. http://www.fairpoint.com/news/faqs.jsp (Accessed August 17, 2009).

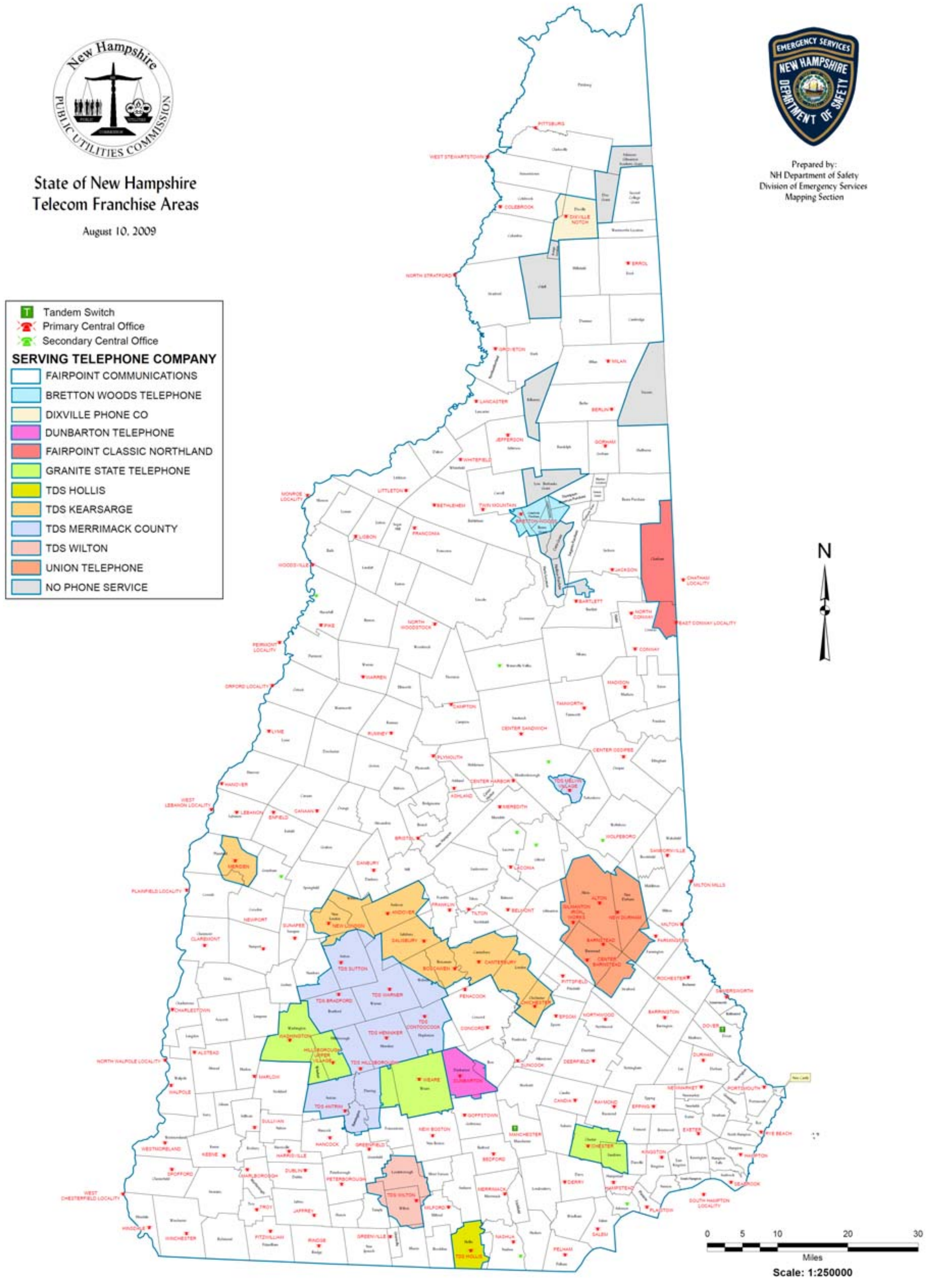

Figure I-6 – Map of New Hampshire incumbent telephone exchanges.

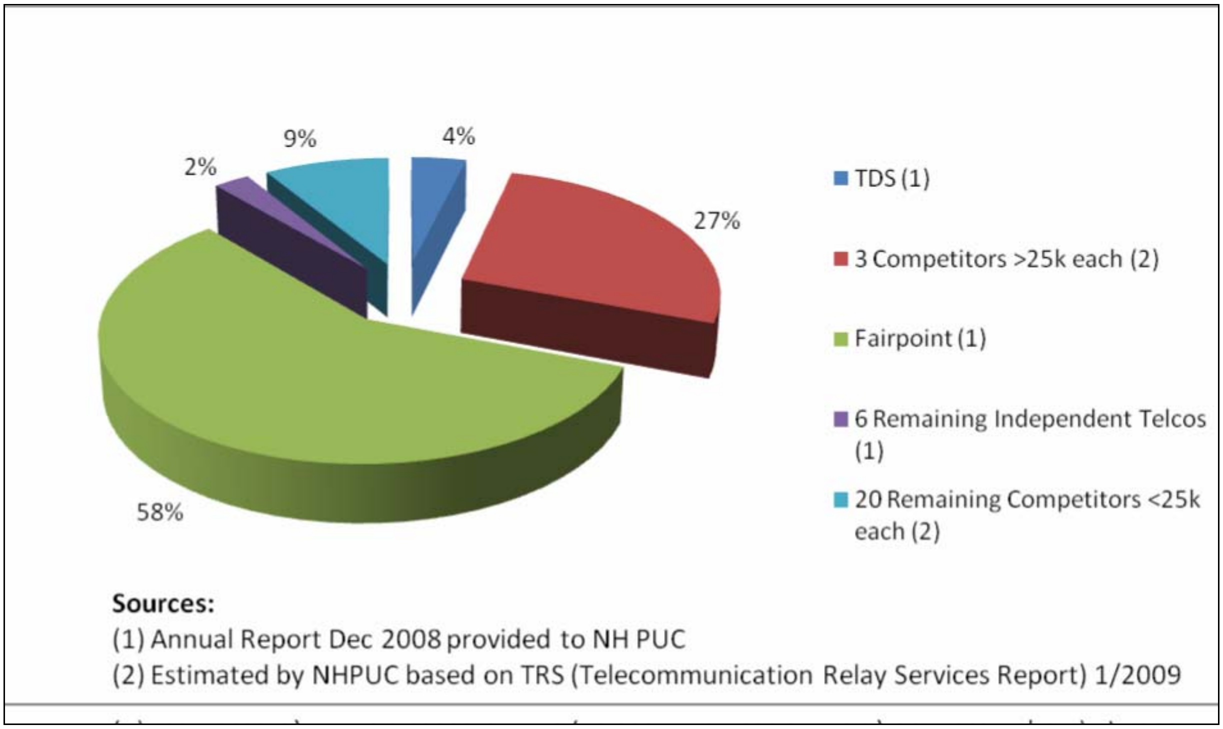

Figure I-7 – Relative sizes of the New Hampshire telecommunications companies based on number of customers as of December 30, 2008.[8]

B. APPROACH

The four electric utilities were evaluated in three general areas: effective preparation for prolonged emergencies, efficient and timely response to outages, and restoration of service. The two telecommunications companies were reviewed under a somewhat different set of criteria than that used to review the electric utilities, due to the differing roles played by telecommunications companies and electric companies in the wake of an emergency. The assessment was conducted in the following steps:

Step One: Orientation and Planning

The objectives of this first step of the investigation were to:

- Review specific NHPUC objectives for this assessment
- Develop a clear understanding of the events surrounding the December 2008 ice storm that resulted in power outages to New Hampshire consumers

[8] Provided by Knepper R. "RE: Number of customers served by the telecommunications utilities." E-mail to Oertli, C. August 12, 2009.

- Become familiar with each utility's organization, particularly those departments and groups responsible for communications, customer service, operations and maintenance, construction, human resource planning, and emergency preparedness
- Gain an understanding of the requirements for providing service and communicating with customers, the media, regulatory bodies, other governmental agencies, and public officials

The orientation and planning step involved three primary activities:

- Initial interviews and presentations
- Preliminary data gathering and analysis
- Project planning

Based on the information collected in step one, working hypotheses were developed for each of the major areas to be evaluated and a detailed work plan was developed to guide the efforts during the remainder of the investigation.

Step Two: Detailed Analysis and Verification

Step two involved investigation and data collection. Its purpose was to gather the data needed to examine and assess the issues described in the Work Tasks in the NHPUC's Request for Proposal (RFP). The project team integrated and summarized information gained during this step and developed preliminary findings, conclusions, and recommendations. Work tasks included the following:

- Submission of numerous data requests to each of the utilities to obtain detailed information
- Interviews with various utility and public officials with regard to the effects and impact of the ice storm
- Analysis of each utility's activities and performance before, during, and after the storm, including preparation, emergency management, and restoration
- Review of power restoration procedures, specifically those pertaining to each utility's electric retail service territory
- Review of each utility's service related operations manuals, system restoration plans, emergency procedures, and service regulations
- Review of each utility's public information and communication procedures concerning its ability to provide timely and accurate restoration timetable information to:
    - New Hampshire electric retail customers
    - Emergency preparedness entities
    - Other agencies and organizations responsible for public health and safety

- Review of each utility's preventive maintenance program
- Review of the system planning, design, construction, and protection practices and procedures of each utility to determine their effectiveness during the adverse weather conditions witnessed during the storm
- Review of the operations, maintenance, and vegetation management programs of each utility to determine their effectiveness during the adverse weather conditions witnessed during this storm
- Review to determine whether some of the adverse effects of the storm might have been mitigated by an aggressive pole upgrade program, an underground cable installation program, or an accelerated tree trimming program
- Analysis of precipitation totals resulting from the 2008 storm using historical records of past storms
- Development of suggested best practices based on discussions with each New Hampshire utility and NEI team experiences with similar electric and telecommunications utilities in other parts of the country
- Review of public comments regarding the ice storm damage and restoration efforts, including concerns submitted in response to an NHPUC online questionnaire, written statements filed with the NHPUC, and comments voiced in ten public hearings held jointly by the New Hampshire Public Utilities Commission and the New Hampshire Department of Safety, Division of Homeland Security and Emergency Management between March 18 and April 30, 2009.[9] [10]

Step Three: Report Preparation

On July 17, 2009, NEI submitted a draft report to the NHPUC staff for review and comment. After incorporating various comments from the NHPUC staff, this final report was prepared. It provides a detailed analysis for each of the tasks set forth in the Commission's RFP, and contains conclusions and recommendations resulting from the analysis done during this study. This report also contains reasoning and evidence supporting the conclusions reached as a result of the analysis.

There are cases where conflicting data exists for the December 2008 ice storm. This may be due to the sheer magnitude of data involved as well as the varying methods used by each utility for gathering and recording data. Of particular note are the conflicts that occurred in reports of the numbers of customers without power and the number of field crews working at any given instant.

[9] Public statement hearings were held in Peterborough, Exeter, Raymond, Salem, Plaistow, Milford, Derry, New London, Goffstown, and Rochester.
[10] December 2008 Ice Storm, "Transcripts of Ice Storm Meetings", 2009. http://www.puc.state.nh.us/2008IceStorm/December2008IceStorm.htm. (Accessed August 17, 2009).

Among the utilities studied, there are variations in the ways such numbers are counted, estimated, and recorded. Depending upon how data is chosen, more than one value may exist for a particular variable. When conflicting values for any data point were encountered, the data with the most reasonable results and sampling method was used. This report endeavors to use the most consistent data set possible for the numbers and conclusions presented.

AUDITING STANDARDS AND QUALITY ASSURANCE

The parties involved in the quality assurance process for this audit were NEI consultants, the NEI Project Manager, and the NEI Engagement Director. The approach to project management and preparing an audit trail are essential components of the quality assurance process. The quality review process is designed to assure adherence to generally accepted auditing standards in accordance with "Government Auditing Standards" (2007 Revision GAO-07-731G) issued by the Comptroller General of the United States.

The Project Manager was responsible for day-to-day monitoring of work, reviewing work products for compliance with project goals and objectives, and for anticipating and responding to problems or concerns. He ensured that the consultants were adequately supported, enforced administrative controls, assured consistency among approaches and methods, and scheduled work to ensure that the consultants were efficient in their efforts. He periodically reviewed the work in progress by attending interviews, assessing the processes used in analysis, testing conclusions, and checking the clarity and completeness of all written materials.
The NHPUC staff reviewed the process and analysis used by the consultants, and reviewed the work products prepared by the review team. The NHPUC provided extensive comments and input during the period of July 17th through October 2nd, 2009. There were numerous changes made in all of the chapters based on their comments. The NEI project team was not in agreement with the inclusion of the evaluation criteria matrices which as stated by the utilities are subjective. The NH PUC staff removed the criteria matrices in Chapter 8 due to their disagreement.

The review process ensures that work is factually based, that the observations and comments formed are supported by relevant data, that professional judgment is differentiated from analytical results, and the results of the review are traceable to the sources of information. Prior to issuance of this report, each utility was provided the opportunity to review the facts in this report to ensure their accuracy. NEI reviewed those comments and made factual changes where appropriate.

CHAPTER II

Storm Restoration Performance

Chapter Structure

This chapter provides an overview and assessment of the respective responses to the December 2008 ice storm of the following four New Hampshire electric utilities:

- Public Service Company of New Hampshire (PSNH)
- Unitil Energy Systems (Unitil)
- Granite State Electric Company (d/b/a National Grid)
- New Hampshire Electric Cooperative, Inc. (NHEC)

The conclusions were based upon the review of numerous utility procedures with regard to the storm, beginning with the identification of the threat to the electric transmission and distribution system, and ending with the evaluation of the companies' efforts to develop improved plans for responding to similar incidents in the future. The review included (1) an examination of the organizational relationships within and among the departments responsible for responding to the storm; (2) the processes and practices employed; and (3) the measures used to evaluate each company's performance in restoring power. Particular attention was given to evaluating communications with customers, government officials, and emergency agencies regarding power restoration schedules and efforts. NEI also reviewed the ways in which each utility handled calls from customers when reporting outages, as well as their ability to provide timely and accurate information related to estimated restoration times (ETRs).

A. BACKGROUND

The Storm

The National Climatic Data Center (NCDC) Storm Event Database reported the following description of the December 2008 ice storm in New Hampshire:

> ***11 December 2008, 4 am to 12 December 2008, 10 am** – A cold frontal boundary dropped south of New England on the evening of the 10th. Low pressure developed along the frontal boundary across the southeastern states late on the night of the 10th into the 11th. The low then tracked rapidly to the northeast, spreading a significant amount of precipitation into New England. A deep layer of warm air aloft and sub-freezing air at the surface resulted in a major ice storm across interior Massachusetts and southern New Hampshire as well as much of northern New England. The hardest hit areas in southern New England were the Monadnock region of southwest New Hampshire, the Worcester Hills in central Massachusetts, and the east slopes of the Berkshires in western Massachusetts. Anywhere from half an inch to an inch of ice accreted on many exposed surfaces. Especially when combined with breezy conditions, the ice downed numerous trees, branches, and power lines which resulted in widespread power outages* [1]

One of the best indicators of the severity of a storm is the peak number of customers who simultaneously lose power as a result. Figure II-1 shows the effects of the storm on New Hampshire's four largest electric power companies as reflected by the number of customers experiencing power outages by date for each utility.

[1] National Climatic Data Center. "Storm Events – New Hampshire." http://www4.ncdc.noaa.gov/cgi-win/wwcgi.dll?wwevent~ShowEvent~744812 (Accessed May 27, 2009).

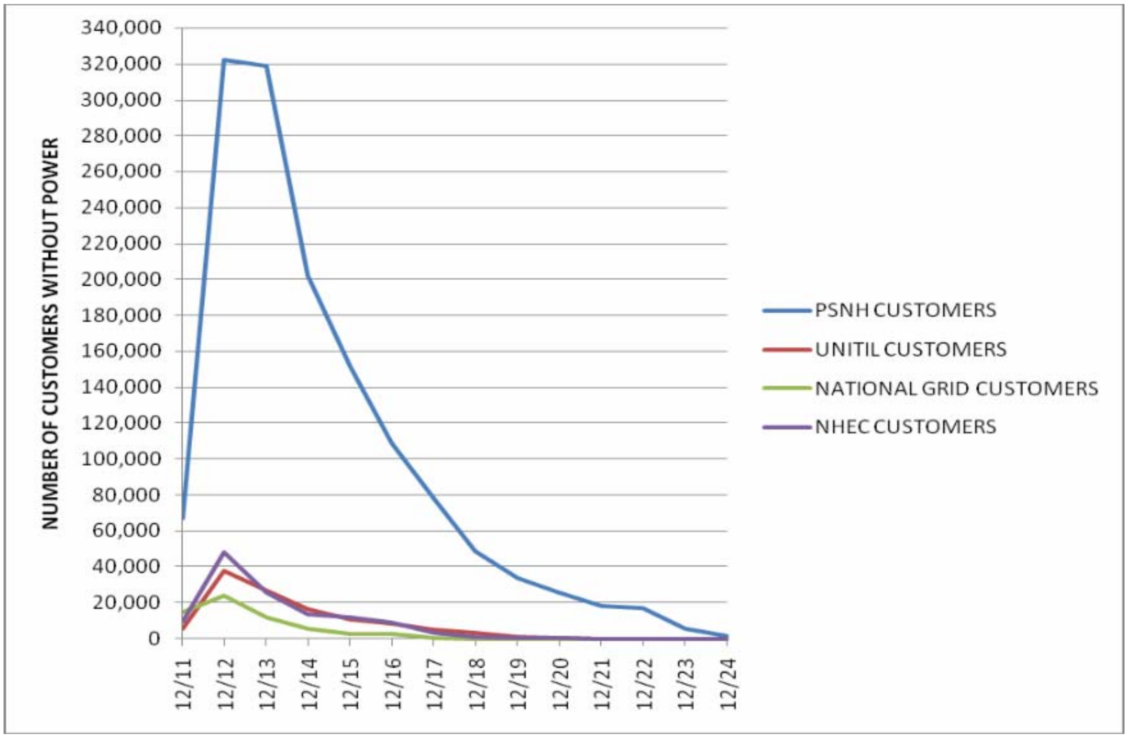

Figure II-1 – The total customers without power for each utility during the ice storm.[2 3 4 5]

As shown in Table II-1, each of the utilities had power interrupted to a large percentage of its customers during the storm. The maximum number of customers who were simultaneously without power was 432,632. Of the customers shown in Table II-1, 26,213 of NHEC's customers were without power due to sub-transmission system failures on lines owned by PSNH, and 5,401 of National Grid's customers were without power for 54 hours and 35 minutes due to a failure on a transmission line jointly owned and operated by National Grid and PSNH.

[2] Unitil. (July 9, 2009). Data Response UT0010. NEI.
[3] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 10.
[4] PSNH. (June 29, 2009).Data Response PS0018.NEI.
[5] NHEC. (June 8, 2009). Data Response CO0006.NEI.

Table II-1 – The number of customers who were without power in New Hampshire, by major utility.[6] [7] [8] [9]

Utility	PSNH	Unitil	National Grid	NHEC	Totals
Total Customers as of December 2008	492,803	74,115	40,470	78,424	685,812
Maximum Number of Customers Without Power	322,438	37,800	24,164	48,230	432,632
Percent of Total Customers Without Power	65%	51%	60%	61%	63%

The Utilities' Restoration Response

To restore power to customers, repair crews were deployed by the utilities. During the outage restoration period, which began late on Thursday, December 11 (Day 1) and lasted through Wednesday, December 24 (Day 14), the utilities employed hundreds of field crews made up of line crews (a/k/a bucket crews), tree crews, and digger crews. These crews worked around the clock to clear debris, replace damaged structures, and restore service. The makeup of field crews varies somewhat between the different utilities. In general, a line crew consists of two to four people and one or two trucks, and is responsible for switching, repair of equipment and hardware, and the final energization of the line. A digger crew typically consists of two to four people and one truck and is responsible for the replacement of poles. A tree crew consists of two or three people and one truck, and is responsible for the removal and disposal of downed trees. Figure II-2 shows the number of field crews of all types, as supplemented by assistance from other utilities and contractors, that the New Hampshire electric utilities had available to respond to outages during the duration of the restoration. In addition to the personnel reflected in Figure II-2, other personnel such as trouble-men (workers dedicated to finding and repairing problems), field spotters, and various types of support personnel were vital to the restoration effort.

[6] Unitil. (July 9, 2009). Data Response UT0011.NEI.
[7] National Grid. (June 23, 2009). Data Response NG0021.NEI.
[8] PSNH. (June 29, 2009). Data Response PS0019.NEI.
[9] NHEC. (June 22, 2009). Data Response CO0007.NEI.

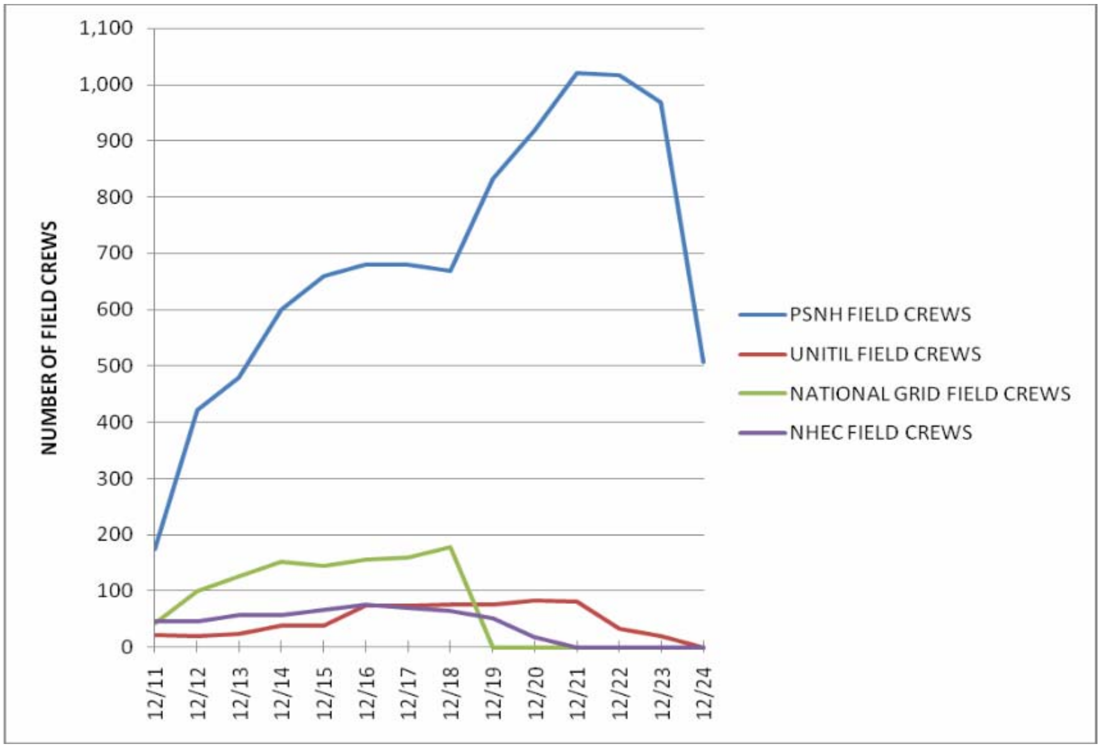

Figure II-2 – Graph showing the total number of field crews deployed by utility during the ice storm.[10] [11] [12] [13]

A comparison of the number of field crews working each day and the number of customers without power on those days is given in Figure II-3. This graph shows the total of all the utilities involved and later in this chapter the totals for each utility are given. A breakdown of the maximum number of customers without power each day and the maximum number of field crews working to restore power each day is given in Table II-2.

[10] Unitil. (February 27, 2009). Data Response STAFF 1-22. NHPUC.
[11] National Grid. (February 27, 2009). Data Response STAFF 1-22. NHPUC.
[12] PSNH. (February 2, 2009). Data Response STAFF 1-22. NHPUC.
[13] NHEC. (February 22, 2009). Data Response STAFF 1-22. NHPUC.

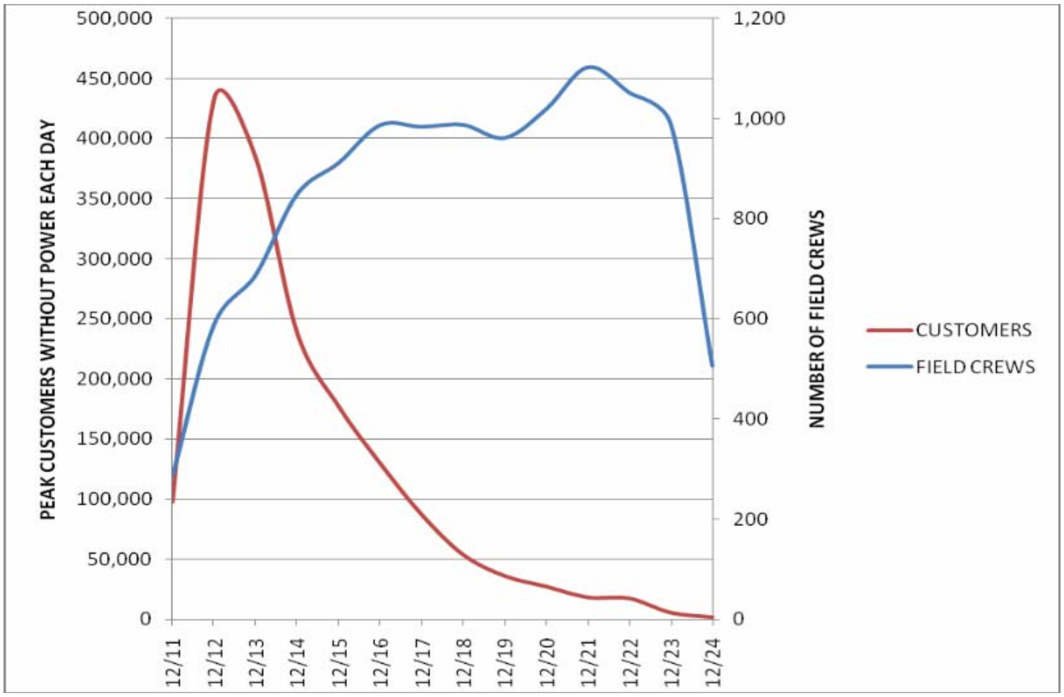

Figure II-3-Graph showing the total field number of field crews working each day compared with the total number of customers without power.

Table II-2-The total number of customers without power and number of field crews working each day.

	PSNH		Unitil		National Grid		NHEC		TOTAL	
Date	Field Crews	Customers Without Power	Field Crews	Customers Without Power	Field Crews	Customers Without Power	Field Crews	Customers Without Power	Field Crews	Customers Without Power
12/11	174	67,530	23	5,450	43	15,000	46.5	9,656	286.5	97,636
12/12	422	322,438	20	37,800	100	24,164	46.5	48,230	588.5	432,632
12/13	479	319,250	24	27,000	126	11,995	58	26,078	687	384,323
12/14	600	202,360	39	16,584	152	5,991	57.5	13,579	848.5	238,514
12/15	659	151,769	39	10,754	145	2,695	68	12,011	911	177,229
12/16	679	109,180	74	8,807	157	2,816	76.5	9,017	986.5	129,820
12/17	679	78,247	74	4,952	160	481	70	3,492	983	87,172
12/18	668	49,046	76	3,176	178.5	186	64.5	1,380	987	53,788
12/19	833	34,150	76	1,250	0	0	52	775	961	36,175
12/20	917	26,218	83	325	0	0	18.5	769	1,018.5	27,312
12/21	1,020	18,346	82	36	0	0	0	0	1,102	18,382
12/22	1,017	17,460	0	0	0	0	0	0	1,017	17,460
12/23	968	5,618	0	0	0	0	0	0	968	5,618
12/24	506	1,854	0	0	0	0	0	0	506	1,854

An examination of Figure II-1, Figure II-2, and Figure II-3 shows the rate of restoration efforts and the amount of resources committed. The slope of the graph in Figure II-1 indicates the rate at which customers were being restored. It is expected that the slope would be the steepest immediately after the storm, showing that the most rapid rate of restoration was occurring during that time. The slope should then gradually decrease as time progressed due to the decrease in the rate of restoration. This decrease would occur because more time will be required to restore power to the most heavily damaged areas of the power system, and the heavily damaged areas with few customers would likely be the last restored.

Care should be taken in interpreting these graphs, especially for the first two days following the storm. The graphs show peak values for each 24-hour period rather than the number of customers without power at the end of each period. For example, the peak number of customers without power on December 12 for PSNH was 322,438 and the peak number for December 13 was 319,250. These numbers were not recorded 24 hours apart as might be assumed; in fact, they were taken only a few hours apart. The first was taken at approximately 5:00 p.m. on December 12, and the second was taken a few hours later just after midnight December 13, since that is when the peak number of customers without power occurred on those days. After the first two days, the graphs become more representative of the speed of the restoration efforts, as the number of customers without power was more consistently measured at times shortly before midnight.

Table II-3 shows the peak number of customers who were still without power for each field crew deployed by each utility during each day of the event. It may be seen in Table II-3 that National Grid was consistently able to deploy more crews per customer without power than any of the other three utilities. This no doubt contributed to their ability to restore power to all their customers sooner than any of the other utilities.

It may also be seen that PSNH was able to deploy more crews at first than Unitil and NHEC, but on Day 3, Saturday, December 13, NHEC had fewer customers without power per crew than did PSNH. It was not until Day 6, Tuesday, December 16, that Unitil equaled PSNH in customers without power per crew deployed.

Table II-3-The number of customers without power for each field crew deployed. (blank spaces mean all customers had power)

Date	PSNH	Unitil	National Grid	NHEC
12/11	388	237	349	208
12/12	764	1,890	242	1,037
12/13	666	1,125	95	450
12/14	337	425	39	236
12/15	230	276	19	177
12/16	161	119	18	118
12/17	115	67	3	50
12/18	73	42	1	21
12/19	41	16		15
12/20	29	4		42
12/21	18			
12/22	17			
12/23	6			
12/24	4			

Table II-4 shows the number of customers restored for each crew-day worked by each utility over the entire storm restoration period. Taking an average of all the crews of all utilities, the average crew was able to restore 36 customers per day during the whole restoration period. The National Grid number in Table II-4 was lower than the other utilities. This was due to the fact that it was able to devote more crews per outage to the restoration effort than were the other utilities. National Grid kept this relatively large number of crews deployed until all customers were restored instead of reducing the number at the end of the restoration effort. Consequently, each crew had fewer outages to restore. This resulted in National Grid completing the restoration of its customers one week before PSNH restored power to all its customers. National Grid's advantage lies in the fact that it covers a very small area in New Hampshire with relatively few customers, as well as it being a relatively large company with more resources than the other utilities.

Table II-4-The number of customers restored for each crew-day worked.

PSNH	Unitil	National Grid	NHEC
34	57	23	86

Another way to look at Table II-4 is that it shows the obstacles each utility faced and the amount of damage each utility had to repair to restore its customers. NHEC's service area experienced less damage from the storm than that of PSNH, which is one reason it was able to restore more customers for each crew-day worked.

Analysis of the Resources Deployed

It is instructive to compare Table II-3 and Table II-4 with an understanding of the nature of the storm and the sizes of each utility. It is clear that National Grid devoted more resources per outage; on average it had 96 customers restored per crew, it restored power faster to its area, and restored fewer customers for each crew-day. This all indicates that National Grid devoted more resources to the restoration effort than did the other utilities, likely because it had more resources at its disposal due to the size of the company.

PSNH averaged 204 customers restored per crew, which was far less than National Grid, but still sufficient so that each crew had to restore only 34 customers per day. PSNH is much larger and serves more customers than Unitil or NHEC and has more resources at its disposal. Its area is also larger and was heavily damaged by the storm. PSNH tried, especially at the beginning of the restoration effort, to acquire more crews. Had it been possible to acquire crews more rapidly, the total length of the outage would have been reduced.

NHEC had on average 235 customers restored per crew, nearly the same as PSNH, and it restored 86 customers for each crew day. This high restoration rate may reflect the fact that most of its service area was more lightly damaged. However, it too could have benefited from additional crews if they had been available.

Unitil had on average 440 customers restored per crew, showing its lack of available man-power. However, it had a relatively high restoration rate of 57 customers restored per crew-day. This high restoration rate may be due to Unitil's service area being more densely populated than that of the other utilities. High customer density facilitates a crew's ability to restore many customers at once since several customers may all be without power due to a single failure. This makes it possible to restore large numbers of customers with a relatively small number of repairs. The result is that power is restored to more customers with less effort than would otherwise be possible if customers were spread out and extensive repairs were needed to restore each one.

If all four utilities had been able to devote the same resources per customer without power as National Grid was able to deploy, the following estimation of potential changes can be made to the duration of the restoration effort. On average for the whole storm, there were 850 crews working per day and 121,605 customers per day without power. During the restoration, National Grid supplied, on average, one crew for every 96 outages. If the other utilities had supplied sufficient crews to equal those of National Grid, then an average of approximately 1,270 crews per day would have been supplied statewide. If the utilities restored power at the same average rate of 36 customers per crew day (as was done during the storm), 45,720 customers would have been restored each day, resulting in all 432,632 customers who were without power at the peak of the storm being restored in approximately 9 1/2 days. It is reasonable to assume that if all the utilities could have supplied resources at the same rate and quantity as National Grid, all power would have been restored to the state approximately 4 days sooner than actually occurred.

Safety during the Storm

Throughout the restoration period, safety was appropriately emphasized by all of the utilities. Each utility has a safety plan for day to day operations to meet OSHA and other requirements for safety. These plans call for a daily safety meeting with all field employees to discuss known safety issues. These issues might change from day to day depending on the type of restoration work anticipated for that day. Even though this was an emergency situation, the existing safety plans were strictly followed during the restoration work. Throughout the restoration effort, personnel and public safety was remarkable in view of the fact that thousands of linemen and right of way workers were engaged. PSNH reported a total of 38 incidents involving personnel and equipment. None of the incidents were serious injuries or resulted in lost time during the restoration effort.[14] No safety incidents were incurred by any Unitil employee, Unitil contractor, or Unitil mutual aid company during the entire restoration effort.[15] Only one safety incident involving a National Grid employee was reported for the duration of the restoration effort in New Hampshire. The incident was not serious and did not impact restoration efforts. National Grid also reported only one vehicle accident. No damage resulted and there were no injuries.[16] [17] NHEC reported that one service contractor injured his lip when struck by a falling tree limb.[18] NHEC also reported five minor vehicle incidents, but none resulted in loss of use during the storm restoration period.[19]

Material Supply

One concern that occurs with many large storms is securing adequate material in a timely manner to support the repair effort. In general, this did not appear to be an issue for this storm. All four utilities were able to secure sufficient material from suppliers in a timely manner to keep the flow sufficient so as not to hamper the repair efforts. In short, the supply chain worked efficiently. None of the utilities experienced any difficulty acquiring the large quantity of materials and tools needed to make repairs. Despite the fact that many establishments were affected by the storm and did not have power themselves, none of the utilities experienced any significant difficulties with meals or lodging for the crews.[20] [21] [22] [23]

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[14] PSNH. (February 2, 2009). Data Response STAFF 1-45. NHPUC.
[15] Unitil. (February 27, 2009). Data Response STAFF 1-45. NHPUC.
[16] National Grid. (February 27, 2009). Data Response STAFF 1-45. NHPUC.
[17] National Grid. (February 27, 2009). Data Response STAFF 1-46. NHPUC.
[18] NHEC. (February 19, 2009). Data Response STAFF1-45. NHPUC.
[19] NHEC. (February 19, 2009). Data Response STAFF 1-46. NHPUC.
[20] Unitil. (February 27, 2009). Data Response STAFF 1-23, 24. NHPUC.
[21] National Grid. (February 27, 2009). Data Response STAFF 1-23, 24. NHPUC.
[22] PSNH. (February 2, 2009). Data Response STAFF 1-23, 24. NHPUC.
[23] NHEC. (February 19, 2009). Data Response STAFF 1-23, 24. NHPUC.

Economic Impact

The substantial economic impact of the December 2008 ice storm on the State of New Hampshire may never be precisely known due to the wide spread damage and loss of business and employment opportunities during the holiday shopping season. However, the financial impact reported by the local utilities, New Hampshire residents, and state and federal governments has shown this number to be in excess of $152 million. These reported losses are shown in Table II-5.

Table II-5 – The economic impact of the storm as reported for the State of New Hampshire.

Entity Reporting the Loss	Loss Value
NHEC[24]	$ 2,126,000
National Grid[25]	$ 2,565,000
PSNH[26]	$ 75,000,000
Unitil[27]	$ 3,196,665
FairPoint[28]	$ 4,788,090
TDS Communications[29]	$ 272,180
Division of Resources and Economic Development (DRED) (Private business losses) [30]	$ 11,370,000
FEMA Assistance to towns, municipal organizations, and non-profit organizations[31]	$ 17,874,000
Personal Insurance Claims[32]	$32,411,901
Commercial Insurance Claims[33]	$4,057,292
Cable TV Companies[34 35]	$1,633,900
Total Reported Losses	**$ 155,295,028**

[24] NHEC. (July 1, 2009). Data Response GN0012. NEI.
[25] National Grid. (July 2, 2009). Data Response GN0012. NEI.
[26] PSNH. (February 2, 2009). Data Response Staff 1-49. NHPUC.
[27] Sprague, K. Director of Engineering, Unitil. Interview by Mike Joyner. May 21, 2009.
[28] FairPoint.(July 8, 2009). Data Response Staff 6-1. NHPUC.
[29] TDS. (July 10, 2009). Data Response TE0041. NEI.
[30] Avery, D. DRED. Interview by Mike Joyner. June 30, 2009.
[31] Knepper, R. NHPUC. Interview by Malmedal K. 8-14-09.
[32] Knepper, R. NHPUC. "RE: Reported Numbers by Dept. of Insurance for Table II-5." E-mail to Nelson, J. August 19, 2009.
[33] Knepper, R. NHPUC. "Re: Reported Numbers by Dept of Insurance for Table II-5 ." E-mail to Nelson, J. August 19, 2009.
[34] Barstow, J.. "RE: Ice storm costs." E-mail to Bailey, K. July 21, 2009.
[35] Hodgdon, C. Director, Legislative Affairs, Comcast.. "RE: Comcast ice storm follow-up." E-mail to Bailey, K. August 17, 2009.

Storm Timeline

To understand the response of the utilities and their use of resources, a timeline of the storm event is useful. The information below was gathered from interviews, data responses, National Weather Service reports, and news reports. As nearly as may be determined from the amount and types of information available, the sequence of events is given below:

Day minus 2, Tuesday, December 9

Weather reports indicate a winter storm is likely in Upstate New York and New England.

PSNH- No known actions are taken.

Unitil- No known actions are taken.

National Grid- Conference call is held and crews are pre-staged to Albany, N.Y.

NHEC- No known actions are taken.

Day minus 1, Wednesday, December 10

Throughout the day the various professional weather forecasting services and the National Weather Service issue Winter Weather Advisories for possible ice accumulations of up to 1” in southwestern New Hampshire.

6:00 a.m.– PSNH receives first forecast of “possible significant icing” on Thursday.

6:25 a.m.– NHEC disaster recovery executive notifies its staff via e-mail of the impending storm. Managers and supervisors respond with crew availability reports. Contractor crews on standby are activated and requests for additional crews are issued.

8:00 a.m.– PSNH receives a report from its professional weather service of a:

“*Significant icing event possible on Thursday midday through Friday morning for portions of northwestern Connecticut, southwestern Massachusetts, and southwestern New Hampshire.”*

8:47 a.m. - PSNH issues an initial Weather Advisory to alert personnel about the possibility of an impending storm.

<u>Day minus 1</u>, Wednesday, December 10 (continued)

8:51 a.m. - National Grid Emergency Planning notifies Electric Distributions Operations of a potential ice event on Dec 11-12.

During the day, Unitil UES Capital and UES Seacoast Emergency Operations Centers perform pre-storm planning activities.

3:00 p.m. - National Grid holds its first system-wide storm conference call. It is noted amounts of ½ inch ice accretions are causes for serious concern. and ¾ inch of ice is projected from southwest portions of NH, northeast of Laconia and south to Manchester/Nashua area.

3:11 p.m. - Unitil receives from its professional weather service a forecast for its Seacoast/Capital areas of a Winter Storm Watch for Thursday afternoon through Friday afternoon with potential for significant icing from the foothills to interior coastal counties and heavy snowfall of 6 inches or more in the mountains and foothills.

5:10 p.m.- A National Weather Service forecast is issued for heavy ice pellets or freezing rain for Thursday night. The forecast states that the potential for a major ice storm exists but the most likely locations for ice in excess of 1" on horizontal surfaces are not yet known. Significant icing and ice pellets are expected for Jaffrey, Keene, Peterborough, Nashua, Weare and Manchester, New Hampshire. An ice storm warning is issued for Massachusetts and a winter storm warning is issued for New Hampshire. Also notes indicate "*This is a potentially dangerous situation with long duration power outages possible.*"

<u>Day 1</u>, Thursday, December 11

12:43 a.m.- The National Weather Service issues an ice storm warning, a flood watch is issued for Massachusetts, and a winter storm warning is issued for parts of Vermont.

6:00 a.m. to 9:00 a.m.- Freezing rain begins in Jaffrey, Concord, and Manchester, New Hampshire.

6:00 a.m.- National Grid receives from its professional weather service a forecast of: *"Potentially devastating ice storm… 3/4 to 1-inch likely with over an inch possible in some areas..."*

Day 1, Thursday, December 11 (continued)

7:12 a.m.- A forecast is issued for heavy accumulating ice with power outages expected for portions of Maine and New Hampshire. Freezing rain is expected to approach 1 inch over interior sections. Heavy ice accumulations are expected across portions of the coast and depending upon the weather pattern could be greater than 1/2 inch. High terrain areas (elevation 700 to 800 ft) could see "*crippling effect*"

8:30 a.m.- The Northeast Mutual Aid Group (NEMAG) conducts its first conference call, PSNH, Unitil, and National Grid attend. (NHEC is not a member of NEMAG.) The call revealed that all New England utilities anticipated the storm would impact their territories. A second call is scheduled for 6:00 a.m. on December 12.

8:34 a.m.- PSNH Customer Operations conducts a PSNH Storm Conference call and issued a Level I Emergency Planning Advisory. A weather advisory to alert customers is issued.

11:00 a.m.- New Hampshire State Emergency Operations Center (EOC) is open at Level I

New Hampshire Department of Safety, Homeland Security, and Emergency Management holds a conference call with the utilities.

11:52 a.m.- National Grid Emergency Planning contacts Field Assistant Strike Team members for mobilization assignments in Massachusetts and New Hampshire.

1:15 p.m.- Unitil issues a public service announcement (PSA) to warn employees, customers and public officials of the impending storm.

1:30 p.m.- National Grid holds second system-wide storm conference call.

In the afternoon, National Grid mobilizes ten contractor crews that are moved from Massachusetts and pre-staged to Lebanon to be ready to go to work at first light. Extra storm restoration materials are delivered to garages. Overnight crew trucks are fueled for the next day's restoration work.

During the afternoon, PSNH issues a Level II- Emergency Preparation Advisory

Day 1, Thursday, December 11 (continued)

4:28 p.m.- An ice storm warning is issued for western Massachusetts and southern New Hampshire. A winter weather advisory and flood watch are issued for eastern, northeastern, and western Massachusetts and an ice storm warning and flood watch are issued for central and eastern Massachusetts.

4:30 p.m.- New Hampshire State EOC escalates to Level II.

5:00 p.m.- Base Crews Available per Electric Utility

PSNH – 84 Line Crews, 11 Contractor Crews, 7 Digger Crews, 78 Tree Crews

Unitil – 11 Line Crews, 8 Contractor Crews, 0 Digger Crews, 4 Tree Crews

NHEC – 27.5 Line Crews, 5 Contractor Crews, 0 Digger Crews, 14 Tree Crews

National Grid – 11 Line Crews, 17 Contractor Crews, 0 Digger Crews, 6 Tree Crews

6:00 p.m.- Freezing rain begins at Lebanon, New Hampshire.

8:00 p.m.- Unitil opens its Division Emergency Operations Centers in Seacoast and Capital Districts.

9:00 p.m.- NHEC activates its EOC.

Unitil's Seacoast Division calls in crews and supervisors.

10:00 p.m.- Unitil's Capital Division calls in crews and supervisors

11:00 p.m.- PSNH issues a Level III Emergency Response Organization Activation and activates its EOC.

NHEC records 9,656 members without power.

Day 2, Friday, December 12

Midnight- National Grid opens its North Andover Division Storm Room.

PSNH records 67,530 customers without power.

Unitil records 5,450 customers without power.

National Grid records a peak of 15,000 customers without power.

Day 2, Friday, December 12 (continued)

2:00 a.m.-	National Grid opens its New England EOC in Northborough, MA
4:00 a.m.-	Key National Grid personnel told to report to EOC.
3:00 a.m. to 5:00 a.m.-	Freezing rain begins at Whitefield and Berlin, New Hampshire.
3:00 a.m. -	PSNH reports 200,000 customers with out power to NHPUC.
6:00 a.m.-	All four electric utilities begin damage assessment.
	Second NEMAG conference call, PSNH requests 250 crews, Unitil requests 30 crews, and National Grid also requests additional crews. At this time no additional crews are available from NEMAG.
	NHEC requests additional contract line crews and finds that none are available. NHEC contacts Northeast Public Power Association (NEPPA) and this call is also unsuccessful in obtaining additional crews. It gets commitments for six crews from three co-ops in New York, Vermont, and Maine. NHEC has 46.5 crews dispatched.(Alton- 4.5, Andover- 2.5, Meredith- 7, Ossipee- 4.5, Plymouth- 5.5, Raymond- 12, Sunapee- 10.5).
	PSNH has 205 crews dispatched (Southern Division (So.)- 79, Western/Central Division (W/C) - 68, Seacoast/North Division (S/N) - 47), Contract Crews – 11).
	National Grid has a peak of 24,164 customers without power and 59 crews are dispatched (16-Charlestown, 14.5-Lebanon, 28.5-Salem).
	Unitil records a peak of 37,800 New Hampshire customers without power and 20 crews are dispatched (8- UES Capital, 12 – UES Seacoast).
	NHPUC staff reports to State EOC.
6:50 a.m. -	Unitil reports 6,000 Capital and 29,000 Seacoast customers without power to NHPUC.
7:00 a.m.-	New Hampshire State EOC escalated to Level III.
9:00 a.m.-	NHEC records a peak of 48,230 members without power.
	Governor Lynch declares State of Emergency and activates National Guard.
10:00 a.m.-	Governor Lynch with NHPUC Chairman Getz holds conference call with senior executives of NHEC, PSNH, National Grid, Unitil, and Fairpoint.

Day 2, Friday, December 12 (continued)

11:30 a.m.- Unitil issues Advisory Notice describing the storm's impact and restoration operations are under way. Unitil continues to issue Public Service Announcements throughout the storm using media outlets, key community leaders, and using the company's Integrated Voice Response system.

12:00 p.m.- Third NEMAG conference call also included New York Mutual Assistance Group (NYMAG) and Mid-Atlantic Mutual Assistance (MAMA). PSNH again requests 250 crews, Unitil requested an additional 10 crews bringing the total requested to 40 crews, National Grid did not request additional crews.

PSNH was allocated 170 crews from the NEMAG call.

Unitil was allocated 40 crews from the NEMAG call.

2:00 p.m.- Unitil secured an additional six line crews out of Nashua, NH. Total crews committed to Unitil is 46.

3:00 p.m.- The first NHEC co-op crews requested at 6:00 a.m. arrives.

During the day National Grid begins posting news releases on its website with public service announcements.

5:00 p.m.- PSNH records a peak of 322,438 customers are without power and 422 crews have been dispatched. 217 additional crews have arrived during the day.

Unitil is informed 14 of the crews committed from NEMAG would not be available due to a resource shortage reducing committed crews to 31.

5:33 p.m.- New Hampshire Public Radio reports 24 shelters are open along with several warming stations.

11:59 p.m.- Precipitation has ended over the whole state of New Hampshire. Exact times and locations are unknown due to widespread outages interrupting power to automated recording weather stations.

Day 3, Saturday, December 13

12:00 a.m.- PSNH records 319,250 customers without power.

Unitil records 27,000 customers without power.

National Grid records 11,995 customers without power.

4:00 a.m.- NHEC records 26,078 members without power.

<u>Day 3</u>, Saturday, December 13 (continued)

6:00 a.m.-	PSNH has 479 crews dispatched throughout its system.
	NHEC has 58 crews dispatched on its system.
	Unitil has 24 crews dispatched on its system.
	National Grid has 126 crews dispatched on its system.
	PSNH uses contracted helicopter that was being used for transmission line repair prior to storm for damage assessment.
10:00 a.m.-	Governor Lynch holds second teleconference with senior management of NHEC, PSNH, National Grid, Unitil, and Fairpoint.
4:00 p.m.-	National Grid begins providing updates via its New England media hotline. Updates are provided each day at 6:00 a.m., 11:00 a.m., 4:00 p.m., and 9:00 p.m. Updates include the number of customers still without power.

<u>Day 4</u>, Sunday, December 14

12:00 a.m.-	PSNH records 202,360 customers without power.
	Unitil records 16,584 customers without power.
	National Grid records 5,991 customers without power.
1:00 a.m.-	NHEC records 13,579 members without power.
6:00 a.m.-	PSNH has 600 crews dispatched throughout its system.
	NHEC has 57.5 crews dispatched on its system.
	Unitil has 39 crews dispatched on its system.
	National Grid has 152 crews dispatched on its system.
	PSNH uses helicopter for damage assessment.
	President Bush declares State of Emergency in New Hampshire.
12:30 p.m.-	Unitil issues its first restoration update with numbers of customers out of service in each town served.

<u>Day 5</u>, Monday, December 15

12:00 a.m.-	PSNH records 151,769 customers without power.
	Unitil records 10,754 customers without power.
	National Grid records 2,695 customers without power.
6:00 a.m.-	PSNH has 659 crews dispatched on its system.
	NHEC has 68 crews dispatched on its system
	Unitil has 39 crews dispatched on its system.
	National Grid has 145 crews dispatched on its system.
	New England Cable News (NECN) reports 27 shelters are open in New Hampshire.
8:00 a.m.-	Governor Lynch holds meeting with senior executives of PSNH, Unitil, National Grid, NHEC, and FairPoiont.
9:36 a.m.-	Television station WMUR reports 56 shelters have been opened state wide with space for 6,000 people.
1:00 p.m.-	NHEC records 12,011 members without power.

<u>Day 6</u>, Tuesday, December 16

12:00 a.m.-	PSNH records 109,180 customers without power.
	Unitil records 8,807 customers without power.
	National Grid records 2,816 customers without power.
2:00 a.m.-	NHEC records 9,017 members without power.
6:00 a.m.-	PSNH has 679 crews dispatched on its system.
	NHEC has 76.5 crews dispatched on its system.
	Unitil has 74 crews dispatched on its system.
	National Grid has 157 crews dispatched on its system.
8:10 a.m.-	PSNH issues first estimated restoration time indicating when communities would be 95% restored.
9:00 a.m.-	NHEC issues first estimated restoration time for members without power.

Day 7, Wednesday, December 17

12:00 a.m.-	PSNH records 78,247 customers without power.
	Unitil records 4,952 customers without power.
	National Grid records 481 customers without power.
6:00 a.m.-	PSNH has 679 crews dispatched on its system.
	NHEC has 70 crews dispatched on its system.
	Unitil has 74 crews dispatched on its system.
	National Grid has 59 crews dispatched on its system.
9:00 a.m.-	NHEC records 3,492 members without power.
11:30 a.m.-	PSNH begins posting daily estimated restoration dates on its website.
	Snow showers during the day with snow totals of approximately 3 inches.

Day 8, Thursday, December 18

12:00 a.m.-	PSNH records 49,046 customers without power.
	Unitil records 3,176 customers without power.
	National Grid records 186 customers without power.
6:00 a.m.-	PSNH has 668 crews dispatched on its system.
	NHEC has 64.5 crews dispatched on its system.
	Unitil has 76 crews dispatched on its system.
	National Grid has 179 crews dispatched on its system.
7:00 a.m.-	NHEC records 1,380 members without power.
12:00 p.m.-	PSNH opens satellite emergency operations center in New Ipswich.
1:00 p.m.-	PSNH opens satellite emergency operations center in Peterborough, NH.
6:30 p.m.-	PSNH opens satellite emergency operations center in Fitzwilliam, NH.
10:19 p.m.-	National Grid records last customer power restored.

Day 9, Friday, December 19

12:00 a.m.-	Unitil records 1,250 customers without power.
5:00 a.m.-	PSNH records 34,150 customers without power.
6:00 a.m.-	PSNH has 833 crews dispatched on its system.
	NHEC has 52 crews dispatched on its system.
	Unitil has 76 crews dispatched on its system.
9:00 p.m.-	NHEC records 775 members without power.

Day 10, Saturday, December 20

12:00 a.m.-	Unitil records 325 customers without power.
6:00 a.m.-	PSNH has 917 crews dispatched on its system.
	NHEC has 17.5 crews dispatched on its system.
	Unitil has 83 crews dispatched on its system.
7:00 a.m.-	New Hampshire State EOC escalated to Level IV.
9:00 a.m.-	NHEC records 769 members without power.
4:00 p.m.-	PSNH records 26,218 customers without power.
	NHEC records last member power restored. Note some seasonal homes are inaccessible until Spring.
	Snow storm beginning on Day 9 ends with snow totals averaging 9 inches.

Day 11, Sunday, December 21

12:00 a.m.-	PSNH records 18,346 customers without power.
	Unitil records 36 customers without power.
6:00 a.m.-	PSNH has 1,020 crews dispatched on its system.
	Unitil has 82 crews dispatched on its system.
	Second snow storm in two days brings an additional 12 inches of snow to New Hampshire.

Day 12, Monday, December 22

12:00 a.m.-	PSNH records 17,460 customers without power.
6:00 a.m.-	PSNH has 1,017 crews dispatched on its system.
	Unitil has 34 crews dispatched on its system.

Day 13, Tuesday, December 23

12:00 a.m.-	PSNH records 5,618 customers without power.
6:00 a.m.-	PSNH has 968 crews dispatched on its system.
	Unitil has 20 crews dispatched on its system.
12:00 p.m.-	Unitil records last customer power restored.

Day 14, Wednesday, December 24

12:00 a.m.-	PSNH records 1,854 customers without power.
6:00 a.m.-	PSNH has 506 crews dispatched on its system.
1:00 p.m.-	New Hampshire State EOC returned to Level I.
6:00 p.m.-	PSNH records 99.9% of customer power restored. Some seasonal homes are inaccessible until Spring.

-End of Storm Response-

The following maps track the location of customers without power in New Hampshire following the storm and show the progress of the restoration effort. These maps were prepared by the NHPUC using data they recorded during the storm restoration. They are instructive because they show the general progression of the restoration patterns with the final customers being restored located at the very south-central part of the state which was the area most damaged by the storm.

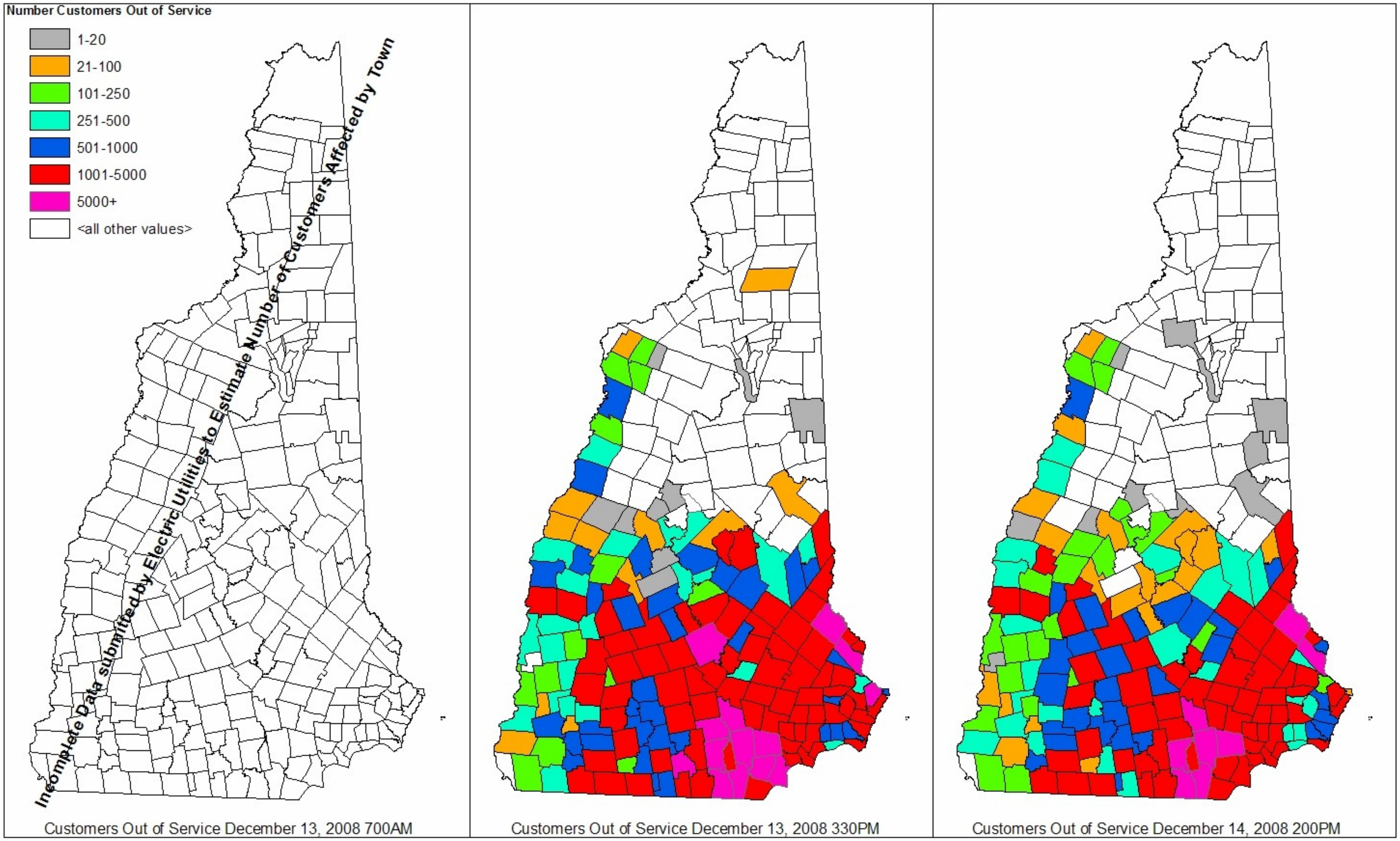

Figure II-4 – New Hampshire electric utility customers without power by municipality.

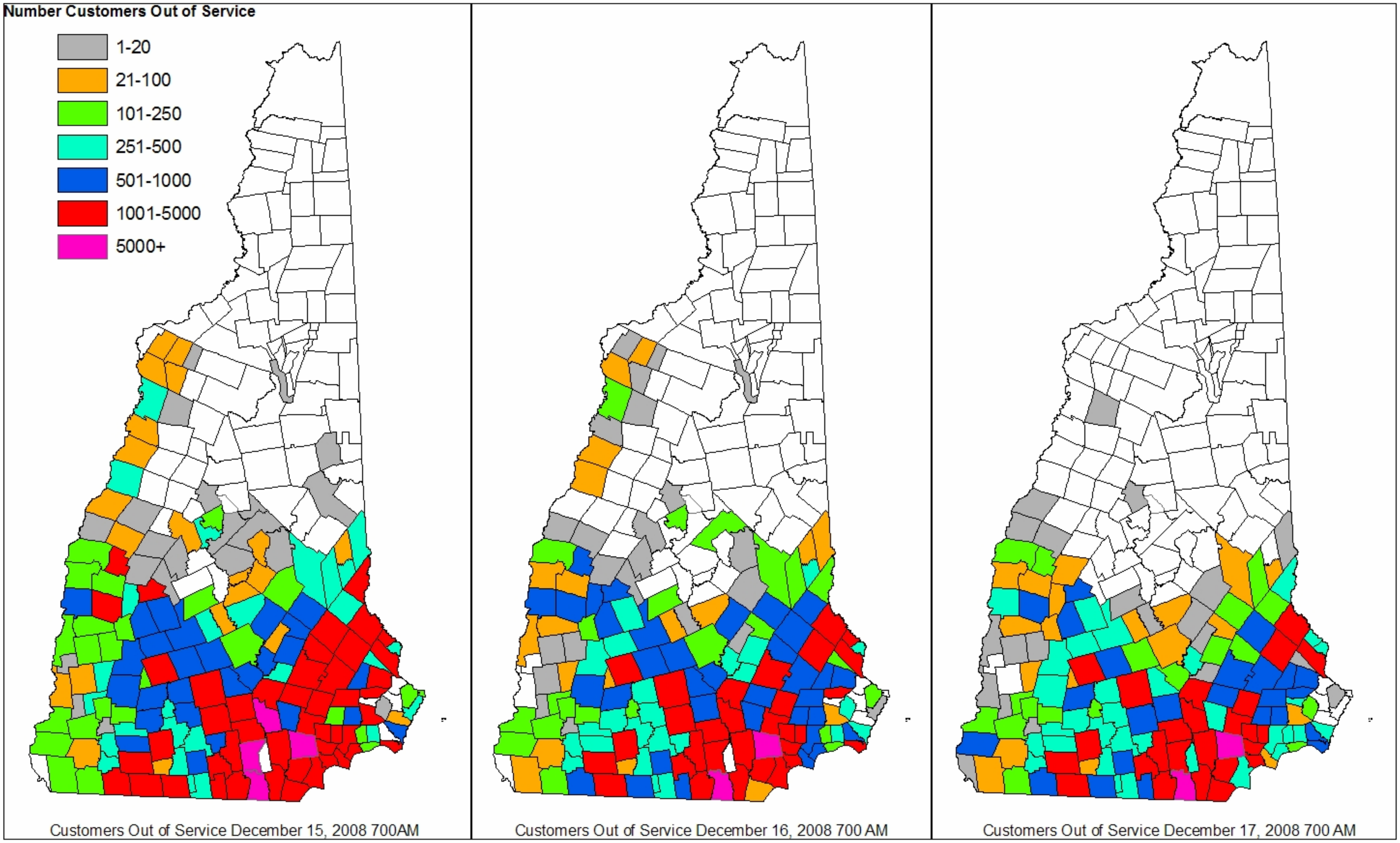

Figure II-5 – New Hampshire electric utility customers without power by municipality.

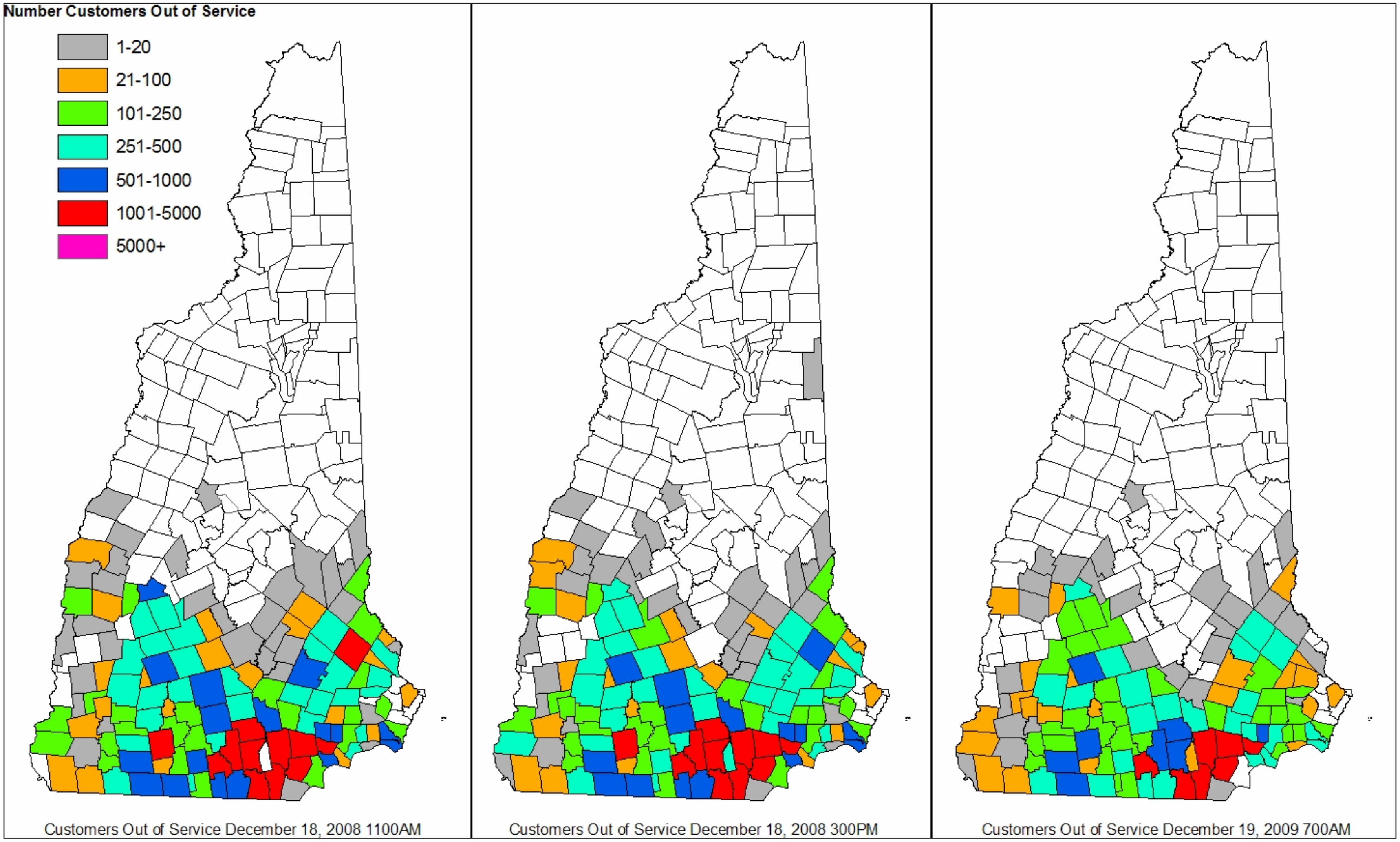

Figure II-6 – New Hampshire electric utility customers without power by municipality.

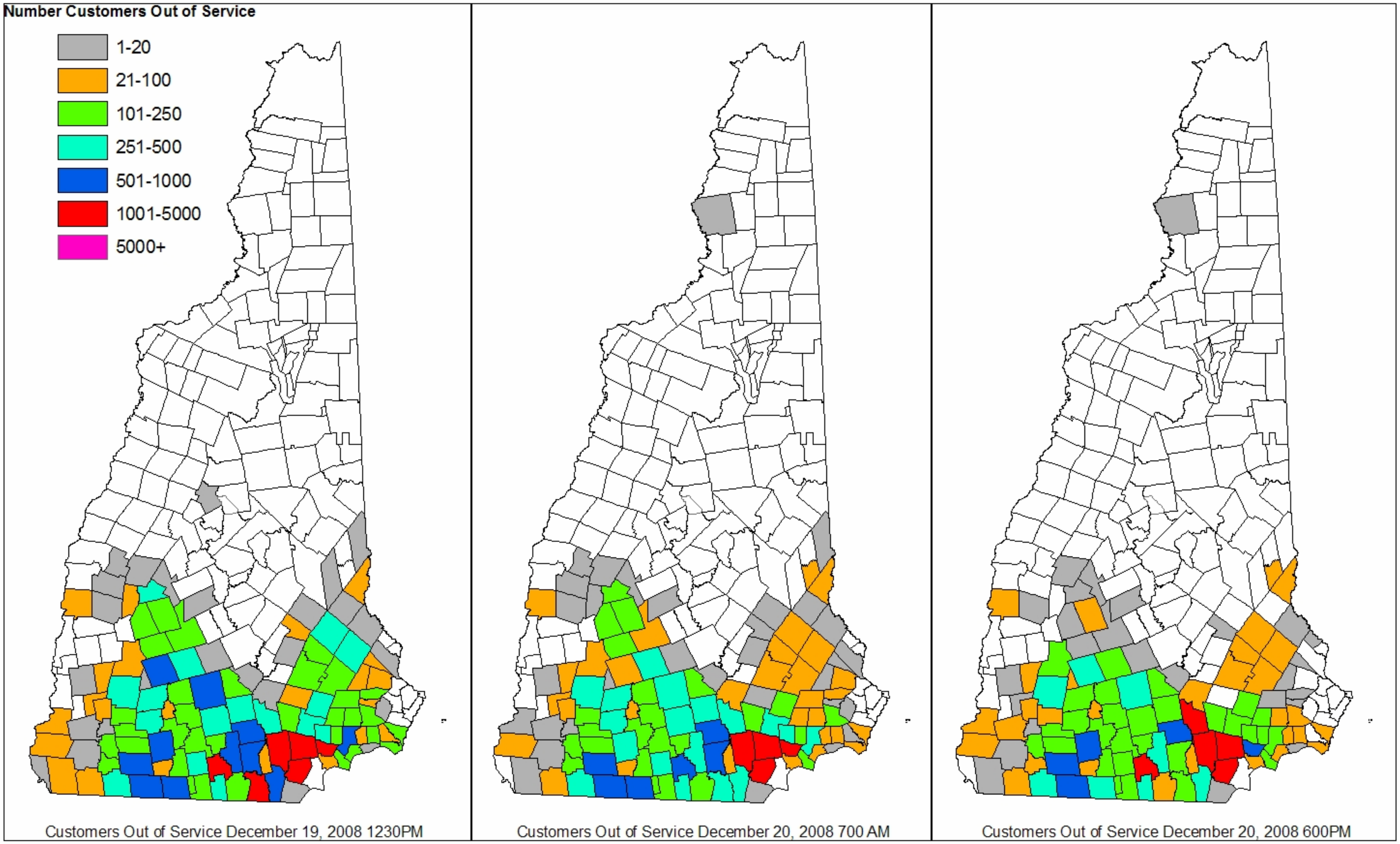

Figure II-7 – New Hampshire electric utility customers without power by municipality.

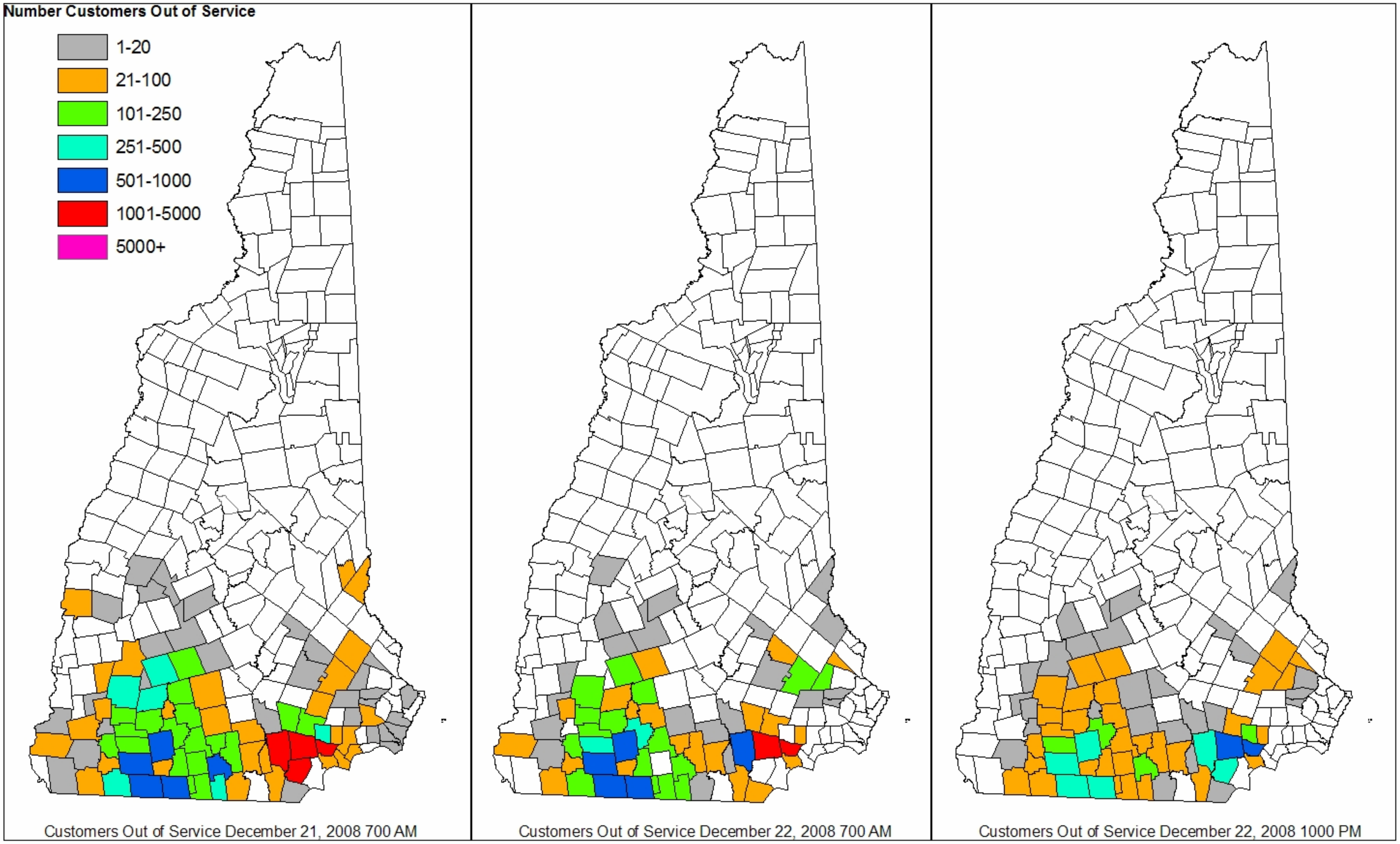

Figure II-8 – New Hampshire electric utility customers without power by municipality.

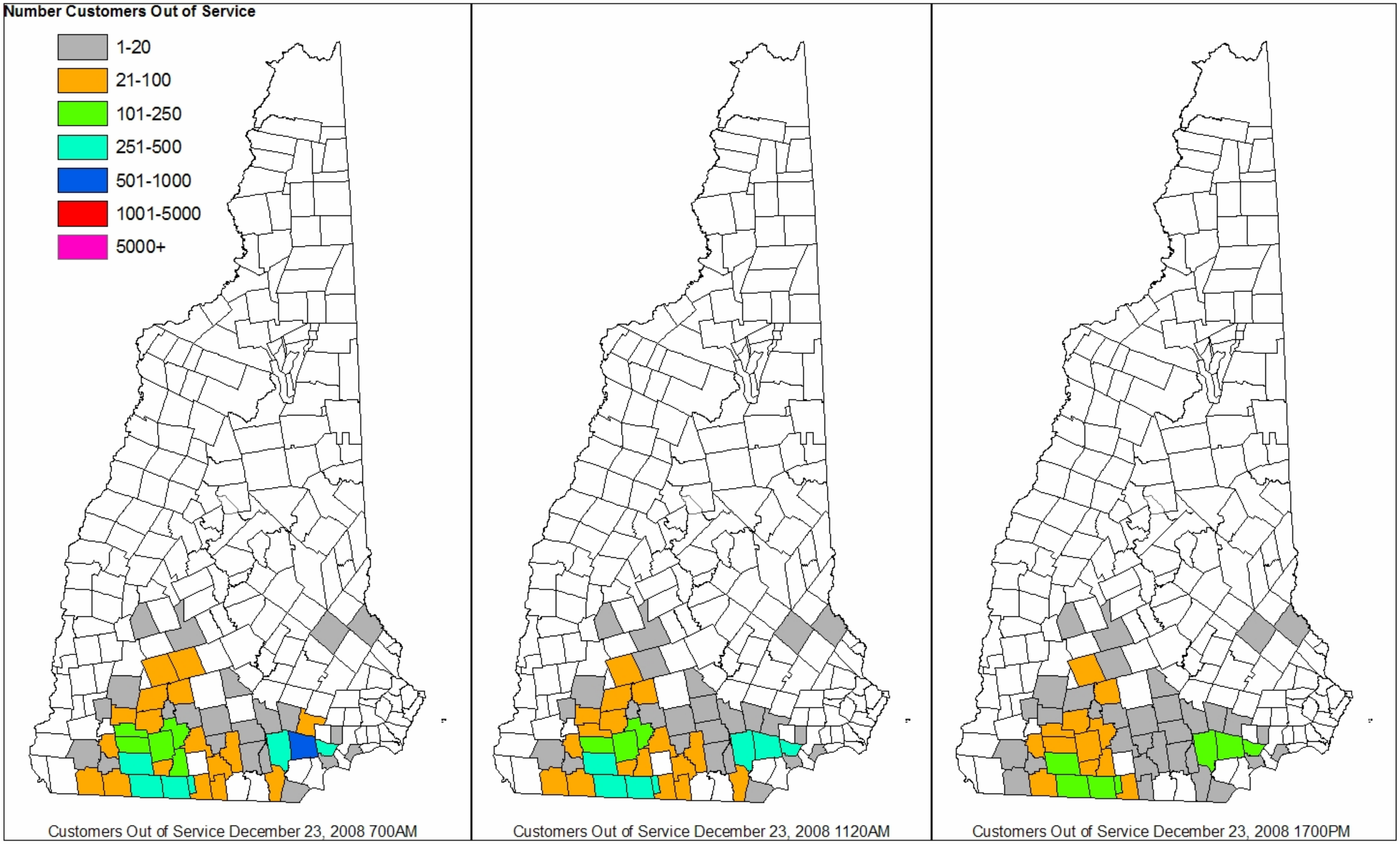

Figure II-9 – New Hampshire electric utility customers without power by municipality.

B. EVALUATIVE CRITERIA

The storm restoration efforts of each utility were evaluated using four specific criteria. These are:

1. The effectiveness of procedures for deploying resources.
2. The effectiveness of the mechanism for collecting and maintaining information on customer outages.
3. The efficiency of restoration efforts.
4. The timeliness and accuracy of external communication.

1. During storm restoration, the companies should have an effective process for deploying and managing both internal and external resources.

- Beginning with the first indication of an impending storm that is expected to cause power disruptions, each utility should immediately notify the appropriate personnel to prepare for a major storm. At minimum, the following staff should be notified:
    - Emergency operations center staff
    - Safety coordinators and training personnel
    - Work management and other information systems technicians
    - Logistics and materials managers
    - Customer call centers
- Damage assessment personnel should be pre-positioned to various locations in order to be able to provide a timely indication of storm damage.
- Customer call centers should begin ramping up staffing levels in order to prepare to handle incoming customer calls.
- Communications personnel should contact the news media, communities, and local officials following the first indication of the approaching ice storm.
- Calls to mutual assistance utilities and contractors should be made at the earliest possible moment.
- Operations managers should hold crews on location and develop restoration schedules before sending crews home.
- The utility should have effective systems and tools for developing estimates of damage and projecting outage durations and resource requirements.

2. The companies should have effective systems and tools for collecting and maintaining customer outage information.

- The information should be accurate.
- The systems should facilitate thorough collection of all available information regarding customer outages.

- The tools used by the utility should allow for regular updating and reassessment of the extent of damages and estimated restoration times.
- The information delivered should be consistent with that provided in external communications.

3. Storm restoration efforts should be efficient and effective.

- The utility should make use of all available intelligence to determine the extent of the damage and number of customers without power.
- The utility should activate its process for insuring public safety and relieving emergency personnel (police and fire) from responsibility for downed wires.
- System repairs should be made in an orderly and expeditious manner, with emphasis on restoring the largest number of customers in the least amount of time.
- Customer call centers should answer customer calls in a reasonable amount of time and call center representatives should be able to adequately respond to customer questions and inquiries. During the peak of the outage all customers may not be able to access either the integrated voice response system (IVR) or speak with a customer service representative (CSR) due to the large volume of calls, but with repeated calls every customer should be able to leave a message on the IVR system or speak with a CSR within a 3-hour period. As the restoration efforts progress the time to answer a customer's call should decrease.
- An effective process should be in place to constantly monitor, update, and eliminate old or incomplete outage information from outage management systems (OMSs).
- Orders should be closed out as work is completed in order to avoid a large decrease in remaining outages at the end of the work day.
- Record keeping should be sufficient to allow all managers and supervisors to be well apprised of the status of outages, conditions at other work centers, and local conditions in their respective areas of the system.
- Records should be sufficient to provide for a thorough reconstruction of restoration efforts and lessons learned assessment.

4. Communications with customers, local officials, state agencies, and the public should be adequate to provide timely and accurate information.

- The utility should designate a single point of contact and designate multiple backups so someone is always readily available for external communications.
- Updates should be provided to the news media on a regular basis and planned to coincide with the needs of customers and public officials.
- Executive managers should be fully cognizant of all information being provided in external communications.

- The utility should have an effective process for insuring public safety by communicating the locations of downed wires.

The following four tables indicate the extent to which each of the utilities met the criteria. These tables were not prepared to compare one utility with another. The four utilities are very different, face different problems, and experienced different amounts of damage to their systems. They were prepared to show where each utility may improve its performance in preparation for the next storm or other disaster. A further explanation for the improvements that are recommended to each of the utilities may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table II-6 - PSNH Storm Restoration Performance Evaluation Matrix

1) EFFECTIVE PROCESS FOR RESOURCE DEPLOYMENT	
Beginning with 1st indication of impending ice storm, companies should have immediately notified appropriate personnel to prepare. Contacts should have been made.	●
Damage assessment personnel should have been pre-positioned to various locations to provide timely indication of storm damage.	○
Customer call centers should have begun ramping up staffing levels to handle incoming customer calls.	○
Communications personnel should have contacted news media, communities & local officials following 1st indication of approaching ice storm.	○
Calls to mutual assistance utilities & contractors should have been made at earliest moment.	○
Operations managers should have held crews on location & developed restoration schedules before sending crews home.	◐
Company should have had effective systems & tools for developing estimates of damage & projecting outage durations & resource requirements.	◐

2) COLLECTION MECHANISMS FOR MAINTAINING CUSTOMER OUTAGES	
Information should have been accurate.	○
Systems should have facilitated thorough collection of all available information regarding customer outages.	○
Tools should have allowed for regular update & reassessment of extent of damages & estimated restoration times.	◐
Information should have been consistent with that provided in external communications.	○

3) EFFICIENCY OF RESTORATION EFFORTS	
Company should have made use of all available intelligence to determine extent of damage & real outages.	○
Company should have a process for ensuring public safety & relieving emergency personnel (police & fire) from responsibility for downed wires.	◐
System repairs should have been made in orderly & expeditious manner, with emphasis on restoring largest number of customers in least amount of time.	◐
Customer call centers should have answered customer calls in reasonable amount of time & call center reps should have been able to respond to customer inquiries.	◐
Effective process should have been in place to constantly monitor, update & eliminate old or incomplete outage information from outage mgmt systems.	○
Orders should have been closed out as work was completed to avoid large decrease in remaining outages at end of workday.	○
Recordkeeping should have been sufficient to allow managers & supervisors to be well apprised of status of outages & local conditions in their respective areas of system.	◐
Records should have been sufficient to provide for thorough reconstruction of restoration efforts & lessons learned assessment.	○

4) TIMELINESS & ACCURACY OF EXTERNAL COMMUNICATIONS	
Companies should have designated single points of contact (with multiple backups) for external communications.	●
Updates should have been provided to news media on regular basis & planned to coincide with needs of customers & public officials.	●
Executive managers should have been fully cognizant of all information being provided in external communications.	●
Companies should have had effective process for ensuring public safety by communicating locations of downed wires.	◐

Table II-7 - Unitil Storm Restoration Performance Evaluation Matrix

1) EFFECTIVE PROCESS FOR RESOURCE DEPLOYMENT	
Beginning with 1st indication of impending ice storm, companies should have immediately notified appropriate personnel to prepare. Contacts should have been made.	●
Damage assessment personnel should have been pre-positioned to various locations to provide timely indication of storm damage.	○
Customer call centers should have begun ramping up staffing levels to handle incoming customer calls.	○
Communications personnel should have contacted news media, communities & local officials following 1st indication of approaching ice storm.	○
Calls to mutual assistance utilities & contractors should have been made at earliest moment.	○
Operations managers should have held crews on location & developed restoration schedules before sending crews home.	●
Company should have had effective systems & tools for developing estimates of damage & projecting outage durations & resource requirements.	◐

2) COLLECTION MECHANISMS FOR MAINTAINING CUSTOMER OUTAGES	
Information should have been accurate.	○
Systems should have facilitated thorough collection of all available information regarding customer outages.	○
Tools should have allowed for regular update & reassessment of extent of damages & estimated restoration times.	○
Information should have been consistent with that provided in external communications.	○

3) EFFICIENCY OF RESTORATION EFFORTS	
Company should have made use of all available intelligence to determine extent of damage & real outages.	◐
Company should have a process for ensuring public safety & relieving emergency personnel (police & fire) from responsibility for downed wires.	◐
System repairs should have been made in orderly & expeditious manner, with emphasis on restoring largest number of customers in least amount of time.	●
Customer call centers should have answered customer calls in reasonable amount of time & call center reps should have been able to respond to customer inquiries.	◐
Effective process should have been in place to constantly monitor, update & eliminate old or incomplete outage information from outage mgmt systems.	○
Orders should have been closed out as work was completed to avoid large decrease in remaining outages at end of workday.	◐
Recordkeeping should have been sufficient to allow managers & supervisors to be well apprised of status of outages & local conditions in their respective areas of system.	◐
Records should have been sufficient to provide for thorough reconstruction of restoration efforts & lessons learned assessment.	○

4) TIMELINESS & ACCURACY OF EXTERNAL COMMUNICATIONS	
Companies should have designated single points of contact (with multiple backups) for external communications.	◐
Updates should have been provided to news media on regular basis & planned to coincide with needs of customers & public officials.	◐
Executive managers should have been fully cognizant of all information being provided in external communications.	●
Companies should have had effective process for ensuring public safety by communicating locations of downed wires.	◐

Table II-8 - National Grid Storm Restoration Performance Evaluation Matrix

1) EFFECTIVE PROCESS FOR RESOURCE DEPLOYMENT	
Beginning with 1st indication of impending ice storm, companies should have immediately notified appropriate personnel to prepare. Contacts should have been made.	●
Damage assessment personnel should have been pre-positioned to various locations to provide timely indication of storm damage.	●
Customer call centers should have begun ramping up staffing levels to handle incoming customer calls.	○
Communications personnel should have contacted news media, communities & local officials following 1st indication of approaching ice storm.	○
Calls to mutual assistance utilities & contractors should have been made at earliest moment.	○
Operations managers should have held crews on location & developed restoration schedules before sending crews home.	◐
Company should have had effective systems & tools for developing estimates of damage & projecting outage durations & resource requirements.	◐

2) COLLECTION MECHANISMS FOR MAINTAINING CUSTOMER OUTAGES	
Information should have been accurate.	◐
Systems should have facilitated thorough collection of all available information regarding customer outages.	○
Tools should have allowed for regular update & reassessment of extent of damages & estimated restoration times.	◐
Information should have been consistent with that provided in external communications.	◐

3) EFFICIENCY OF RESTORATION EFFORTS	
Company should have made use of all available intelligence to determine extent of damage & real outages.	◐
Company should have a process for ensuring public safety & relieving emergency personnel (police & fire) from responsibility for downed wires.	◐
System repairs should have been made in orderly & expeditious manner, with emphasis on restoring largest number of customers in least amount of time.	◐
Customer call centers should have answered customer calls in reasonable amount of time & call center reps should have been able to respond to customer inquiries.	◐
Effective process should have been in place to constantly monitor, update & eliminate old or incomplete outage information from outage mgmt systems.	○
Orders should have been closed out as work was completed to avoid large decrease in remaining outages at end of workday.	◐
Recordkeeping should have been sufficient to allow managers & supervisors to be well apprised of status of outages & local conditions in their respective areas of system.	◐
Records should have been sufficient to provide for thorough reconstruction of restoration efforts & lessons learned assessment.	◐

4) TIMELINESS & ACCURACY OF EXTERNAL COMMUNICATIONS	
Companies should have designated single points of contact (with multiple backups) for external communications.	●
Updates should have been provided to news media on regular basis & planned to coincide with needs of customers & public officials.	◐
Executive managers should have been fully cognizant of all information being provided in external communications.	●
Companies should have had effective process for ensuring public safety by communicating locations of downed wires.	◐

Table II-9 - NHEC Storm Restoration Performance Evaluation Matrix

1) EFFECTIVE PROCESS FOR RESOURCE DEPLOYMENT	
Beginning with 1st indication of impending ice storm, companies should have immediately notified appropriate personnel to prepare. Contacts should have been made.	●
Damage assessment personnel should have been pre-positioned to various locations to provide timely indication of storm damage.	○
Customer call centers should have begun ramping up staffing levels to handle incoming customer calls.	○
Communications personnel should have contacted news media, communities & local officials following 1st indication of approaching ice storm.	○
Calls to mutual assistance utilities & contractors should have been made at earliest moment.	◐
Operations managers should have held crews on location & developed restoration schedules before sending crews home.	◐
Company should have had effective systems & tools for developing estimates of damage & projecting outage durations & resource requirements.	●

2) COLLECTION MECHANISMS FOR MAINTAINING CUSTOMER OUTAGES	
Information should have been accurate.	●
Systems should have facilitated thorough collection of all available information regarding customer outages.	○
Tools should have allowed for regular update & reassessment of extent of damages & estimated restoration times.	◐
Information should have been consistent with that provided in external communications.	◐

3) EFFICIENCY OF RESTORATION EFFORTS	
Company should have made use of all available intelligence to determine extent of damage & real outages.	◐
Company should have a process for ensuring public safety & relieving emergency personnel (police & fire) from responsibility for downed wires.	◐
System repairs should have been made in orderly & expeditious manner, with emphasis on restoring largest number of customers in least amount of time.	◐
Customer call centers should have answered customer calls in reasonable amount of time & call center reps should have been able to respond to customer inquiries.	○
Effective process should have been in place to constantly monitor, update & eliminate old or incomplete outage information from outage mgmt systems.	◐
Orders should have been closed out as work was completed to avoid large decrease in remaining outages at end of workday.	●
Recordkeeping should have been sufficient to allow managers & supervisors to be well apprised of status of outages & local conditions in their respective areas of system.	◐
Records should have been sufficient to provide for thorough reconstruction of restoration efforts & lessons learned assessment.	○

4) TIMELINESS & ACCURACY OF EXTERNAL COMMUNICATIONS	
Companies should have designated single points of contact (with multiple backups) for external communications.	◐
Updates should have been provided to news media on regular basis & planned to coincide with needs of customers & public officials.	●
Executive managers should have been fully cognizant of all information being provided in external communications.	●
Companies should have had effective process for ensuring public safety by communicating locations of downed wires.	◐

C. TASKS

In order to fully examine the storm restoration efforts of the four largest New Hampshire electric utilities, NEI conducted interviews with utility managers and reviewed documents provided by the NHPUC Staff and the utilities. Specific tasks included the following:

- Review and evaluate the adequacy of each company's emergency procedures.
- Review the storm plans at the company and local level
- Review all storm related records, beginning with the first indication of the impending ice storm through the restoration of the last customer outage.
- Develop a detailed chronology of the storm restoration efforts of each company.
- Develop and review the work-down curves and compare them to other indicators such as staffing levels, customer call volume, and the number of remaining customers without power.
- Assess all service interruption reporting systems.
- Interview appropriate utility personnel associated with the outage.
- Interview public safety and municipal officials.
- Provide an overall assessment of each company's storm restoration efforts.

D. FINDINGS AND CONCLUSIONS

Conclusion: In the field, the utilities carried out an excellent tactical response to the December 2008 ice storm generally directing resources effectively once field crews were acquired, mobilized, and put to work.

In response to major weather events such as hurricanes and ice storms, electric utilities must mobilize a tremendous volume of resources in order to quickly rebuild transmission and distribution systems that are literally torn apart. In an era in which even a momentary power outage may cause economic losses and inconvenience to customers, these restoration efforts never seem to be fast enough. Nonetheless, all four New Hampshire electric utilities responded effectively once crews were acquired, mobilized and put to work. The effectiveness may be shown by the fact that over 40% of all customers without power were restored in the first day following the storm.

PSNH

On Day 1, Thursday, December 11, an internal weather advisory was issued at PSNH in response to forecasts for a major winter storm. Using a custom designed weather modeling tool developed for PSNH by Plymouth State University in 2004, the company determined that a major power outage event was likely to occur. The information given by this tool did not appear to provide better or more accurate information than was available from the weather services at the time, and did not appear to increase PSNH's early response to the storm. It is still in development and may at some time in the future provide useful data to predict the number of outages that may be expected from certain types of storms.

In accordance with its Emergency Response Plan, PSNH issued an Emergency Management Advisory on Day 1, Thursday, December 11 to begin preparations for the storm. Those preparations included:

- Alerting all personnel and planning for adequate staffing
- Fueling and stocking line trucks and other emergency response vehicles with necessary equipment
- Preparing for meals and lodging for field employees
- Stocking first aid equipment, road and circuit maps, flashlights, batteries, and office supplies
- Preparing reception areas and procedures for outside crews[36]

PSNH's central Emergency Operations Center (EOC) was activated at approximately 11:00 p.m. on Day 1, Thursday, December 11. At that time the typical compliment of 174 crews were already working to restore service to customers without power.

The EOC is the emergency command post, the headquarters for managing the storm and communicating with everyone inside and outside the company. It is the central location where information is gathered and from which the restoration effort is directed. The EOC would include representatives from all disciplines: operations, communications, customer service, logistics, etc.

An operating work center is a local point where a manager and whatever staff he has available work on storm restoration activities. It would include trucks, linemen, supervisors, damage assessors, and other types of crews and support personnel. The operating work centers would usually report in to the EOC. The crews actually work from work centers located in major areas of the territory served (fig I-4), and the EOC coordinates allocation of resources for the work dispatched from these centers.

By the time the EOC was activated power outages were already beginning to occur. Recognizing the magnitude of the storm, PSNH immediately requested help from other utilities and contract crews in New England. Unfortunately, because the storm was impacting the entire region, many of the contract crews in the area were already committed to helping other utilities. Those utilities were given priority under the regional Mutual Aid Agreement (agreements between utilities to aid each other in the case of emergencies) since they had sustained damage before PSNH.[37] As PSNH cast a wider net to solicit help from utilities along the East Coast, in the Midwest, and into Canada, local employees were mobilized to begin restoring power. Despite the efforts of over 400 PSNH crews working statewide by Day 2, Friday, December 12,

[36] PSNH. (March 24, 2009). New Hampshire Ice Storm 2008: Record Outage, Record Recovery, pg 10.
[37] See Conclusions No. 25, 26, and 27 in Chapter III of this report for additional information on mutual aid agreements.

the number of power outages continued to climb. By 5:00 p.m. more than 322,000 PSNH customers were without power. By Day 4, Sunday, December 14, more than 300 additional tree and line crews had arrived in New Hampshire to help restore power to PSNH customers. PSNH continued to focus its resources on clearing and repairing damaged lines that would restore the greatest number of customers in the shortest time. By nightfall on Sunday, crews had restored service to more than half of the PSNH customers who had lost power in the storm.[38]

During the next few days, crews continued to arrive from as far away as Maryland, Ohio, and Canada to augment PSNH's in-house staff of approximately 176 line and tree crews. By Day 9, Friday, December 19, more than 800 line, tree, and service crews were working for PSNH in New Hampshire. Power had been restored to more than 300,000 PSNH customers, about 89% of the customers that had been affected by the storm. By Day 10, Saturday, December 20, the last portion of restoration work had been completed in the Seacoast and northern regions of the state, and PSNH's restoration workforce had grown to more than 900 crews.[39]

PSNH is unique among electric utilities in New Hampshire in that it is responsible for service restoration up to and including the meter socket. In order to handle the large number of damages to customer premises equipment, PSNH hired more than 100 local electricians. During the first half of the restoration effort PSNH concentrated on restoring major lines and the medium voltage (above 1000V) system while also restoring services as they progressed. After many of the major lines were restored PSNH began hiring electricians on Day 7, Wednesday, December 17 to restore the low voltage services from the transformers to the customer's homes and businesses. This freed up linemen so they could continue with the major repairs to the medium voltage system while allowing the electricians to restore the low voltage services. They continued hiring additional electricians throughout the storm until the last service repair on Day 14, Wednesday, December 24.

In addition to the external electricians PSNH had service crews from multiple contractors and utilized some internal service crews. At its peak, PSNH had more than 130 service crews working to repair services. PSNH estimates that the electricians and service crews worked in excess of 11,100 crew hours and repaired more than 3,000 services. This approach kept line crews working on damaged circuits and resulted in the restoration of power significantly earlier than would have been possible if PSNH had relied exclusively upon its own line crews to perform the repairs.[40] Hiring outside electricians was a departure from PSNH's everyday operations but turned out to be an effective way to handle the responsibility PSNH has to restore the low voltage services to buildings. Moreover, the electricians were local and did not require food and lodging. While occurring relatively late during this outage, using local electricians

[38] PSNH. (June 29, 2009). Data Response PS0018. NEI.
[39] PSNH. (February 2, 2009). Data Response STAFF 1-22. NHPUC.
[40] PSNH. (February 2, 2009). Data Response STAFF 1-18. NHPUC.

during a large outage is something that should be included in PSNH's plans for response to future storms.

In the three areas where the storm damage was most severe PSNH activated additional satellite emergency operation centers to manage the efforts of the massive number of crews, support staff, and equipment. These areas were activated on Day 8, Thursday, December 18 and were located in Peterborough (operational at 1:00 p.m.), New Ipswich (operational at noon), and Fitzwilliam (operational at 6:30 p.m.), New Hampshire. These satellite EOCs were staffed by personnel from Division EOCs which were moved from the Northern/Seacoast Division of PSNH after power had been restored at those locations and there was no longer a need for the Division EOCs. Resources were also moved from areas that were already restored to areas still needing attention. In the final three days of restoration, Days 12-14, December 22-24, PSNH's workforce totaled more than 1,000 crews, who worked around the clock to restore service to nearly 20,000 PSNH customers who were still without power. These repairs were particularly time-consuming, as most of the remaining outages had been caused by damage to equipment that served just one residence or a small pocket of homes. PSNH was able to restore power to more than 99.9 percent of its customers by 6:00 p.m. on Day 14, Wednesday, December 24.[41] Figure II-10 shows the total number of crews PSNH had working on its system each day of the restoration effort compared to the peak number of customers without power. The graph indicates that the number of field crews did not reach its maximum until ten days after the storm. If more of the field crews had begun working on the system sooner, it is likely that the restoration would have been completed earlier.

[41] PSNH. (February 2, 2009). Data Response STAFF 1-25. NHPUC.

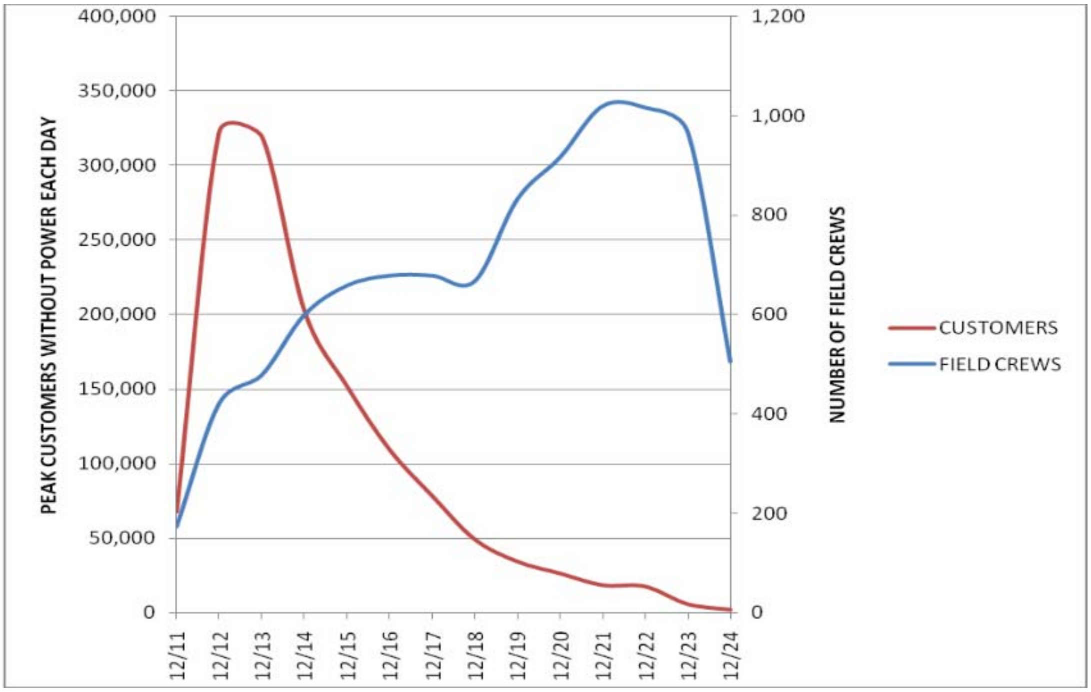

Figure II-10 – Graph showing the number of PSNH field crews and customers without power following the ice storm.[42] [43]

The slope of the customers graph in Figure II-10 indicates the rate at which customer power was being restored. Ideally, if the utility had the philosophy of restoring as many customers as possible in the shortest amount of time this graph would be the steepest right after the storm when the restoration efforts began and would gradually flatten out as fewer and fewer customers were without power and more effort was needed to restore each customer. In other words, it would normally be expected that power would be restored to the most customers immediately after the storm and the rate of restoration would gradually decrease. Ideally the utility should dedicate sufficient resources so that the customer line in Figure II-10 would be a smooth curve, and descend at the steepest rate possible allowing for the available resources.

While it is generally true that the customer curve in Figure II-10 is smooth and gradually flattens as expected, showing that PSNH deployed crews in such a way that the rate of restoration was as expected, the response on Day 2, Friday, December 12, to Day 3, Saturday, December 13, appears to be unusual. The flattening of the curve on Day 2 is merely an artifact of the way data was recorded and shown. Since the data shows the peak number of customers without power on each day, these numbers may not be taken exactly 24-hours apart, which is the case for the data on Day 2. This makes it appear that rate of restoration was much slower than it was in truth.

Another anomaly seen in the customer curve of Figure II-10 is that the slope once again changes on Day 12, Monday, December 22. This occurred at the same time that the number of crews was

[42] PSNH. (February 2, 2009). Data Response STAFF 1-22. NHPUC.
[43] PSNH. (February 2, 2009). Data Response PS0019. NEI.

decreasing. This may be an indication that PSNH began releasing crews slightly too quickly, mutual aid crews were recalled by their own company, or outside crews were leaving to be home for the holidays. PSNH could have used the additional help for another day. This effect is minor and may represent only a few hours in the time needed to restore all customers' power.

Unitil

Unitil's System Dispatchers as a standard practice review the weather hourly. When a storm front is predicted a weather advisory e-mail message is sent to key personnel within the company. Based on the content of weather advisories Unitil's Director of Electric Operations scheduled several conference calls with the electric system managers and other operating personnel to discuss the impending storm. The purpose of each of the calls was to assess the current weather forecasts and determine the potential impact to Unitil's electric system and to discuss pre-storm readiness activities including notifying all operations staff and line personnel of the potential for widespread outages.

The electric systems managers also notified Unitil's contract line crews that the company was in storm readiness mode. If a contactor crew is working on Unitil's system, and a storm or other emergency is anticipated that could cause damage to the electrical system, Unitil has the right of first refusal for the services of that contractor. In other words, if a contractor is currently engaged by Unitil in Unitil's territory and its services are requested by another utility, the contractor is obligated to complete the work required on Unitil's system until "released" by Unitil to the other entity.[44] During 2008 Unitil had an average of 16 contract line and tree crews[45] working for it. At the time the storm began on Day 1, December 11, Unitil had 23 crews available both contract and employed by Unitil.

Also on December 11, e-mail communications were sent to key management personnel informing them that operations personnel would be needed to help with the storm restoration effort. Unitil then issued a pre-storm Public Service Announcement (PSA) at 1:15 p.m. on December 11 which went to an extended list of employees and managers, a list of public officials, and was posted on the Company website. This announcement stated that due to the ice storm warning Unitil had put its personnel and emergency crews on alert and that all customers were advised that the storm could cause short power outages that night and the next day. Customers were also notified that it was possible that extended outages could occur and then listed telephone numbers for customers to call if they were without power.[46]

Unitil's restoration effort was led by the Director of Electric Operations with the Distribution Operating Center (DOC) managers each serving in the capacity of Restoration Coordinator or Manager in their respective divisions. The DOC managers assumed responsibility for the day-to-

[44] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 19.
[45] Unitil. (February 27, 2009). Data Response STAFF 1-15.NHPUC.
[46] Unitil. (March 27, 2009). Data Response STAFF 2-15.NHPUC.

day conduct of damage assessment, prioritization of repair work, and dispatch of Unitil and outside crews during the restoration effort. Unitil appropriately adhered to the restoration priorities set forth in its emergency response plans, working down the priority list instead of dispatching crews to individual trouble locations as would typically occur in a smaller outage. The restoration effort proceeded from the very top of the priority list starting with the substations and then proceeding to individual circuits, until crews and electricians were finally restoring individual services to customers. Crews were first focused on substations and began working downstream, repairing the main circuits first.[47]

To the extent possible, tree crews proceeded in advance of bucket crews. Repairs to circuits usually required clearing and isolating all side taps, laterals, and downstream circuits before the mainline portions could be energized. Crews then began the process of restoring increasingly smaller portions of circuits and, similar to what was experienced by the other utilities, as the restoration progressed more effort was needed per customer to restore power.

The typical number of Unitil crews for an average day in New Hampshire is approximately 20. Unitil eventually amassed a restoration workforce composed of approximately 19 internal line and tree crews and 64 external crews that amounted to a total of 83 at its peak on Day 10, Saturday, December 20.[48] Service was restored to the last of Unitil's New Hampshire customers in the Capital Division on Day 10, Saturday, December 20 and in the Seacoast Division on Day 13, Tuesday, December 23.[49] Figure II-11 shows the total number of crews Unitil had working on its system each day of the restoration effort compared to the peak number of customers out of power on that day. The graph indicates that the peak number of crews working on Unitil's New Hampshire system did not reach its maximum until ten days after the storm began. As discussed further in the conclusions below, restoration could have been completed sooner if the additional crews had been acquired earlier. Unitil had fewer crews dispatched per outage than any of the other utilities until Day 6, Tuesday, December 16, when it finally procured enough crews to equal PSNH and NHEC. Of the four utilities Unitil could have benefited the most from additional crews.

[47] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 39.
[48] Unitil. (February 27, 2009). Data Response STAFF 1-22.NHPUC.
[49] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 43.

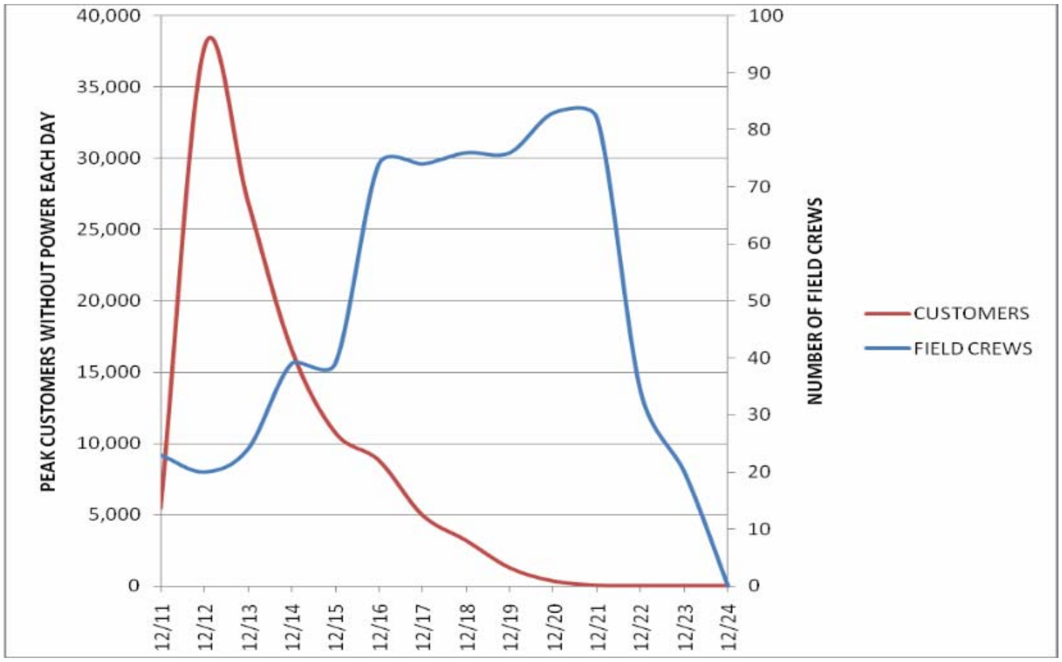

Figure II-11 – Graph showing the number of Unitil field crews and customers without power following the ice storm.[50] [51]

Figure II-11 clearly shows the difficulty that Unitil had in quickly acquiring enough crews. The field crews curve flattens out on December 16 showing they stopped acquiring additional crews even when the rate of restoration decreased as shown on the customer graph for this date. If more crews were available they should have continued acquiring them. While this hurt the speed of their restoration effort the customers graph shows that the crews that were available efficiently restored customers at a rate that would be expected until December 16 at which time the restoration rate slowed.

[50] Unitil. (February 27, 2009). Data Response Staff 1-22. NHPUC.
[51] Unitil. (July 9, 2009). Data Response UT0011. NEI.

National Grid

National Grid began preparation several days ahead of the December 2008 ice storm by alerting key personnel with advance weather warnings, holding emergency response team conference calls (the first on Wednesday, December 9) and staging company line crews in the Albany, NY, area so they would be available to the National Grid utilities as needed. All four utilities appeared to have similar warnings about the storm, but National Grid acted on these warnings sooner and began its preparation for the storm a full day before the other utilities. This preparation helped it to respond more quickly once the storm occurred and its scope became apparent. The early planning allowed it to allocate more assets per outage than any of the other utilities and the resources directed to New Hampshire caused it to be the first of the four utilities to restore power to all its customers.

By midday on Day 1, Thursday, December 11, National Grid's Customer Operations organization issued orders to pre-position crews and extra storm restoration materials throughout the northern portions of its New England service territory. A total of ten contractor line crews were transferred from its Massachusetts service area to Lebanon, New Hampshire during the afternoon of December 11, in the event that travel on the following day was hampered by the ice.[52] Key emergency restoration personnel were told at 4:00 a.m. on Day 2, Friday, December 12, by National Grid's Vice President of Customer Operations to report to the Emergency Operations Center. Damage assessment personnel were notified to be ready to begin examining the New Hampshire system at 6:00 a.m. on Day 2, Friday December 12.[53] [54]

Also on Thursday, December 11, National Grid's Materials Management organization verified an appropriate level of inventory and contacted vendors to arrange for an uninterrupted supply of stock. The Fleet Services organization fueled all trucks overnight so that line crews could begin to restore service at daybreak. National Grid's bargaining unit contract calls for linemen to work up to 18 hours per day, with the objective being to allow for 6 hours for rest. The other three utilities also had agreements with their employees to allow for similar working hours. During the restoration effort, National Grid kept two or three crews active at night, in order to maintain an around the clock presence and be prepared to clear unsafe conditions that may emerge.[53] [54]

National Grid's customer outages peaked on Day 2, Friday, December 12, at 24,164 customers. By the end of Day 3, Saturday, December 13 more than half had been restored and by the end of Day 4, Sunday, December 14, less than 6,000 customers were still without power. National Grid was the first utility to get all customers restored, with restoration officially complete at 10:19 p.m. on Day 8, Thursday, December 18.[55] While it is true that National Grid had fewer customers without power than any of the other utilities, it is also true that they allocated far more

[52] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 7.
[53] Kearns, R. Director Emergency Planning, National Grid. Interview by Joyner, M. June 9, 2009.
[54] Demmer, K. Manager Electric Distribution New Hampshire, National Grid. Interview by Joyner, M. June 9, 2009.
[55] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 10.

resources per outage to the restoration effort than the other utilities did. They also began planning for the storm sooner than the other utilities. This is why National Grid representatives rightly attribute the relatively early restoration of their system to heavily applying resources, having a good plan, doing early damage assessments, getting help from outside the utility, and cooperating with the municipal officials and agencies.[56] [57] To augment its internal staffing of approximately 20 line and tree crews, National Grid received all the crews it needed.[58] [59] Nonetheless, as discussed in the conclusions, if the additional crews had arrived sooner, it is likely that restoration would have been completed sooner. Figure II-12 shows the total number of crews National Grid had working on its system each day of the restoration effort compared to the peak number of customers out of power.

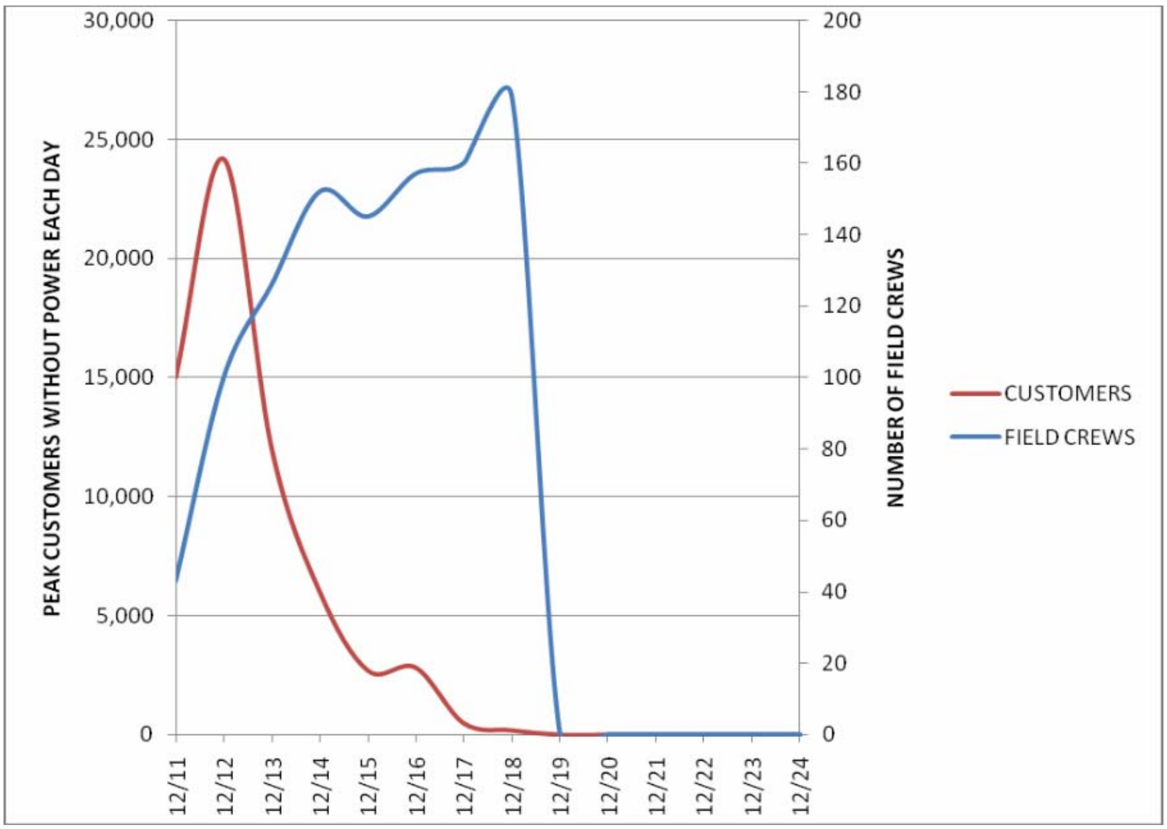

Figure II-12 – Graph showing the number of National Grid field crews and customers without power following the ice storm.[60] [61]

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[56] Kearns, R. Director Emergency Planning, National Grid. Interview by Joyner, M. June 9, 2009.
[57] Demmer, K. Manager Electric Distribution New Hampshire, National Grid. Interview by Joyner, M. June 9, 2009.
[58] Sankowich, S. M. Manager Vegetation Management Strategy Asset Strategy & Policy, National Grid. Interview by Joyner, M. May 8, 2009.
[59] Ramsey, J. Manager Senior Arborist, National Grid. Interview by Joyner, M. May 8, 2009.
[60] National Grid. (February 27, 2009). Data Response STAFF 1-22. NHPUC.
[61] National Grid. (June 23, 2009). Data Response NG0021. NEI.

The field crew curve in Figure II-12 shows that National Grid procured field crews more quickly than did the other utilities and the slope of the curve is steeper for a longer period of time than the other utilities. The customer curve decreases at a rapid and expected rate until December 15 when the number of customers without power increased slightly. This was due to the fact that some line switching was needed which resulted in some previously restored customers being taken back out of service for a short time so additional work could be done to adjacent lines serving other customers. It was safety related switching and was unavoidable. In general National Grid received sufficient resources and put them to work effectively and quickly and this is reflected in the slope of both the customer and field crew graphs.

NHEC

Early on Day -1, Wednesday, December 10, in response to the weather forecasts, NHEC's Disaster Recovery Executive issued a statement via e-mail to ensure that all NHEC staff was aware of the impending storm. The message pointed out that the potential existed for heavy snowfall in the mountains and foothills and significant amounts of freezing rain and sleet in the southern areas of New Hampshire. A response was sent back by managers and supervisors identifying employees who were available for storm duty. Supervisors also reviewed their emergency checklists for vehicles, materials, fuel and equipment to ensure they were well supplied and ready.[62] Contract crews, which included line and tree crews, were put on notice.[63]

NHEC has a continuously staffed control center located in Plymouth, NH. The control center is responsible for notifying the Disaster Recovery Executive when weather reports or customer outage calls indicate an approaching storm. In each of NHEC's 10 operating districts, a line crew is kept on call to respond to customer outage calls. When outage calls become too numerous for one crew, additional crews are called in to work. Outage reports received during the night on Day 1, Thursday, December 11 and early morning December 12, rapidly exceeded the capability of available trouble crews in six of NHEC's districts. Based on a call from the control center during the late evening of Day 1, Thursday, December 11, the Disaster Recovery Executive activated NHEC's Emergency Operations Center (EOC) at 9:00 p.m.[64]

NHEC members without power peaked on Day 2, Friday, December 12 at 48,230 members.[65] By Day 5, Monday, December 15, NHEC had 68 crews working on its system and had reduced the number of members without power to 12,011. On Day 6, Tuesday, December 16, the NHEC storm restoration workforce peaked at 76.5 crews.[66] Late on Day 9, Friday, December 19, NHEC had completed repairs to all known major outages and reduced the number of members still out of power to 90. Later that night a tree on a wire caused another 658 members to lose

[62] NHEC. (February 19, 2009). Data Response STAFF 1-8. NHPUC.
[63] NHEC. (February 19, 2009). Data Response STAFF 1-10. NHPUC.
[64] NHEC. (June 18, 2009). Data Response CO0006. NEI.
[65] NHEC. (June 22, 2009). Data Response CO0007. NEI.
[66] NHEC. (February 19, 2009). Data Response Staff 1-22. NHPUC.
Note: NHEC crews normally consist of 2-3 line workers. Less than the full complement represents a half crew.

power. Those members were restored early morning on Day 10, Saturday, December 20, leaving only scattered outages, primarily related to individual service lines.[67]

NHEC is responsible for attaching overhead service drops to the weather head at customer premises. This presented a significant challenge to the restoration effort because a large number of service lines were damaged during the ice storm. NHEC handled more than two hundred service orders for damaged service lines and also repaired many that were found and not recorded. NHEC used in house electricians and other licensed and experienced employees to make these repairs in parallel with other efforts so the overall restoration process would not be delayed.[68] [69] [70] Customers were notified if problems existed that were not the responsibility of NHEC so that they could be corrected and power safely restored.[71] The situation where the utility is responsible for the service drop is somewhat unusual among utilities. Typically the utility is responsible for installing the medium voltage equipment (above 1000 Volts) and the transformer which steps the voltage down from medium to low voltage and the service drop to the customer's weather head/service mast. The customer is responsible for providing the connection between the service drop and the meter and an electrician the customer hires normally takes care of this connection. To be consistent with what is typically done nationally, and what is done in New Hampshire (except for PSNH) we suggest that NHEC crews in future concentrate on repairing the medium voltage distribution system and let customers privately take care of their low voltage system from the service drop to the meter.

Service was restored to the last NHEC member without power during the afternoon of Day 10, Saturday, December 20.[72] Figure II-13 shows the total number of crews NHEC had working on its system each day of the restoration effort compared to the peak number of customers out of power.

[67] NHEC. (February 19, 2009). Data Response STAFF 1-42. NHPUC.
[68] Gosney, W. Executive Vice President, NHEC. Interview by Joyner, M., June 17, 2009.
[69] Bakas, J. Vice President of Engineering and Operations, NHEC. Interview by Joyner, M. June 17, 2009.
[70] Lynch, H. Disaster Recovery Executive, NHEC. Interview by Joyner, M. June 17, 2009.
[71] NHEC. (February 19, 2009). Data Response STAFF 1-18. NHPUC.
[72] NHEC. (February 19, 2009). Data Response STAFF 1-25. NHPUC.

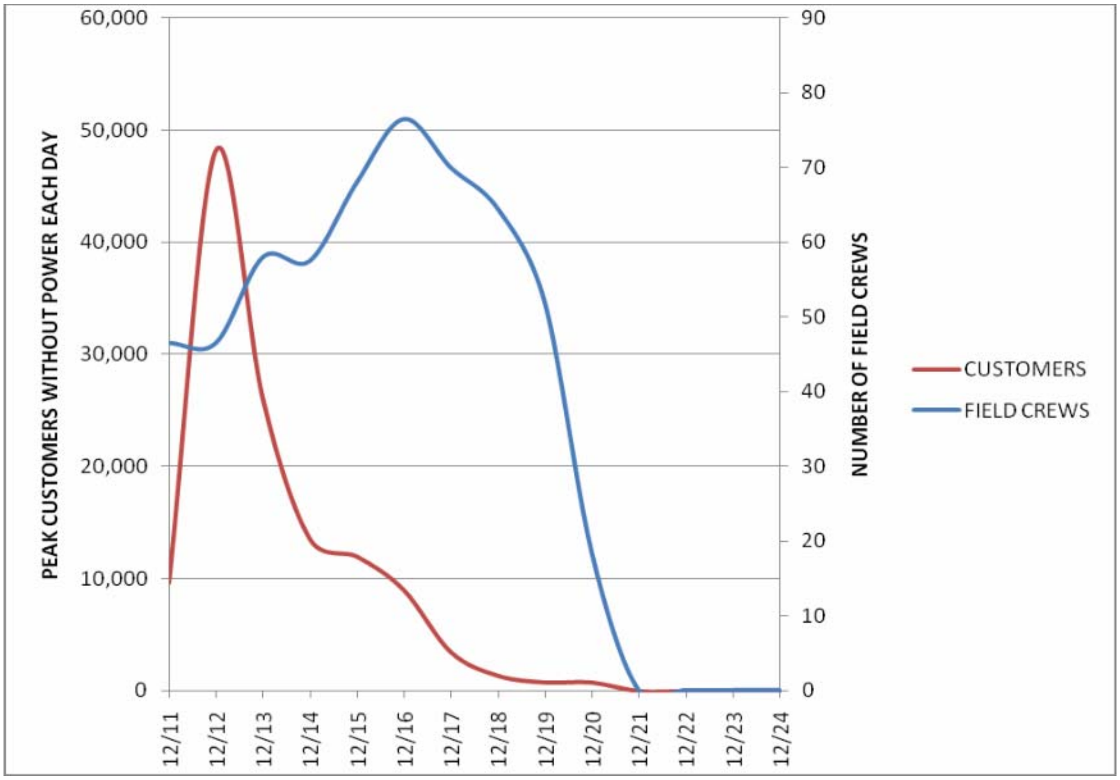

Figure II-13 – Graph showing the number of NHEC field crews and customers without power following the ice storm.[73] [74]

The curves on the above graph indicate that the maximum number of crews working on NHEC's system occurred on Day 6, December 16, four days after the peak number of customers without power. The field crew graph shows a slower than desirable rate of the ramp-up of crew numbers and this is reflected in a flattening of the customer graph after December 14, when the number of crews held steady and then began to increase again on December 15. This is an indication that NHEC would have benefitted by having more crews working after December 14 and the slow increase in the number of crews working hampered the speed of restoration. As discussed further in Conclusion 5, if the line and tree crews had been put to work sooner, it is likely that restoration could have been completed earlier.

Conclusion: At Unitil, the restoration strategy during the ice storm was inappropriate.

The restoration strategy at Unitil[75] during the December 2008 ice storm was to attempt to get all customers restored at the same time. The other three utilities try to restore customers as rapidly as possible which means that some customers who are more isolated or on systems with more damage, may wait longer for power to return. The philosophy of Unitil may impede the rate at which customers are restored. This may be an issue in making the customer curve in Figure

[73] NHEC. (June 22, 2009). Data Response CO0007. NEI.
[74] NHEC. (February 19, 2009). Data Response STAFF 1-22. NHPUC.
[75] Unitil. (February 27, 2009). Data Response STAFF 1-47. NHPUC.

II-11 shallower at the beginning of the storm than those of Figure II-12 and Figure II-13 since the rate of restoration is slower. If all customers were indeed restored at the same time the graph would be horizontal until the final day at which point it would be vertical. A philosophy of restoring the largest number of customers as quickly as possible would make the customer graphs in Figure II-11 steeper and more exponential, and Unitil's philosophy of restoring all customers at once would make this graph less steep and more horizontal.

The fact that all of the customer graphs including Unitil's show a relatively steep exponential shape indicates that the philosophy of Unitil is impractical to achieve and probably an inappropriate goal. To achieve this goal would mean that some customers who could be restored quickly with little effort may have to wait until resources have also restored more heavily damaged customers.

The de-facto result of the restoration efforts by all the utilities in this storm is that many customers were restored at the beginning of the effort. Customers receiving more damage or who were more remote and difficult to reach waited longer, which is why the customer curves in the graphs flatten out at the ends. It is clear from the graphs that Unitil's philosophy of trying to restore all customers at the same time was not carried through even though they may have tried. In reality it would be impractical to restore all customers at the same time. A true concerted effort to do so would have extended the outage for all but a handful of customers.

While this goal of trying to restore all customers at the same time may represent a means of being fair to all customers (i.e., everyone gets served at the same time), NEI believes that this strategy was inappropriate and may have led Unitil to improperly allocate its resources. As a result, its restoration effort was adversely impacted because the system area with the most damage rather than the most customers was assigned the greatest amount of resources. If any area completed restoration before others, those resources were then assigned to other locations.[76]

As shown in Table II-10, Unitil's Massachusetts territory received what appears to be an inordinate number of crews relative to the number of customers without power. Although 100% of the customers in Unitil's Massachusetts area were without power, a larger number of Unitil's customers in the New Hampshire area were without power. Since the damage in Massachusetts was known to be more severe it would be expected that restoration efforts would be more effective and more of Unitil's customers would be restored at a faster rate by assigning resources to the New Hampshire area first even though this would certainly have delayed restoring the customers in Massachusetts. This would have steepened the slope of the customer graph in Figure II-11 immediately after restoration began while flattening the tail of the graph at the end of the restoration effort. We believe that a more appropriate and effective strategy is to attempt to restore service to the largest number of customers as rapidly as possible as was done by PSNH, National Grid, and NHEC.

[76] Unitil. (March 25, 2009). Background, The December 2008 Ice Storm and Unitil's Response, pg 1.

Table II-10 – The Unitil balance sheet showing the resources deployed in MA and NH.[77]

	Massachusetts	New Hampshire
Customers Without Power At Peak	28,496	39,746
Maximum Number of Crews Assigned	299	84
Customer Outages Per Crews Assigned (Max.)	95.3	473.2
Average Daily Number of Crews Assigned	100	36
Customer Outages Per Crew Assigned (Avg.)	285	1104
Feet of Wire Replaced	192,729	93,012
Feet of Wire Replaced Per Crew Assigned (Avg.)	1927	2584
New Poles Set	212	67
New Poles Set Per Crew Assigned (Avg.)	2.12	1.86
Transformers replaced	170	71
Transformers Replaced Per Crew Assigned (Avg.)	1.70	1.97
Splices	6,000	8,000
Splices Per Crew Assigned (Avg.)	60	222.2
Estimated Storm Related Expenditures [78]	$15,298,624.00	$3,196,665.00

Recommendation No. 1: Unitil should adopt a storm restoration strategy that is based on achieving restoration for the largest number of customers in the least amount of time.

- Unitil should allocate storm restoration resources among communities or circuits within the service area or between non-contiguous parts of the service territory based upon the number of customers experiencing outages. Crews should not be assigned purely determined by the extent of the damage; rather, the restoration strategy should be targeted at restoring service to large numbers of customers as expeditiously as possible. Crews should be focused on tasks that will provide the greatest pay-off in terms of overall customers restored in the least amount of time.

[77] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report pg 16.
Note: Although differences are not significant, some of this data does not match data supplied in information requests submitted by the NPUC Staff and NEI.
[78] Unitil. (July 21, 2009). Fitchburg Gas and Electric Company 2008 Ice Storm Costs As of July 21, 2009. Docket D.P.U. 09-Exhibit 1.

Conclusion: Initial damage assessments were slow or nonexistent and the processes used to develop and disseminate accurate estimates of service restoration dates and times were not effective.

In response to a major storm utilities normally conduct an initial assessment to determine the extent of damage to the system and to decide on the number of crews that will be required to restore service. Trained damage assessors are utilized to perform the initial damage assessment, and provide regular updates as the restoration effort proceeds. These assessors are typically in-house employees with long experience dealing with the construction methods and practices used by the utility. The information collected by damage assessors is usually combined with that from other sources, such as trouble reports from customers, data from the outage management system (if such a system exists) and reports from government officials. In addition to helping to plan and organize the restoration effort, damage assessments are also used to inform customers and communities of estimated restoration times.

In recent years it has become increasingly important for utilities to develop and communicate estimated restoration times (ETRs) following storms, because customers are no longer satisfied to simply wait until service is restored. Businesses must decide when to ask employees to report for work and families need to know if they should rent hotel or motel rooms, relocate to emergency shelters or stay with relatives until the power is back on. Municipalities and critical care facilities must plan for maintenance and refueling of emergency generators. For most utilities developing and communicating ETRs is a time-consuming and labor intensive activity that does little to actually contribute to the rate of restoration effort. Nonetheless, it is a critical part of the emergency response process since public demand for ETRs is high and is not dependent upon whether the information contributes to the restoration effort.

PSNH

On the morning of Day 2, Friday, December 12, after the storm had passed, PSNH realized it had a serious problem. Based on incoming trouble reports from customers it was apparent that damage to the system was far greater than had been anticipated. Company personnel responsible for managing the restoration effort expected that an initial damage assessment would take several days. Customer service representatives were told by customer service managers via e-mail to stop providing customers with the standard three hour restoration time and begin telling customers to plan for an extended outage and that the damage assessment had not yet been completed so exact restoration times could not be provided.[79] [80] [81] [82] PSNH also informed

[79] Hybsch, R. Director of Customer Operations, PSNH. Interview by Joyner, M. June 4, 2009.
[80] Kellerman, G. Manager-Operations Support, PSNH. Interview by Joyner, M. June 4, 2009.
[81] Comer, D. Director of Call Center Relations Experience, PSNH. Interview by Joyner, M. June 4, 2009.
[82] Fanelli, M. Manager-System Restoration and Emergency Preparedness, PSNH. Interview by Joyner, M. June 4, 2009.

customers that priority during the restoration effort was being given to hospitals, nursing homes, police and fire facilities, schools (for shelters), etc., and until those were completed, the company would not be able to restore most residential customers.[83]

At 6:00 a.m. on Day 2, Friday, December 12, PSNH initially deployed 141 in-house damage assessors to various locations throughout the state. This number increased as additional personnel became available. The company also called upon retired employees with experience who were qualified to work as damage assessors. At PSNH, during significant storm events, employees initially perform their primary storm assignments but are often moved from one position to another as the situation demands and based on the employee's skill set. Thus, the exact number of damage assessors PSNH used at any given time is difficult to determine.[84] Nonetheless, as the restoration effort continued, PSNH realized it could have used more damage assessment personnel earlier in the process.[85] [86] [87] [88]

Beginning the morning of Day 2, Friday, December 12, PSNH conducted regular damage assessments in each regional work center. As restoration work proceeded, PSNH compiled damage assessments on a daily basis and held conference calls twice daily to discuss restoration progress. At the end of each day, damage assessment documents were brought into the PSNH EOC for review. Estimated time for restoration (ETR) reports were first prepared for each community late on the Day 5, Monday, December, 15 and disseminated to customers and the media via a PSA at 8:10 a.m. on Day 6, Tuesday, December 16.[89] These reports were prepared by the EOC from reports of the field damage assessors.

After several days, PSNH began telling customers that line crews and tree crews were working to restore the main line of each circuit. Once each main line was complete, crews would then begin repairs on all of the side taps off of the main lines. Individual service lines from the street to a home that were damaged would likely be among the final problems to be corrected on any given circuit. Restoration times were not provided to customers in these situations.[90]

By Day 6, Tuesday, December 16, PSNH had introduced a system that called for developing restoration estimates by town every evening, based on information received from the field employees during the day. The intent was to estimate the day and time when 95% of each town with outages would be restored. Town lists were updated each night so that by early morning, the customer service representatives (CSRs) would have the new list. These lists were also placed on

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[83] PSNH. (March 6, 2009). Data Response STAFF 2-20. NHPUC.
[84] PSNH. (February 2, 2009). Data Response STAFF 1-27. NHPUC.
[85] Hybsch, R. Director of Customer Operations, PSNH. Interview by Joyner, M. June 4, 2009.
[86] Kellerman, G. Manager-Operations Support, PSNH. Interview by Joyner, M. June 4, 2009.
[87] Comer, D. Director of Call Center Relations Experience, PSNH. Interview by Joyner, M. June 4, 2009.
[88] Fanelli, M. Manager-System Restoration and Emergency Preparedness, PSNH. Interview by Joyner, M. June 4, 2009.
[89] PSNH. (March 6, 2009). Data Response Staff 2-20. NHPUC.
[90] PSNH. (March 6, 2009). Data Response Staff 2-20. NHPUC.

the PSNH website.[91] The first such posting was made on the morning of Day 7, Wednesday, December 17, at 11:30 a.m. [92] If it was not yet known when a town would be at the 95% restoration level, customers were advised to plan on at least several more days without power.[93]

The first PSNH Storm ETR Report from Day 6, Tuesday December 16, showed that service had been restored to approximately 28% of the more than 200 towns served by the company. More than 100 towns were expected to be restored on Day 6, Tuesday, December 16, Day 7, Wednesday, December 17, or Day 8, Thursday, December 18. Restoration times were unknown for the remaining 44 towns. The ETR Report for the Day 7, Wednesday, December 17 showed that restoration was complete or had reached 95% completion in 92 towns, almost twice the number for the previous day. Even so, the projected restoration date for 14 towns had been changed to Day 9, Friday, December 19, and the number of unknown restoration dates had increased to more than fifty. On December 18, the number of unknowns had dropped to 31, but the projected restoration dates for fifteen towns had been moved to Day 10, Saturday, December 20. The ETR issued on Day 9, Friday, December 19 showed that almost three-quarters of the towns were at least 95% restored, but restoration dates for seventeen towns had been moved to Day 11, Sunday, December 21, with 34 still unknown. The ETR issued Day 10, Saturday, December 20 showed that six more towns were complete, but estimated dates for ten others had been moved to Day 12, Monday, December 22. The ETR for Day 11, Sunday, December 21 showed projected restoration dates for three towns moved to Day 13, Tuesday, December 23, with 18 towns still unknown.[94] By Day 12, Monday December 22, PSNH customers still without power were being told that the company expected all remaining restoration to be complete by midnight on Day 14, Wednesday, December 24.[95]

Unitil

Unitil's procedure which is communicated to employees in training sessions, calls for an initial damage assessment to begin at the first indication of an impending storm. Based upon the weather forecast, the Director of Electric Operations, along with the affected Electric System Managers, will estimate the potential impact to the energy delivery system. This estimate is based upon prior experience with similar weather patterns. The information is used to predict the volume of anticipated system troubles, including which areas of the system will be affected and the extent to which damage will cause service interruptions. The company will then analyze staffing levels, including both internal and external resources that may be available for restoration.[96]

[91] PSNH. (March 6, 2009). Data Response Staff 2-20. NHPUC.
[92] Knepper, R.. "Re: FW: Clarification." E-mail to Joyner, M. July 1, 2009.
[93] PSNH. (March 6, 2009). Data Response STAFF 2-20. NHPUC.
[94] PSNH. (June 19, 2009). Data Response PS0014. NEI.
[95] PSNH. (March 6, 2009). Data Response Staff 2-20. NHPUC .
[96] Unitil. (February 27, 2009). Data Response STAFF 1-9. NHPUC.

Unitil had a total of 33 in-house personnel performing damage assessment in New Hampshire during the December 2008 ice storm.[97] Efforts were initially focused on sub-transmission facilities and primary distribution circuits. The process was complicated by the fact that many public roadways were impassable and because new damage continued to occur as ice-covered trees and limbs fell onto power lines. As a result, it took about four days to complete the initial damage assessment.[98]

The principal method Unitil used for keeping customers informed during the restoration effort was through Public Service Announcements (PSAs) which were issued in advance of and during the ice storm and the restoration process. PSAs were issued to all news media as well as to community leaders. PSAs were also posted on the company website. Additional information was supplied by conversations with storm restoration personnel when Unitil prepared and updated messages in the company's Integrated Voice Response (IVR) system. All of this information was provided on a regular basis to customer service personnel.[99]

Unitil issued a total of 35 PSAs, beginning with a storm advisory to its customers on Day 1, Thursday, December 11, and ending with a statement on estimated bills on December 29. Mid-day on the Day 4, Sunday, December 14, Unitil began including in the PSAs a table that listed each town served, the number of uncorrected troubles and number of customers interrupted. Specific estimated restoration times were not included, but the PSA did say the company anticipated that restoration efforts would continue for several days.

On the morning of Day 6, Tuesday, December 16, Unitil issued its first PSA that provided an estimated time of restoration. At that time, the total number of Unitil's customers without power in New Hampshire was about 10,500, with 9,628 in the Seacoast area and 902 in Concord. Unitil said it expected to have power restored in the Capital region within 24 hours, with the exception of some service lines serving individual homes. No estimate was provided for the Seacoast region. A message entitled "Statement on Expected Service Restoration Times" was issued at 6:00 p.m. on Day 6, Tuesday, December 16, that reiterated the estimated restoration time for the Capital region and for the first time advised Unitil's customers in the Seacoast region that restoration of service was expected to be complete during the overnight hours of Day 7, Wednesday, December 17. A PSA issued late on Day 9, Friday, December19, indicated that 1,250 customers in the Seacoast region were still without power and advised that all major lines would be in service by the morning of Day 10, Saturday, December 20. On Day 12, Monday, December 22 a PSA reported that only a few dozen service outages still existed in Unitil's New Hampshire service areas. There were eight additional messages sent out, regarding emergency

[97] Unitil. (February 27, 2009). Data Response STAFF 1-27. NHPUC.
[98] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 30.
[99] Unitil. (March 27, 2009). Data Response STAFF 2-15. NHPUC.

shelters, frequently asked questions, a statement from Unitil's Chairman and CEO, and tips for preparing for power restorations.[100]

National Grid

National Grid did not complete a comprehensive initial damage assessment, per se. Rather, the damage assessment process was fluid, and did not result in the production of a single complete list of estimated restoration times for the various parts of the system.[101] [102] With respect to the distribution system, damage assessment included a public safety phase during which available resources were initially focused on identifying the locations of downed wires, so as to de-energize the system where unsafe conditions may exist. Damage assessment was initially conducted with twelve[103] supervisors and on-duty line workers.

National Grid's mutual aid needs were based on man-hours shown in its outage management system (PowerON, by GE), combined with judgment provided by the field managers. Unfortunately, due to the widespread and extreme nature of the damage to the distribution system, the estimated time of restoration feature of PowerOn was disabled very early in the storm. As the restoration effort progressed, damage assessors and line crews were able to project more accurately the expected restoration times for individual neighborhoods and distribution circuits. As estimated restoration days and times became available, that information was added to the outage management system and the company's web site for communication to customers.[104]

National Grid also received help from municipal fire department personnel in assessing storm damage. Fire department personnel helped National Grid to understand the extent of damage in particularly bad areas. This was beneficial in safely getting the most customers back on as soon as possible.

Following the storm, National Grid's goal was to provide information to media and customers that was timely, consistent, and accurate. This was done using press releases and relaying information through their CSR. The information conveyed in these releases throughout the duration of the storm focused on safety, the magnitude of the damage, the magnitude of the restoration effort, and once available, estimated restoration dates and times.

Upon daylight on the morning of Day 2, Friday, December 12, damage assessment teams were operational and were assigned to perform a main line assessment of the circuits that had locked out as a result of the ice damage. That survey consisted of a rapid assessment of the (three-phase) main lines on the impacted feeders. National Grid issued a press release reporting that the ice storm that had swept across eastern New York, Massachusetts, Rhode Island and New

[100] Unitil. (March 27, 2009). Data Response STAFF 2-15. NHPUC.
[101] Demmer, K. Manager Electric Distribution New Hampshire, National Grid. Interview by Joyner, M. June 9, 2009.
[102] Kearns, R. Director Emergency Planning, National Grid. Interview by Joyner, M. June 9, 2009.
[103] National Grid. (February 27, 2009). Data Response STAFF 1-27. NHPUC.
[104] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 9.

Hampshire the night before had left more than 500,000 of its customers without power; approximately 24,000 of those customers were in New Hampshire.[105] At peak, 24.164 customers in the company's New Hampshire service area experienced outages, which represented approximately 60% of its customers.[106] The afternoon press release on Day 2 stated that damage assessment surveys were still being conducted, but no specific estimated time of restoration was offered. The company said only that the effort would take several days and perhaps longer.

Beginning on the morning of Day 3, Saturday, December 13, damage assessment progressed to include the entire circuits. That survey consisted of a detailed analysis of all impacted infrastructure.[107] On that day National Grid reported that about 12,000 New Hampshire customers were still out of power and projected that by the night of Day 4, Monday, December 15 all major restoration efforts would be complete with remaining work focused on small pockets of significant damage.[108] Although National Grid continued to make steady progress, as of Day 6, Tuesday, December 16, the company still had more than 2,800 customers without power. No revised estimated restoration times were issued. National Grid's last customer was restored at 10:19 p.m. on Day 8, Thursday, December 18.[109]

NHEC

At NHEC, when a major storm event is being experienced, the affected districts assign trained personnel to assess damage in the field and provide reports to the respective District Supervisor. The initial damage assessment is based primarily on the information collected in the field, but also includes data from the company's outage management system (OMS). In fact, OMS data is normally used as a first good indicator of potential damage which helps to focus the initial damage assessment in the field. The years of experience of the District Supervisors and the Disaster Recovery Executive are also important in completing the assessment and determining the level of restoration resources that will be needed.[110]

NHEC had two communications goals during the December 2008 ice storm. They were to inform the general public about the progress of storm restoration and, when possible, inform members and town officials in the communities that were affected by power outages. NHEC had eight employees dedicated to the customer and community communications effort during the storm. Two of these employees were specifically assigned with contacting town managers and other local officials in the communities affected by power outages. Beginning on Day 5, Monday, December 15, phone calls were made to the Police and Fire Chiefs and Emergency Management personnel of the 17 towns in the NHEC service territory that were without power. From then on, updates were provided several times per day and concluded with the last calls

[105] National Grid. (March 27, 2009). Data Response STAFF 2-15. NHPUC.
[106] National Grid. (June 17, 2009). Data Response NG0020. NEI.
[107] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 9.
[108] National Grid. (March 27, 2009). Data Response Staff 2-15. NHPUC.
[109] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 10.
[110] NHEC. (February 19, 2009). Data Response STAFF 1-9. NHPUC.

being made on the morning of Day 10, Saturday, December 20. These updates informed town officials of outage street locations and estimated restoration times. In addition, officials had the opportunity on these calls to speak directly with NHEC staff to address any questions or concerns, or call back later using cell phone number that were provided.[111] NHEC also relied on its website and statewide news media to disseminate information relating to power restoration. Within two days of the storm, NHEC began providing restoration updates three times daily. These updates included information from the outage management system and from field assessments provided by the District Supervisors to the Disaster Recover Executive, a senior executive at NHEC who fulfills this role during emergencies. Many of the news media entities posted on their own websites links to outage information provided by NHEC. Local shelters were contacted and updated on power restoration efforts.[112]

When NHEC prepares estimated times of restoration (ETOR's) during outages the following elements are part of the restoration situational status updates:

- Present and forecasted weather conditions
- Line assessment reports, which provide damage and other key information for the deployment and scheduling of crews based on priorities
- Crew availability and road status (primarily road access for restoration efforts)
- Equipment requirements, focusing on equipment deployment and also equipment availability (especially off road equipment)
- Material availability
- The number of continuous days crews have worked restoring power
- The experience of the field supervision and staff in charge[113]

NHEC conducts extensive and ongoing communication with PSNH and National Grid when they experience an outage on the transmission and sub-transmission lines that serve NHEC substations or delivery points. This communication is to determine the estimated restoration times for these transmission outages.[114]

During any outage restoration event, NHEC always strives to provide its customers with the most current and accurate information available, even if that means saying, "We do not know at this time." The level of detail that is provided regarding estimated restoration times is limited by the extent of outage information that is available during the inquiry, status of the restoration effort, the number of crews dispatched, and projected time to restore the system. The information provided includes any and all of the following, if known at the time of the inquiry:

- NHEC is aware of the outage.

[111] NHEC. (July 2, 2009). Data Response CO0009. NEI.
[112] NHEC. (February 19, 2009). Data Response Staff 1-42. NHPUC.
[113] NHEC. (March 24, 2009). Data Response STAFF 2-19. NHPUC.
[114] NHEC. (March 24, 2009). Data Response STAFF 2-19. NHPUC.

- NHEC estimates we will have power restored within "x" amount of time based on the initial/current information provided from the outage management system (OMS).
- A crew or crews have been dispatched and are in route to the outage.
- Crews are at the scene.
- NHEC estimates that power will be restored by "x" time.

NHEC began its initial damage assessment at first light on Day 2, Friday, December 12. Damage assessments of each district were conducted by the District Supervisors. Coverage was focused, based on outage calls from customers. Due to the extensive damage, and the large number of roads closed because of fallen trees, the initial damage assessment took several days to complete.[115] [116] [117]

NHEC issued its first specific estimated restoration time at 9:00 a.m. on Day 6, Tuesday, December 16. By then fewer than 10,000 co-op members were still without power, down from a high of more than 48,000 on Day 2, Friday December 12. NHEC projected that all outages would be restored by the evening of Day 10, Saturday, December 20. NHEC restated that ETR the next morning, Day 7, Wednesday, December 17. At 2:30 p.m. on the Day 7, NHEC issued an update that provided a list of 16 towns with estimated restoration times for each. Service was expected to be restored in four of the towns on Day 8, Thursday, December, three towns on Day 9, Friday, December 19 and the remaining nine on the Day 10, Saturday, December 20. At 6:00 p.m. on Day 10, NHEC reported that at 4:00 p.m. a co-op line crew had restored the last member still in the dark as a result of the ice storm.[118]

Recommendation No. 2: Each electric utility should improve the systems and processes it uses to develop damage assessments and communicate ETRs to customers during storm restoration efforts.

- The electric utilities should adopt a policy requiring that estimated times of restoration following storms be prepared and disseminated to customers within 24 to 48 hours of the event. This will require the dedication of personnel who are directly responsible for the effort of gathering the required information from the field personnel and putting it into a form that can be released to the press, communicated by the utility's customer service personnel, and posted on the utility's web site.

- The electric utilities should modify emergency procedures to assign responsibility for assessing damage and estimating the number of outages expected and projecting the number of resources required for restoration.

[115] Gosney, W. Executive Vice President, NHEC. Interview by Joyner, M., June 17, 2009.
[116] Bakas, J. Vice President of Engineering and Operations, NHEC. Interview by Joyner, M. June 17, 2009.
[117] Lynch, H. Disaster Recovery Executive, NHEC. Interview by Joyner, M. June 17, 2009.
[118] NHEC. (February 19, 2009). Data Response STAFF 1-42. NHPUC.

- The electric utilities should assign damage assessment personnel to specific areas and pre-stage these resources ahead of major events.

Conclusion: All four of the electric utilities underestimated the expected impact of the storm as well as the extent of the resultant damage.

Although advance meteorological warnings provided a relatively accurate description of the approaching storm, when it arrived, the storm turned out to be highly unusual due to the breadth and extent of its damage. While most ice storms in New Hampshire occur along a fairly narrow strip, ranging between 25 and 50 miles, the December 2008 ice storm spread across a range of 75 to 100 miles. The amount of precipitation was extremely large, with much of it falling as freezing rain. Moreover, none of the utilities had ever experienced a storm that caused the total amount of state-wide damage that resulted from the December 2008 ice storm. In terms of power outages, the 2008 ice storm was more significant than PSNH's top four prior storms combined.[119] Only NHEC had experienced a storm which caused more damage to its system in terms of repair costs than the December 1998 ice storm.[120] None of the utilities anticipated the amount of damage they eventually incurred. As a result, the utilities were less than optimally prepared during the early days of the storm. National Grid appeared to begin preparation sooner than the other utilities and this was one reason they were able to restore power to their areas sooner than the other utilities. The other three utilities responded to the approach of the storm in similar ways.

Three of the four New Hampshire electric utilities (all except NHEC) subscribe to professional weather services that provided advance warning of severe weather conditions.[121] [122] [123] [124] In addition to the warnings and reports provided by those services, various weather websites were monitored prior to and during the December 2008 ice storm. PSNH also participated in the New Hampshire Department of Safety, Homeland Security and Emergency Management conference call at 3:00 p.m. on Day 1, Thursday, December 11.[125]

PSNH

As early as Day -2, Tuesday, December 9, the PSNH weather service predicted that a low pressure system would develop and be moving towards the Mid-Atlantic States on Thursday night and then over New England on Friday. A "rain/wintry mix" was expected, with parts of New Hampshire having a chance for moderate to heavy snow and sleet accumulation. Gusty winds were expected on Friday. Ice was first mentioned on Day -1, Wednesday, December 10,

[119] PSNH. (March 25, 2009). New Hampshire Ice Storm 2008: Record Outage, Record Recovery, pg 5.
[120] NHEC. (February 19, 2009). Data Response STAFF 1-49. NHPUC.
[121] Unitil. (February 27, 2009). Data Response STAFF 1-5. NHPUC.
[122] National Grid. (February 27, 2009). Data Response STAFF 1-5. NHPUC.
[123] PSNH. (February 2, 2009). Data Response STAFF 1-5. NHPUC.
[124] NHEC. (February 19, 2009). Data Response STAFF 1-5. NHPUC.
[125] PSNH. (February 2, 2009). Data Response STAFF 1-7. NHPUC.

with accretions in excess of 1/2-inch possible. The greatest threat from heavy ice was expected to be across elevated terrain between 1,000 and 2,000 feet. On the morning of Day 1, Thursday, December 11, the weather forecast summary said significant ice accumulations were possible across southwestern New Hampshire. For PSNH specifically, the forecast called for more than 1 inch of ice. On Thursday evening the forecast called for 1/2 to 1 inch of ice accretion in parts of southern New Hampshire.

Unitil

Unitil's weather service announced a winter storm watch for the utility's New Hampshire service area during the afternoon of Day -1, Wednesday, December 10, saying the potential existed for significant icing due to freezing rain and sleet. The exact track of the storm remained uncertain but would ultimately determine where the most significant icing and snowfall would occur. On Day 1, Thursday, December 11, Unitil issued an Electric System Advisory (public service announcement) to its customers saying that in response to the National Weather Service's winter storm warning and ice storm warning, Unitil personnel and emergency crews had been placed on alert. The advisory went on to say that severe weather conditions might occur later that evening, Day 1, Thursday, December 11 and into Friday, December 12. Customers were advised that the severe weather conditions might interrupt electric service in some areas. Most electrical outages were expected to be for relatively short periods of time; however, the advisory pointed out that severe weather conditions could create substantial damage to the electrical system, and restoration could take an extended period of time.[126]

On the morning of Day 1, Thursday, December 11, Unitil's weather advisory changed to a winter storm warning. Heavy freezing rain accretion was expected to occur with between 1/2 and 1 inch of accumulation. That forecast continued through Thursday afternoon. Late Thursday evening the weather service added that "some areas of Massachusetts, Vermont, and New Hampshire could see another 1 inch of solid ice." By mid-morning, Day 2, Friday, December 12, the storm had exited Unitil's New Hampshire service area, and the forecast changed to milder temperatures with gusty winds up to 25 mph.[127]

National Grid

National Grid began receiving severe weather forecasts as early as Day -3, Monday, December 8. A forecast provided by the weather service at 6:00 a.m. on Day -1, Wednesday, December 10, indicated that sleet and freezing rain might develop across portions of southern Vermont, New Hampshire, and northern Massachusetts that could produce possible significant icing. By early afternoon ice accretion of from 1/2 to 3/4 inch and possibly more was predicted as far north as Laconia, New Hampshire. Wind gusts of up to 50 mph were also mentioned as being possible. By late afternoon on the Day -1, Wednesday, December 10, the weather service had high

[126] Unitil. (March 27, 2009). Data Response STAFF 2-15. NHPUC.
[127] Unitil. (February 27, 2009). Data Response STAFF 1-7. NHPUC.

confidence that up to a 1/4 inch of ice would accumulate in National Grid's New Hampshire service area. In the early morning on Day 1, Thursday, December 11, a forecast described as "high confidence" called for more than 1 inch of ice. The early evening and midnight forecasts for ice remained high, though the amount predicted was first reduced to 1/2 to 3/4 inch and then raised to 3/4 to 1 inch. Additional ice accretion on Friday was expected to be light.[128]

NHEC

NHEC does not subscribe to any professional weather forecasting services, having found that weather information could be acquired free via the Internet and other sources such as television and radio. Weather is constantly monitored in the co-op's system control center in Plymouth. In addition to a number of online services that provide an abundance of weather data, the company collects information broadcasted by local news stations, the New England news networks, and the National Weather Service. NHEC did not record any of the weather data before or during the December 2008 ice storm.[129] [130] [131] [132]

Conclusion: The utilities relied too heavily upon local mutual aid agreements, which delayed the process of securing additional resources.

Utilities, whether investor-owned, municipal or cooperative, rarely have sufficient resources to respond to a major storm using just their own people. When major storms hit, utilities rely on a vast network of support contractors and crews from other utilities. Typically the number of restoration personnel deployed by a utility peaks a day or two after a major storm, due to the time it takes to acquire and mobilize the extra workers required to restore power. This extra workforce usually declines as progress is made in restoring outages.

Mutual aid (or assistance) is generally considered the primary means of obtaining extra line crews to assist with storm restoration efforts. Naturally, the first priority of every utility is to restore service to its own customers before releasing crews to other utilities. The Northeast Mutual Assistance Group (NEMAG) was formed in 2007 by a group of New England and Canadian electric utilities to facilitate the sharing of crews among its members in order to aid one another in response to emergencies. Prior to the formation of NEMAG, any utility seeking aid would have to rely upon its own contacts with neighboring utilities. NEMAG now serves as the regional coordinator for allocating resources among electric utilities in the northeast region during storm restorations.[133]

At 8:30 a.m. on Day 1, Thursday, December 11, NEMAG held its first conference call to discuss the forecast and the potential need for mutual aid crews among members. PSNH, Unitil and

[128] National Grid. (February 27, 2009). Data Response STAFF 1-7. NHPUC.
[129] Unitil. (February 27, 2009). Data Response STAFF 1-5,6,7. NHPUC.
[130] National Grid. (February 27, 2009). Data Response STAFF 1-5,6,7.NHPUC.
[131] PSNH. (February 2, 2009). Data Response STAFF 1-5,6,7. NHPUC.
[132] Unitil. (March 27,2009). Data Response STAFF 1-5,6,7. NHPUC.
[133] Unitil, (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 20.

National Grid all participated (NHEC is not a member of NEMAG). On this initial conference call, NEMAG members discussed the weather forecasts, crew availability, and other items according to the NEMAG procedures. It was evident that all of the New England utilities were concerned with the possibility of crew shortages due to the impending storm. Because the storm had not yet materialized, but was expected to move across the region during the evening of December 11, no commitments for mutual assistance were made. National Grid recommended that the list of participants on future calls be expanded to include the New York Mutual Assistance Group and the Mid-Atlantic Mutual Assistance Group.[134] A follow-up conference call was scheduled for 6:00 a.m. on Day 2, Friday, December 12.[135]

During the 6:00 a.m. NEMAG conference call on Day 2, Friday, December 12, participants began with a summary of their individual damage assessments, crew availability, and requirements. The three participating utilities reported ice accretions of up to 1/2 inch with forecasted levels of 1 inch in some areas. Even if no further ice accretion occurred, it was clear to all participants that they were likely to experience substantial damage and widespread customer outages. It was also apparent that the storm had impacted a significant portion of New England, as the initial crew requests made by participants far exceeded the number of available resources among the member utilities since by this time many crews were already allocated to other areas.

PSNH

PSNH opened its emergency operations center at approximately 11:00 p.m. on Day 1, Thursday, December 11. At that time, massive power outages were already beginning to occur in its service area. Like the other utilities, PSNH recognized the magnitude of the storm and immediately put out requests for help from other utilities and contract crews in New England. PSNH participated in all three NEMAG conference calls, requesting 250 crews during the second and third calls.[136] Unfortunately, since the storm was impacting the entire region, many of the contract crews in the area were already committed to helping other utilities. PSNH then expanded its search and began requesting crews from utilities throughout the East Coast, the Midwest, and into Canada. To the extent they were available, PSNH secured hundreds of tree and line crews outside of the mutual aid process.

By Day 4, Sunday, December 14, PSNH had acquired more than 300 additional tree and line crews and by nightfall on Day 4, those crews had helped to restore service to more than half of the PSNH customers who had lost power in the storm. Over the next few days, crews continued to arrive from as far away as Maryland and Ohio. By the Day 8, Thursday December 18, more than 650 line, tree, and service crews were working for PSNH and power had been restored to more than 275,000 PSNH customers (about 86 percent of those affected by the storm. By Day

[134] National Grid, (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 7.
[135] Letourneau, R. Director-Electric Operations, Unitil. Interview by Joyner, M. May 19, 2009.
[136] Desbiens, A. “RE: NEI Question-Mutual Aid Crew Request.” E-mail to Joyner, M.. July 9, 2009.

11, Sunday, December 21, the last portion of restoration work had been completed in the Seacoast and northern regions of the state, and the PSNH restoration workforce had grown to over 1,000 crews.[137]

PSNH also had access to the resources of its affiliate utility, Connecticut Light and Power (CL&P). This support is recognized and relied upon as part of PSNH's emergency restoration procedures. About sixty of the crews that supplemented the PSNH workforce on Day 4, Sunday, December 14, were from CL&P.[138]

Figure II-14 and Figure II-15 show the number of additional crews requested by PSNH from mutual aid, contractors, or other sources, versus the number that eventually arrived on a daily basis and cumulatively. Ideally, the two curves in Figure II-14 would mirror each other and be slightly offset with the crews arrived curve being slightly to the right of the crews requested curve. This would indicate that all the crews requested did indeed arrive in a timely manner. The space between the curves would indicate the speed with which the crews were supplied, the smaller the space, the faster the supply of crews. If the crews had arrived on the same day they were requested, and all crews requested arrived, the two curves would lie on top of each other.

The curves in the graph in Figure II-15 would also ideally lie on top of each other if crews were requested and supplied on the same day. The space between the curves shows the time lag between request and supply and the curves would mirror each other if all the crews requested were supplied.

The graphs demonstrate that mutual aid crews that were requested were supplied in a timely manner, typically within twenty-four hours. The graphs also suggest that PSNH may have lost valuable restoration time by not ramping up restoration workforces until several days after the storm damage occurred.

[137] PSNH. (February 2, 2009). Data Response STAFF 1-19. NHPUC.
[138] PSNH. (February 2, 2009). Data Response STAFF 1-21. NHPUC.

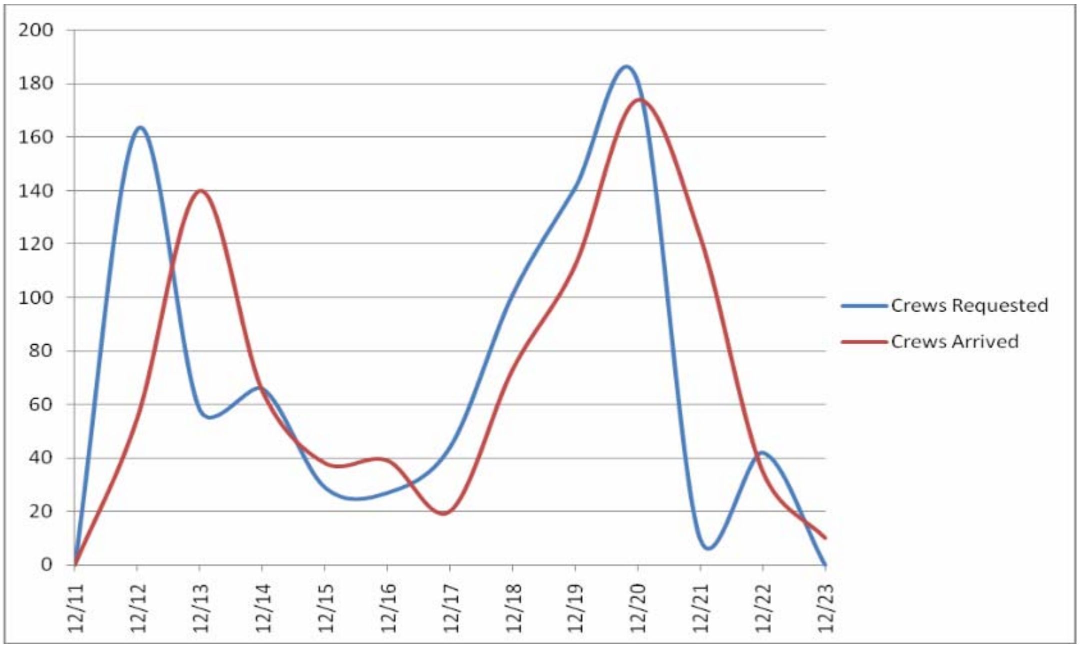

Figure II-14 – Graph showing the number of PSNH crews requested and when they arrived.

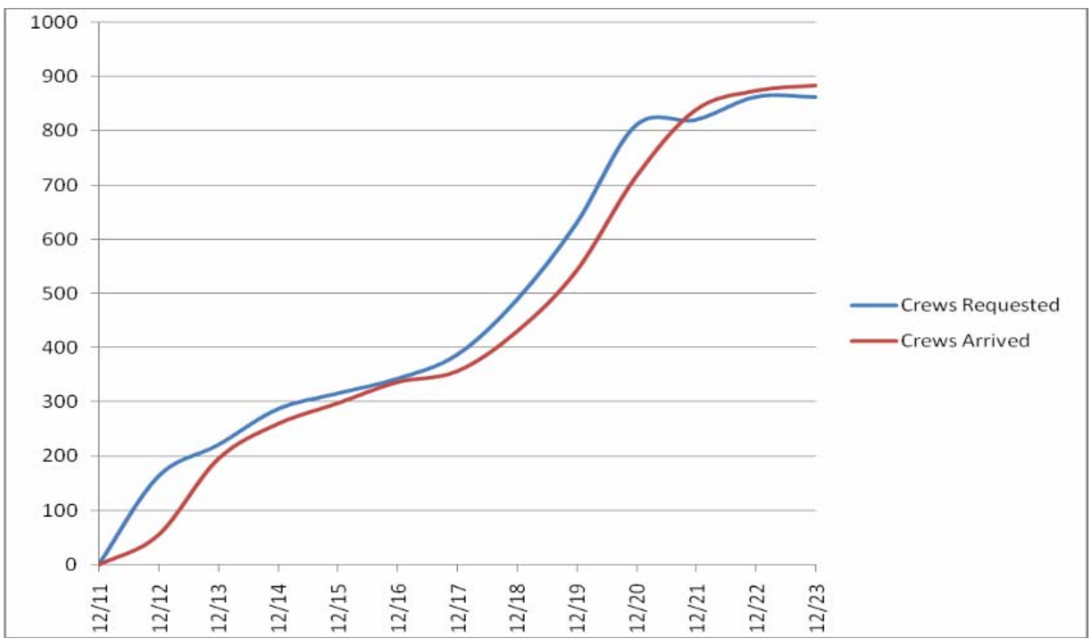

Figure II-15 – Graphs showing the cumulative number of PSNH crews requested and when they arrived.

Unitil

Based on the damage reports that came in during the early morning hours of Day 2, Friday, December 12, it became obvious that Unitil would require an unprecedented amount of assistance from outside crews. During the 6:00 a.m. call on the Day 2, Unitil reported approximately 69,000 customers without power system-wide, including about 38,000 customers in New Hampshire and all of its Massachusetts customers. Unitil made an initial mutual aid request for 30 crews. Unfortunately, similar to the call the previous morning, no crews were made available to any of the utilities expressing needs.[139] All of the utilities indicated their crews were still needed locally.

A third NEMAG conference call was established for noon on Day 2, Friday, December 12. Unitil's storm boss hoped that the noon call might be more fruitful.[140] During this call, Unitil requested an additional 10 crews, bringing the total number requested to 40. Unitil got commitments from the Philadelphia Electric Company (PECo) for 20 of the needed crews (10 in-house and 10 from a PECo contractor) and another 20 from two contractors released by the Dayton Power and Light Company (DP&L) in Ohio.[141]

Unitil secured six crews from O'Donnell Line Construction Company located in Nashua, NH, also outside of the mutual aid process. That brought the number of additional crews committed to Unitil to 46. Combined with Unitil's 25 existing crews a total of 71 crews were available at that time to work on Unitil's system.[142]

Figure II-16 and Figure II-17 show the number of additional crews requested by Unitil versus the number that eventually arrived on a daily basis and cumulatively. Ideally, the two curves in Figure II-16 would mirror each other and be slightly offset with the crews arrived curve being slightly to the right of the crews requested curve. This would indicate that all the crews requested did indeed arrive. The space between the curves would indicate the speed with which the crews were supplied, the smaller the space, the faster the supply of crews. If the crews had arrived on the same day they were requested, and all crews requested arrived, the two curves would lie on top of each other.

The curves in the graph in Figure II-17 would also ideally lie on top of each other if crews were requested and supplied on the same day. The space between the curves shows the time lag between request and supply and the curves would mirror each other if all the crews requested were supplied.

The graphs demonstrate that in Unitil's case, the mutual aid crews that were requested were not supplied until nearly Day 6, Tuesday, December 16. The graphs also suggest that Unitil may have lost valuable restoration time by not ramping up restoration workforces until several days after the storm damage occurred.

[139] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 21.
[140] Letourneau, R. Director-Electric Opeations, Unitil. Interview by Joyner, M. May 19, 2009.
[141] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 21.
[142] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report, pg 21.

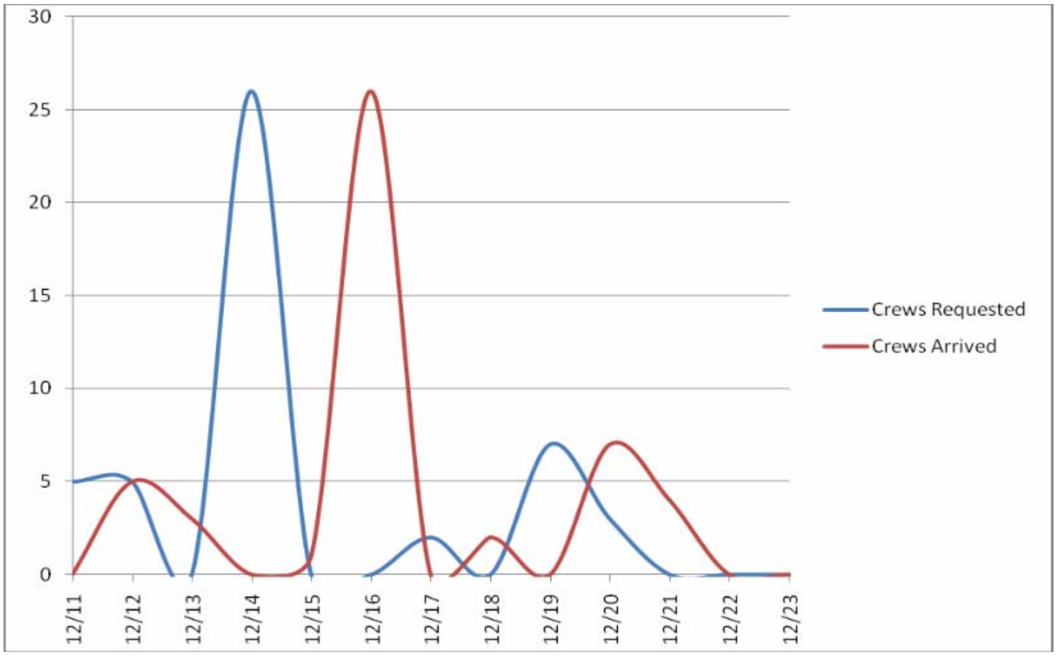

Figure II-16 – Graph showing the number of Unitil crews requested and when they arrived.

Figure II-17 – Graph showing the cumulative number of Unitil crews requested and when they arrived.

National Grid

National Grid also participated on the 6:00 a.m. call on Day 2, Friday December 12, and reported 250,000 customer outages in its New England service area and requested a large number of mutual assistance crews. Other utilities responded with estimates ranging from only a few thousand interruptions, to tens of thousands of customer interruptions. Participants on the call anticipated that these estimates would increase as the storm lingered. As a result, National Grid continued to request resources from mutual assistance utilities.[143]

National Grid reported a peak of over 500,000 customer interruptions, with more than 24,000 in New Hampshire. The mutual assistance resources National Grid acquired for its New England region via the noon call on Day 2, Friday, December 12, included crews from utilities in Ohio, Virginia, Indiana, Delaware and Maryland, all outside of NEMAG. National Grid was also promised assistance from line contractors located in Indiana, Michigan, North Carolina, Ohio, Pennsylvania, Tennessee, and Virginia.[144]

At the conclusion of the noon call the NEMAG process had achieved its purpose of supplying the requested crews and no further calls were scheduled. Although no further NEMAG calls were held once the available resources were assigned, the impacted utilities remained in contact with one another as their respective restoration efforts progressed. With this on-going communication, National Grid requested additional resources from the Mid-Atlantic Mutual Assistance Group on Day 4, Sunday, December 14. Baltimore Gas & Electric (Maryland) and Public Service Enterprise Group (New Jersey) responded to the mutual assistance request with a number of internal line crews.[145]

Figure II-18 and Figure II-19 show the number of additional crews requested by National Grid versus the number that eventually arrived on a daily basis and cumulatively. Ideally, the two curves in Figure II-18 would mirror each other and be slightly offset with the crews arrived curve being slightly to the right of the crews requested curve. This would indicate that all the crews requested did indeed arrive. The space between the curves would indicate the speed with which the crews were supplied, the smaller the space, the faster the supply of crews. If the crews had arrived on the same day they were requested, and all crews requested arrived, the two curves would lie on top of each other.

The curves in the graph in Figure II-19 would also ideally lie on top of each other if crews were requested and supplied on the same day. The space between the curves shows the time lag between request and supply and the curves would mirror each other if all the crews requested were supplied.

[143] National Grid. (February 27, 2009). Data Response STAFF 1-20. NHPUC.
[144] National Grid. (February 27, 2009). Data Response STAFF 1-20. NHPUC.
[145] National Grid. (2-27-09). Data Response Staff 1-20.NHPUC.

The graphs demonstrate that mutual aid crews that were requested were supplied in a timely manner to National Grid, typically within twenty-four hours. The graphs also suggest that National Grid requested crews more quickly than the other utilities which probably contributed to being able to restore power to its service area before the other utilities.

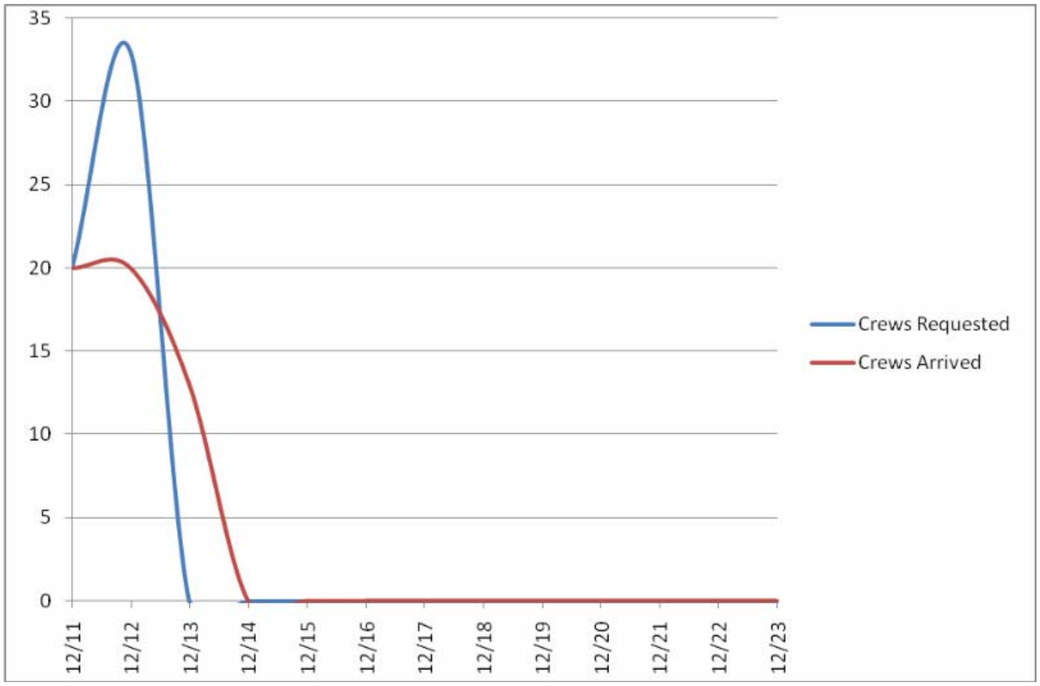

Figure II-18 – Graph showing the number of National Grid crews requested and when they arrived.

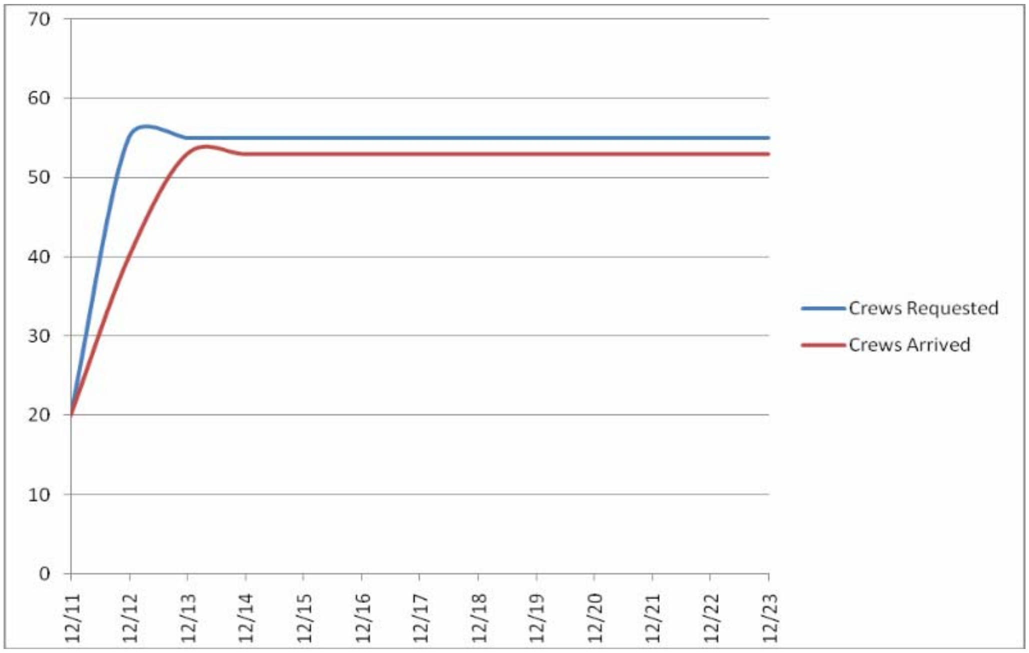

Figure II-19 – Graph showing the cumulative number of National Grid crews requested and when they arrived.

NHEC

NHEC's emergency operations center was staffed by and activated by 9:00 p.m. on Day 1, Thursday, December 11. Requests were immediately issued for extra line and tree crews from contractors working on NHEC's system. Contract line and tree crews that had been on standby were activated. On the morning of the Day 2, Friday, December 12, a request was sent to all other line contractors on NHEC's approved list; however, none were available. Additional contract tree crews were procured, but their projected arrival times varied because of the unfavorable road conditions.[146]

A call to the Northeast Public Power Association (NEPPA) for mutual aid was unsuccessful. NEPPA is an organization for electric cooperatives and municipalities that is the counterpart of NEMAG for investor owned utilities. A utility will generally belong to one or the other depending upon the type of utility, co-op, municipal, or investor owned, but usually will not belong to both organizations. NEPPA is the organization that NHEC would look to for mutual aid.

The extent of damages experienced by the companies that comprise NEPPA was such that all of their crews were needed locally. Calls for assistance continued throughout Day 2, Friday, December 12, with positive responses from three cooperatives in New York, two in Vermont and one in Maine. One of the crews from those six cooperatives arrived and began working the afternoon of Day 2, Friday, December 12. The rest started Day 3, Saturday, December 13, with the exception of one that started the afternoon of Day 4, Sunday, December 14. Nonetheless, field assessments that were being returned to the district supervisors on Friday and Saturday indicated that even more line crews would be needed to expedite the restoration process. Contact was then made with the Pennsylvania Rural Electric Association and 6 more crews started on the morning of Day 4, Sunday, December 14. All of the mutual aid crews requested by NHEC were working on the co-op's lines by the morning of Day 5, Monday, December 15.[147]

Figure II-20 and Figure II-21 show the number of additional crews requested by NHEC versus the number that eventually arrived on a daily basis and cumulatively. Ideally, the two curves in Figure II-20 would mirror each other and be slightly offset with the crews arrived curve being slightly to the right of the crews requested curve. This would indicate that all the crews requested did indeed arrive. The space between the curves would indicate the speed with which the crews were supplied, the shorter the space, the faster the supply of crews. If the crews had arrived on the same day they were requested, and all crews requested arrived, the two curves would lie on top of each other.

The curves in the graph in Figure II-21 would also ideally lie on top of each other if crews were requested and supplied on the same day. The space between the curves shows the time lag

[146] NHEC. (February 19, 2009). Data Response STAFF 1-20. NHPUC.
[147] NHEC. (February 19, 2009). Data Response STAFF 1-20. NHPUC.

between request and supply and the curves would mirror each other if all the crews requested were supplied.

The graphs demonstrate that mutual aid crews that were requested were supplied in a timely manner to NHEC, typically within twenty-four hours.

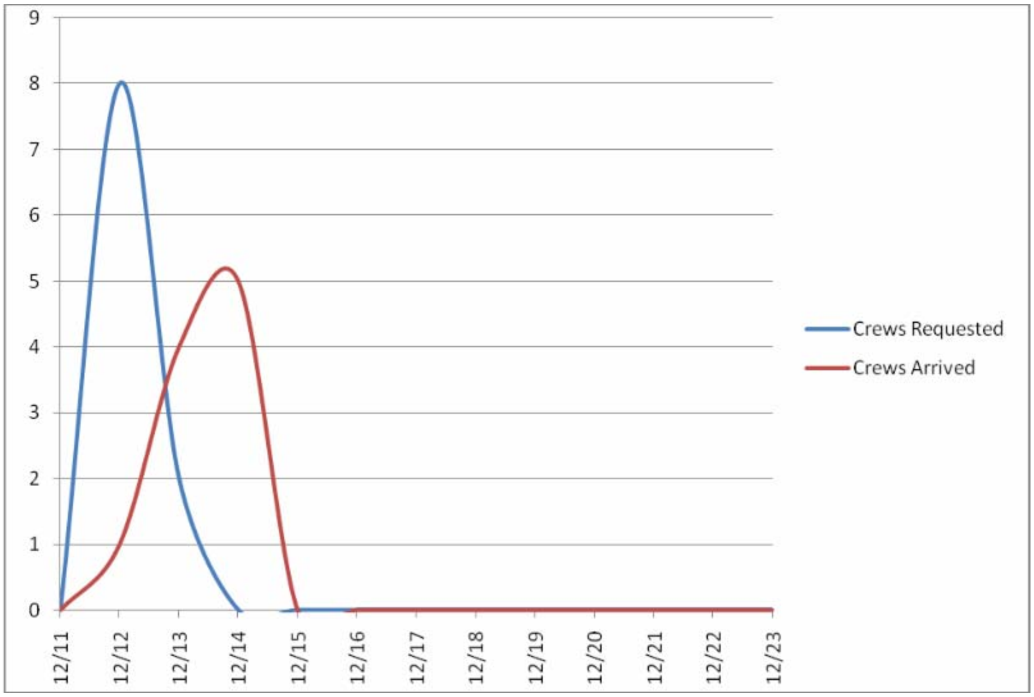

Figure II-20 – Graph showing the number of NHEC crews requested and when they arrived.

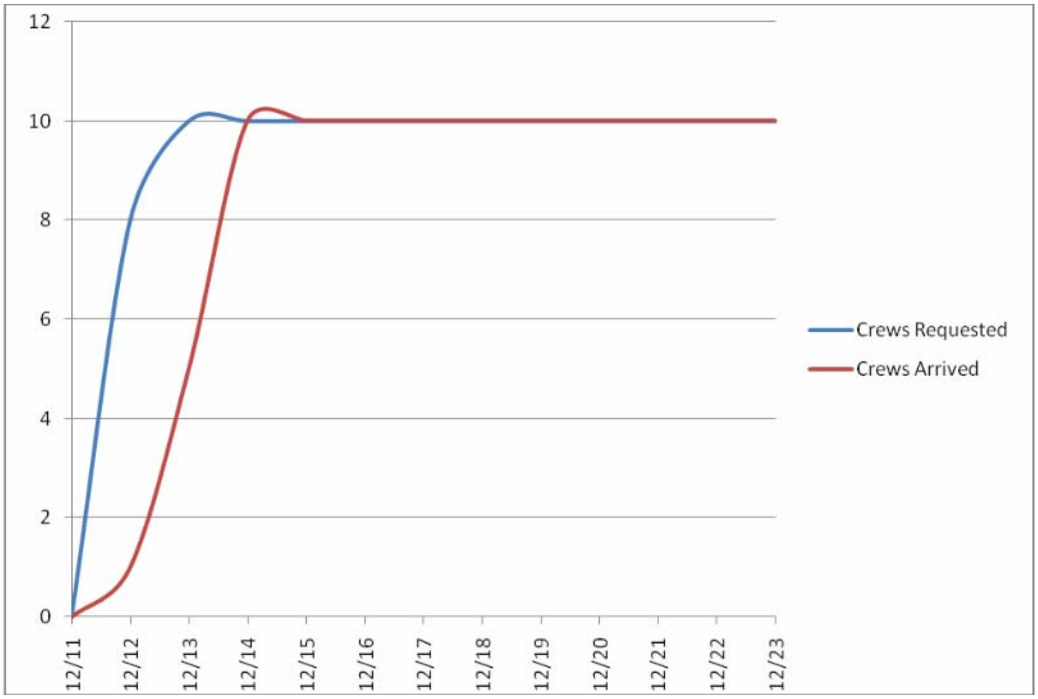

Figure II-21 – Graph showing the cumulative number of NHEC crews requested and when they arrived.

Recommendation No. 3: Each electric utility should adopt storm restoration procedures that require the process of procuring additional crews to begin at the first indication of an impending storm and include utilities and contractors beyond the local area.

- The electric utilities should continue to maintain their existing mutual aid agreements with NEMAG and NEPPA for use in future storm restoration efforts.
- The electric utilities should maintain, or expand upon, existing agreements with local line and tree contractors.
- The electric utilities should develop mutual aid agreements with utilities and contractors outside the New England region.
- The electric utilities should implement storm restoration procedures that call for expanding the search for assistance crews outside the local area at the earliest indication that a storm may potentially result in damages that exceed the capacity of restoration resources in the local area.

Conclusion: Communications with state and municipal government officials and emergency response agencies were mostly ineffective. None of the utilities provided details or responded in a timely basis when specific inquiries were made.

Any utility's response to a major storm includes more than the field work required to restore service to customers who have experienced outages. It also includes establishing and maintaining communications with the news media, government officials, emergency response agencies, and customers in the affected communities. These communications are essential in order to provide warnings of an impending storm, as well as instructions regarding safety and what the public should do during a power outage. Utilities must coordinate restoration efforts with local fire, police and public works departments in order to complete repairs safely and efficiently.

In recent years communicating estimated restoration times has become increasingly important, as customers are no longer satisfied to simply wait until service is restored. Businesses must decide when to ask employees to report for work and families need to know if they should find shelters or travel to other locations until the power is back on. The modern global business environment leaves little room for businesses to handle the impacts that power outages might have on their bottom line. Public safety officials must make important decisions regarding their emergency efforts, school closings, and shelter openings, and depend on accurate restoration times for specific locations for planning purposes and resource deployment.

PSNH

In accordance with its Emergency Response Plan, communications efforts at PSNH were coordinated by the Communications Chief. During the 13-day restoration effort, at least one of four designated Communications Chiefs was stationed in the EOC at all times. A total of 28 PSNH employees were dedicated to public communications during the storm restoration effort. Of these 28 employees, 12 were embedded in local communities in order to be better able to respond directly to municipal needs.[148]

Starting at 4:30 a.m. on Day 2, Friday, December 12, PSNH began issuing regular, proactive updates in order to keep the public as informed and safe as possible during the storm restoration effort. Updates were issued to customers and community officials through e-mail and were also posted on PSNH's website. PSNH continued issuing these updates until 5:00 p.m. on Day 14, Wednesday, December 24, the day on which its last customer was restored. These updates reflected the best information available at the time.[149]

To help facilitate communication with the State, PSNH employees were assigned to provide around-the-clock information to the Division of Homeland Security and Emergency Management and the NHPUC. PSNH officers and senior managers also participated in planning and reporting sessions with Governor Lynch, NHPUC Chairman Getz, and Safety Division Director Knepper. At the community level, PSNH employees provided regular updates to municipal officials and emergency response organizations. In the hardest-hit communities, PSNH placed employees in the municipal Emergency Operations Centers in order to meet the communities' need for more detailed, up-to-the-minute information.[150]

As soon as reliable information was confirmed from the field, PSNH began publishing restoration estimates for each town. Information for each community was gathered directly from the appropriate personnel in the field each day in order to ensure that estimates were accurate. Unfortunately, PSNH was late in implementing a process for developing restoration estimates for each town. ETRs for each community were first prepared late on Day 5, Monday, December 15 and were not disseminated to customers and the media until the morning of Day 6, Tuesday, December 16.[151]

In addition to traditional information outlets, PSNH also used a Web-based tool called "Twitter" to send and receive short bursts of information via the Internet and cell phones. Within days of the storm, the number of subscribers "following" PSNH's Twitter posts increased from 100 to about 1,900. Many subscribers found PSNH's posts especially useful since they did not have electricity, but they were able get information on their cellular telephones via Twitter.[152]

[148] PSNH. (February 2, 2009). Data Response STAFF 1-42. NHPUC.
[149] PSNH. (February 2, 20092-2-09). Data Response STAFF 1-42. NHPUC.
[150] PSNH. (February 2, 2009). Data Response STAFF 1-42. NHPUC.
[151] PSNH. (March 6, 2009). Data Response STAFF 2-20. NHPUC.
[152] PSNH. (February 2, 2009). Data Response STAFF 1-42. NHPUC.

PSNH also produced and posted on the internet a total of six videos that outlined the extent of the damage and what the company was doing. A podcast was posted to the Internet, featuring a Plymouth State University professor of meteorology explaining why the storm was so devastating and how it differed from previous storms. PSNH also provided on the Internet a means of sharing storm-related photographs by the company and customers. Throughout the restoration effort, PSNH used a secondary website, psnhnews.com, to aggregate all available information, including links to the social media sites.

Unitil

Prior to and during the 2008 ice storm, Unitil relied upon public service announcements (PSAs) to provide information about the storm and restoration efforts to its customers and community officials. The first PSA was distributed to company employees, news media, emergency response agencies, and government officials on Day 1, Thursday, December 11 at 1:15 p.m. This PSA provided toll-free numbers for Unitil, advised customers of supplies that would help them endure a power outage, and provided a forecast of anticipated weather conditions. Subsequent PSAs were issued up to five times per day and contained additional information such as the number of customers still without power.[153] Eventually PSAs also contained some indication of expected restoration times, although these were not published until the morning of Day 6, Tuesday, December 16.[154]

Unitil personnel received hundreds of calls and messages from public officials and from the media, and made efforts to respond to every one as quickly as possible and with the best information available. However, given the overwhelming impact of the storm and the challenges of the restoration efforts, there were some delays in responding to calls and requests for information. Moreover, as the restoration proceeded and repairs proved to be more extensive and time-consuming than originally expected, estimated restoration times were increased. This led to customer confusion, anxiety and a loss of confidence in the information being provided by Unitil.[155]

On Day 8, Thursday, December 18, a full week after the storm, when customers became increasingly frustrated, Unitil met with the chiefs of police of the thirteen seacoast communities to discuss opportunities to improve communication. Unitil had become concerned with the safety and welfare of line crews and field workers and sought assistance from local police to protect them from disgruntled customers. The outcome of that meeting was that Unitil implemented twice daily conference calls with emergency officials. The first was to provide an update of the plan for the day, including restoration objectives and locations where crews were expected to be working; the second call was to review the day's progress and discuss priorities

[153] Unitil. (February 27, 2009). Data Response STAFF 1-42. NHPUC.
[154] Unitil. (March 27, 2009). Data Response STAFF 2-15. NHPUC.
[155] Unitil. (February 27, 2009). Data Response STAFF 1-42. NHPUC.

for the next day. This process worked well for the remainder of the ice storm and has become a standard operating procedure for future storms.[156]

Rumor control also proved to be a significant challenge for Unitil during the restoration process. Every effort was made to immediately dispel incorrect or misleading information. Unitil also had personnel changes and experienced delays in assigning personnel to serve as contact points for communication with public officials. As the customer call center became unable to meet the demands from customers for information due to large call volume, personnel shortages and a lack of accurate data, pressures from local public officials increased significantly. As the restoration period lengthened, customers and public officials sought very specific information about the status of restoration efforts, the locations of crews, and the length of time it would take to restore specific streets or addresses. This type of specific information was generally not available.[157]

National Grid

National Grid's Energy Solutions Services department was responsible for communicating with state and local public officials during the December 2008 ice storm. At least four people in the department were dedicated to communicating with New Hampshire officials, including the Public Utilities Commission, Governor's office, and the Town of Salem Emergency Operation Center. This group used various forms of communication during the storm, such as:

- Notifying officials that a dedicated phone line was activated for communicating with municipal officials
- Hosting conference calls for public officials
- Face-to-face visits between Company personnel and local officials
- Proactive outreach to communities on a daily basis
- Follow up meetings with police and fire officials

At 6:00 a.m. on Day 2, Friday, December 12, the Municipal Room in North Andover, Massachusetts was activated and readied to accept calls from the southern communities of National Grid's New Hampshire service territory – Derry, Pelham, Salem, and Windham. A letter faxed to police, fire, and other public officials provided the direct phone number and the "wire-down" number. This was followed up with a phone call to each community asking if they received the faxed information and that they understood that the municipal phone line was activated.

National Grid also conducted frequent conference calls with public officials during the ice storm. The calls included a high-level overview of available resources, identified problem areas, and provided an estimate as to when power would be restored. Specific questions, such as requests

[156] Unitil. (February 27, 2009). Data Response STAFF 1-42. NHPUC.

[157] Unitil. (February 27, 2009). Data Response STAFF1-42. NHPUC.

for ETRs for individual locations, were discouraged because of the large number of people participating in the call. Individuals with specific questions were encouraged to call the number designated for communicating with municipal officials. Five daily conference calls were conducted. National Grid implemented face-to-face visits with communities that had large numbers of customers interrupted, on Day 4, Sunday, December 14. By that time in the restoration process, National Grid had mostly completed its damage assessment of the impacted areas. Representatives from both the Energy Solutions Services department and the division also met with police and fire chiefs at the Town of Salem Emergency Operations Center. An update of the Company's restoration activities and priorities was presented to the officials during these face-to-face visits.[158]

NHEC

Following the storm NHEC reached out to its members by placing calls to all emergency shelters to provide updates regarding the outage and projected restoration times as they were determined. NHEC also placed calls to town managers, police & fire chiefs in affected towns to update them on the progress of the restoration effort. Estimated times of restoration were first communicated on Day 5, Monday, December 15, to the seventeen towns still experiencing outages. From then on, daily outreach calls to each of the towns were directed to the appropriate fire and rescue, police or emergency center where one existed. Each town was provided with the latest estimate for the completion of restoration work and a direct call-back phone number should questions arise before the next outreach call. Estimated restoration times were provided to customer service operators, the state news media, and posted on the NHEC website. The NHEC website has a real-time outage map that provides outage information. During the ice storm additional more detailed outage information provided on a web page that was created during the storm.[159]

Recommendation No. 4: Each electric utility should improve procedures for communications with state and municipal government officials and emergency response agencies during major storms.

- The electric utilities should establish specific contact points with state agencies and municipalities to inform and educate customers regarding the company's emergency plans and what to expect during major storms.
- The electric utilities should establish a process for providing accurate and frequent ETRs for each town. This may take the form of web pages or other web-based systems, communications with town officials, and announcements to local media.
- The electric utilities should strengthen liaisons with emergency response agencies and identify areas where communications channels can be enhanced.

[158] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 13.
[159] NHEC. (March 25, 2009). Data Response STAFF 2-15.NHPUC.

- The electric utilities should establish a single point of contact for each town throughout the service territory and assign responsibility to that person for providing information from the utility to the town officials or contacts.

Conclusion: All four electric utilities took the initiative to develop lessons learned from the ice storm.

PSNH

In January of 2009, PSNH began a thorough review of events surrounding the December 2008 ice storm. Completed in February, the results were published in mid-April in a confidential document entitled, "Incident Management System Review, December 11, 2008 Ice Storm." The document contains approximately fifteen pages of observations and suggestions for improving the company's methods and procedures for responding to major storms. Roles and responsibilities, organizational strengths, and opportunities are discussed and overall comments are offered regarding the key positions in the incident management system structure. The content is primarily complimentary; however, many significant shortcomings are identified. PSNH needs to follow through with detailed implementation plans for each of the perceived deficiencies.

Unitil

In early January, 2009, Unitil conducted a self-assessment to review the company's performance in restoring power to all of its customers (both in Massachusetts and New Hampshire) following the December 2008 ice storm. The purpose of the review was to identify lessons learned and to prepare a set of specific recommendations that, when implemented, will improve Unitil's ability to withstand and respond to a future major storm or other emergency of comparable magnitude to the 2008 ice storm. Unitil's report includes a review of the circumstances that existed prior to the ice storm, restoration activities by all participants in the effort, and actions taken subsequent to storm. The report contains 28 specific recommendations related to Unitil's ability to prepare for major storms and restore outages that occur. The recommendations cover preparations for an impending storm, conducting damage assessment, staffing and training, field restoration activities, logistics support, public and customer communications, maintenance activities that improve the ability of facilities to withstand a storm, and planning efforts that prepare the supporting organizations to help with storm response. Some of the initiatives have already been implemented.[160] Detailed implementation plans are needed for the remaining recommendations.

National Grid

National Grid conducted three storm critiques that included New Hampshire and addressed the December 2008 ice storm. Each of the storm critiques identified improvement opportunities, which require further investigation and evaluation. National Grid needs to follow through with

[160] Unitil. (February 27, 2009). Data Response STAFF 1-48. NHPUC.

detailed implementation plans for each of the perceived deficiencies identified during those critiques.

NHEC

In early 2009, NHEC had competed storm critiques with key personnel. Lessons learned were communicated throughout the cooperative. New storm restoration improvement initiatives were identified and assigned for further review during more in-depth discussions. They will be included in the emergency restoration plan as appropriate.[161]

Conclusion: Staffing levels at the customer call centers for Unitil, NHEC and PSNH were inadequate to manage all CSR offered calls during the December 2008 ice storm. NHEC, in addition, did not have enough phone lines available to manage the call volume during the storm.

PSNH

PSNH has 238 telephone lines for incoming calls from customers within New Hampshire and another 119 incoming lines for customer calls generated outside the state. These incoming lines can also be used as overflow when the all 238 of the New Hampshire lines are busy. PSNH also has 69 incoming lines that are dedicated to handling Manchester local traffic only. Manchester customers may also have access to the 238 New Hampshire lines by dialing the company's 800 number. PSNH employs Twenty First Century Communications (TFCC) based in Columbus, Ohio, to handle overflow traffic when an usually high volume of calls occurs, such as during the ice storm. TFCC guarantees a certain number of lines will be available to each of its customers. If other TFCC customers are not using their lines, their lines are also available to PSNH.[162] For approximately one hour on Day 2, Friday, December 12, when call volume exceeded PSNH's capacity, customer calls were routed to TFCC.[163]

PSNH (NUSCO) employs about 62 customer service representatives (CSRs) during normal weekday hours to handle all calls both in New Hampshire and outside New Hampshire. The average peak staffing for the Manchester call center that handle PSNH calls is 45 employees. Actual staffing varies depending upon the particular time of day and day of the week. Staffing levels after hours and on weekends and holidays are substantially lower due to the decreased volume of calls. Peak staffing at the call center during the ice storm varied considerably as shown in Figure II-22. This chart shows staffing levels during the storm as compared with typical staffing levels for those days.

[161] NHEC. (February 19, 2009). Data Response STAFF 1-48. NHPUC.
[162] PSNH. (March 6, 2009). Data Response STAFF 2-9. NHPUC.
[163] PSNH. (March 6, 2009). Data Response STAFF 2-11. NHPUC.

Staffing was commensurate with call volume during the period, with the exception of Day 2, Friday, December 12; Day 10, Saturday, December 20; and day 11, Sunday, December 21.[164] Figure II-23 shows the call volume each day compared to the normal call volume on that day of the week. It may be seen that on Day 2, Friday, December 12, call volume was about twice as high as any other day during the storm, yet call center staffing levels were only slightly above normal. It is apparent from these graphs that PSNH did not ramp up staffing in anticipation of customer calls related to the storm. On the Day 10, Saturday, December 20 and Day 11, Sunday, December 21, staffing levels dropped dramatically despite the fact that customer calls were still well above normal levels.

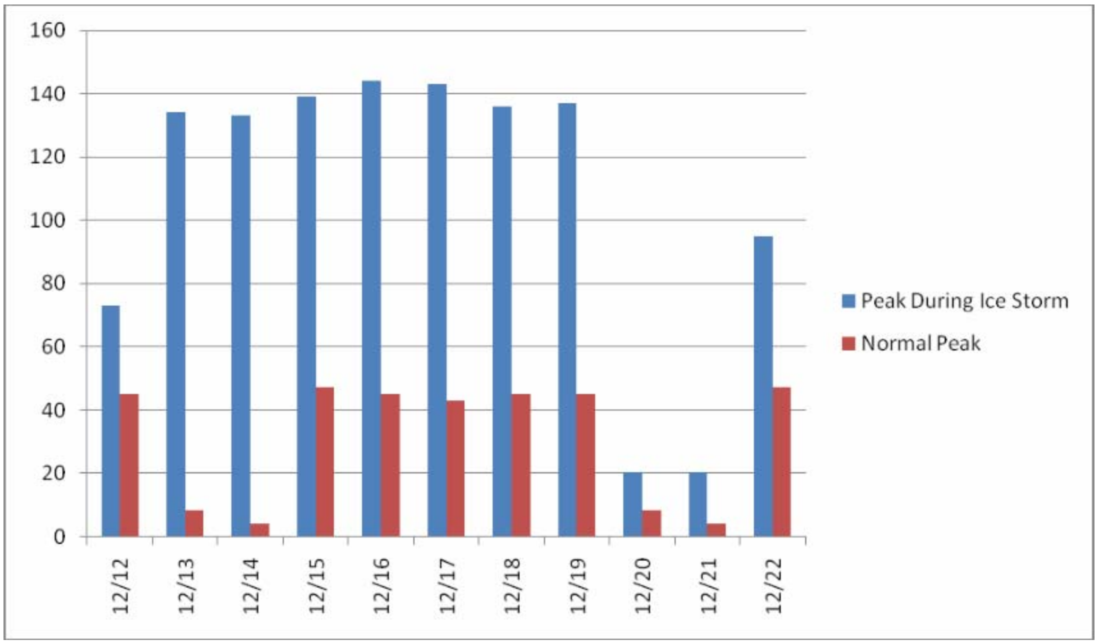

Figure II-22 – Graph showing the PSNH call center staffing levels and normal staffing levels on the days shown.[165]

[164] PSNH. (March 6, 2009). Data Response STAFF 2-9. NHPUC.

[165] PSNH. (March 6, 2009). Data Response STAFF 2-9. NHPUC.

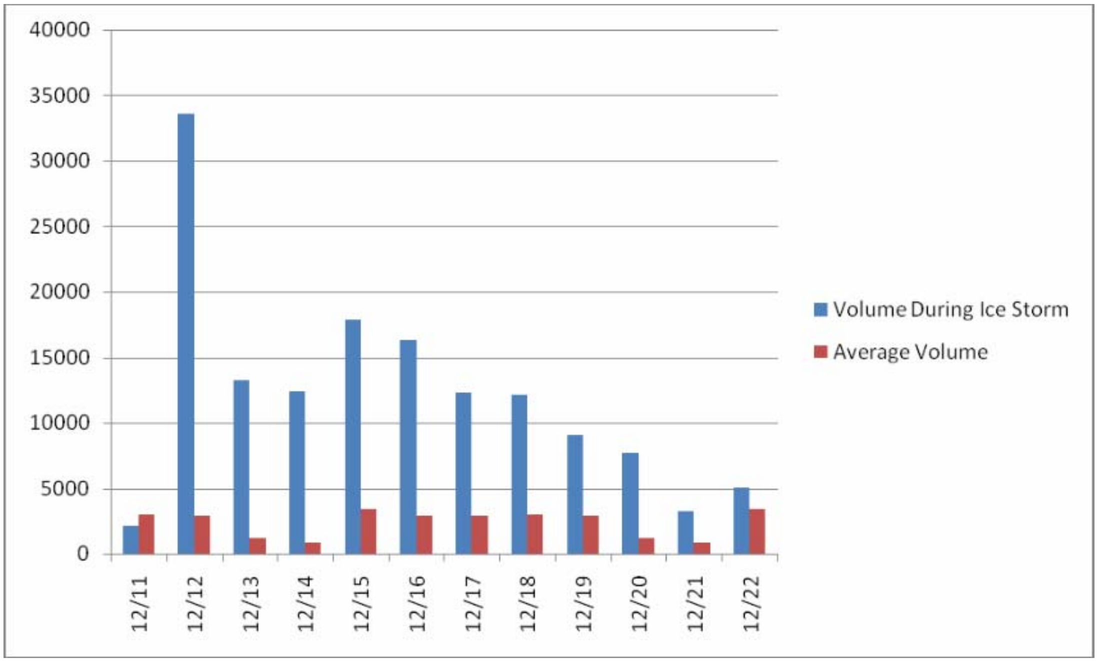

Figure II-23 – Graph showing PSNH call center call volume and the normal call volume on the days shown (CSR offered calls).[166]

[166] PSNH. (March 6, 2009). Data Response STAFF 2-9. NHPUC.

Unitil

Unitil's Customer Service Call Center is located in Concord, NH and is the central call center operation for all of the Unitil companies. At the time of the 2008 ice storm, the company had 72 lines on three 24-channel circuits. Four lines were reserved for system connectivity, leaving 68 available for incoming calls. As depicted in Table II-11, normal customer call volume at the call center requires approximately 15 customer service representatives (CSRs) to be available simultaneously during the peak period of the day. This would correspond to a normal daily call volume of approximately 1,000 calls received by the interactive voice response (IVR) system and approximately 650 answered by CSRs or 43.3 calls per representative. During the ice storm, 41 CSRs were available simultaneously to answer customer calls during the peak period of the outage which corresponded to 24,880 calls received by the IVR and 3,855 answered by the CSRs. The average number of calls answered per CSR was 94, more than twice the normal average, which indicates CSR staffing should have been higher.

Table II-11 – Volume of calls Unitil received and staffing CSR staffing levels following the storm.[167]

	Staffing	Calls Answered by CSRs	Calls Answered Per CSR
Normal	15	650	43.3
December 2008 Ice Storm	41	3,855	94

National Grid

National Grid's Customer Contact Center has 238 incoming lines along with an additional 236 backup for a total of 531 lines. At peak, National Grid's Customer Contact Center had approximately 165 employees taking incoming calls. To further streamline the process the Center shifted to handling only power outage calls during the storm event. Automatic messages from the IVR explained to customers that due to the storm, power outage and emergency calls were the priority but customers with routine requests could use the IVR menu to enter a request that would be addressed by the Company after the restoration was completed. Table II-12 represents the call volume that National Grid representatives managed for New Hampshire during each day of the ice storm.[168] The fact that nearly 100% of all calls received during the storm restoration effort were answered indicates that National Grid's call center staffing levels were appropriate.

[167] Unitil. (March 27, 2009). Data Response STAFF 2-9.NHPUC.
[168] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 14..

Table II-12 – Volume of calls National Grid CSR's received and answered following the storm.[169]

Date	Calls Offered	Calls Abandoned	Total Calls Answered	% Calls Answered
Dec 11	802	4	798	99.5%
Dec 12	5,591	77	5,514	98.6%
Dec 13	1,832	40	1,792	97.8%
Dec 14	1,887	6	1,881	99.7%
Dec 15	1,327	10	1,317	99.2%
Dec 16	953	3	950	99.7%
Dec 17	575	8	567	98.6%
Dec 18	395	1	394	99.7%
Dec 19	315	0	315	100.0%

NHEC

NHEC staffs its customer call center in Plymouth, New Hampshire with ten full time employees Monday through Friday from 8 a.m. to 5 p.m. After hours and on weekends and holidays one dispatcher is on duty to take calls. During the ice storm the call center was staffed 24 hours a day beginning on Day 1, Thursday, December 11, at approximately 9:30 p.m. Around the clock operations were maintained through 5:00 p.m. on Day 8, Thursday, December 18. At the peak staffing point 18 people were available to take calls.[170]

NHEC's telephone system has the capacity to handle a combined maximum of 115 inbound or outbound calls at one time. Any inbound calls that exceed that limit automatically go to the IVR system queue for the next available agent. While in the IVR system callers can select and listen to prerecorded messages or wait for the next available customer service representative. Normal daily call volume averages about 900 calls. Average daily inbound call volume for the outage period from Day 1, Thursday, December 11 and Day 8, Thursday December 18 was 16,778. This number represents all calls received, both normal and outage, and includes overflow calls, i.e. those calls that were not answered and resulted in a busy signal. Out of a total of 114,517 calls received, 108,391 were received by NHEC's IVR, meaning 6,126 calls could have received a busy signal.[171] These numbers indicate that some additional staffing could have been helpful to respond to customer inquiries.

Recommendation No. 5: Each electric utility should modify emergency planning procedures in order to implement a more effective means of estimating resource requirements.

- The electric utilities need to recognize that customer expectations have changed and will continue to escalate both during normal business and in emergencies.

[169] National Grid. (April 1, 2009). New Hampshire, 2008 Ice Storm Report, pg 14.
[170] NHEC. (March 24, 2009). Data Response STAFF 2-9. NHPUC.
[171] NHEC. (March 24, 2009). Data Response Staff 2-9. NHPUC.

- The electric utilities should develop and implement a more thorough means of estimating the number of outages expected during an emergency and use this information to estimate the number of customer calls that will need to be answered as a result.
- The electric utilities should develop and implement a procedure for rapidly increasing customer call center staffing levels based on the estimates.

CHAPTER III

Emergency Planning and Preparedness

Chapter Structure

A. BACKGROUND

Introduction

The purpose of this chapter is to provide an assessment of the New Hampshire electric utilities' emergency planning and preparedness. The primary goal of this review is to determine the actions, processes, and procedures that could be instituted by the utilities to improve emergency response during future widespread electric system disruptions. This would include interruptions that exceed 48 hours in length and require the use of crews from outside the normal area of operations. As part of this process, the utilities' plans and procedures were reviewed to ensure they are adequate and that they properly prioritize the items needed to facilitate restoration efforts. As a result of the review, areas for improvement are identified and recommendations are provided.

Emergency Preparedness

Emergency preparedness is one critical factor determining if a utility can respond quickly and safely to a storm or other emergency. It includes having in place the processes, tools, and procedures needed to implement a utility's emergency plan. Unless a utility has both a complete plan in place prior to an event and the tools needed to implement the plan, its effort to restore service may become an uncoordinated exercise. This lack of structure may leave it without an accurate way of assessing damage or estimating restoration dates. Once an event occurs, it is too late to put these procedures into place. The utility is then forced to resort to ad hoc methods to try to complete the restoration. This is especially true of large, multi-day events which require a fundamentally different management approach than smaller storms.

The electric utilities in New Hampshire suffered massive infrastructure damage in the December 2008 ice storm. The perception of their ability to handle major events also suffered in the eyes of regulators and the public.[1] Each of the utilities is aware of these public perception issues and has made efforts to improve them.

Challenges Faced by the New Hampshire Electric Utilities

New Hampshire utilities face two types of unique challenges. The first is due to New Hampshire's geography and the second is due to the structure of local governments within the state. The utilities must make adjustments to meet these challenges when planning for emergencies.

Geographic Challenges

Each New Hampshire utility faces unique resource procurement problems because of the state's geography. Since the geography obviously cannot be changed, it must be considered by the companies when planning for emergencies.

In widespread outages, utilities rely on resources from other utilities and outside contractors. These resources come in a myriad of forms, such as crews employed by other utilities and contractor crews, neither of which may ever have worked in New Hampshire before. Larger utilities, such as National Grid and PSNH, can supply resources from affiliates within the same region. Even so, during the 2008 ice storm restoration process, all of the utilities brought crews into their New Hampshire service areas from outside the state. Some crews came from outside the New England region.[2]

New Hampshire must look primarily south and west to obtain resources during a major outage. Since Maine and the Canadian Maritimes Provinces do not have the population base typically needed to support having large utility resources on hand, any resources that can be drawn from those areas will be minimal at best. Crews from Canadian utilities such as Hydro-Quebec are considered throughout the industry to be excellent, but they still have limitations such as:

- Potential delays associated with border crossings
- Equipment restrictions such as heavily equipped trucks designed for the rigors common in Canada but not always applicable to New Hampshire land areas[3]
- Language barriers due to some crewmembers not speaking English

The weather conditions and population density in the northeast United States also combine to hamper resource procurement for the New England utilities. Figure III-1 shows the flow of resources into New Hampshire following the ice storm.

[1] New Hampshire Public Utilities Commission. "December 2008 Ice Storm." (2009). http://www.puc.state.nh.us/2008IceStorm/December2008IceStorm.htm (Accessed August 24, 2009).
[2] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.
[3] Hydro-Quebec crews operate very large four wheel drive bucket trucks.

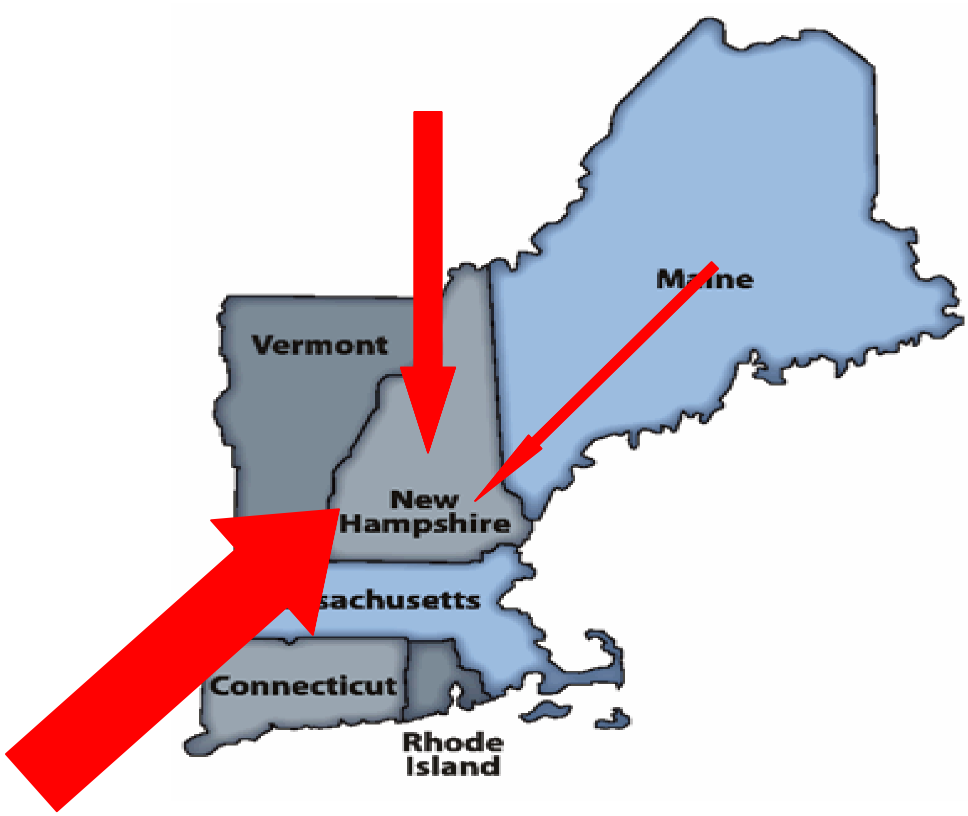

Figure III-1 - December 2008 ice storm resource flow map.
(Arrow thickness reflects the quantity of resource potentially available.)

Unlike many past ice storms where the damage tended to be localized, recent ice storms causing significant damage in New Hampshire have been widespread and have affected large areas.[4] [5] [6] [7] [8] [9] The damage from the December 2008 ice storm, for example, extended from New York through New Hampshire and south into Massachusetts. The utilities in these more populated states, with relatively larger numbers of crews available, were themselves significantly impacted by the storm. Not only did the December 2008 ice storm require these utilities to retain their crews and contractors, but also put them in direct competition for obtaining crews from outside the New England and Mid-Atlantic areas.

Efficient response to a disaster would prohibit crews from traveling through and past areas of damage to get to damaged areas farther away. The most efficient method would be for them to restore the closest damage first and then move on to more distant areas. Similarly, efficiency would dictate that areas with the largest numbers of impacted customers should be addressed

[4] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.
[5] Lynch, H. Disaster Recovery Executive, NHEC. Interviewed by Fowler, M. June 17,2009.
[6] Letourneau, R. Director Electric and Gas Operations, Unitil. Interviewed by Fowler, M. May 1, 2009.
[7] Kearns, R. Director Emergency Planning, National Grid. Interviewed by Fowler, M. June 9, 2009.
[8] Demmer, K. Manager Electric Distribution National Grid. Interviewed by Fowler, M. June 9, 2009.
[9] Francazio, R. Director of Emergency Planning, Unitil. Interviewed by Fowler, M. May 20, 2009.

first. Both of these factors place New Hampshire at a disadvantage following a large scale storm since crews coming from the south and west would likely be called upon to assist in restoration efforts in New York and Pennsylvania before arriving in New Hampshire.

Challenges of New Hampshire's Local Government Structure

New Hampshire's local governmental structure also presents a challenge to the utilities. New Hampshire has 234 incorporated cities and towns, most with some form of emergency management. The size, professionalism, and sophistication of the emergency management personnel, and the resources each town has at its disposal, vary tremendously. Figure III-2 illustrates the variation in population among the 234 municipalities as reported by the New Hampshire Office of Energy and Planning. New Hampshire communities vary in size from Manchester, with a population of more than 100,000, to towns that are home to only 32 people. Of the 234 municipalities, 47 had a 2007 population of less than 1,000 residents.

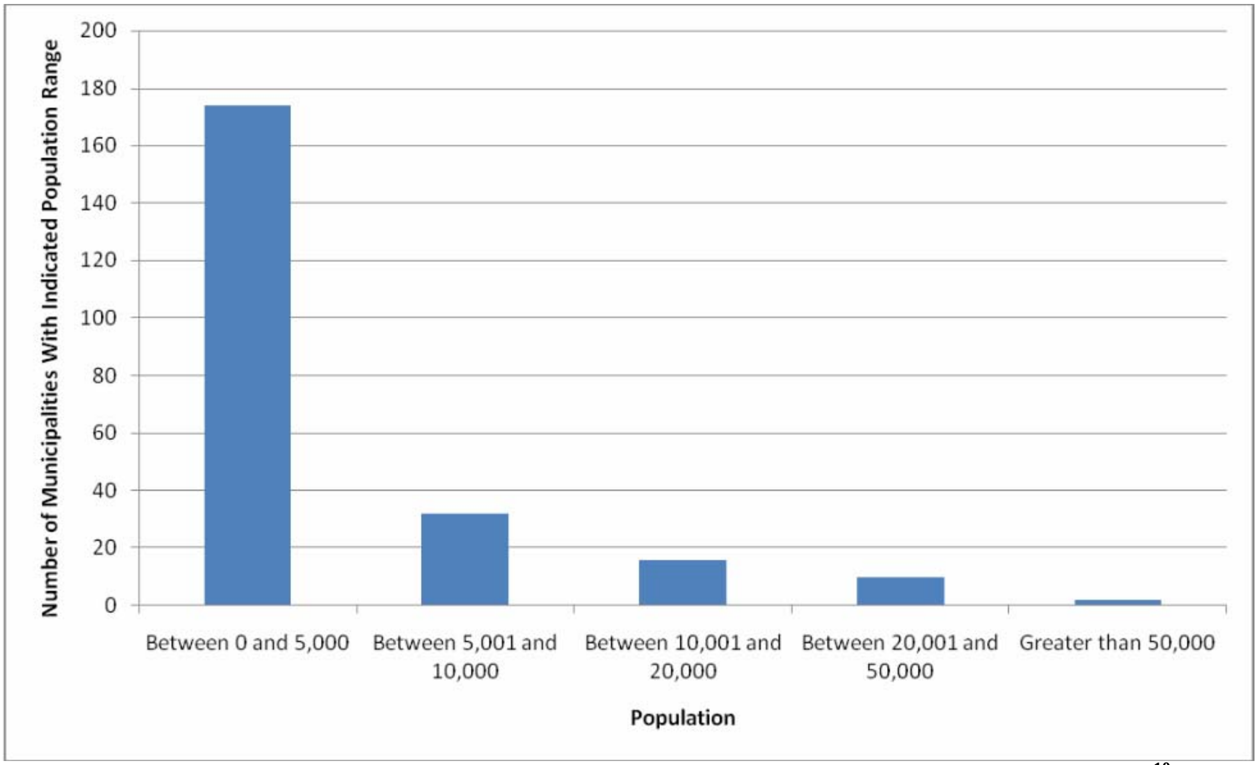

Figure III-2: Number of municipalities in New Hampshire with populations ranging as shown.[10]

Since the utilities must interact with each town affected by an emergency, their emergency plans must be designed to handle the tremendous variation that exists within their respective service

[10] New Hampshire Office of Energy and Planning State Data Center Library. "Population Estimates." (n.d.). http://www.nh.gov/oep/programs/DataCenter/Population/documents/ranking_population_by_municipality_2007_estimates.xls (Accessed August 24, 2009).

territories. The methods each utility may need to coordinate with such a diverse range of municipalities must be reflected in their plans. A "one size fits all" approach will not work for the New Hampshire electric utilities.

The four New Hampshire electric utilities are also vastly different from each other in terms of service territory, organizational structure, and numbers of customers served in New Hampshire. A description of the electric utilities, along with a map showing the territories they each serve in New Hampshire, may be found in Chapter I of this report.

Emergency Plans

Emergency planning forms the basic underpinning of any company's ultimate performance during an emergency. Without a workable emergency plan, a company simply cannot perform during a storm in other than a disorganized, reactive manner. A plan must be more than a document that occupies shelf space; it must be workable and well distributed throughout the organization, and it must use past storm experiences to ensure it realistically represents actual storm restoration conditions.

Increasingly, utilities are finding that emergency response requires a dedicated and well trained staff to put their emergency plans into practice. The utility must have facilities specifically designed for housing the emergency management operation. Emergency response is becoming a dedicated professional aspect of electric utility operations.

Storm Preparation

Storm preparation includes the actions a utility takes to be ready for an imminent storm. This generally means the activation and staffing of the utility's Emergency Operations Center (EOC). In New Hampshire, PSNH and NHEC both have statewide emergency operations centers. Unitil uses its corporate EOC due to the relatively small geographic area of its operations. National Grid does not have a statewide EOC in New Hampshire since it serves only a small number of customers in the state. National Grid activates its emergency response at the local level in New Hampshire, and large outages are managed at the corporate level EOC in Northborough, MA.

Communications

There were many communications problems following the December 2008 ice storm, including failure to properly communicate with the public, local officials, and other utilities.[11] Company self-assessments, comments collected from customers, and interviews with state and local officials all point to communications as the number one area needing improvement. Additionally, comments from hundreds of citizens were solicited by the NHPUC after the storm

[11] New Hampshire Public Utilities Commission. "December 2008 Ice Storm." (2009). http://www.puc.state.nh.us/2008IceStorm/December2008IceStorm.htm (Accessed August 24, 2009).

at a series of ten town hall meetings and on the NHPUC web site to gather input from the public.[12] Those comments point repeatedly to communication failures.

Communicating with state regulators is also important for the utilities. Utilities are accustomed to working with regulators in a structured, paced environment, and the need to provide real-time information is somewhat new. The New Hampshire utilities have all begun efforts to enhance their communications with state agencies during emergencies,[13] but additional reporting efforts will be needed. The communication enhancements planned include standardizing the following:

- Terminology used
- Frequency of communications
- Communications methods used
- Content of the communications to be delivered.

B. EVALUATIVE CRITERIA

Four criteria were chosen to evaluate the utilities. These are:

1. Content of the emergency plan
2. Emergency preparedness
3. Emergency organization and facilities
4. Communications

1. Each utility should have an emergency plan.

- Each utility should have an up-to-date plan that reflects what experience shows actually happens during a storm or other emergency.
- Each utility should maintain and modify their plans as needed.
- Each electric utility should include the following in their plan:
    - Weather monitoring and alert procedures
    - Storm damage classifications
    - Duty supervisor coverage
    - Resource procurement, mutual aid, and contractors
    - Safety protocols
    - Emergency operating center locations, technology standards, and facilities
    - Facility contingency plans
    - Activation checklists
    - Call-out and hold-over procedures

[12] New Hampshire Public Utilities Commission. "December 2008 Ice Storm." (2009). http://www.puc.state.nh.us/2008IceStorm/December2008IceStorm.htm (Accessed August 24, 2009).
[13] The utilities and representatives of the New Hampshire EOC are meeting monthly to develop procedures for communicating information.

- Process for transitioning trouble-men from dispatch control to emergency control
- Ramp-up and ramp-down protocols
- Damage assessment and restoration time procedures
- Electric system information and the process for distribution information
- Emergency first responder contact information and responsibility for coordination
- Public safety personnel procedures (wire watchers)
- Cut in clear and make safe procedures
- Critical infrastructure, hospitals, nursing homes, etc.
- Fleet operations, fueling, permitting, security
- Logistics procedures, sanitation, food, lodging, clean-up, lighting, laundry
- Staging areas
- Outage management system procedures
- Coordination with forestry and external crews
- Information on responding to multiple and simultaneous large-scale outages, including a prioritization procedure
- Plans for communicating with local officials, state agencies, and the public.
- Clear trigger points at which it is activated
- An escalation process that will take place as additional trigger points are reached.
- A clear management strategy for storm restoration (For example, the strategy might require all necessary resources be deployed for customers to be restored within seven days of a major storm.)
- A clear definition of roles and responsibilities for all participants during an emergency
- Procedures for obtaining adequate personnel, equipment, and facilities for storm response
- Procedures for deploying and managing outside resources
- Procedures for assessing the accuracy of collected outage data
- Procedures for assessing damage and developing service restoration estimates
- Procedures for responding to multiple simultaneous large-scale outages in different operating areas

2. Each utility should prepare for the emergency using drills, training, and post-drill critiques.

- A formal schedule of training and drills should exist at each utility; the drills should be fully described as to the scenario and realism.
- Post-event critiques of the training efforts should be performed.

3. Each utility should have the proper emergency organization and facilities in place.

- The utility should have a dedicated facility for emergency response operations.
- The facility should be maintained in a mode to allow prompt activation.
- The Incident Command System (now Incident Management System) should be in place.
- Employees should be trained and familiar with the organization being used.

4. Each utility should have policies in place to ensure effective communications during emergency events.

- The utility should have procedures that include communications on every level, including communications with state and local officials and the media.
- The utility's procedures should ensure that the content of all communication is reliable and consistent.
- The utility should have procedures to ensure that information is passed to customer service personnel who interface directly with customers.
- The utility should have procedures in place to ensure that first responders always have a means for contacting utility officials.
- All of the utilities should work with the state to develop communication protocols prior to an emergency.
- All of the utilities and the state EOC should have single points of contact for use during an emergency.

The following tables indicate the extent to which each of the utilities met the evaluative criteria. These tables were not prepared to compare one utility with another. The four electric utilities are very different, face different problems, and experienced different amounts of damage to their systems due to the storm. These tables were prepared to show where each utility may improve its performance in preparation for the next storm or other disaster. A further explanation for the improvements that are recommended to each of the utilities may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are as follows:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table III-1 – PSNH Emergency planning and response evaluation matrix.

1) CONTENT OF THE EMERGENCY PLAN	
The utility has an up-to-date plan that reflects what experience shows actually happens during an emergency.	◐
The utility maintains and modifies the plan as needed.	●
The plan includes trigger points for when it is activated and when it escalates.	●
The plan includes a clear management strategy for storm restoration.	○
The plan defines roles and responsibilities for all participants.	◐
The plan includes each of the items suggested in the report.	◐
The plan includes procedures for obtaining adequate personnel, equipment, and facilities for storm response.	◐
The plan includes procedures for deploying and managing outside resources.	◐
The plan includes procedures for assessing the accuracy of collected outage data.	○
The plan includes procedures for assessing damage and developing restoration estimates.	○
The plan includes procedures for responding to multiple simultaneous large-scale outages in different operating regions.	●
2) EMERGENCY PREPAREDNESS	
The emergency plan is actually used to manage emergency events.	●
The utility has a formal schedule of training and drills.	◐
The utility does post event critiques of training events.	●
3) EMERGENCY ORGANIZATION & FACILITIES	
The utility has a dedicated facility for emergency response operations.	◐
The emergency response facility is maintained in a mode to allow prompt activation.	○
The utility has an Incident Command System.	◐
Personnel are trained in the organization being used.	◐
4) COMMUNICATIONS	
The utility has procedures that include communication to state and local officials and the media.	◐
The utility has a procedure to ensure that the content of all communication is reliable and consistent.	◐
The utility has procedures to ensure that information is passed to customer relations personnel.	◐
The utility has procedures to ensure that first responders have means for contacting the utility.	◐
The utility works with the state to develop communications protocols for use during an emergency.	●
The utility and the state EOC have single points of contact during and emergency.	●

Table III-2 – Unitil emergency planning and response evaluation matrix.[14]

1) CONTENT OF THE EMERGENCY PLAN	
The utility has an up-to-date plan that reflects what experience shows actually happens during an emergency.	○
The utility maintains and modifies the plan as needed.	○
The plan includes trigger points for when it is activated and when it escalates.	○
The plan includes a clear management strategy for storm restoration.	○
The plan defines roles and responsibilities for all participants.	○
The plan includes each of the items suggested in the report.	○
The plan includes procedures for obtaining adequate personnel, equipment, and facilities for storm response.	○
The plan includes procedures for deploying and managing outside resources.	○
The plan includes procedures for assessing the accuracy of collected outage data.	○
The plan includes procedures for assessing damage and developing restoration estimates.	○
The plan includes procedures for responding to multiple simultaneous large-scale outages in different operating regions.	○
2) EMERGENCY PREPAREDNESS	
The emergency plan is actually used to manage emergency events.	○
The utility has a formal schedule of training and drills.	○
The utility does post event critiques of training events.	○
3) EMERGENCY ORGANIZATION & FACILITIES	
The utility has a dedicated facility for emergency response operations.	○
The emergency response facility is maintained in a mode to allow prompt activation.	○
The utility has an Incident Command System.	○
Personnel are trained in the organization being used.	○
4) COMMUNICATIONS	
The utility has procedures that include communication to state and local officials and the media.	○
The utility has a procedure to ensure that the content of all communication is reliable and consistent.	○
The utility has procedures to ensure that information is passed to customer relations personnel.	○
The utility has procedures to ensure that first responders have means for contacting the utility.	○
The utility works with the state to develop communications protocols for use during an emergency.	○
The utility and the state EOC have single points of contact during and emergency.	○

[14] Unitil has made significant changes to its plan since the audit and has indicated to NEI that all evaluative criteria items are now included in the plan. The NEI matrix addresses the plan at the time of the audit.

Table III-3 – National Grid emergency planning and response evaluation matrix.

1) CONTENT OF THE EMERGENCY PLAN	
The utility has an up-to-date plan that reflects what experience shows actually happens during an emergency.	●
The utility maintains and modifies the plan as needed.	●
The plan includes trigger points for when it is activated and when it escalates.	●
The plan includes a clear management strategy for storm restoration.	●
The plan defines roles and responsibilities for all participants.	●
The plan includes each of the items suggested in the report.	●
The plan includes procedures for obtaining adequate personnel, equipment, and facilities for storm response.	●
The plan includes procedures for deploying and managing outside resources.	●
The plan includes procedures for assessing the accuracy of collected outage data.	●
The plan includes procedures for assessing damage and developing restoration estimates.	●
The plan includes procedures for responding to multiple simultaneous large-scale outages in different operating regions.	●
2) EMERGENCY PREPAREDNESS	
The emergency plan is actually used to manage emergency events.	●
The utility has a formal schedule of training and drills.	●
The utility does post event critiques of training events.	◐
3) EMERGENCY ORGANIZATION & FACILITIES	
The utility has a dedicated facility for emergency response operations.	●
The emergency response facility is maintained in a mode to allow prompt activation.	●
The utility has an Incident Command System.	●
Personnel are trained in the organization being used.	●
4) COMMUNICATIONS	
The utility has procedures that include communication to state and local officials and the media.	◐
The utility has a procedure to ensure that the content of all communication is reliable and consistent.	◐
The utility has procedures to ensure that information is passed to customer relations personnel.	◐
The utility has procedures to ensure that first responders have means for contacting the utility.	◐
The utility works with the state to develop communications protocols for use during an emergency.	◐
The utility and the state EOC have single points of contact during and emergency.	◐

Table III-4 – NHEC emergency planning and response evaluation matrix.

1) CONTENT OF THE EMERGENCY PLAN	
The utility has an up-to-date plan that reflects what experience shows actually happens during an emergency.	◐
The utility maintains and modifies the plan as needed.	◐
The plan includes trigger points for when it is activated and when it escalates.	●
The plan includes a clear management strategy for storm restoration.	○
The plan defines roles and responsibilities for all participants.	◐
The plan includes each of the items suggested in the report.	◐
The plan includes procedures for obtaining adequate personnel, equipment, and facilities for storm response.	◐
The plan includes procedures for deploying and managing outside resources.	◐
The plan includes procedures for assessing the accuracy of collected outage data.	●
The plan includes procedures for assessing damage and developing restoration estimates.	●
The plan includes procedures for responding to multiple simultaneous large-scale outages in different operating regions.	◐

2) EMERGENCY PREPAREDNESS	
The emergency plan is actually used to manage emergency events.	●
The utility has a formal schedule of training and drills.	○
The utility does post event critiques of training events.	◐

3) EMERGENCY ORGANIZATION & FACILITIES	
The utility has a dedicated facility for emergency response operations.	◐
The emergency response facility is maintained in a mode to allow prompt activation.	○
The utility has an Incident Command System.	○
Personnel are trained in the organization being used.	◐

4) COMMUNICATIONS	
The utility has procedures that include communication to state and local officials and the media.	●
The utility has a procedure to ensure that the content of all communication is reliable and consistent.	●
The utility has procedures to ensure that information is passed to customer relations personnel.	●
The utility has procedures to ensure that first responders have means for contacting the utility.	◐
The utility works with the state to develop communications protocols for use during an emergency.	◐
The utility and the state EOC have single points of contact during and emergency.	◐

C. TASKS

In assessing emergency planning and preparedness, various employees and managers of the four electric utilities were interviewed. A number of data requests were submitted and the responses were analyzed. During this analysis, focus was placed on the plan each electric utility had in place and how each plan was executed following the storm. The response of the public to the preparedness of the utilities was examined and the recommendations given here should serve to improve the planning and preparedness of the four electric utilities for the next storm.

Some significant modifications are already being made by the electric utilities. This is especially true with Unitil, which experienced some of the most negative public and regulatory scrutiny following the storm. Some of the recommendations that follow may already have been implemented by the time this report is published.

D. FINDINGS AND CONCLUSIONS

Conclusion: Both PSNH and National Grid had thorough Emergency Operations Plans and organizations during the ice storm but Unitil and NHEC did not.[15]

PSNH manages storms operationally on a state-wide basis with a corporate organization at Northeast Utilities (NU) providing logistics and support. All Emergency Operations Centers (EOCs) personnel for New Hampshire reside within the state and report to the PSNH EOC during an event. All administration, drills, training, and other functions pertaining to emergency preparedness are handled within the New Hampshire organization. The other two Northeast Utilities electric companies, Western Massachusetts Electric Company and Connecticut Light and Power, operate their own EOCs using NU in the same support role.

Unitil had a plan in place prior to the December 2008 ice storm; however, the plan proved inadequate for the severity of the storm and the amount of damage that was experienced. Unitil is a relatively small utility in terms of customer base, geographic coverage, and staffing. The staffing element in particular put Unitil at a significant disadvantage. Its resources were stretched during the prolonged outage caused by the storm and it did not have the manpower to adequately manage a large inflow of external resources.

In March of 2009, Unitil published the results of a comprehensive self-assessment.[16] The self-assessment document included 28 recommendations, many with multiple components. Unitil is currently acting upon these recommendations. Unitil also hired the person who managed National Grid's deployment to Unitil's service territory during the 2008 storm as its new Director of Business Continuity and Emergency Planning. He also has experience with Florida Power and Light, which is considered an industry leader in emergency restoration. His

[15] Unitil. (February 27, 2009). Data Response STAFF 1-1. NHPUC.
[16] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report.

responsibilities include developing the new Emergency Plan and organization for Unitil which was underway at the time of the audit.

National Grid uses a different organizational approach than the other utilities. All emergency plan administration, exercise development, training, and administration are handled at the corporate level in a support organization. All emergency operations functions are handled in a separate operations organization.

NHEC does not have a formal emergency plan.[17] Despite the lack of a formal plan, NHEC performed well during the December 2008 ice storm and even provided crews to assist other utilities in the restoration effort. This was the result of several factors. NHEC was fortunate that much of the severe damage occurred outside of its service territory. It is also staffed with very experienced people who are thoroughly familiar with their jobs. Nonetheless, the lack of a thorough plan places too much responsibility on the few employees it has to draw upon in an emergency. This poses a significant risk for NHEC's business continuity during an emergency.

Conclusion: The utilities conduct post-storm reviews but these are not part of the emergency plans.

All four New Hampshire electric utilities performed self-assessments using various degrees of formality following the storm. Those post storm self-assessment procedures are not presently part of any of the utilities' Emergency Operations Plan.

Recommendation No. 1: Each electric utility should include post-storm critiques and lessons learned should be included in their Emergency Operations Plan.

- Each electric utility should include a procedure for post-storm self-assessments in its Emergency Operations Plan.
- Each electric utility should include in its plan the requirement that self-assessments should be performed after any event that results in customers being without power for 72 hours or more.
- Each electric utility should include in its plan the requirement that the self-assessment should include:
    - Accuracy of weather predictions if weather was involved
    - Customers restored per crew day
    - Actual restoration times versus projections
    - A critique of contract or foreign crews that participated in the outage
    - Suggestions from all involved as to needed improvements
    - Identification of things that were done well

[17] NHEC. (March 24, 2009). Data Response STAFF 1-1. NHPUC.

Conclusion: The utilities have business continuity plans but they are not integrated with storm plans.

At times the worst case scenario may occur. To prepare for such eventualities, the utilities have developed business continuity plans that address pandemics such as the flu and other issues beyond simple utility operation following a storm. As is customary, these plans are separate from the emergency operations plans.

Recommendation No. 2: Each electric utility should include a contingency for coincidental emergencies in their Emergency Operations Plan.

- Each electric utility should include in its emergency plan procedures for responding to a major outage coincident with an epidemic flu outbreak or other widespread health emergency which could reduce the size of the available work force.
- Each electric utility should include its business continuity plans in its Emergency Operations Plan.

Conclusion: Critical customer lists are not being consistently updated and coordinated with local cities and towns.

Critical customers are those who have been identified by local towns and cities as having a high priority for restoration. These include facilities that support first responders and provide essential community services such as police and fire facilities, hospitals, water and wastewater facilities, and buildings that may be used as shelters. Establishing communications between the utilities and the emergency directors of each town to obtain and update these lists can be useful for future cooperation during an emergency.

Recommendation No. 3: Each electric utility should have its representatives make contact in person with the emergency directors of each of the towns in its service territory to gather information on critical customers within those towns. Where practical, this should be done within 60 days after the publication of this report.

- The utility representative making contact with the town should be the actual person who would serve as primary contact for the local emergency operations center.
- The utility representative should use this visit for planning and information gathering.
- Both the utility representative and the town representative should confirm the points of contact and name alternates in each organization.
- The utility’s representative and the town’s representative should prepare an accurate list of critical customers.
- The utility’s representative and the town’s representative should agree on a process for updating the critical customers list and arrange for future periodic contact.
- The great variation in New Hampshire municipalities and towns may require that the smallest population centers be contacted after 60 days.

Conclusion; None of the utilities' emergency plans include procedures for communications with telephone and cable companies.[18] [19] [20] [21]

Historically, telecommunications restoration has been conducted after all electric restoration has been completed. The purpose of this timing has been to ensure that damaged areas are safe for telecommunications workers to enter prior to performing their repairs. Following the 2008 ice storm, this approach hampered the use of tools that rely on the telephone system to function. These tools could have helped the electric utilities understand the amount of damage they were facing and where the damage was occurring if loss of the telecommunications system had not prevented them from operating.

In the case of Unitil, the damage to the telephone infrastructure prevented communications to its substations. This rendered much of its electric system intelligence gathering technology useless since the data it collects is carried over telephone lines. As the utilities install more sophisticated smart metering in the future, and use it in conjunction with their outage management systems (OMS), communications will become even more vital. Any disruption to the communications system may result in sophisticated technology becoming useless during the restoration effort.

Recommendation No. 4: Each electric utility should expand its emergency response plans to include procedures for communicating with telephone and cable companies so vital telecommunications can be restored as quickly as possible.

- Each electric utility should provide restoration time estimates to the telecommunications companies so they can coordinate their own efforts in providing emergency generators for cell sites and other critical installations.
- The electric utilities and the telephone companies should coordinate their efforts so that telecommunications, especially to substations and other supervisory control and data acquisitions (SCADA) terminals, can be restored as soon as it is safe to do so.
- Each electric utility should include the cable providers in this effort to the extent that they provide communications that could be of aid to the electric utilities during their restoration efforts.

Conclusion: Security was inadequate during the December 2008 ice storm.

The day-to-day security provided by many utilities for their critical facilities is normally quite extensive. During large and prolonged outages additional staging areas are needed to accommodate the large influx of outside personnel and equipment. These staging areas are not normally included in the electric utility's operational infrastructure and may include facilities

[18] Unitil. (February 27, 2009). Data Response STAFF 1-1. NHPUC.
[19] PSNH. (February 2, 2009). Data Response STAFF 1-1. NHPUC.
[20] National Grid. (February 27, 2009). Data Response STAFF 1-1. NHPUC.
[21] NHEC. (February 19, 2009). Data Response STAFF 1-1. NHPUC.

such as malls, dormitories, and schools. These facilities may not have sufficient security in place to protect electric utility equipment and restoration materials around the clock.

Security is important not only for preventing theft of the electric utility's equipment and material, but also for protection of the customers. During prolonged outages customers' frustration sometimes leads them to enter marshalling areas. People have also been known to attempt to enter headquarters and other facilities, which is disruptive and potentially dangerous to the electric utility's operations and personnel.

Recommendation No. 5: Each electric utility should arrange for security services as part of its emergency plan.

- Each electric utility should identify security services and secure contracts to provide for patrols of offsite staging areas, fueling depots, EOC's, and other facilities
- Each electric utility should arrange to provide standby security services and place them on alert prior to storms in the same way and at the same time that other elements used for emergency response are placed on standby.
- Each electric utility should make one person responsible for activation of the security contact and deployment of the resources.
- Each electric utility should coordinate with its EOC logistics staff to ensure that the security forces have food and lodging.
- Each electric utility should identify secure operational staging areas in all service territories using the response to the December 2008 storm as a guide.
- Each electric utility should list the staging areas within its emergency response plan including contacts for the area, maps, GPS coordinates, description of the facilities, and any limitations such as truck restrictions, weight limits, or fueling difficulties.

Conclusion: The New Hampshire electric utilities perform very little forensic analysis of storm damage, do not document major weather events, and do not use a predictive damage model.

None of the four utilities makes an organized effort to collect information on the damage that occurs during storms or the exact causes of that damage. The utilities also do not attempt to determine the extent of damage that will be incurred in future storms based upon weather predictions.[22] [23] [24] [25]

[22] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.
[23] Lynch, H. Disaster Recovery Executive, NHEC. Interviewed by Fowler, M. June 17,2009.
[24] Demmer, K. Manager Electric Distribution, National Grid. Interviewed by Fowler, M. June 9, 2009.
[25] Letourneau,R. Director Electric and Gas Operations, Unitil. Interviewed by Fowler, M. May 1, 2009.

Stories and anecdotes abound about the weather conditions and the amount of damage seen during the December 2008 ice storm, but the utilities gathered virtually no evidence concerning the actual amount of ice that accumulated or the exact type of damage that occurred. It would be useful to try to correlate the storm prediction, the actual storm results, and the amount and types of damage resulting from the storm. This could aid in planning for storm damage when the next storm threatens. In order to develop a damage prediction model, the utilities would need to collect data on actual weather events, along with directly associated damage to their facilities. None of the utilities in New Hampshire is presently collecting this information.

Recommendation No. 6: Each electric utility should develop a method for collecting and archiving data following emergency events and use this data to develop a predictive damage model for use in future storm planning.

- Each electric utility should develop as part of their emergency response plans document retention policies regarding:
    - Weather alerts and communication with weather services
    - Measurements of the amount of ice, wind, or other phenomena experienced
    - Estimated restoration time provided to all parties
    - Crew requests
    - Mutual aid calls
    - Conference call notes
    - Activation time of the state EOC
    - Any internal crew hold-overs
    - The number of crews, their locations, and any overtime worked
    - Any calls made to mutual aid, contractors, and other external resources
    - All weather information gathered, including forecast and actual experience
    - External personnel and crews used and the time required to obtain these crews
    - Estimated and actual restoration times
    - Call center statistics including average speed of answer, staffing per shift or hour, and blocked calls
    - The amount of equipment replaced.
- Each electric utility should retain this information for all storms lasting more than one day.
- Each electric utility should include the methods for recording and retaining this data in their Emergency Operations Plan.
- Each utility should make use of the Cold Regions Research and Engineering Laboratory (CRREL) to determine exact storm precipitation and wind values. This information should be used to develop construction requirements that are more suitable for conditions

found in New Hampshire than the general methods contained in the National Electrical Safety Code (NESC).

Conclusion: The utilities' current storm drill does not include participation by state and local governments, mutual aid, first responders, telecommunication companies, or other utilities.

Drills are an integral part of storm preparations and allow utilities to find and correct weaknesses in a test environment. All of the utilities conduct drills but these include only electric utility personnel and do not include any of the interactions that should occur with outside entities. As seen during the December 2008 ice storm, the complications resulting from large-scale storm response came mainly from outside the company. The complications result from the increased need for communication and coordination with entities beyond the channels normally used for communication within the company. Communication channels to diverse groups such as police and fire officials, regulators, the media, other utilities, contractors (both line and forestry) and customers become vital during an emergency.

Recommendation No. 7: Each electric utility should expand emergency readiness drills beyond the individual companies.

- Each electric utility should conduct at least a bi-annual drill that is coordinated with the New Hampshire electric and telecommunications utilities, mutual aid organizations, cities and towns, and the state Homeland Security and Emergency Management organization.

Conclusion: All of the New Hampshire utilities except NHEC use professional weather services, but none maintain in-house meteorologists.

Each of the four electric utilities generally does a good job of monitoring the weather and activating its EOC when threatening weather approaches. Three of the electric utilities utilize professional weather services on a contract basis to provide weather advisories, warnings and alerts. In addition to storm preparation, each electric utility continually monitors weather conditions to prepare for temperature and weather associated load changes. Each of the utilities also monitors publicly available data provided by television, radio weather stations, and internet weather sites.

NHEC is the only one of the four electric utilities in the state that does not subscribe to a professional weather service. NHEC's position is that it can obtain adequate information at no cost from the media and other public services. Further, it makes use of weather data that is available through the Federal Aviation Administration (FAA) and the National Oceanic and Atmospheric Administration (NOAA). Lack of advance warning concerning the ice storm did not appear to be an issue in delaying response to the storm for any of the utilities. This fact, along with NHEC's excellent response to the December 2008 ice storm, makes its position appear reasonable.

Conclusion: The New Hampshire utilities have not totally implemented the Incident Command System.

The Incident Command System (ICS) is a concept for managing emergencies that has been adopted throughout the U.S. and other parts of the world. ICS, which is now integrated under the National Incident Management System (NIMS), is universally used by federal, state, and local agencies. Its use is required in order for these agencies to receive federal funding. Utilities across the U.S. and Canada are adopting ICS in at least a modified version.

The ICS has a number of attributes that make it attractive to utilities. It is a scalable and flexible management structure that allows for expansion and contraction of the organization as required. Under the ICS, all entities speak a common language and chains of command and communication are clearly defined. This could have been helpful during the December 2008 ice storm restoration effort since communication was a principal failing of all of the utilities.

PSNH operates under a NIMS structure, but only at the PSNH Area Commander level.[26] PSNH decentralizes the actual management of the storm restoration to the three Division Incident Commanders and the Area Work Center (AWC) Incident Commanders within each Division. The Divisions do not replicate the Area Commander's organization. Those departments reporting directly to the Area Commander include:

- Administrative Support
- Division Incident Commanders (Operations)
- Planning
- Logistics
- Safety and Environmental
- Communications
- Customer Service
- Control Center
- Central Warehouse
- Automotive Maintenance
- Information Technology

Those reporting directly to the Division Incident Commander include:

- Administrative Support
- AWC Incident Commanders (operations)
- Resource Planning

[26] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.

Under a fully implemented NIMS organization, most of the Area Commander functions would have complimentary functions under the Divisions and in some cases the Area Work Centers.

The previous Unitil plans were ill suited to large scale emergencies. They were also inconsistent among its three divisions. These are all problems that an IMS structure is designed to resolve. The Unitil Emergency Management structure is presently being developed and implemented. It will likely resemble an ICS structure when completed. There is also a wealth of training readily available, and the structure being developed will mean Unitil would be using the same terminology and organization as the community first responders and the state EOC.

National Grid's emergency management structure most closely aligns with the modified ICS structure used by many utilities. It includes tiered roll-ups in responsibility from Division to Region to System.

NHEC has an emergency management structure in place which performed very well during the storm. However, its emergency structure is not well developed.

Recommendation No. 8: Each electric utility should fully implement the Incident Command System (ICS) concept and Unitil should adopt the IMS as its new structure for emergency management.

- Unitil, National Grid, and NHEC need to take major steps toward implementing the ICS concept.
- PSNH should expand its IMS approach further into the organization and better align Division and Area Work Center organizations with the EOC functions.
- PSNH should continue to expand the IMS approach into its field organizations.
- PSNH should implement those recommendations noted in its "Incident Management System (IMS) Review."
- PSNH should add a planning chief to the Division.
- PSNH should add communications personnel to Divisions and Area work centers.
- PSNH should evaluate other IMS functions and add or remove Divisions and Area work Center functional components as needed.
- Unitil should continue to modify its Emergency Operations Plan and adopt the IMS as its structure for emergency management.

Conclusion: Of the four New Hampshire electric utilities, only National Grid operates a dedicated Emergency Operations Center (EOC).

Emergency Operations Centers are the control hub of the restoration effort. They tend to vary widely in makeup from one utility to another. Many utilities continue to use facilities normally used for other purposes, as their EOCs during emergency conditions. The trend in the industry appears to be constructing a facility dedicated only to emergency response.

PSNH has an area of its headquarters facility that it uses for an EOC but has no dedicated facility set aside for use as an operations center.[27] At present, the PSNH EOC is a series of tables, cubicles, and a conference room. This is insufficient to manage the normal chaos of a major restoration event. The facility should at a minimum be secure, have a back-up power supply, and have pre-existing dedicated phone lines, radio communications, extra computer terminals, and television monitors for weather and news coverage. PSNH does have remote emergency command posts.

Unitil had no dedicated facility for an EOC, but is in the process of establishing one for the future.[28] As of July 2009, floor plans were under review for the facility that will be located in North Hampton, New Hampshire.

NHEC utilizes a conference room that has no pre-existing emergency facilities other than tables, chairs, and some telephones. NHEC has obtained an OMS, a GIS, and they are attempting to expedite the deployment of an AMI system. These are excellent tools during a widespread outage. The implementation of these tools would only leave the absence of a dedicated EOC as a weak point in their emergency response plan.

Only National grid operates a dedicated EOC.

Recommendation No. 9: PSNH should dedicate an emergency response area solely for the purpose of managing outage events; Unitil should continue with their plans for a dedicated EOC; NHEC should explore options for building a dedicated EOC or obtaining a mobile command center.

- PSNH should develop a dedicated area for a state emergency operations center and should revise its emergency response plan to include the specifics needed for an EOC.
- Unitil should continue with its goal to have a fully functional EOC in place by November 2009.
- NHEC should explore options of building a dedicated EOC or obtaining a mobile command center.

Conclusion: Neither PSNH nor Unitil operated an outage management system (OMS) during the December ice storm.

Outage management systems and their functions are often misunderstood. This is due in part to the fact that the term OMS has historically been used to refer to a variety of systems providing different functions. Some utilities internally develop their own systems while others purchase either stand-alone systems or systems that are part of a suite of applications.

[27] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.
[28] Francazio, R. Director of Emergency Planning, Unitil. Interviewed by Fowler, M. May 20, 2009.

An OMS is a set of algorithms that attempt to calculate the extent of an outage based upon criteria either entered into the system or measured by associated systems, such as automatic metering systems, AMI or SCADA systems. Both Unitil and PSNH perform the functions of outage management by having employees manually perform the calculations and analysis otherwise performed by a computer running OMS software. While handling outage management in this manner is possible, it is very labor intensive and delays receiving results. It is also subject to human errors and can become exhausting for employees during a long outage. A more in-depth discussion of OMS is found in Appendix G.

One misconception about OMS is that its use can result in drastic improvements in restoration times. An OMS can allow a utility to significantly improve outage awareness and focus restoration efforts during smaller scale outages. A trained operator can quickly ascertain the extent of a problem and dispatch resources accordingly. This is especially true if a utility complements the OMS with AMI, SCADA, or other remote monitoring devices.

When the whole distribution system is affected, as it was during the 2008 ice storm, the useful information provided by the OMS is limited. The utility must still perform damage assessment as if the OMS did not exist in order to understand the exact level of damage sustained by the system. Notwithstanding this limitation, the OMS can help operators determine the parts of the system that are undamaged, and will definitely reduce restoration times toward the end of the outage as major systems are restored. As circuits are restored, the OMS can help identify the customers who remain without power and the extent of remaining damage. During the final stages of restoration, the OMS becomes an invaluable tool that enables utilities to obtain a quick picture of the number of customers remaining without power. This can improve the utility's ability to restore customers quickly near the end of the restoration. The automatic systems included in the OMS also allow valuable personnel to be assigned to other duties rather than performing the manual outage analysis steps.

While neither PSNH nor Unitil had an OMS in place during the storm, Unitil has recently purchased an OMS and has plans to install it by the end of 2009. This leaves PSNH as the only New Hampshire electric utility without an OMS or plans for implementing one.

PSNH is including one building block of an OMS in an upcoming rate case, a geographic information system (GIS).[29] A GIS is a critical component of an effective automated OMS. PSNH's plan to purchase a GIS will be one step in the process of developing a complete OMS.

[29] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.

Recommendation No. 10: PSNH should purchase an Outage Management System and deploy the system within 12 months of acquiring and implementing a GIS, and Unitil should continue with its present plans for installing an OMS.

- PSNH should replace the manual system it is presently using with a dedicated modern OMS. An OMS can be installed in coordination with the GIS system PSNH is presently planning to purchase. PSNH should make future integration and compatibility with an OMS system an important requirement in selecting a GIS system.
- Unitil should continue with its plan to implement an OMS.

Conclusion: The electric utilities did not have enough damage assessment personnel available immediately following the storm. This hindered their ability to provide restoration times.

To effectively manage the work of line and tree trimming crews, damage assessments must be conducted as early as possible following a storm. Following the December 2008 ice storm, it took the utilities many days to provide initial damage assessments. Even considering the extensive tree damage that made access to some areas difficult due to blocked roads, the length of time to perform the damage assessments indicates the utilities did not have a sufficient number of trained damage assessors available to respond to a storm of this magnitude.

Recommendation No. 11: Each electric utility should identify and train additional damage assessment personnel and have them activated prior to the storm.

- Each electric utility should use the December 2008 ice storm as a model and determine the number of damage assessors that would be required to perform a detailed damage assessment within 24 hours.
- Each electric utility should determine the shortage of assessors and plan to eliminate the gap between the number of assessors needed and the number available.
- Each electric utility should cross train existing employees to be used as assessors.
- Each electric utility should evaluate the possibility of using contracted assessors.
- Each electric utility should evaluate the possibility of using fire personnel from the communities as assessors.
- Each electric utility should expand mutual aid agreements to include damage assessors.
- Each electric utility should evaluate using formerly employed retirees as assessors.
- Each electric utility should develop procedures to activate the needed assessors before a storm event occurs.

Conclusion: None of the electric utilities had a mechanism for providing global estimated restoration times to customers and government entities.

A global estimated restoration time is an initial, broad estimate of the magnitude of damage to an electric system and a "worst case" estimate for service restoration. The estimate is usually provided within hours of the end of a storm and is meant to provide a totally different level of detail than is gathered from detailed damage assessments done later in the storm response process. The purpose of a global estimated restoration time is to provide customers and communities with the information necessary to make decisions such as:

- Should customers consider moving to hotels or other temporary lodging?
- Do public officials need to open emergency shelters?
- Should first responders be called in from off duty?
- Should extra fuel be procured for generators?
- Should provisions be made for critical care customers?
- Do public officials need to implement plans to distribute water and food?

None of the utilities provided global estimated restoration times. Each waited until it completed detailed damage assessments before providing estimated restoration times. In some cases, those assessments were not competed until several days after the storm concluded.

During many emergency events, especially ice storms and wind storms, travel is difficult due to the numbers of roads blocked with downed trees. It is impossible in many cases to drive down roads to get an estimate of the overall extent of the damage. Use of rotor and fixed wing aircraft is a partial solution to this problem. The utilities should contract with charter services for aircraft and pilots to provide reconnaissance flights as soon after storms as is safe.

Recommendation No. 12: Each electric utility should develop a mechanism for quickly assessing global damage and providing restoration times in order to allow customers and government to take prompt appropriate action.

- Each electric utility should develop a process by which they quickly determine the overall extent of damage.
- Each electric utility should make a global estimate of the amount of time required to restore service and publish this estimate within 24 to 48 hours after the end of a storm.
- Each electric utility could state their global restoration time using the following categories:
    - Less than 24 hours
    - Between 24 and 72 hours
    - Between 72 hours and one week
    - Greater than one week

- Each electric utility should contract with helicopter or fixed wing aircraft charter services to assist in initial global damage estimates. This will require the training, allocation, and assignment of utility personnel.

Conclusion: All of the utilities did a good job of utilizing "nontraditional" resources, but those efforts were not sufficient during the December 2008 ice storm.

All of the New Hampshire utilities have done a good job of identifying and training resources from outside traditional operations roles for storm restoration duty. Nontraditional resources are those utility employees who do not normally play a role in operations or direct support. Using nontraditional resources can mean that every person in the organization is used in some capacity during the restoration effort. The tasks performed by these types of resources might include anything from wire watchers, crew guides, and stock helpers, to people doing laundry and delivering lunches to crews. While the effort to use nontraditional resources is commendable, it still leaves companies vulnerable to personnel shortfalls, especially during large and prolonged outages.

Recommendation No. 13: Each electric utility should expand its available resource pool to reach across the boundaries between cooperative and investor owned utilities (IOU), and consider using resources from other sources.

- Each electric utility should expand its available resource pool by determining the resources that might be available from all sources, not just their traditional organizations.
- The electric utilities should continue the discussions they have already initiated with other utilities with the objective of producing a plan for better sharing of resources during an emergency.
- Each electric utility should identify other utilities using the same OMS and explore the availability of obtaining experienced personnel during an emergency.
- Each electric utility should aggressively solicit retirees who can be used during an emergency.
- Each electric utility should make use of the capabilities of first responders who may know if areas are without power and can provide global damage reports.
- Each electric utility should consider the use of contractors for support personnel including damage assessment, wire watchers, and logistics roles.
- Each electric utility should evaluate the use of contract services for food catering and tent services.

Conclusion: The utilities need to improve communication with first responders.

The utilities have special telephone lines established for use by first responders to request immediate assistance. However, the methods established for their use during an emergency have displayed weaknesses in practice. For example: Calls to National Grid's emergency line go to a central call center, not to a local office. This may result in life threatening emergencies being misunderstood. Since the personnel in the central call center may not realize the severity of local conditions, they may incorrectly classify the priority of a call. At least one example of this occurred during the December 2008 ice storm. A vehicle struck a pole, resulting in live wires laying across a vehicle and denying emergency personnel access to the victim. When the call came to the utility it was categorized as a simple "wires down" call with no other information given. As a result the utility's response was delayed since the call was not given the correct priority.

Another problem experienced by the employees taking these calls during an emergency is that much of the information delivered is redundant. If an entire circuit is without power, then reporting numerous wires down does not add much useful information. The process used during the December 2008 ice storm needs additional modification before the next major event occurs.

In a major emergency, first responders need a means of reporting wires down without overwhelming the utility desks taking emergency calls. A simple and very effective method employed in at least one of New Hampshire's fire departments is to collect all "wires down" reports into one batch and send it to the utility via email every 30 to 60 minutes during a major emergency. This frees up the telephone lines for true emergency calls.

Recommendation No. 14: Each electric utility should work with the community first responders to develop a process for "batching" wires down calls during a major emergency.

- Each electric utility should arrange with community first responders to collect simple "wires down" reports into batches and then e-mail these to the utilities every 30 to 60 minutes during an emergency.
- Each electric utility should ensure that dedicated telephone lines are used for handling emergency calls only, and communicate to first responders the method they must use to notify the utility of life-threatening conditions.
- Each electric utility should define and communicate to first responders the events during an emergency that would activate this reporting process and cause normal operations to be superseded.
- Each electric utility should make the methods used consistent with all first responders in its service territory.
- Each electric utility should define primary and backup communication schemes (e-mail, faxes, web posting, etc.).

Conclusion; Customers lack an understanding of how the utility restoration process works.

The utilities have made efforts to educate the public about the power restoration process. However, a review of the public comments provided after the storm indicates that there is still considerable misunderstanding about what utilities do to restore power after a storm.

One of the more frequent comments was that utility trucks were seen in an area and then left prior to restoration being completed.[30] There are many logical reasons for this, but the general public only knows that they are without power and the utility vehicle is leaving. Customers are also confused about where the utility's responsibility for repair stops and the customer's responsibility begin. To make matters worse, these responsibilities vary among the four utilities. PSNH owns and maintains the electrical facilities up to the meter on a customer's house. The other three utilities only own and maintain facilities up to the point where the wires connect to the house, which is usually high in the air on a structure called a weather-head.

Customers were also angered by the fact that once service had been restored to the neighborhood, they were still left without power if there was damage to the electric facilities at their property. They then had to obtain the services of an electrician for repairs, and in some cases, have the repairs inspected and approved by local building officials. PSNH minimized this problem during the December 2008 ice storm by hiring electricians to help in the restoration effort. Unfortunately, this simple and effective solution would not work as well for the other three utilities whose ownership stops earlier, at the point where wires attach to the house.

Recommendation No. 15: Each electric utility needs to expand its communications program to better educate their customers about the restoration process.

- The electric utilities need to expand even further their efforts to educate their customers on the restoration process.
- The electric utilities might use the following suggested methods to communicate with customers:
    - Interviews on radio and television
    - Public service announcements
    - The utilities' web sites
    - Communication with local officials
    - Bill inserts
    - Attendance and presentations at local meetings

Conclusion: The utilities should develop better communication with municipal and other governmental entities.

Customers, regulators, and the utilities all agreed that there were severe breakdowns in communications following the December 2008 ice storm. In some cases, municipal organizations indicated they had no communications with the utilities for days following the storm.

The utilities were not the only ones suffering communications problems. Governmental channels of communication also failed. For example, one municipality carelessly placed a non-

[30] New Hampshire Public Utilities Commission. "December 2008 Ice Storm." (2009). http://www.puc.state.nh.us/2008IceStorm/December2008IceStorm.htm (Accessed August 24, 2009).

public utility emergency response number on a portable electronic billboard. This is equivalent to giving out the personal cell phone numbers of police and fire personnel to use for 911 calls. The result of this action undermined utility response efforts.

Another issue that hindered communications was that many towns seemingly ignored their own emergency protocols. Effective protocol, and especially incident management, requires a single point of communication between utilities and towns in their service territories. Yet utilities received calls from multiple persons within the same towns asking for identical information. Public officials routinely attempted, using any means at their disposal, to secure information for their cities and towns. Officials called upon any utility contacts they had in an effort to get information. This attempt at information gathering quickly overwhelmed the utilities' resources, distracted employees from the restoration effort, and resulted in the spread of misinformation.

New Hampshire Homeland Security and Emergency Management has already made strides in attempting to identify and correct the communications lapses witnessed between the utilities and the state during the ice storm. State officials have had and continue to have a series of meetings and discussions with the four electric utilities that have resulted in an initial framework for communications improvements. The meetings have defined information that the utilities will provide to the state, how frequently that information will be provided, and how communications will flow.

Recommendation No. 16: Each electric utility should better define the methods it uses for communications with government officials during emergencies.

- Each electric utility should report to the state the number of line and tree crews and other personnel working on storm restoration.
- State officials should clearly communicate to each electric utility what facilities, equipment, and functions (such as emergency fueling, marshalling equipment, temporary lodging or road closures) it can provide.
- Each electric utility should include the procedures for communications with state and local governmental officials in its emergency plans.
- Each electric utility should clearly define the information channels available for use by public officials and provide those officials with the training needed to use them effectively.
- Each electric utility should rigidly enforce the planned use of its communications channels and decline to give out information through any means other than the proper channels defined by the emergency management structure.
- Each electric utility should each maintain toll-free numbers for first responders and these numbers should be kept secure.
- Each electric utility should prepare for any potential compromise of the main emergency telephone numbers by maintaining secure backup numbers that can be utilized immediately by first responders.

Conclusion: Prior to the storm, the Public Utilities Commission (PUC) and the New Hampshire State EOC had limited knowledge of each utility's Emergency Operating Plans. Additionally, there are no clear guidelines for when utilities should report that an emergency situation exists.

In New Hampshire, utilities are not required to file their Emergency Operating Plans with the PUC or any other organization. Each of the utilities maintains some formal documentation about emergency procedures, but those plans were not on file with the state. It is important that the commission be familiar with company plans and procedures prior to an actual emergency event.

The utilities also have no clear guidance about when to contact the state during an emergency event or, for that matter, even what constitutes an emergency event. A call is usually placed to the PUC's Director of Safety or the Director of the Electric Division when each utility feels it has an emergency, but the threshold for this notification, as well as the information that is provided, is not well defined and varies between the utilities.

Recommendation No. 17: Each electric utility should file their Emergency Operating Plans with the State Homeland Security and Emergency Management Office (state EOC) and work with the state to define thresholds which would trigger communications with the EOC.

- Each electric utility should increase its communication with the Homeland Security and Emergency Management Office.
- Each electric utility should file its Emergency Response Plans with the state EOC and NHPUC.
- Each electric utility should notify the EOC and NHPUC annually about changes to its plan.
- The NHPUC should reserve the right to request that a utility re-file its complete plan if the NHPUC determines that the changes made during the year constitute a major revision.
- Each electric utility should collaborate with the NHPUC to define exactly what conditions will require notification to the Commission and the EOC that an emergency has occurred, and then determine a workable process for this notification.
- Each electric utility should report all major events to the NHPUC as a matter of routine. This report should include a synopsis of the event and the actions taken by the utility involved.
- Each electric utility and the NHPUC should meet to define the content of the reports that will be filed after an event, and agree upon the criteria for determining when reports are required.

CHAPTER IV

System Planning, Design, Construction, and Protection

Chapter Structure

A. BACKGROUND

Transmission and Distribution

The December 2008 ice storm caused extensive power outages throughout the state of New Hampshire. Since the backbone of any electric system involves the transmission system, a review was made of the transmission systems that support PSNH, Unitil, National Grid, and NHEC in order to ascertain how they were affected by the ice storm. In New Hampshire, transmission voltage levels begin at 69 kV. Voltages below 69 kV are typically categorized as distribution.

While states may have laws or regulations that influence the transmission system, the reliability criteria for transmission systems are normally dictated by federal agencies such as the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC). In most cases, transmission systems are designed, constructed, protected, and operated with higher utility industry standards than distribution systems. The reliability criteria applicable to most transmission lines require that the loss of a single transmission line will not result in an outage to customers. Additional distinctions between the transmission and distribution systems and the sub-transmission system are discussed below.

Transmission System

Figure IV-1 shows a modern 115 kV transmission line located in Manchester, New Hampshire. This figure shows a common double circuit with single steel pole construction. Note the contrast with the traditional two-pole, H-Frame construction shown in Figure IV-2.

Figure IV-1 - 115kV transmission line structures located near Mall of New Hampshire in Manchester. (Photo by NEI – PSNH System)

Figure IV-2 - Common H-Frame transmission line construction. (Photo courtesy of NHPUC)

Overhead transmission lines are typically placed on larger structures and elevated higher above the ground than common distribution circuits. Another distinction is that transmission lines will normally have a large, well managed right-of-way (ROW). The vegetation management practices typically followed for transmission lines commonly include the wire-zone border-zone practice, which requires clearing vegetation immediately under the conductors (wire-zone) and on either side of the conductors to the edge of the ROW (border-zone). The wire-zone border-zone practice has been effectively endorsed by FERC and NERC.[1]

In New Hampshire there are four commonly used transmission voltage levels:

- 115 kV ac[2]
- 230 kV ac
- 345 kV ac
- 450 kV dc[3]

[1] "New Diagrams and Applications for the Wire Zone-Border Zone Approach to Vegetation Management on Electric Transmission Line Rights-of-Way." *Arboriculture & Urban Forestry*, 33, (6), November 2007, pgs 435-439.

[2] ac – alternating current – The most widely used transmission, distribution and utilization voltage in New Hampshire and the United States.

The 115 kV voltage level is commonly used to deliver power to sub-transmission systems and distribution substations. The 230 kV and 345 kV voltage levels are commonly used to deliver bulk power to transmission and sub-transmission substations. Systems operating at 450 kV dc are used to transfer bulk power through the state of New Hampshire and are not presently used to directly serve loads.

During the December 2008 ice storm, the transmission system received relatively minor damage and resulted in a single power outage to one substation that supplies approximately 5,400 customers in the Pelham area.

Sub-Transmission System

Technically the utility industry defines only two systems: transmission and distribution. In practice, however, a third system exists. It is considered a distribution system, but operates similarly to a transmission system by delivering power to distribution substations. This system is identified as the sub-transmission system. The sub-transmission system is used to supply power and energy to electric substations, but is not planned, designed, and constructed to the same utility industry standards as the transmission system. While the sub-transmission system may operate at voltages from approximately 15 kV through 138 kV, the sub-transmission systems in New Hampshire are primarily operated at 34.5 kV, with some 23 kV and 46 kV systems. During the December 2008 ice storm, the electric sub-transmission systems of New Hampshire received heavy damage primarily from ice laden limbs and trees falling onto sub-transmission power lines.

Figure IV-3 shows a pair of 34.5 kV sub-transmission lines on the Unitil system. The 34.5 kV circuit on the left consists of single wood poles, three current-carrying conductors attached to cross arms, and a grounded neutral wire attached to the pole below the cross arm. The 34.5 kV circuit on the right has three current carrying conductors, but has no grounded neutral wire and thus relies on the neutral of the other line in the ROW for single-phase, 19.9 kV distribution loads. In both circuits, the current carrying conductors are bare and rely on air for electrical insulation. Note that the construction of the sub-transmission lines is not as robust as the previously described transmission lines and, in this case, consists of wood poles and cross-arms that take on a similar appearance to the distribution system described below. Also note in this case that the electric sub-transmission lines are located in a dedicated ROW that is reasonably free of tall vegetation. There are no trees under or between the lines and the tall vegetation at the edges of the ROW is kept clear of the lines. The ROW in Figure IV-3 represents a very good practice and is more typical of a transmission ROW than a distribution ROW. The practice of clearing vegetation from the ROW results in greater reliability for the line. It limits incidental contact between the energized lines and vegetation and reduces the possibility that wild fires could occur under the line causing damage.

[3] dc – direct current – Used primarily by electric utilities for bulk power transmission.

Figure IV-3 – Two 34.5kV sub-transmission lines located on the Unitil system. (Photo by NEI - Unitil System)

Distribution System

In this report, the distribution system will be defined as that portion of the electric system extending from the distribution substation to the end customer, including the customer's meter. The portion of the electric system from the secondary (low voltage) side of the distribution transformer to the customer meter is normally referred to as a "service" or "service drop." Distribution poles in New Hampshire are typically jointly owned by the local electric utility and the local telephone company to minimize the number of poles needed to provide both services. Distribution poles may also be used to support electric equipment, street lighting, cable TV lines, fiber optic lines, and municipal alarm and communication lines. A considerable amount of electric and communications material may be attached to a single pole.

Figure IV-4 shows an urban distribution pole located in Concord, New Hampshire. Inspection of this installation reveals the following equipment has been attached to the pole:

- Cross-arm with three distribution, high voltage conductors on insulators
- Single phase distribution transformer to convert the distribution high voltage to 120/240 Volt residential service voltage

- Street light
- Two, triplex service conductors to serve a residential customer
- Multiple, large bundle telephone cables

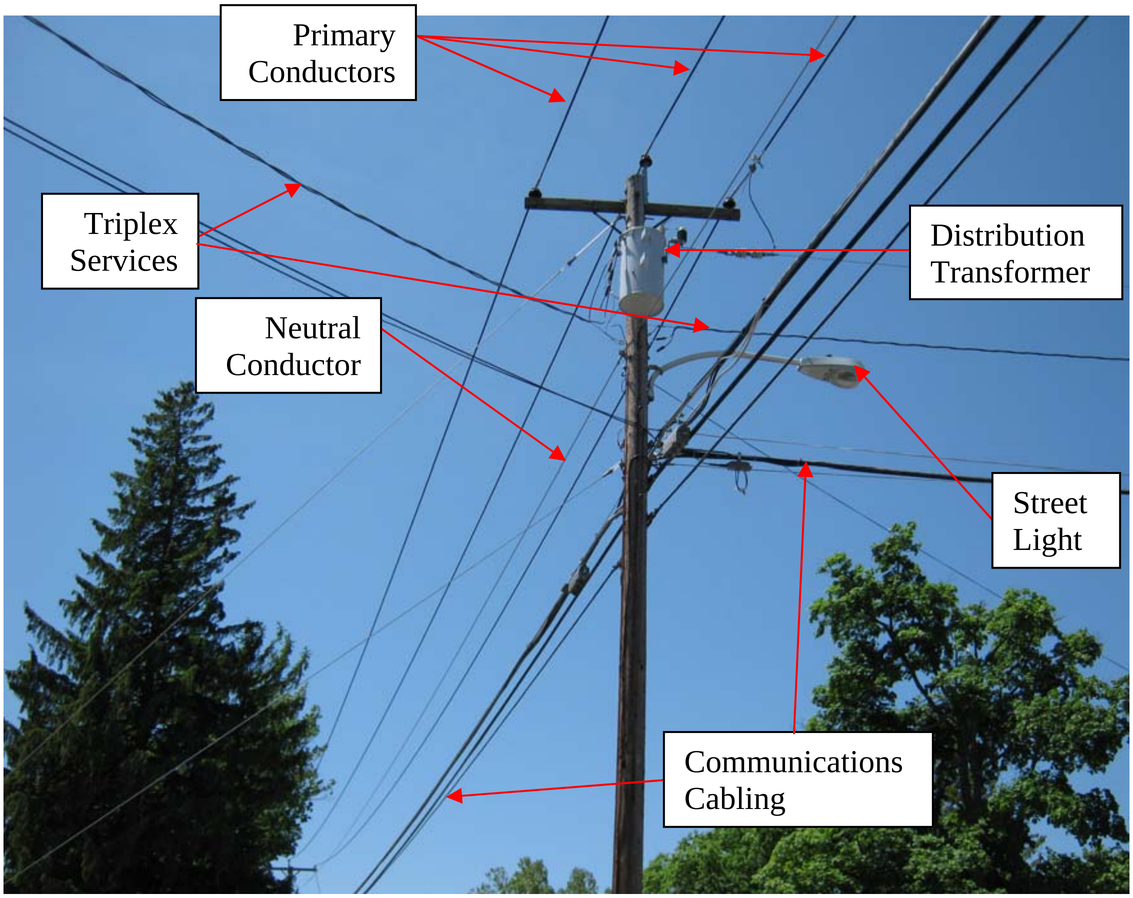

Figure IV-4 – Urban distribution line located in Concord, New Hampshire. (Photo by NEI – Unitil System)

Figure IV-5 shows a typical rural overhead distribution line located in southwestern New Hampshire. Distribution lines in New Hampshire are usually constructed adjacent to roads and highways where they share a combination of public and private land and compete for space with trees. This distribution line follows the road and each pole must be capable of handling the cables and equipment shown in Figure IV-4. Unlike the transmission and sub-transmission lines shown in Figure IV-1, Figure IV-2, and Figure IV-3, the ROW under this line has not been well cleared.

Figure IV-5 -Typical PSNH distribution circuit near Greenville, New Hampshire. (Photo by NEI - PSNH System)

Distribution systems are planned, designed, constructed, and protected in accordance with the National Electrical Safety Code and good utility distribution practices. During the December 2008 ice storm, the electric distribution system in New Hampshire was extensively damaged by ice laden tree limbs and whole trees falling onto power lines. Absence of a clear ROW, as is shown in Figure IV-5, can contribute to such damage.

Electric Distribution Substations

Electric distribution substations are used to reduce voltage levels from transmission and sub-transmission to distribution level. This allows power to be delivered by distribution lines to distribution transformers that further reduce the voltage to a level useable by the customer. Figure IV-6 shows a relatively small electric distribution substation that reduces Unitil's 34.5 kV sub-transmission voltage to 13.8 kV, which is then distributed to industrial, commercial, and residential customers.

A typical electric distribution substation will have the following equipment:

- Incoming transmission or sub-transmission line
- Distribution transformer
- Transformer protection including such things as fuses, circuit breakers and lightning arresters
- Voltage regulators to raise or lower the distribution voltage as required

- Electric outgoing distribution circuits complete with metering and circuit protection as circuit breakers or reclosers
- A substation fence for safety and security purposes

Figure IV-6 – 34.5kV to 13.8kV Unitil electric distribution substation located in East Kingston, New Hampshire. (Photo by NEI-Unitil System)

During the December 2008 ice storm, the electric distribution substations were affected mainly by external causes, with minimal internal problems. Electric distribution substations lost power due to tree limbs and trees falling onto incoming power lines. The resultant damage caused circuit breakers and reclosers to open upstream from the substations to disconnect the damaged lines. In most cases, equipment located inside the electric distribution substations was unaffected, except for the normal operation of circuit breakers due to problems occurring outside of the substation.

Transmission System Protection

Transmission systems are typically constructed and protected as a network system[4] such that a faulted (short circuited) section of the system can be isolated without causing interruption of

[4] Network system – An electric system that has at least two sources (lines) of power supply such that the loss of one line will not result in loss of power to an electric customer.

power to a customer. Transmission system protection includes not just the protection of the transmission lines, but also the generators, transformers, and substation buses that complete the transmission system. However, for the purpose of this report, the focus on transmission system protection will be limited to the protection of the transmission lines. (See Appendix E for a more thorough and technical discussion of transmission system protection.)

Distribution System Protection

Electric distribution systems, including those in New Hampshire, are typically radial systems, which means that the lines originating at the substation radiate outward toward their loads. The radial power lines normally have multiple taps from the main feeder, called laterals, which provide power to individual customers. The distribution system protection consists of feeder breakers with relay controls, feeder reclosers possibly both inside and outside of the substation, line sectionalizers, and line fuses. In the case of a large weather event, such as the December 2008 ice storm, a majority of the distribution system may be affected. As a large storm event develops, more and more of the distribution system, including main distribution lines, will experience permanent faults. This results in the loss of the ability to effectively sectionalize a distribution line or restore power through automatic reclosing. During the early hours of the December 2008 ice storm, the distribution system protection performed as expected by removing permanently faulted sections of line and restoring power through automatic reclosing for temporary faults. As the damage from the storm increased, the distribution system protection continued to perform as expected by disconnecting lines as they were damaged, causing more and more customers to be without power. (See Appendix E for a more thorough and technical explanation on distribution system protection.)

Substation Protection

The degree of substation protection is often determined by the size and importance of the substation itself as it relates to the power system. Normally, higher voltage substations and larger transformer sizes require more intricate protection schemes, whereas smaller substations may only require minimal protection, such as fuses. (See Appendix E for a more thorough and technical discussion on substation protection.)

SCADA

Supervisory control and data acquisition (SCADA) systems are used to collect real-time information about the power system and provide control of system equipment. SCADA provides a centralized master station with information from substations and equipment in the field. The information collected can help in load management, provide important information on the health of the power system, and help determine the location of damaged lines and equipment. SCADA systems also make it possible for equipment in substations and in the field to be operated remotely to provide voltage control, switching for maintenance and repair work, and rerouting of power around faulted sections of lines.

Covered Wire

Covered wire (tree wire and covered wire systems (Hendrix Cable™)) is commonly used in New Hampshire on overhead sub-transmission and distribution lines. Covered wire consists of bare conductors with a rubber or plastic outer layer. The purpose of the outer layer is to provide protection from incidental contact with trees that could cause temporary faults (short circuits). Temporary faults which may occur on bare overhead conductors become a nuisance because protective devices must operate by disconnecting the circuit to clear the fault. This may cause a momentary or prolonged power outage on that line due to what may be a relatively minor contact. The rubber outer layer on covered wire systems may be effective in protecting the line from vegetation contact during everyday operations; it does not provide a substantial advantage during large weather caused events. Over time it has not been found to provide a substantial advantage over bare wire. Although covered wire may allow power to continue to be supplied even when contacted by trees and other objects, the power line must be de-energized to clear debris and repair damage. In addition, when damaged, the covered wire may be more difficult to repair and replace.[5] [6] [7]

Figure IV-7 is a photograph of a covered wire installation on the NHEC system which shows the covered wire installation at the top of the pole and a standard cross arm distribution circuit on cross-arms below. The photo shows that the three covered wires are separated by a spacer and the entire assembly is attached to the messenger wire at the top. Note the more compact construction and the lack of need for a standard cross-arm, which are both advantages of the covered wired installation. The bare messenger wire is continuously grounded and acts as a system neutral wire. Therefore, it does not need to be covered.

[5] Demmer, K. Manager Electrical Distribution New Hampshire, National Grid. Interview by Ackerman, A. May 8, 2009.
[6] Doe, S. Manager-System Planning & Strategy, PSNH. Interview by Ackerman, A. June 2, 2009.
[7] Zogopoulos, A.J. Design and Standards Specialist, Unitil. Interview by Nelson, J., May 21, 2009.

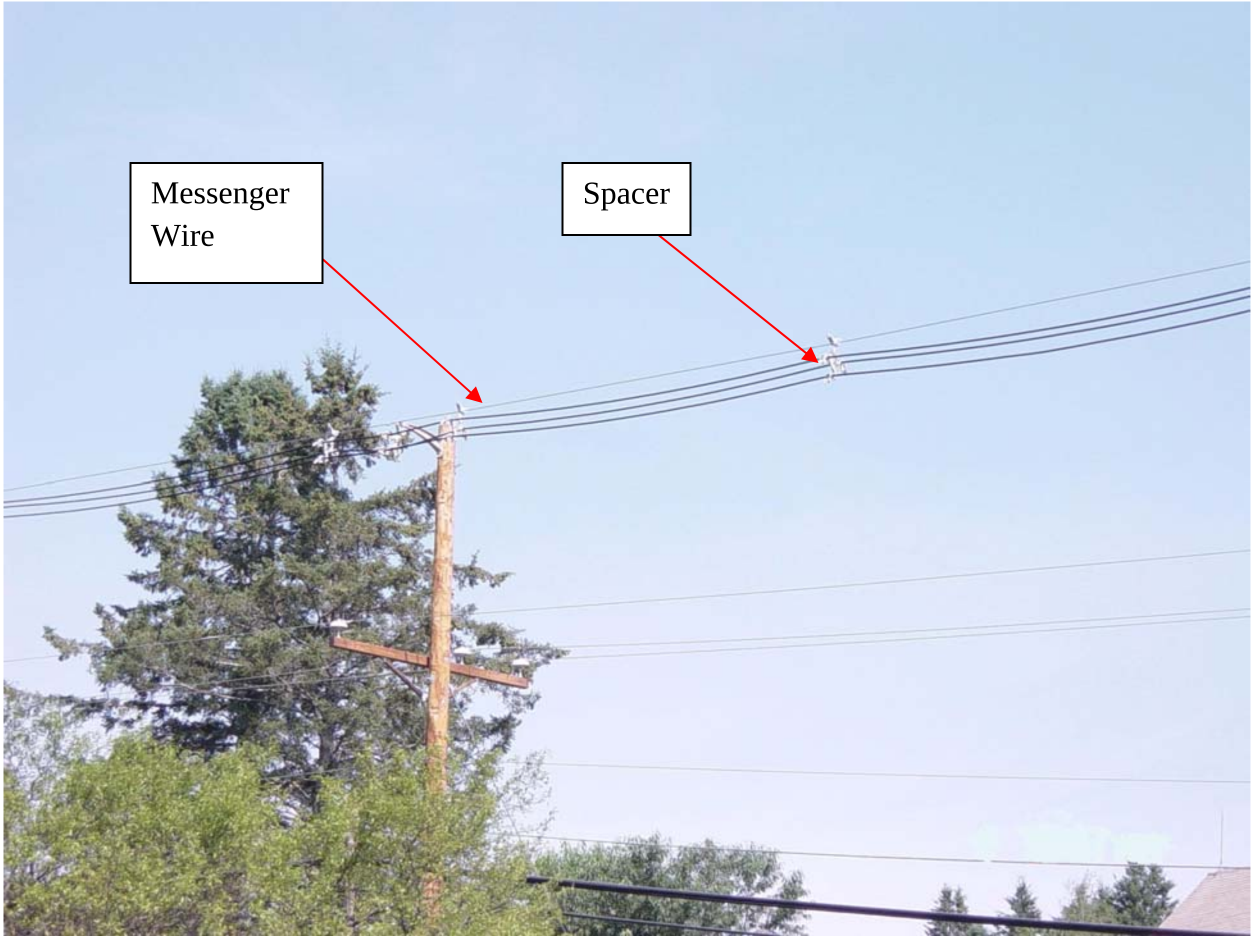

Figure IV-7 – Covered wire system in Colebrook, New Hampshire. (Photo Courtesy NHEC)

Pole Construction and Loading

Prevailing laws and practices in most states, including New Hampshire, require overhead lines be designed, at the very minimum, to meet the National Electrical Safety Code (NESC).[8] In addition, some states, such as California, have adopted by law their own codes, which are similar to NESC requirements.[9] In the United States most structures, other than transmission lines, are built according to the International Building Code (IBC), which often defaults to American Society of Civil Engineers (ASCE) standards on such issues as loading and design methods.

Current practice is to design structures using two well accepted design methods. The first and oldest is the "Allowable Stress Design" (ASD) method, and the other is "Load and Resistance Factor Design" (LRFD), which is the method most commonly taught in colleges and appears to be the one toward which the industry is moving.

[8] New Hampshire PUC 300 Rules, Part PUC 306.1.
[9] Dagher, H.J. (2001). "Reliability of Poles in NESC Grade C Construction." *IEEE Rural Electric Power Conference 2001*, Pgs C4/1-C4/6. (10.1109/REPCON.2001.949521).

The NESC, however, uses neither of these commonly accepted methods. Instead it historically used an ultimate stress design method with overload factors included to provide the needed factors of safety. The NESC method differs from all other commonly accepted design methods, and loading requirements contained in the NESC are different than those used in any other code. NESC rules for selection of design loads and for safety factors are largely based on successful experience, but have little basis in theory.[10] The more modern methods of design such as LRFD have been developed using successful experience as well as structural theory that has become accepted over the years. As a result, the NESC in recent editions has begun to gradually move toward the methods commonly accepted for other types of construction. The NESC should be considered in process of transition, and its requirements do not closely match the requirements that would be necessary to build a habitable structure.

The load and strength factors used in the 2007 version of the NESC are designed for use with both traditional NESC district loading and 50 years recurrence loading as shown in ASCE Standard 7 maps (See Figures F-2 and F-3 in Appendix F). Even though only NESC district loading cases are required for structures less than 60 feet, it is recommended that the higher wind and ice loading cases required by ASCE data also be taken into account for the design of all structures no matter their height. This approach should produce a more realistic design than the NESC district loading cases alone for the conditions that can be expected in New Hampshire. This would include determining from local sources the actual wind and ice loads that can be expected in the special wind areas shown on ASCE maps, rather than relying on loading data from NESC maps (See Appendix F for a more thorough and technical discussion on pole construction and loading as well as ASCE Standard 7 maps).

B. EVALUATIVE CRITERIA

Prior to the December 2008 ice storm, each utility should have been planning, designing, and developing electrical system protection schemes in order to maximize reliability of its system during an abnormal event. The following criteria were used to assess each utility:

1. The transmission and sub-transmission system should be properly planned, designed, constructed, and protected.
2. The distribution system should be properly planned, designed, constructed, and protected.
3. Substations should be properly planned, designed, constructed, and protected.

1. The transmission and sub-transmission system should be properly planned, designed, constructed, and protected.

[10] Bingel, Nelson and Dagher, Habib, et.al. (2003). "Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code." *Transmission and Distribution Conference and Exposition 2003*, Vol. 3, Pgs 1088-1093. (10.1109/TDC.2003.1335100).

- The correct ice and wind loading conditions should have been used during design.
- The proper criteria should be used to determine when to replace and upgrade aging equipment.
- Aging equipment should not have had an adverse impact on the system during the storm.
- The utility should have adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.
- The system should be designed and constructed to handle expected extreme weather conditions.
- The protection systems should be well designed, coordinated, and maintained.
- Reasonable planning, design, protection, and construction budgets should be available in order to maintain and operate the existing system and to design and build new parts as needed.

2. The distribution system should be properly planned, designed, constructed, and protected.

- Distribution lines and equipment should be properly designed.
- The correct wind and ice loading criteria should be used in planning and design.
- The proper criteria should be used to determine when to replace and upgrade aging equipment.
- Aging equipment should not have had an adverse impact on the system during the storm.
- Proper planning for distribution line sectionalizing should exist.
- The utility should have adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.
- The protection systems should be well designed, coordinated, and maintained.
- Reasonable planning, design, protection, and construction budgets should be available in order to maintain and operate the existing system and to design and build new parts as needed.

3. Substations should be properly planned, designed, constructed, and protected.

- Substations should be adequately planned and constructed to serve the loads under various system conditions.
- Substations should not have been adversely impacted during the storm.
- The proper criteria should be used to determine when to replace and upgrade aging equipment.
- Aging equipment should not have had an adverse impact on the system during the storm.
- The utility should have adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.
- Substations should be well designed and constructed to handle expected extreme weather conditions.

- The protection systems should be well designed, coordinated, and maintained.
- Reasonable planning, design protection, and construction budgets should be available in order to maintain and operate the existing system and to design and build new parts as needed.

The following tables indicate the extent to which each of the utilities met the above criteria. These tables were not prepared to compare one utility with another. The utilities are very different, face different problems, and experienced different amounts of damage to their systems. These tables were prepared to show where each utility may improve its performance in preparation for the next storm or other disaster. A further explanation for the improvements that are recommended to each of the utilities may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table IV-1 – PSNH system planning, design, construction & protection evaluation matrix.

1) THE TRANSMISSION AND SUB-TRANSMISSION SYSTEM SHOULD BE PROPERLY PLANNED, DESIGNED, AND PROTECTED.	
The correct ice and wind loading condition were used during design.	◐
The proper criteria were used to determine when to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	●
The utility had adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.	◐
The system was designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated and maintained.	◐
Reasonable planning, design, protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

2) THE DISTRIBUTION SYSTEM SHOULD BE PROPERLY PLANNED, DESIGNED, AND PROTECTED.	
Distribution lines and equipment were being properly designed.	◐
Proper wind and ice loading criteria were used in planning and design.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have had an adverse impact on the system during the storm.	◐
Proper planning for distribution line sectionalizing exists.	◐
Adequate planning and engineering staff is available to perform all necessary planning, design, and protection work in a timely fashion.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design, protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

3) SUBSTATIONS SHOULD BE PROPERLY PLANNED, DESIGNED, AND PROTECTED.	
Substations were adequately planned and constructed to serve the loads under various system conditions.	◐
Substations were not adversely impacted during the storm.	○
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
Adequate planning and engineering staff were available to perform all necessary planning, design, and protection work in a timely fashion.	◐
Substations were well designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

Table IV-2 – Unitil system planning, design, construction & protection evaluation matrix.

1) EFFECTIVENESS OF TRANSMISSION AND SUB-TRANSMISSION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
The correct ice and wind loading condition were used during design.	◐
The proper criteria were used to determine when to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
The utility had adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.	◐
The system was designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design, protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

2) EFFECTIVENESS OF DISTRIBUTION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Distribution lines and equipment was being properly designed.	◐
Proper wind and ice loading criteria were used in planning and design.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have had an adverse impact on the system during the storm.	◐
Proper planning for distribution line sectionalizing exists.	◐
Adequate planning and engineering staff is available to perform all necessary planning, design, and protection work in a timely fashion.	◐
The protection systems were well designed, coordinated and maintained.	◐
Reasonable planning, design, protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

3) EFFECTIVENESS OF SUBSTATION PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Substations were adequately planned and constructed to serve the loads under various system conditions.	◐
Substations were not adversely impacted during the storm.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
Adequate planning and engineering staff were available to perform all necessary planning, design, and protection work in a timely fashion.	◐
Substations were well designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated, and maintained.	○
Reasonable planning, design protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

Table IV-3 – National Grid system planning, design, construction & protection evaluation matrix.

1) EFFECTIVENESS OF TRANSMISSION AND SUB-TRANSMISSION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
The correct ice and wind loading condition were used during design.	◐
The proper criteria were used to determine when to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
The utility had adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.	◐
The system was designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated and maintained.	◐
Reasonable planning, design, protection and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐
2) EFFECTIVENESS OF DISTRIBUTION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Distribution lines and equipment was being properly designed.	◐
Proper wind and ice loading criteria were used in planning and design.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have had an adverse impact on the system during the storm.	◐
Proper planning for distribution line sectionalizing exists.	◐
Adequate planning and engineering staff is available to perform all necessary planning, design, and protection work in a timely fashion.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design, protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐
3) EFFECTIVENESS OF SUBSTATION PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Substations were adequately planned and constructed to serve the loads under various system conditions.	◐
Substations were not adversely impacted during the storm.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
Adequate planning and engineering staff were available to perform all necessary planning, design, and protection work in a timely fashion.	◐
Substations were well designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were designed, coordinated and maintained.	◐
Reasonable planning, design protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

Table IV-4 – NHEC system planning, design, construction & protection evaluation matrix.

1) EFFECTIVENESS OF TRANSMISSION AND SUB-TRANSMISSION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
The correct ice and wind loading condition were used during design.	◐
The proper criteria were used to determine when to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
The utility had adequate planning and engineering staff to perform all necessary planning, design, and protection work in a timely fashion.	◐
The system was designed and constructed to handle expected extreme weather conditions.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design, protection and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

2) EFFECTIVENESS OF DISTRIBUTION SYSTEM PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Distribution lines and equipment was being properly designed.	◐
Proper wind and ice loading criteria were used in planning and design.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have had an adverse impact on the system during the storm.	◐
Proper planning for distribution line sectionalizing exists.	◐
Adequate planning and engineering staff is available to perform all necessary planning, design, and protection work in a timely fashion.	◐
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design, protection and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

3) EFFECTIVENESS OF SUBSTATION PLANNING, DESIGN, CONSTRUCTION, AND PROTECTION	
Substations were adequately planned and constructed to serve the loads under various system conditions.	◐
Substations were not adversely impacted during the storm.	◐
Proper planning criteria were used to determine the need to replace and upgrade aging equipment.	◐
Aging equipment did not have an adverse impact on the system during the storm.	◐
Adequate planning and engineering staff were available to perform all necessary planning, design, and protection work in a timely fashion.	◐
Substations were well designed and constructed to handle expected extreme weather conditions.	○
The protection systems were well designed, coordinated, and maintained.	◐
Reasonable planning, design protection, and construction budgets were available in order to maintain and operate the existing system and to design and build new parts as needed.	◐

C. TASKS

In conducting this assessment, a large number of executives, managers, engineers, state officials, and system operators in all four electric utilities were interviewed. In addition, a number of data requests were submitted to each utility and the responses were reviewed and analyzed. Inspection tours were made of the following:

- Work centers
- Control rooms
- Substations
- Transmission, sub-transmission, and distribution lines
- Ice Engineering Research Center

Focus was placed on system planning, system design, and system protection as each pertained to the December 2008 ice storm.

D. FINDINGS AND CONCLUSIONS

Conclusion: The transmission system performed reasonably well even though there were some lines adversely affected by the storm.

The New Hampshire transmission system performed reasonably well and only one outage affecting customers was reported by the three utilities that own transmission systems in New Hampshire.

A detailed investigation revealed several issues that affected transmission lines. Those include:

- Fitzwilliam Substation on line 367 was under construction and was not completed. However, the 367 line did not enter the Fitzwilliam Substation and therefore had no adverse impact on the system. Completion of the Fitzwilliam Substation will provide additional support in the Southwestern part of the state and primarily will support the National Grid 115 kV system.[11]
- Several occasions occurred when breakers did not properly reclose. No outages resulted from the failure to reclose and corrective actions have been taken.[12]
- There was one improper operation of a set of line relays which caused line Q171 to trip sympathetically with line B143. Breaker K1650 at Reeds Ferry failed to reclose and was closed by SCADA.[13]
- Circuit 17, operating at 115 kV, was tripped at the Ascutney Substation by Vermont Electric Company (VELCO).[14]

[11] Jiottis, J. Manager Transmission Engineering, PSNH. Interview by Nelson, J. July 9, 2009.
[12] PSNH. (July 10, 2009). Data Response PS0023. NEI.
[13] Jiottis, J. Manager Transmission Engineering, PSNH. Interview by Nelson, J. July 9, 2009.
[14] PSNH. (July 10, 2009). Data Response PS023. NEI.

- Jackman Substation was undergoing modifications during the storm. A new control building was being installed, two new 115 kV capacitor banks were being constructed, and the distribution substation was being upgraded. There was a minor problem with the relay targets on the electro-mechanical relays that were in the process of being replaced with microprocessor relays. However, this had no impact on the operation of the transmission system.
- Static wires were being replaced on circuits H141 and R193 near the seacoast but had no adverse impact on the transmission system.
- A third substation, Saco Valley, was undergoing construction, but was outside of the ice storm area and was not impacted by the storm.[15]

The items listed above each had an effect on the New Hampshire transmission system whether directly impacted by the ice storm or not. The transmission system is designed as a network. Therefore, any section of the system that is out of service, under maintenance, or fails to operate correctly will have an impact on the system as a whole. Based on the information above, the transmission system performed well even though sections were out of service, under maintenance, or failed to operate correctly.

With regard to the New Hampshire transmission system, 5,401 New Hampshire customers lost power as a result of the Y151[16] transmission line being tripped off. This line serves National Grid's Pelham Substation. According to interviews with National Grid personnel, a large number of those customers would have lost power anyway due to outages on the distribution side of the Pelham Substation.

[15] Jiottis, J. Manager Transmission Engineering, PSNH. Interview by Nelson, J. July 9, 2009.
[16] Circuit Y151 is a 115 kV transmission line that is jointly owned by PSNH in New Hampshire and National Grid in Massachusetts. National Grid lost additional 10,291 customers in Massachusetts on line Y151.

Table IV-5 – Miles of transmission line owned by utility in New Hampshire.[17] [18] [19] [20]

Voltage	PSNH	Unitil	National Grid	NHEC
345kV	252.7	0	0	0
230kV	8.9	0	267.3	0
115kV	737.8	0	42.5	6.7
69kV	0	0	0.4	0

[17] PSNH. (February 2, 2009). Data Response STAFF 1-31. NHPUC.
[18] Unitil. (February 27, 2009). Data Response STAFF 1-31. NHPUC.
[19] National Grid. (February 27, 2009). Data Response STAFF 1-31. NHPUC.
[20] NHEC. (February 19, 2009). Data Response STAFF 1-31. NHPUC.

The following is a summary of each utility's transmission line outages including a map in Figure IV-8 that shows the locations of the transmission lines which tripped off during the storm.

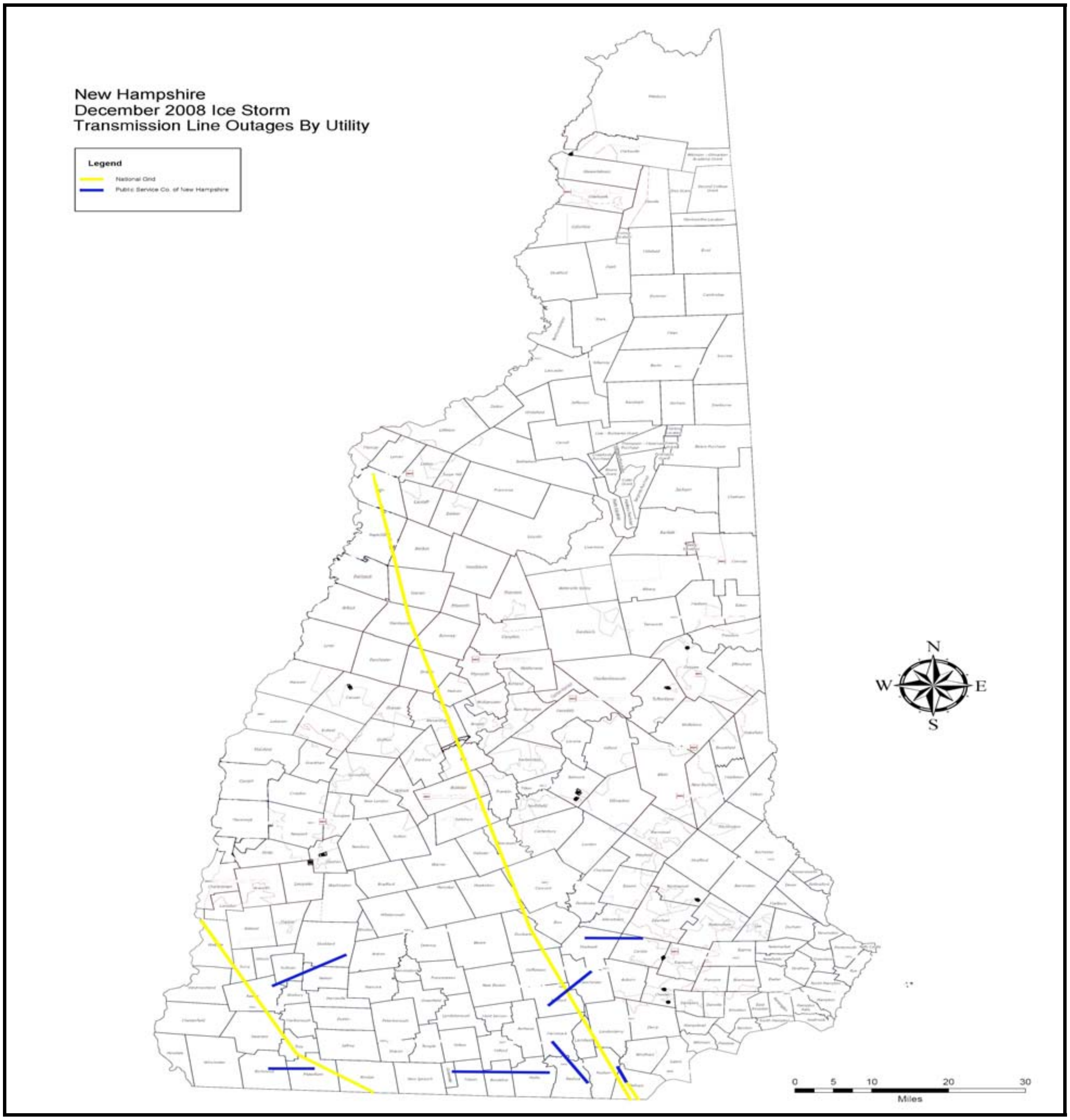

Figure IV-8 – Transmission line outages due to the December 2008 ice storm.

PSNH[21] transmission line damage summary is shown in Table IV-6.

Table IV-6 – PSNH transmission line outages.

Circuit ID	Duration Minutes	kV	Date/ Time	Damage	Customers Affected
F162	0	115 kV	12/12 03:12	None found during aerial Patrol	0
B143	6	115 kV	12/12 0:09	None found during aerial Patrol	0
L163	760	115 kV	12/12 08:30	Out of ROW Tree	0
367	3675	345 kV	12/12 02:29	Ice Broke Static Wire	0
Y151	3275	115 kV	12/12 07:29	Out of ROW Tree Broken Cross-arm	0[22]
G146	719	115 kV	12/12 03:56	None found during aerial Patrol	0
C129	0	115 kV	12/12 00:36	None found during aerial Patrol	0
Q171	301	115 kV	12/12 00:09	None found during aerial Patrol	0
K174	0	115 kV	12/12 09:35	None found during aerial Patrol	0
K174	0	115 kV	12/12 12:35	None found during aerial Patrol	0
K105	0	115 kV	12.12 05:02	None found during aerial Patrol	0
I135	914	115 kV	12/12 05:27	Problem on National Grid System	0
R193	0	115 kV	12/12 07:49	None found during aerial Patrol	0

[21] PSNH. (February 27, 2009). Data Response STAFF 1-28.NHPUC.
[22] No PSNH Customers were impacted, however approximately 5,400 National Grid Customers lost power at Pelham Substation.

National Grid had four transmission line outages in New Hampshire during the December 2008 ice storm. Table IV-7 summarizes the National Grid Transmission Line Outages.

Table IV-7 – National Grid transmission line outages.[23]

Circuit ID	Circuit Name	kV	Date/ Time	Damage	Customers Affected
A201	Comerford – N. Litchfield	230 kV	Dec 12 03:55	Locked Out – Multiple Trees	0
J136N	Bellow Falls - Flagg Pond	115 kV	Dec 12 01:06	Locked Out – Multiple Trees	0
O215	N Litchfield – Tewksbury	115 kV	Dec 12 03:05	Trip and Reclose – No damage found	0
Y151	Hudson – Tewksbury	115 kV	Dec 12 07:29	Locked Out – Multiple trees in both New Hampshire and Massachusetts*	5,401 – New Hampshire 10,291 - Massachusetts

* Y151 is jointly owned with PSNH.

Note: PSNH indicated I135 115 kV line outage for 914 minutes and that the line is owned by National Grid. National Grid does not show this line outage.

Unitil does not own or operate any transmission lines in the state of New Hampshire.[24]

NHEC has only one transmission line located in Conway and it is approximately 6.7 miles in length. During the storm, NHEC experienced no transmission line outages.[25]

Conclusion: There were no substantial planning, design, construction, and protection issues that adversely affected the transmission system during the December 2008 ice storm.

With the exception of the 5,401 National Grid customers that lost power due to the 115 kV transmission line outage to the Pelham Substation, there were no other customers affected by transmission system problems. The loss of the 5,401 customers at Pelham Substation was due to trees falling into the line from outside of the ROW. With regard to the transmission lines that tripped during the December 2008 ice storm, the following causes were identified:

- Out of ROW trees falling into the lines
- Broken static wire
- Unknown[26]

[23] National Grid. (February 27, 2009). Data Response STAFF 1-28. NHPUC.
[24] Unitil. (February 27, 2009). Data Response STAFF 1–28. NHPUC.
[25] NHEC. (February 19, 2009). Data Response STAFF 1-28. NHPUC.
[26] Due to the high speed protection on transmission lines, damage to the lines may be practically invisible and the location of the fault may not be found. Therefore, the cause of the fault may be listed as "unknown."

The PSNH broken static line was probably one of the more severe problems on the transmission system since it affected a 345 kV line that was out of service for over 61 hours. A review of that incident revealed that an ice laden static wire[27] came into contact with energized phase conductors.

Figure IV-9 shows the conditions after the static line failure. As can be seen in the bottom right side of the picture, the static wire which is normally on the top of the right leg of the two-pole wood H-Frame 345 kV structure is now lying on the ground. The static wire attached to the top of the left leg is still in place but sagging extremely low and appears to be near one of the 345 kV phase conductors. While this could be somewhat of an optical illusion, a small wind could blow the static wire into the phase conductor. Evidence that wind accompanied the formation of the ice on the line is shown in Figure IV-10 where it may be seen that the icicles attached to the conductor are not vertical.

The causes for ten of the recorded line faults (see Table IV-7 and Table IV-6) were never determined. These resulted in short outages or successful recloses of transmission line breakers and were likely caused by either ice induced galloping or line jumping. Ice induced galloping is defined as “low-frequency, high-amplitude, wind-induced vibration associated with the effect of ice, glaze or rime deposits on the aerodynamic characteristics of conductors”.[28] Line jumping is caused by ice shedding, which occurs when ice formed on conductors or overhead ground wires suddenly drops off causing the conductor to jump.[29] Either galloping or line jumping may cause phase conductors to move sufficiently so as to come into close proximity, or even direct contact, with other conductors. If two conductors come close enough to each other, an electric arc may occur between them. Even worse, the two conductors may touch each other. Either condition will cause a momentary fault. In the cases where the ice storm did have an impact on the transmission system, the system protection worked effectively to isolate faulted lines and restore the supply of power quickly through reclosing when possible.

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[27] Static wire is a non-current carrying conductor located above the current carrying phase conductors and is commonly used to shield the phase conductors from lightning.

[28] Electric Power Research Institute, (n.d.) *Transmission Line Reference Book, Wind-induced Conductor Motion*, pg.114.

[29] Fekr, M.R. (October 1995). *Dynamic Response of Overhead Transmission Lines to Ice Shedding*, pg. 2.

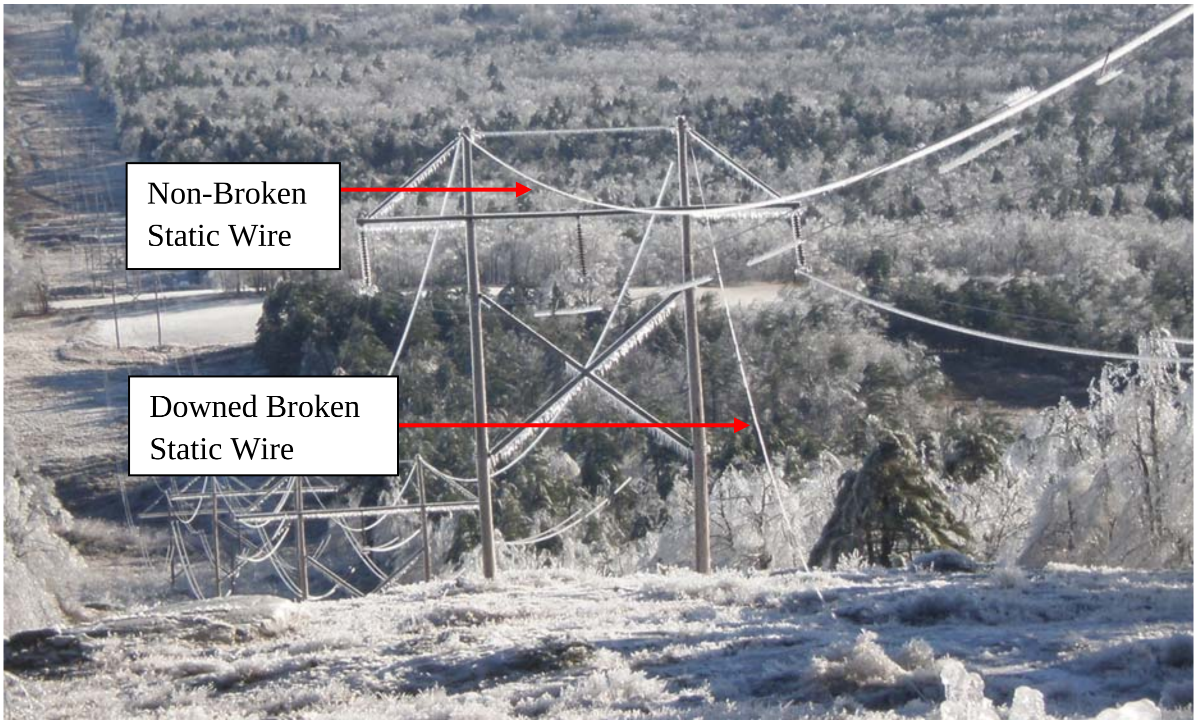

Figure IV-9 - PSNH 345kV line 367 - Static Wire Failure. (Photo courtesy of PSNH)

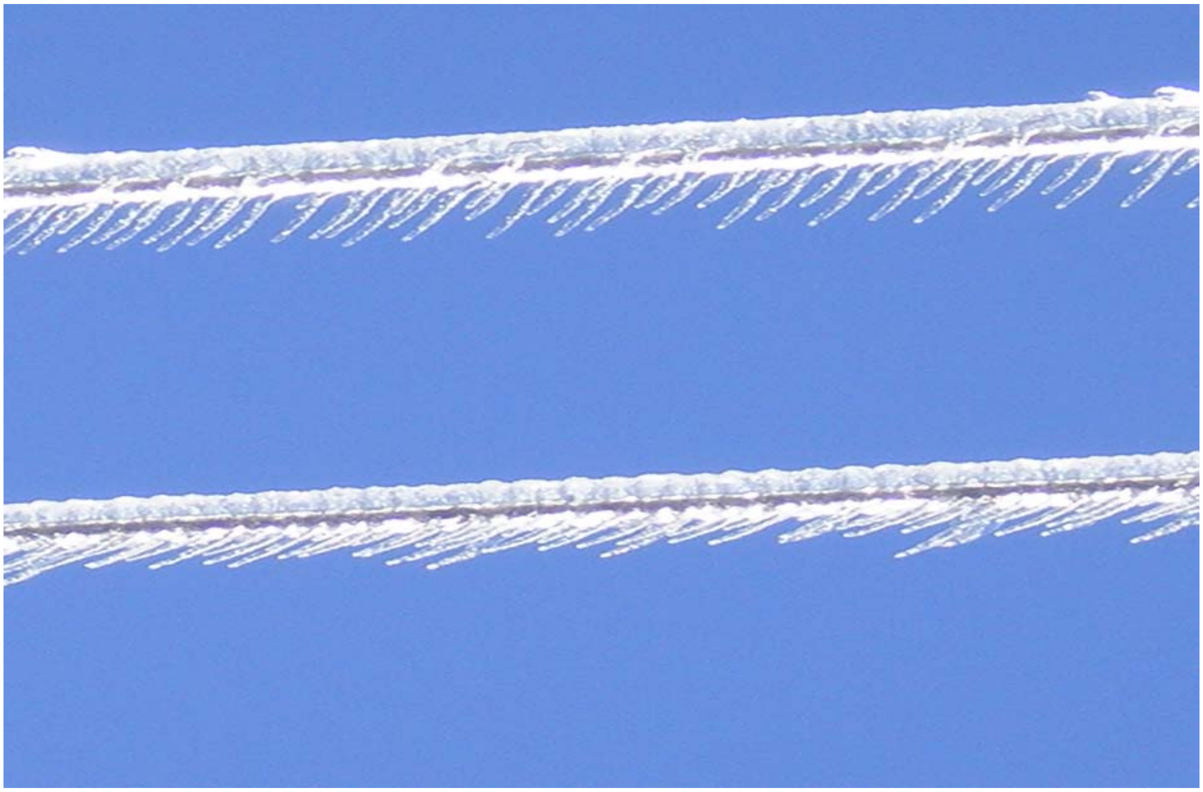

Figure IV-10 - Close-up of ice shown in Figure IV-9. (Photo courtesy of PSNH)

Recommendation No. 1: PSNH should inspect the condition of the static wire on Line 367, compare it with the original design, and present a report to the NHPUC.

- PSNH should determine if the 7 No. 10 Alumoweld static wire was damaged during the December 2008 ice storm.
- PSNH should determine if a similar failure during a similar icing condition is likely in the future.
- PSNH should determine if any upgrades or static wire replacements are needed as a result of the December 2008 ice storm.
- PSNH should determine and document the life expectancy of the remaining static wires on its system.
- PSNH should plan for upgrading static wires which may be reaching the end of their life and consider replacing existing wires with fiber optic overhead ground.

Conclusion: NHEC had limited back-up power for substation SCADA during the December 2008 ice storm.

The installed uninterruptable power supplies (UPS) for SCADA provided back-up power for only approximately 1-1/2 hours at each substation.[30] [31] Since the duration of the power outages exceeded this time period, the batteries for the UPS discharged and SCADA was not available. A better practice, and one recommended by industry standards, is to have eight hours of backup power.

Recommendation No. 2: NHEC should upgrade their substation SCADA back-up power systems to provide reliable power for a minimum of eight hours.

- NHEC should size their battery systems for a minimum of 8 hours of backup power as recommended in RUS Bulletin 1724E-300 – Design Guide for Rural Substations.

Conclusion: The replacement of the existing overhead transmission system in New Hampshire with an underground transmission system is impractical and unwarranted.

With very few exceptions, transmission lines and transmission substations are constructed above ground. Exceptions are typically in urban areas where land is not readily available to construct overhead transmission lines and substations. In addition, construction costs for underground transmission systems are quite high and design constraints are considerable. These include requiring shorter lines at higher voltages, developing methods to handle extreme line charging current due to capacitance, voltage regulation becomes more difficult, and repair times will be unacceptably long. (See Appendix B for a detailed discussion.) In New Hampshire, given the state's mountainous and rural topography, the most practical means of constructing a transmission system is overhead.

[30] Hutchison, J. Manager Engineering Support Services, NHEC. Interview by Ackerman, A. June 8, 2009.
[31] Lynch, H. Disaster Recovery Executive, NHEC. Interview by Ackerman, A. June 8, 2009.

The impact of the December 2008 ice storm on the New Hampshire transmission system was minimal and resulted in only 5,401 customers losing power. Of those 5,401 customers, a large percentage of those customers would have been without power due to distribution feeder outages at Pelham Substation.[32] So, neither financial nor reliability benefits would justify the placement of the overhead transmission system underground.

Conclusion: Unlike the transmission system, the sub-transmission lines were adversely impacted by the December 2008 ice storm, resulting in the loss of power to many customers. However, the adverse impact on the sub-transmission lines was from ice laden trees and tree limbs falling into the power system, and not due to planning, design, construction, or protection issues..

Table IV-8 summarizes the number of customers that were affected by the loss of sub-transmission lines.

Table IV-8 – Customers affected by the loss of a sub-transmission lines.

Utility	Customers affected
PSNH	187,486
Unitil	32,119
National Grid	4,073
NHEC	*26,213
Total	**249,891**

* Supply-side sub-transmission line outages - NHEC had no sub-transmission line outages on their system.

- PSNH had 52 sub-transmission line outages that affected 187,486 New Hampshire customers.[33]
- Unitil had approximately 22 sub-transmission line outages caused by the storm (30 with restoration switching) affecting approximately 32,119 New Hampshire customers[34]. With two exceptions caused by equipment failures within substations and restoration switching, all of those outages were the result of trees and tree limbs falling into the sub-transmission power lines.
- National Grid had two sub-transmission line outages[35] that affected approximately 4,073 New Hampshire customers.
- NHEC had no sub-transmission line outages[36]. All upstream outages were caused by other supplier lines. However, 26,213[37] customers were affected by the sub-transmission lines of NHEC's suppliers.

[32] Manager Electrical Distribution, National Grid. Interview by Nelson, J. May 14, 2009.
[33] PSNH. (July 20, 2009). Data Response PS0020. NEI.
[34] Unitil. (February 27, 20-09). Data Response STAFF 1–29. NHPUC.
[35] National Grid. (February 27, 2009). Data Response STAFF 1–29. NHPUC.
[36] NHEC. (February 19, 2009). Data Response STAFF 1–29. NHPUC.
[37] NHEC. (March 24, 2009). Data Response STAFF 2–22. NHPUC.

Conclusion: Outages to numerous sub-transmission lines during the December 2008 ice storm adversely impacted the operation of distribution substations.

Distribution substations are essential for delivering power to the customer. During the December 2008 ice storm, power on distribution lines exiting the distribution substations could not be restored until the sub-transmission lines were restored. Loss of the sub-transmission lines serving the distribution substations was the result of ice laden limbs and whole trees falling into power lines and was not due to planning, design, construction, or protection of the sub-transmission lines or substations.

Conclusion: In many locations, the sub-transmission lines have distribution loads connected to them.

In New Hampshire, most distribution loads are connected to 5 kV (2,400, 4,160 and 4,800 Volt), 15 kV (12.47, 13.2 and 13.8 kV) or 34.5kV systems. The 34.5 kV (as well as some 23 and 46 kV) voltage class is the common sub-transmission voltage level that is used to supply many distribution substations. Since the loss of a sub-transmission line can affect many customers due to the loss of one or more distribution substations, the importance of reliability on the sub-transmission system is high. Connecting customers directly to the 34.5 kV sub-transmission system adds tap splices, additional overhead lines, pole mounted transformers, and service drops—all of which are vulnerable to damage caused by weather. Adding equipment to any system increases the possibility of damage simply by having more pieces exposed. Twenty-nine PSNH sub-transmission and distribution lines were lost during the storm and affected 82,359 customers.

Recommendation No. 3: Each electric utility should perform a review of distribution loads supplied by sub-transmission lines.

- The electric utilities should include in their extended operations and construction plans a review of distribution loads supplied by sub-transmission lines.
- The electric utilities should examine reliability issues at sub-transmission supplied distribution loads with an emphasis on the effects caused by the December 2008 ice storm.
- The electric utilities should examine alternatives that would remove customers from the sub-transmission lines.

Conclusion: Approximately 100 distribution substations lost power during the December 2008 ice storm, affecting 159,549 customers. These substations are shown in Figure IV-11. Except for two minor exceptions, none of the outages appear to have been the result of inadequate planning, design, construction, or protection of the distribution substations.

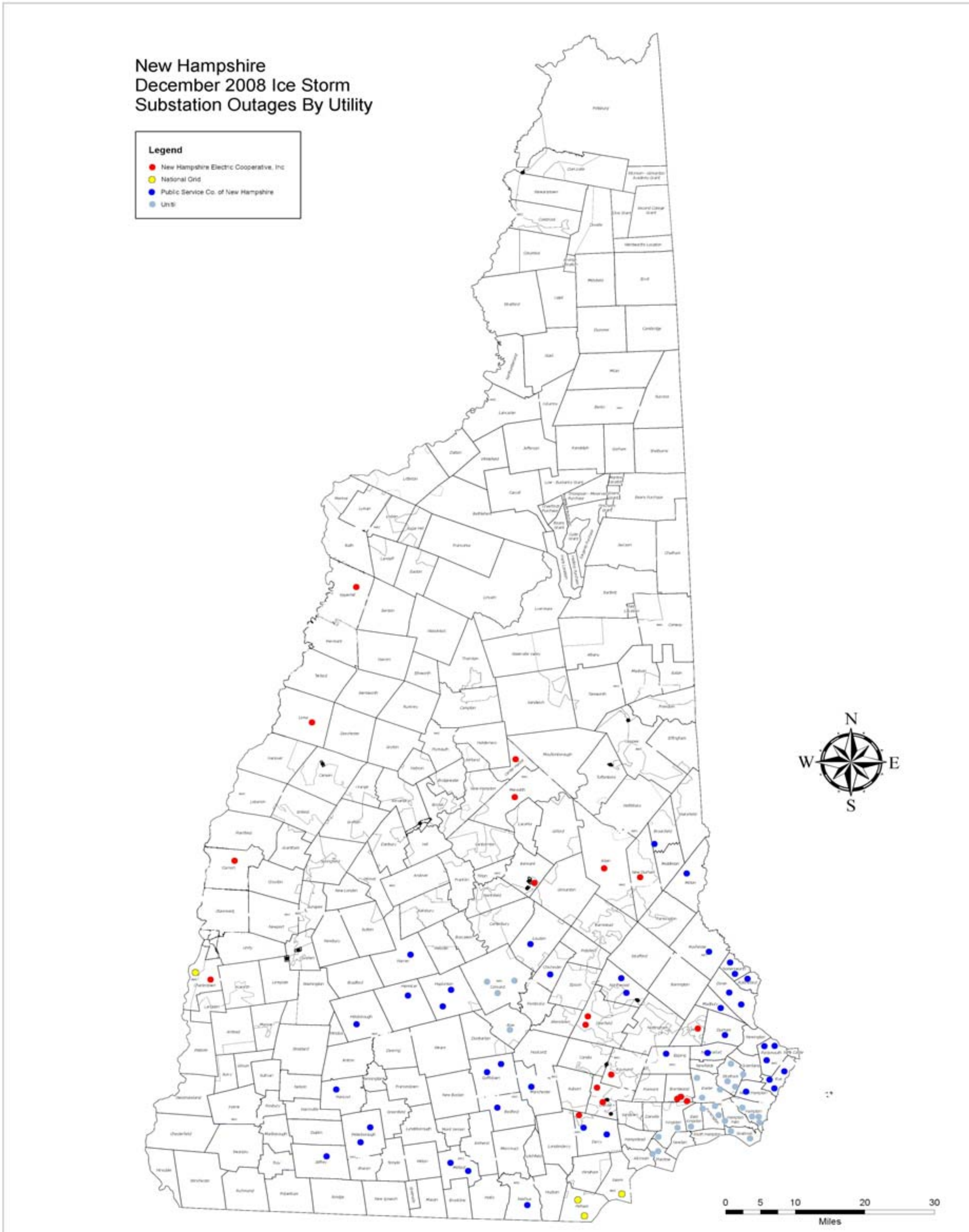

Figure IV-11 – Substation outages due to the December 2008 ice storm.

Table IV-9 summarizes the loss of distribution substations by each utility.

Table IV-9 – Impact of December 2008 ice storm on distribution substations.

Utility	Number of Substations	Customers Affected
PSNH	46	73,292
Unitil	35	47,234
National Grid	4	15,230
NHEC	15	23,793
Totals	**100**	***159,549**

*The number of customers affected due to a substation outage is included in the number of customers affected by a transmission or sub-transmission line outage. For example, National Grid's Pelham Substation lost 5,401 customers due to the 115 kV transmission line outage and the same 5,401 customers lost power due to the Pelham Substation outage.

PSNH lost 46 substations affecting approximately 73,292 customers. With the exception of four substations (one switchgear failure, one breaker failure, and two regulator failures), all 46 of the substations lost were affected by problems on the supply side of the substation. The vast majority of those problems were due to tree limbs and trees falling into the power lines. The four substations with internal equipment problems impacted approximately 13,703 of the 73,292 total customers affected, or 19%. The four PSNH substations that experienced problems with equipment are listed in Table IV-10.

Table IV-10 – PSNH Distribution substation equipment problems.

Substation	Equipment Failure	Customers Affected
Madbury	Circuit Breaker	8,225
West Milford 4 kV	Voltage Regulator	290
Souhegan 4 kV	Voltage Regulator	4
Malvern Street (Manchester)	Switchgear Failure	5,184
Total		**13,703**

Unitil lost approximately 35 substations in New Hampshire, excluding switching outages. Of the 35 substations without power, 33 were due to supply source sub-transmission line outages caused by tree limbs and trees falling into power lines.[38] Approximately 47,234 customers were affected by these substation outages. A total of 5,657 (12%) of the 47,234 customers were

[38] Unitil. (February 27, 2009). Data Response STAFF 1-30. NHPUC.

affected due to equipment problems at two substations. Those two substations are shown in Table IV-11.

Table IV-11 – Unitil distribution substation equipment problems.

Substation	Equipment Failure	Customers Affected
Iron Works Road	Transformer Failure	2,795
Westville	Transformer Fuse Opened	2,962
Total		**5,657**

The Iron Works Road Substation transformer failure was most likely the combined result of the relatively unusual transformer winding connection, grounded-wye/delta/grounded-wye, in conjunction with an upstream single phasing condition. While there was a minimal amount of forensics that took place, the transformer appeared to have overheated. It is quite probable that an upstream 34.5 kV single phasing condition took place. Due to the nature of the transformer windings, the grounded-wye primary winding combined with the delta tertiary would result in the transformer trying to supply power to the 34.5kV side of the phase that was open. Over time, there would have been an overloading of the tertiary winding which may have led to the ultimate failure. High side fuses were used to protect the transformer and this unusual condition could not be sensed by these fuses. The transformer continued to operate in an overloaded condition until it failed. High side breaker protection and better protective relaying may have prevented this failure from occurring. There are other transformers of similar design on the system for which the transformer protection should be reviewed. Another possible solution would be to remove the ground on the primary grounded-wye winding.

Unitil has similar transformers located in other parts of its system. The southern half of Unitil's Capital Division has five substations in which the transformers are connected primary grounded-wye to secondary grounded-wye.[39] Four of those substations have transformers which have a third winding that is delta connected. Due to the delta connection of the third winding in the transformer, there is a reasonable probability that a similar system condition during a storm and similar type of failure could occur in any one of those five substations. Unitil should review this scenario and develop a solution to prevent a future similar problem.

National Grid lost four substations affecting approximately 15,230 customers. All four substations were lost due to supply side transmission or sub-transmission lines outages caused by ice laden tree limbs and trees falling into power lines.

NHEC reportedly had 27 substations affected by the December 2008 ice storm.[40] However, the number of substation outages caused by primary power supply failures was 15, which affected approximately 23,793 customers.

[39] Zogopoulos, A.J., Design and Standards Specialist, Unitil. Interview by Nelson, J. August 8, 2009.
[40] NHEC included all impacts to substations including single phasing and loss of feeders.

Recommendation No. 4: Unitil should investigate the failure of the Iron Works Substation transformer and correct any deficiencies on their system that could result in failures in the future.

- Unitil should investigate and modify if necessary the transformer protection at the Iron Works Road substation.
- Unitil should investigate and modify if necessary the transformer protection at the Bow Junction Substation.
- Unitil should investigate and modify if necessary the transformer protection at the Montgomery Street Substation.
- Unitil should investigate and modify if necessary the transformer protection at the Storrs Street Substation.

Conclusion: Damage to the underground distribution system was non-existent.

The vast majority of damage to the electrical infrastructure in New Hampshire was the result of tree limbs and trees falling into overhead power lines. The underground system was not impacted by the December 2008 ice storm.

Conclusion: Damage to the overhead distribution system was extensive, and with few exceptions, was caused by ice laden tree limbs and trees falling into power lines.

Some collateral damage was noted in a few substations where electrical equipment failed. The December 2008 ice storm was most likely a contributing factor to those failures primarily due to the stresses caused on the substation equipment by upstream and downstream faults.

Conclusion: Conversion of the entire overhead distribution system to underground is not practical, would be very expensive, and would take many, many decades to complete.

Converting the entire distribution system from overhead to underground would be highly impractical in New Hampshire. Conversion of some portions of the distribution system may be practical if the higher costs are acceptable and the following conditions exist:

- The system is an urban (not rural) distribution system with moderately dense population.
- The conversion is done as part of a long term (i.e., decades long) project.
- The conversion is coordinated and can share costs with other maintenance projects such as street repair.
- The conversion is done in conjunction with retiring old overhead lines.
- The municipality passes ordinance making underground lines required for all new construction and new costs are passed on to homeowners.
- The utility should be able to dedicate a full time crew who will be responsible for the conversion during the many years it would likely take.

Some benefits will be seen if the utility decides to place underground those parts of the system that can be economically converted. Following an ice storm the undamaged underground portion of the system can be ignored and resources can be diverted to concentrate on the damaged overhead system. This should speed overall system restoration. (See Appendix B for a more thorough and technical discussion on overhead to underground conversion.)

Table B-1 from Appendix B is reproduced below as Table IV-12, summarizing the data responses from the four electric utilities on the cost of converting the existing overhead distribution system (including the sub-transmission lines) to underground. The total estimated cost for the conversion, based on the data provided by the four electric utilities, is $43 billion. (See Appendix B for costs associated with overhead to underground conversions.) In addition, the amount of construction that would be required could easily take 50 years, at which time the original cable installed at the beginning of the project would need to be replaced due to reaching the end of its service life. In other words, there would be perpetual construction on the underground system. According to the data provided by the four electric utilities, the average cost per customer for the conversion would be in the range of $34,746 with National Grid at the low end to $72,563 with NHEC at the high end. Three of the four utilities' data showed an average cost in the $70,000 range per customer. Using the lowest cost estimate per customer, the average electric customer may see a monthly increase of over $400 to their electric bill in perpetuity. There appears to be no economical benefit to placing the electric distribution system underground except in special cases where costs can be minimized, reliability improved, and the cost to benefit ratio is reasonable.

Table IV-12 – New Hampshire electric utility high level overhead to underground cost summary.

	National Grid	NHEC	PSNH	Unitil
U/G Distribution Costs - Lines and Substations (millions)	$1,288	$3,845	$29,946	$1,664
Overhead Distribution Line Removal Costs (millions)	$55	$364	$305	$627
U/G Distribution Costs – Services to Customer (millions)	$90	$903	$3,360	$562
Total Cost (millions)	$1,433	$5,112	$33,611	$2,853
Number of Customers	41,156	70,422	492,000	41,264
Average Cost Per Customer	$34,819	$72,591	$68,315	$69,140
Average monthly electric bill increase*	$434/mo	$907/mo	$854/mo	$864/mo

*Average Monthly Electric Bill = Average Capital Investment x (FCR)/ 12 months where FCR is the fixed charge rate or annual recovery rate of a capital expenditure into perpetuity. 15% was used for FCR which includes such costs as rate of return, replacement cost, insurance and taxes.

Conclusion: With few exceptions, protection devices operated correctly during the December 2008 ice storm and did not adversely affect the system. However, there are some improvements that should be made by replacing older electromechanical relays.

Due to extensive damage on the power system, a large number of protective circuit devices such as fuses, circuit breakers, reclosers, and sectionalizers operated. There was indication of only one circuit breaker failure that happened late during the power restoration. However, the protective devices acted only to isolate the faulted sections of the system and did not provide pre-fault and fault data so that the operation of the protective device could be analyzed.

State of the art protective devices and communication links are available that provide better protection and control. These devices are capable of capturing pre-fault and fault data, which is very useful for analysis of mis-operation of protective devices and forensic studies of equipment failures.

By replacing electro-mechanical relays with micro-processor based relays system reliability and security can be improved. In addition, by adding micro-processor based relays, the implementation or expansion of SCADA systems will be facilitated. This would improve storm response in the future by providing better system information on both system status and faults.

Recommendation No. 5: Each electric utility should replace existing electro-mechanical relays with microprocessor based relays that feature event reporting ability.

- The electric utilities should implement and/or complete plans to replace all their electro-mechanical relays with microprocessor based relays.
- The electric utilities should choose relays with event recording capability.
- The electric utilities should incorporate the new relays into their SCADA systems.

Conclusion: Covered wire is used extensively by New Hampshire utilities and provides an advantage during normal operations[41] by limiting the number of incidental tree and tree branch contacts with conductors that affect the reliability of the sub-transmission and distribution systems. However, covered wire systems should not be considered a weather hardening protection scheme.

Covered wire does not provide a distinct advantage during extreme weather disturbances due to the need to be de-energized to clear debris and make repairs that often take longer to complete than they would if bare wire was used. In addition, because the covered wire does not have an insulating shield, it is not intended for and cannot be depended upon for absolute personal protection.[42]

[41] Normal conditions are typical days without wind, snow, rain or lightning.
[42]Landinger, C.C., McAulife, J.W., Clapp, A.L., Dagenhart, J.B., Thue, W.A. (April 1997). “Safety Considerations of Aerial Systems Using Insulated and Covered Wire and Cable.” *IEEE Transactions on Power Delivery*, Vol 12, (2), pgs. 1012-1016. (10.1109/61.584430).

Conclusion: The amounts of ice reported in New Hampshire due to the 2008 storm vary greatly among sources and therefore were unreliable for calculating system line performance due to ice and wind loading.

Due to the inconsistent reporting of ice accretion, the amount of ice that accumulated during the storm is somewhat subjective. Many people may measure the size of icicles and report that as the amount of ice. The ice loading which is important to the line designer is the amount of equivalent radial ice, and this is difficult to calculate or measure. Equations have been developed by Army Corp of Engineers Cold Regions Research and Engineering Laboratory (CRREL) that equates an uneven ice measurement to an equivalent thickness of ice that will produce both the same weight load on a line and an equivalent diameter for wind to act on the line. These equations are used to determine the effective amount of radial ice that accumulated during the storm.

Conclusion: The maximum radial ice seen in New Hampshire in the December 2008 ice storm was found to be 1/2 inch. An equivalent storm with this ice thickness can be expected to occur once every ten years.

CRREL in Hanover, New Hampshire worked closely with NEI to study the effects of this storm and report, among other things, the maximum equivalent radial ice observed. It is noteworthy that CRREL is the same group that gathers the data and prepares the ice loading maps which are used by the American Society of Civil Engineers (ASCE) and other code-writing bodies. The weather data provided by CRREL is then used by engineers in the design of overhead power lines. CRREL reports that the maximum radial ice seen in New Hampshire was in the Manchester area and was 1/2 inch. According to empirical evidence cited by CRREL, an ice storm with 1/2 inch of radial ice can be expected approximately every ten years in New Hampshire.[43] Only 4/10 inch of radial ice was found to have occurred in southwestern New Hampshire in the Jaffrey area. This storm was of far smaller magnitude in terms of ice accretion than the storm that occurred in 1998, even though it produced more damage. The 1998 storm damage area was farther north and had greater reported ice accretion, but occurred in a less populated area. NHEC and PSNH experienced significant damage to their system as a result of the 1998 storm.

Conclusion: The four New Hampshire utilities use NESC heavy loading as the basis for distribution and transmission structure designs; however, design standards vary among the utilities.

On its transmission system, PSNH uses NESC heavy loading along with the requirements in the Northeast Utilities Transmission Standard OTRM 060 “Extreme Wind & Ice Loading on Transmission Line Structures”, which appears to contain equal or more conservative design

[43] Jones, Kathleen F. (July 2009) The December 2008 Ice Strom in New Hampshire. Cold Regions Research and Engineering Laboratory.

standards than are contained in the NESC. All transmission lines are built to Grade B construction and all distribution is built to grade B or C as required by the NESC. On the distribution system design, PSNH uses only NESC heavy loading.

Unitil builds all of its system to Grade B or C construction standards, as required by the NESC. Where poles are jointly owned by electric and telecommunications utilities, they are designed jointly and the above conditions are applied.[44] [45] [46] [47] This is true of poles jointly used by all of the electric utilities.

National Grid uses NESC heavy loading and extreme wind standards (on structures only) for all design. For structures above 60 feet, National Grid applies extreme wind standards (on both structures and conductors) and extreme ice with concurrent wind standards, as required by the NESC. The company's transmission system is designed with Grade B construction; distribution lines are designed to either Grade B or C standards, as required by the NESC.

NHEC uses NESC heavy loading standards for all construction, and extreme wind and extreme ice with concurrent wind standards for structures above 60 feet. NHEC builds all 34.5kV and above lines to Grade B standards and everything below 34.5kV to either Grade B or C standards, as required by the NESC.

Conclusion: The structural design for both the transmission and distribution systems were designed to sustain the loading imposed by this storm.

As noted, the maximum equivalent radial ice seen in New Hampshire was 1/2 inch, which is equal to NESC heavy loading ice requirements for design in New Hampshire. According to the CRREL report, wind was not a significant factor during this storm. The amount of ice and wind seen was far below the required 50-year return design criteria for ice with concurrent wind, which is 3/4 to 1 inch of ice with a 40 mile per hour wind. The loading conditions seen by the structures during the December 2008 ice storm were within the design criteria, and the system should have been able to sustain the amount of ice and wind which was seen without sustaining significant damage. The extreme amount of damage seen cannot be attributed to faulty or insufficient line design or construction practices. The design practices used by all the utilities in New Hampshire were the same or similar to those commonly used by utilities across the United States and the system was adequately designed for this storm.

[44] Unitil. (July 10, 2009). Data Response GN0013. NEI.
[45] National Grid. (July 2, 2009). Data Response GN0013. NEI.
[46] PSNH. (July 10, 2009). Data Response GN0013. NEI.
[47] NHEC. (July 2, 2009). Data Response GN0013. NEI.

CHAPTER V

Operations, Maintenance, and Vegetation Management

Chapter Structure

A. BACKGROUND

Operations - General

The electric system, from an operations point of view, begins at the generating station, includes the transmission and distribution system, and ends at the customer's meter. At the meter, the customer takes over the responsibility for the final delivery and utilization of electricity[1]. During the December 2008 ice storm, electric generation was minimally impacted except for the fact that generator demand was significantly reduced because so many customers were without power. As a result, the ice storm's effect on generation is not discussed in this report. However, transmission and distribution operations were affected by the storm, and as such, are addressed here with the primary emphasis being on the sub-transmission and distribution systems.

Operations – OMS

Outage management system (OMS) technology is a recent enhancement to utilities' infrastructures. It has benefitted from developments in metering technology, communications technology, and leaps in computing power. In the most basic terms, an OMS is the method a utility uses to analyze problems on the electrical system in an organized way to facilitate the restoration of power to affected areas. Historically, dispatchers and operators have managed power outages and service restorations using tools such as paper, pencils, hand-generated trouble

[1] Although each utility owns the electric meters, they require the customer to be responsible for the service drop from the weatherhead to the meter. The only exception in New Hampshire is PSNH, which takes responsibility of everything up to the meter, including the weatherhead.

tickets, paper maps, wall boards, map pins, and highlighting markers. Operators would decide how to allocate resources using "gut feelings" for the size of the problem and method needed for restoration.[2] In essence, every utility has an OMS, even if it consists only of a system where telephone calls to the customer service center are used to determine where outages exist and a human decides where to dispatch crews to repair problems and restore power. (See Appendix G for a more thorough and technical discussion of OMS technology.)

Maintenance

Like any complex machine, an electric system needs scheduled periodic maintenance. Without proper maintenance, an electric system will soon fail to operate properly. This is why a properly operated system must also be properly maintained. Maintenance becomes especially challenging as the electrical infrastructure ages.

In addition to the normal aging of the system infrastructure, New Hampshire has an added problem caused by the abundance of trees growing around and near overhead power lines. Vegetation management adjacent to power lines is a key element of electrical system maintenance and represents a substantial expense to the utilities. During the December 2008 ice storm, ice laden tree limbs and entire trees fell onto power lines. This was the cause of most of the power outages which occurred and highlights the importance of vegetation management.

Vegetation Management

On August 14, 2003 a tree in northern Ohio made contact with a high voltage transmission line and caused the line to trip off. The system operators misunderstood what was happening, and over the course of the next 90 minutes three other transmission lines made contact with trees causing additional lines to trip. Thus began the cascading power failure now known as the 2003 Northeast blackout. The final analysis of the Northeast blackout revealed that over 40 million people in the northeastern part of the United States and 10 million people in Canada lost power for up to two days. The 2003 Northeast blackout contributed to at least 11 deaths and an economic cost estimated at $6 billion.[3] The root cause of the blackout was inadequate vegetation management. Since that time, Congress passed the Energy Policy Act of 2005 authorizing the Federal Energy Regulatory Commission (FERC) to solicit, approve, and enforce new reliability standards from the North American Electric Reliability Corporation (NERC). Since then, FERC has approved 96 new reliability standards, many of which revolve around what are known as the three T's: "trees, training, and tools."

[2] Hall, D.F. (2001). "Outage Management Systems as Integrated Elements of the Distribution Enterprise." *IEEE Power Engineering Society Summer Meeting, Vol. 2*, Pages 989-991 (10.1109/PESS.2001.970191).
[3] Minkel, JR. (2008). The 2003 Northeast Blackout—Five Years Later. *Scientific American*, August 13. http://www.scientificamerican.com/article.cfm?id=2003-blackout-five-years-later&offset=2 (Accessed June 18, 2009).

The December 2008 ice storm in New Hampshire was similar to the 2003 Northeast blackout in the fact that the three T's played a large role in the devastation. The ice damaged tree limbs and whole trees falling onto power lines resulted in over 800,000 people in New Hampshire being affected.[4] As a result of the 2003 Northeast blackout, federal regulators mandated that electric utilities take a more aggressive approach to vegetation management, and required utilities to reclaim transmission line right of ways (ROWs) from property owners that allowed trees to interfere with the integrity of the transmission line.[5] State and local agencies in New Hampshire need to consider the same approach on a smaller scale for sub-transmission lines. Sub-transmission lines on a state level are quite similar to transmission lines on a national level. The reliability of sub-transmission lines is essential, and state and local authorities should consider methods at their disposal to support the utilities' efforts in providing better vegetation management on sub-transmission and distribution lines.

At the time the first Europeans came to New England, the forest they found was quite different than the one we know today. The amount of forest cover was greater, as one would expect. However, other characteristics of that forest may differ from our modern expectations, since most of us are only familiar with forests that have regenerated, and have never seen a forest that has been undisturbed for millennia.

In the latter part of the nineteenth century, as much as 50% of the primordial forest was cut for farming and lumber.[6] Photographs of the forest cover in 1880 after it was cleared for farming, and 1990 after it had regenerated, are shown in Figure V-1. Although New Hampshire forests have been regenerating for almost 100 years, the tree species that made up the forest understory in the old growth forest have not returned. The influences of modern humans on this newly regenerated forest will inevitably affect its transition into a mature forest. It is important to understand the history of the forest before planning a management method, especially a method for controlling the forest near telecommunications and power lines.

[4] Getz, T. Knepper, R. and Frantz, T. (Jan. 14, 2009). Brief Legislative Overview of Dec 2008 Ice Storm Impacts [PowerPoint]. Concord, New Hampshire.
[5] NERC Standard FAC-003-2 Technical Reference. (October 22, 2008). Pg. 15.
[6] Foster, David R. and Aber, John D. eds. 2006. *Forests in Time – The Environmental Consequences of 1000 Years of Change in New England*. New Haven: Yale University Press. 10.

Figure V-1 – Photos showing amount of forest removed for farming purposes in 1880 (left), compared to 1990's current level of re-growth (right). The location is the Swift River in the White Mountains of New Hampshire.[7]

For the most part, the December 2008 ice storm did not directly damage the transmission and distribution systems. Instead it damaged the woodlands of New Hampshire, causing tree limbs and whole trees to fall, which in turn damaged the power system by breaking poles, cross arms, hardware, and conductors. Poles and conductors are quite resilient to simple ice loading as is evident in Figure V-2 where it may be seen that wires, poles, and a transformer are all carrying heavy ice loads, yet are all completely intact. If a limb or a tree were to break off due to the ice and fall on the wires or against a pole, the additional stress raises the risk that that poles or wires could fail.

Figure V-2 - Ice loading on lines during December 2008 ice storm.
(Photo courtesy of PSNH, location unknown.)

[7] Harvard Forest. "Forests in Time." (2008). http://harvardforest.fas.harvard.edu/publications/forestsintime.html (Accessed July 16, 2009).

Besides the reforestation of the state in the last hundred years, other factors are affecting the impact that vegetation has on the power system. The last century has seen increases in population in New Hampshire. Many of today's residents along with their elected local officials are reluctant to allow for adequate vegetation management near power lines. This reluctance will continue to adversely affect the reliability of the power system. Better vegetation management techniques and shorter tree trimming cycles are needed in New Hampshire to prevent the next storm from causing damage similar in extent to that caused by the December 2008 ice storm.

B. EVALUATIVE CRITERIA

The operations, maintenance, and vegetation management efforts of each utility were evaluated using the following criteria:

1. The ability to operate the system during adverse weather conditions
2. The effectiveness of system maintenance in preventing unnecessary outages due to equipment failure
3. The effectiveness of vegetation maintenance in preventing contact between conductors and vegetation

1. During adverse weather conditions a utility should be able to isolate problems and restore service in a minimal period of time.

- The utility's system should operate efficiently and automatically with minimal human interaction.
- The utility should maintain the voltage of their system to within industry tolerances.
- The utility should maintain the frequency of their system to within industry tolerances.
- The utility should ensure that when abnormal conditions occur the smallest possible section containing the problem is automatically isolated, minimizing the size of the outage.
- The utility should ensure that an isolated part of the system is restored as quickly as possible.

2. Inadequate maintenance should not adversely impact the electric system during a storm such as the December 2008 ice storm by causing unnecessary outages.

- The utility should adequately inspect and maintain its transmission lines.
- The utility should adequately inspect and maintain its sub-transmission lines.
- The utility should adequately inspect and maintain its overhead distribution lines.
- The utility should adequately inspect and maintain its substations.
- The utility should effectively isolate equipment under maintenance or repair to minimize its impact on system operations.

3. A utility should have a good vegetation management plan (VMP) that limits vegetation and conductor conflicts.

- The utility's vegetation management plan should be cost-effective and have a long term approach.
- The utility should execute its vegetation management plan.
- State and local governments should support the utility's vegetation management efforts.
- The utility's vegetation management practices should use proper arboricultural practices.
- The utility should use integrated vegetation management (IVM) that is efficient and environmentally sound.
- The utility's vegetation management plan should include the systematic use of a consistent and reasonable period of time between trimmings (vegetation management cycle).
- The utility's vegetation management plan should consider aesthetic and property owner issues without compromising electrical reliability.

The following tables indicate the extent to which each of the utilities met the evaluative criteria. These tables were not prepared to compare one utility with another. The four electric utilities are very different, face different problems, and experienced different amounts of damage to their systems due to the storm. These tables were prepared to show where each utility may improve its performance in preparation for the next storm or other disaster. A further explanation for the improvements that are recommended to each of the utilities may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are as follows:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table V-1 - PSNH operations, maintenance, and vegetation management evaluation matrix.

1) **ISOLATING PROBLEMS EFFICIENTLY**	
The system operated efficiently and automatically with minimal human interaction.	◐
System voltage was maintained within industry tolerances.	●
System frequency was maintained within industry tolerances.	●
When abnormal conditions occurred, the smallest possible section containing the problem was automatically isolated, minimizing the size of the outage.	◐
Any part of the system that was isolated was restored as quickly as possible.	○

2) MAINTENANCE OF THE SYSTEM	
The company adequately inspected and maintained transmission lines.	◐
The company adequately inspected and maintained sub-transmission lines.	◐
The company adequately inspected and maintained overhead distribution lines.	◐
The company adequately inspected and maintained Substations.	◐
The company effectively isolated any equipment under maintenance or repair to minimize any impact to systems operations during the storm.	◐

3) VEGETATION MANAGEMENT PLANS	
Vegetation management plans are cost-effective with a long term approach.	○
The utility executes its vegetation management plan.	◐
State and local governments support the utility’s vegetation management plan.	○
The vegetation management plan used proper arboricultural practices.	◐
The utility’s vegetation management plan is efficient and environmentally sound.	○
The utility’s vegetation management plan uses an appropriate management cycle.	○
The utility’s vegetation management plan considers aesthetic and other property owner issues without infringing on electrical reliability.	◐

Table V-2 - Unitil operations, maintenance, and vegetation management evaluation matrix.

1) ISOLATING PROBLEMS EFFICIENTLY	
The system operated efficiently and automatically with minimal human interaction.	○
System voltage was maintained within industry tolerances.	●
System frequency was maintained within industry tolerances.	●
When abnormal conditions occurred, the smallest possible section containing the problem was automatically isolated, minimizing the size of the outage.	○
Any part of the system that was isolated was restored as quickly as possible.	○

2) MAINTENANCE OF THE SYSTEM	
The company adequately inspected and maintained transmission lines.	**NA**
The company adequately inspected and maintained sub-transmission lines.	◐
The company adequately inspected and maintained overhead distribution lines.	◐
The company adequately inspected and maintained Substations.	◐
The company effectively isolated any equipment under maintenance or repair to minimize any impact to systems operations during the storm.	◐

3) VEGETATION MANAGEMENT PLANS	
Vegetation management plans are cost-effective with a long term approach.	○
The utility executes its vegetation management plan.	○
State and local governments support the utility's vegetation management plan.	○
The vegetation management plan used proper arboricultural practices.	◐
The utility's vegetation management plan is efficient and environmentally sound.	○
The utility's vegetation management plan uses an appropriate management cycle.	○
The utility's vegetation management plan considers aesthetic and other property owner issues without infringing on electrical reliability.	○

Table V-3 – National Grid operations, maintenance, and vegetation management evaluation matrix.

1) ISOLATING PROBLEMS EFFICIENTLY	
The system operated efficiently and automatically with minimal human interaction.	◐
System voltage was maintained within industry tolerances.	●
System frequency was maintained within industry tolerances.	●
When abnormal conditions occurred, the smallest possible section containing the problem was automatically isolated, minimizing the size of the outage.	○
Any part of the system that was isolated was restored as quickly as possible.	○

2) MAINTENANCE OF THE SYSTEM	
The company adequately inspected and maintained transmission lines.	**NA**
The company adequately inspected and maintained sub-transmission lines.	◐
The company adequately inspected and maintained overhead distribution lines.	◐
The company adequately inspected and maintained Substations.	◐
The company effectively isolated any equipment under maintenance or repair to minimize any impact to systems operations during the storm.	◐

3) VEGETATION MANAGEMENT PLANS	
Vegetation management plans are cost-effective with a long term approach.	○
The utility executes its vegetation management plan.	◐
State and local governments support the utility’s vegetation management plan.	○
The vegetation management plan used proper arboricultural practices.	◐
The utility’s vegetation management plan is efficient and environmentally sound.	○
The utility’s vegetation management plan uses an appropriate management cycle.	○
The utility’s vegetation management plan considers aesthetic and other property owner issues without infringing on electrical reliability.	◐

Table V-4 - NHEC operations, maintenance, and vegetation management evaluation matrix.

1) ISOLATING PROBLEMS EFFICIENTLY	
The system operated efficiently and automatically with minimal human interaction.	●
System voltage was maintained within industry tolerances.	●
System frequency was maintained within industry tolerances.	●
When abnormal conditions occurred, the smallest possible section containing the problem was automatically isolated, minimizing the size of the outage.	◐
Any part of the system that was isolated was restored as quickly as possible.	◐

2) MAINTENANCE OF THE SYSTEM	
The company adequately inspected and maintained transmission lines.	◐
The company adequately inspected and maintained sub-transmission lines.	◐
The company adequately inspected and maintained overhead distribution lines.	◐
The company adequately inspected and maintained Substations.	◐
The company effectively isolated any equipment under maintenance or repair to minimize any impact to systems operations during the storm.	◐

3) VEGETATION MANAGEMENT PLANS	
Vegetation management plans are cost-effective with a long term approach.	○
The utility executes its vegetation management plan.	◐
State and local governments support the utility’s vegetation management plan.	○
The vegetation management plan used proper arboricultural practices.	◐
The utility’s vegetation management plan is efficient and environmentally sound.	○
The utility’s vegetation management plan uses an appropriate management cycle.	○
The utility’s vegetation management plan considers aesthetic and other property owner issues without infringing on electrical reliability.	◐

C. WORK TASKS

In conducting this assessment, a large number of executives, managers, engineers, arborists, foresters, state officials, vegetation management companies, and system operators in all four major electric utilities were interviewed. In addition, a number of data requests were made to each utility and the responses reviewed and analyzed. Tours were scheduled with each of the utilities that included inspections of the following:

- Work centers
- Control rooms
- Substations
- Transmission lines, sub-transmission lines, distribution lines, and right of ways
- Vegetation management practices.

The focus of this assessment was on maintenance and vegetation management as each pertained to the December 2008 ice storm. While the intent of the assessment was not to compare the utilities with each other, a comparison was made in an effort to formulate best practices using the results from each of the utilities.

D. FINDINGS AND CONCLUSIONS

Conclusion: The four electric utilities in New Hampshire have a wide variation in the types of Outage Management Systems they use.

PSNH

PSNH has an OMS system which was developed over the years in-house. During the ice storm the number of outages overloaded the system and PSNH stopped using it. The result was that PSNH's OMS system was of little value during the storm.

Researchers have developed algorithms that attempt to predict storm damage from weather report data.[8] The OMS used by PSNH included a method developed in-house to try to predict the amount of damage which could be expected from a storm. A predictive tool of this type could be very useful for planning; however, the information provided by the tool used by PSNH was too general and vague to be of much value to the utility during the restoration. The PSNH system is not based on a Geographical Information System (GIS), limiting its ability to display outage and restoration information and interface with web-based tools to convey information to the public. Most modern tools are GIS based, and the lack of a GIS database makes it difficult to pass information from the existing system to other systems. PSNH also lacks an automatic meter reading (AMR) or automated metering infrastructure (AMI) system, and instead depends on

[8] Lubkeman, D. and Julian, D.E. (2004). "Large Scale Storm Outage Management." *IEEE Power Engineering Society General Meeting 2004*. (10.1109/PES.2004.1372741).

human meter readers periodically visiting each meter. While there is an argument that the meter readers can be helpful personnel in assessing damage, it is also true that this information could be automatically collected by the AMR/AMI system and then integrated and displayed by the OMS instantly. Valuable information from field inspections can also be manually entered into the OMS, but due to the additional time needed, this method cannot take the place of the near real-time information available from an AMR/AMI system integrated with an OMS.

The trend in the industry has been for utilities to install AMR systems and phase out manual meter reading. Over the past several years the number of AMR systems has been growing at a rate of 25% per year among Rural Electric Cooperatives. However, there has been a somewhat slower acceptance rate among larger investor owned utilities.[9]

PSNH has made the argument that they are waiting for technology to improve, and are afraid that if they purchase any one system (either OMS or AMI), it will soon become obsolete. This argument is not without merit; however, in this age of rapidly developing computer technology, this argument may always have some validity. Most conceivable benefits to be derived from a fully integrated OMS can be implemented with currently available equipment, and waiting to install such a system does not seem warranted.

Unitil

Unitil has an AMI system and since the storm has chosen to add an OMS system made by ABB.[10] They had an AMI system in place during the storm, but since it was not integrated with an OMS it was of limited value during restoration. As a result, the Unitil personnel were unprepared to use their AMI for large scale outage restoration, and attempts to use the system following the storm were ad hoc, evolving as the restoration progressed.

National Grid

National Grid's existing OMS does not have the ability to integrate SCADA, AMR, or AMI information, but it does provide a way of tracking outages and restoration efforts. National Grid is in the process of choosing a new system that can integrate with their SCADA system.[11] This new system should be implemented in coming years. However, while integrating a new OMS with a SCADA system is an excellent idea, National Grid should also consider choosing a system that can integrate with an AMR/AMI system. Information from the SCADA system can supply the OMS with status of the sub-transmission and distribution system down to the substation level, and the AMR/AMI system can provide the OMS with information from the substation level to the customer level.

[9] Steklac, I., Tram, H. (2005). "How to Maximize the Benefits of AMR Enterprise-Wide." *IEEE Rural Electric Power Conference 2005*. (10.1109/REPCON.2005.1436325).
[10] Francazio, R. Director Emergency Management and Compliance, Unitil. Interview by Nelson, J. August 7, 2008.
[11] Demmer, K. Manager Electrical Distribution New Hampshire, National Grid. Interview by Nelson, J. August 7, 2009.

NHEC

Among the four electric utilities, NHEC has the most sophisticated OMS. It is an integrated automated system that includes a web-based tool capable of displaying up to date outage data and restoration times for public use. While not fully used after the 2008 ice storm, this system has great potential for aiding in future restoration efforts and in delivering valuable data to the public.

Recommendation No. 1: PSNH should abandon its existing OMS system in favor of a modern fully integrated GIS based system, Unitil should continue on the path they have begun and choose an OMS, and National Grid and NHEC should continue on with their plans for their OMS.

- PSNH should replace its existing OMS with a system that can integrate with its SCADA system.
- PSNH should consider installing an AMR/AMI system which can also be integrated with its OMS system.
- PSNH should lose no time in converting their record keeping and system information to a GIS based system.
- PSNH should develop a tool to make restoration information available on the Internet.
- Unitil should choose an OMS that will integrate with their existing AMI.
- Unitil should work with the manufacturer of their existing AMI system to maximize the integration and usefulness of the AMI system into their chosen OMS.
- Unitil should purchase an OMS that will integrate with their SCADA system.
- Unitil should develop a web-based method for informing the public about the status of the restoration effort.
- Unitil should assign sufficient personnel to install, integrate, maintain, and train their operators, dispatchers, and line crews in the use of the OMS system.
- National Grid should install an OMS that will integrate with their SCADA system and any future AMR/AMI system.
- National Grid should also develop a web-based system that can allow customers access to restoration information.
- NHEC should develop a method for keeping the information provided by their web-based tool up to date during a large outage.
- NHEC should assign and train sufficient personnel in the use of their OMS so that the information it displays for the public is kept up-to-date during a wide area outage.
- NHEC should continue developing web-based tools for displaying restoration information to the public.

Conclusion: The failure of telecommunications following the ice storm hampered the electric utilities' restoration effort and limited the value of Unitil's AMI system.

The value of Unitil's AMI system determining the scale of the outage was limited due to the fact that telephone communication was lost between the substations and Unitil operations centers. To make their OMS useful during an event which causes large scale damage, Unitil and the other utilities must find a way to harden their communications system. Technologies such as fiber optics, microwave, and spread spectrum radio are available to provide primary and backup communications between substations and the central control room.

As an alternative to providing a communications system that would operate even when the joint use poles were damaged, the electric utilities could coordinate with the telephone utilities to restore communications to an area as soon as possible after the electrical system is restored. The goal would be to minimize the time between restoring electricity and restoring communications. It is especially important to restore telephone communications to the supervisory control and data acquisition (SCADA) and AMI hubs at the substations. This would allow the OMS capability to be restored quickly.

The restoration of the communications systems following the December 2008 ice storm was slower than necessary. This hampered the flow of information from the remote systems that did exist. Even so, this was of limited importance during this storm since none of the utilities had an OMS sufficient to use any information that may have been generated. After Unitil and the other utilities have sophisticated OMS in place, any lack of communications during a future storm could severely hamper their restoration efforts. Hardened or redundant communication to the substations is necessary for the proper function of any future OMS.

Recommendation No. 2: Each electric utility should include provisions for rapid restoration of communications in their disaster recovery plans.

- The electric utilities should develop plans for backup telecommunications systems to their AMI and SCADA hubs or develop plans for rapid restoration of communications to these vital access points.
- The electric utilities should periodically review and update this plan.
- The electric utilities should train all members of the disaster recovery team in the steps necessary to recover from a disaster which interrupts communication.

Conclusion: The operation of the transmission system during the December 2008 ice storm was not adversely impacted by the storm.

The bulk of the transmission system in New Hampshire is owned by PSNH with small portions owned by National Grid and NHEC. Unitil owns no transmission lines.[12] [13] With the exception

[12] Unitil. (February 27, 2009). Data Response STAFF 1-28.NHPUC.
[13] NHEC. (February 19, 2009). Data Response. STAFF 1-28.NHPUC.

of National Grid's Pelham 115 kV substation, there were no losses of transmission substations during the storm. Pelham Substation was lost due to damage caused by several trees falling onto parts of the Y151 circuit which is jointly owned by PSNH and National Grid. The loss of this substation affected 5,401 customers. Even if transmission circuit Y151 had not been damaged, many of those same customers would have lost power due to damage on the distribution system. The dispatchers were able to properly handle the outages that occurred on the transmission system by managing the line inspections and restoration of service. After completing their repair of the transmission system, the employees assisted in restoring the distribution system.

Conclusion: The operation of the distribution substations connected to the sub-transmission system was minimally impacted by the December 2008 ice storm.

Table IV-9 from Chapter IV is reproduced here as Table V-5 to show the impact of the storm on the substations. This table also shows the number of customers which lost power as a result of loss of power to these substations.

Table V-5 – Impact of December 2008 ice storm on distribution substations and customers.

Utility	Number of Substation Outages	Customers Affected by These Outages
PSNH	46	73,292
Unitil	35	47,234
National Grid	4	15,230
NHEC	15	23,793
Totals	**100**	**159,549**

The total number of customers that were affected by distribution substation outages due to the December 2008 ice storm was 159,549. The vast majority of the substation outages were the result of damage caused by trees and tree limbs falling on sub-transmission lines supplying these substations rather than damage to the substations themselves. Many of the same customers affected by the loss of these substations were also affected by damage to the distribution system, so even if the substations had not lost power, the customers still would have.

Conclusion: The operation of the underground distribution system was not adversely impacted during the December 2008 ice storm except as affected by upstream outages.

With the exception of outages caused by the loss of upstream power delivery, the December 2008 ice storm had no direct impact on the operation of the underground distribution system.

Conclusion: The operation of the overhead distribution system was adversely affected by December 2008 ice storm.

An estimated 280,000 customers were without power after the December 2008 ice storm solely due to distribution system damage. It is also likely that the remainder of the customers, who were without power due to transmission and sub-transmission system damage, would have remained without power because of distribution system damage even if no transmission or sub-transmission system damage had occurred.

Figure V-3 shows the number of poles and cross arms each electric utility replaced in its distribution system due to damage from the December 2008 ice storm. It may be seen that each utility suffered significant damage to its distribution system. A few things to note when analyzing Figure V-3 are that NHEC did not provide the number of cross arms they replaced which is why none are shown, Unitil's numbers include some poles that were actually the responsibility of FairPoint, and the telecommunications companies are not shown in this chart.

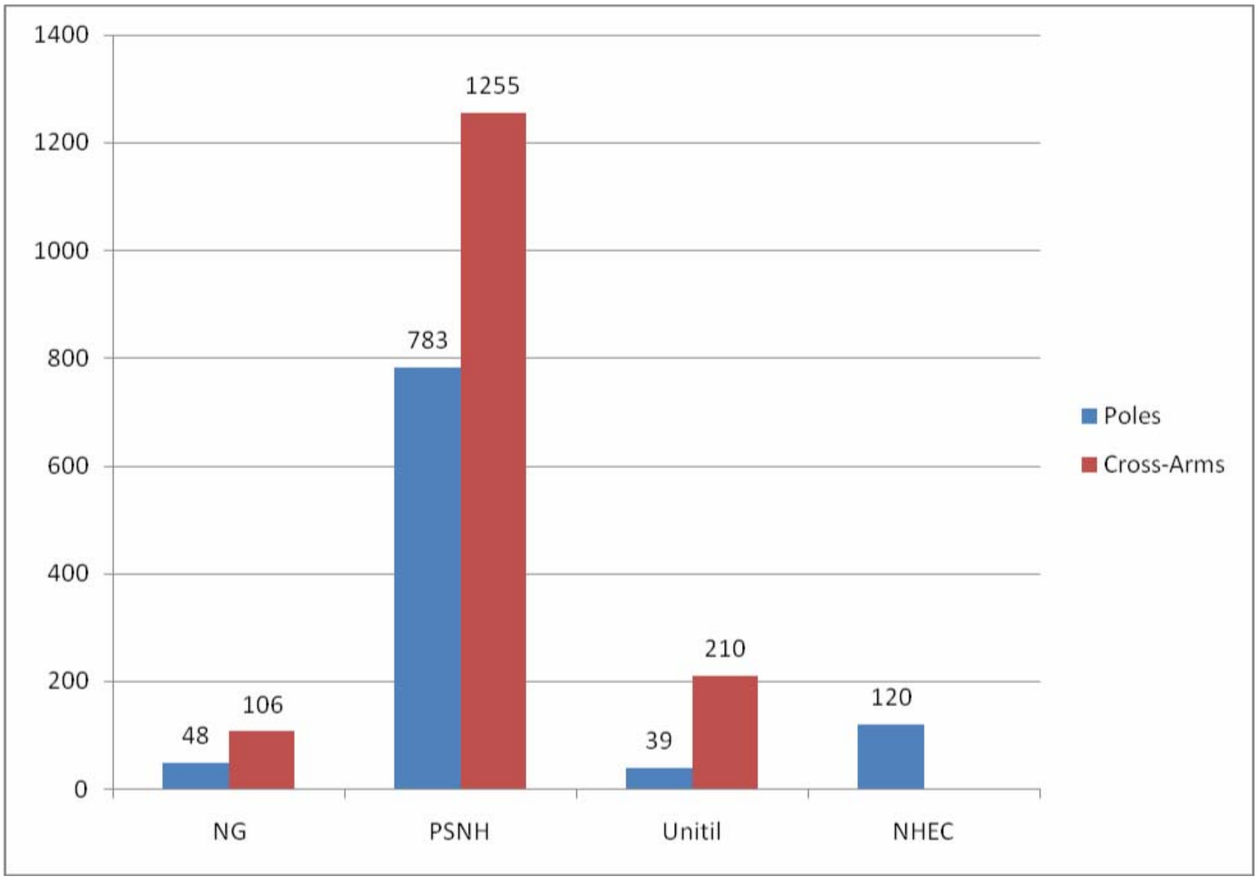

Figure V-3 – Poles and cross arms replaced by each utility following the December 2008 ice storm.[14] [15] [16] [17]

[14] PSNH. (February 2, 2009). Data Response STAFF 1-35.NHPUC.
[15] Unitil. (February 27, 2009). Data Response STAFF 1-35.NHPUC.
[16] National Grid. (February 27, 2009). Data Response STAFF 1-35.NHPUC.
[17] NHEC. (February 19, 2009). Data Response STAFF 1-35.NHPUC.

Conclusion: Aging poles and equipment did not contribute significantly to the storm damage or restoration times.

There was considerable damage to the distribution infrastructure as a result of the December 2008 ice storm. However, the damage was primarily the result of the impact of tree limbs and whole trees falling onto power lines. There was no evidence that poles and cross-arms failed due to deterioration because of age. Since so little forensic evidence was examined and none was kept by any of the utilities, it is possible deterioration due to age could have played a part in small number of poles and cross-arm failures; however, it is impossible to determine the exact extent aging played in the failures that were seen.

Conclusion: Joint pole use issues exist and have been discussed with the NHPUC; however, it appears that the issues have not yet been resolved.

It is important that poles be periodically inspected and that these inspection cycles should be kept current. Some of the poles used by the electric utilities are subject to joint use agreements with the telecommunications companies. These agreements may place the responsibility for vegetation management and pole maintenance on either company. It is possible that the electric utility's pole inspection may fall behind schedule due to inadequate pole maintenance or vegetation management by the telecommunications company it shares its poles with. This problem was consistently cited relative to FairPoint, and even though it was discussed with the NHPUC, a solution is still pending.[18] [19] [20] [21] [22] [23] [24] [25]

Recommendation No. 3: Each electric utility should ensure that all its poles, including joint use poles, are being properly inspected.

- Each electric utility should ensure that all poles, including joint use poles, undergo ground line inspections at a minimum of every ten years.
- Each electric utility should monitor their joint use pole agreements to ensure that jointly used poles are being properly inspected and maintained.

[18] Franz, T. Director, Electric Division, NHPUC. Interview by Nelson, J. April 24, 2009.
[19] Frabrizio, L. Staff Attorney, NHPUC. Interview by Nelson, J. April 24, 2009.
[20] Knepper, R. Director, Safety Division, NHPUC. Interview by Nelson, J. April 24, 2009.
[21] Paul Sanderson. Staff Attorney for Local Government Center. Interview by Nelson, J. and Joyner, M. May 28, 2009.
[22] Sprague, K. Director of Engineering, Unitil. Interview by Nelson, J. May 21, 2009.
[23] Demmer, K. Manager Electric Distribution, National Grid. Interview by Nelson, J. April 28, 2009.
[24] NHPUC. *Work Product Topic 1, Emergency Management*. DM 05-172 Generic Investigation into Utility Poles. n.d.
[25] NHPUC. *Work Product Topic 2, Joint Ownership Responsibilities for the Operation and Maintenance of Utility Poles*. DM 05-172 Generic Investigation into Utility Poles. August 29, 2007.

Conclusion: All the tree crews, except Unitil's, responded quickly, safely, and effectively following the December 2008 ice storm.

At the time of the storm's onset, Unitil had only two tree crews assigned in the Seacoast area for tree trimming operations. Downed trees blocking roads made mobilization of crews quite difficult for the first few days following the storm. Unitil requested twenty-five additional crews from Ohio and Pennsylvania, but these were not available immediately.[26] [27] This lack of tree crews slowed Unitil's response to downed and damaged trees until the outside crews arrived.

Conclusion: Ice buildup on trees adjacent to power lines resulting in tree limbs and whole trees falling onto power lines was the most significant cause of damage and the subsequent power outages during the December 2008 ice storm.

The National Weather Service describes an ice storm as one resulting in a glaze of ice formed to a thickness in excess of 1/4 inch. The Cold Regions Research and Engineering Laboratory (CRREL) performed an analysis of the December 2008 ice storm, which can be seen in Appendix D. Their analysis determined that the maximum radial thickness of ice seen in New Hampshire was 1/2 inch.

Accumulations of 1/4 inch or more of radial ice[28] will cause some damage to tree limbs and may cause trunk failures of some immature or very weak trees. Amounts over 1/2 inch can be expected to cause much more damage to a wider variety of trees. As trees grow they attempt to maximize their sunlight exposure by growing vertically and laterally. In doing so, they increase their risk of limb or trunk failure when weight loads increase at the end of long moment arms, thereby causing classical bending type failures of their underlying wood structure.

Given the current overhead trimming practices, even minor ice loads will have an impact on power lines in New Hampshire. This potential is a known risk, but the question of whether risk reduction is possible is now more important given the amount of damage and cost to the state incurred due to the December 2008 ice storm. Furthermore, it is possible that unseen additional damage to the trees occurred during the ice storm which may have long-term effects on the reliability of the electrical system in the event of future storms. Figure V-4 shows evidence of damage to a large limb next to a three phase power line. Figure V-5 also shows remnants of storm damage which left small branches in the power line.

[26] Wade, S. Operations Manager Seacoast Operating Center, Unitil. Interview by Beatty, B. June 16, 2009.
[27] Shelto, G. VP/Area Manager NH, Asplundh. Interview by Beatty, B. June 16, 2009.
[28] Radial ice has a uniform thickness on the complete surface of an object such as a tree branch or limb

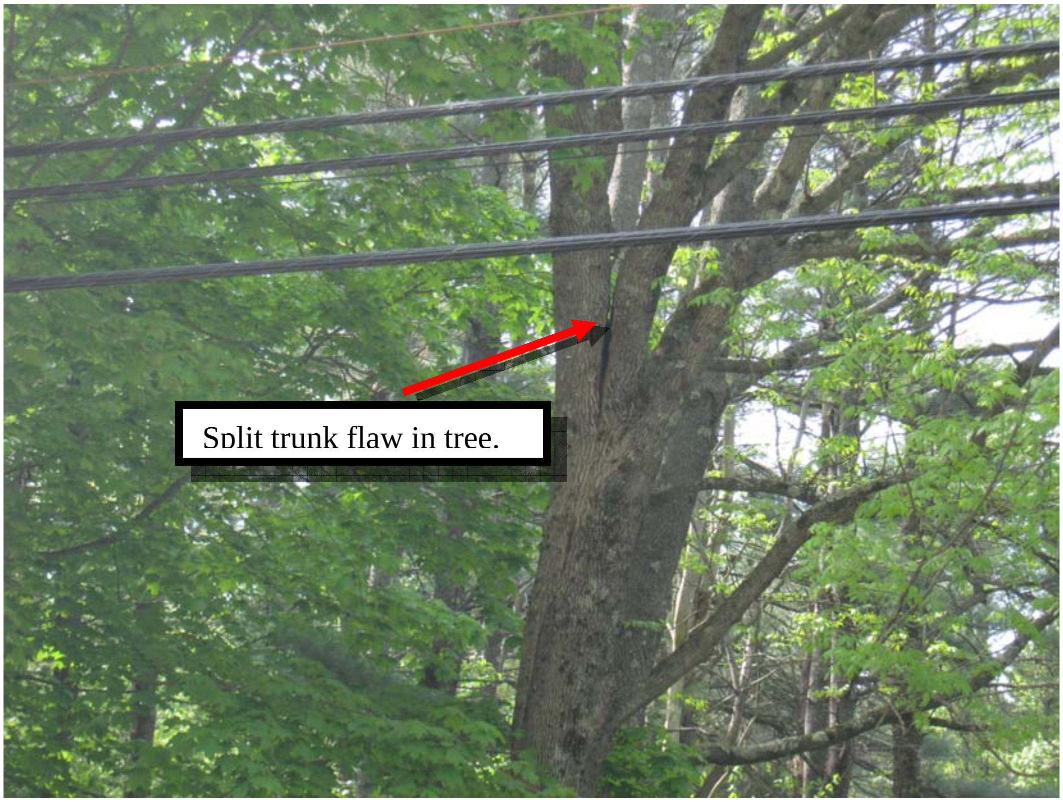

Figure V-4 - Neglected damage and weakness to large limb of tree near Hampton, NH. (Photo by NEI)

Figure V-5 - Small diameter immature trees broken above conductors in New Ipswich, NH. (Photo by NEI)

Species of trees that are prone to ice damage because of their structure or growth habits dominate the New Hampshire forest.[29] These include native trees such as:[30]

- Basswood, *Tilia americana*
- Beech, *Fagus grandifolia* with decay
- Birch, *Betula spp.*
- Black locust, *Robinia pseudoacacia*
- Black cherry, *Prunus serotina*
- Elm, *Ulmus spp.*
- Red oak, *Quercus rubra* with decay
- Red maple, *Acer rubrum*
- Sugar maple, *Acer saccharum* with decay
- White ash, *Fraxinus americana*
- White pine, *Pinus strobes*

Also common in New Hampshire, and susceptible to ice damage, are planted ornamental trees such as:

- Bradford pear, *Pyrus calleryana*
- Honey locust, *Gleditsia triacanthos*
- Pin oak, *Quercus palustris*
- River birch, *Betula nigra*
- Silver maple, *Acer saccharinum*
- Willow, *Salix alba*

Conclusion: Outages to overhead power systems caused by trees generally take longer to restore than outages due to other causes such as equipment failures, lightning, etc.

The reliability index known as Customer Average Interruption Duration Index (CAIDI) measures the average time an outage lasts for the average customer of a particular utility. Figure V-6 shows the impact that outages due to trees can have on CAIDI, especially in a state like New Hampshire with an abundance of trees. Figure V-6 shows current CAIDI in minutes for PSNH during the past five years. Using another reliability index recorded by most utilities, System Average Interruption Frequency Index (SAIFI), it is possible to estimate what CAIDI would look like if 1/2 of the tree related outages were eliminated. This is also shown in Figure V-6. It may be seen that in the case of PSNH, CAIDI (average time of an outage) is between 90 and 125 minutes overall, but for outages caused by trees it ranges between 108 and 155 minutes. It is clear that tree-related outages take longer to restore on average than outages occurring for other

[29] Hauer, W. "Ice Storm Damage to Urban Trees." *Journal of Arboriculture*. 2003. pg. 19.
[30] University of New Hampshire Cooperative Extension "Ice Resistant Tree Populations." March 1999.

reasons. If tree related outages were reduced by half, the average time a customer could be without power every year would be substantially reduced.

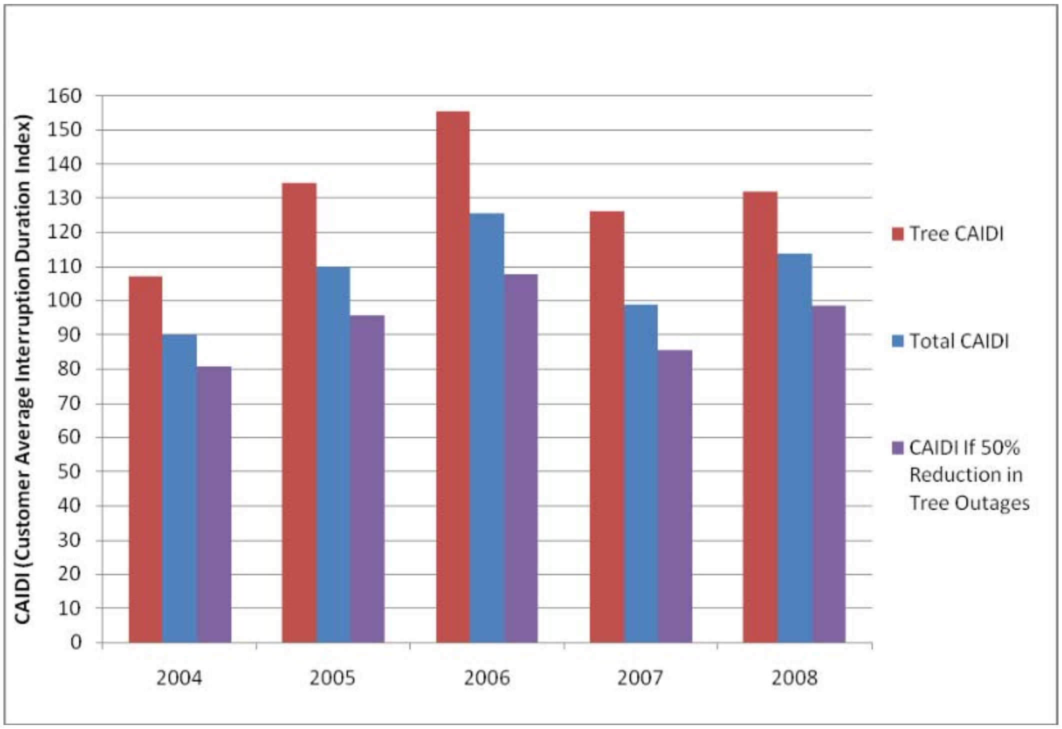

Figure V-6 - PSNH CAIDI statistics.[31]

Conclusion: The potential exists for future tree related problems to adversely affect New Hampshire's power line corridors.

New Hampshire is 90% woodland, and while most residents enjoy the scenic forests of the state, they also remember scenes such as shown in Figure V-7 and the damage done by trees to roads and power lines. In many parts of the state, roads were impassable and power was not restored for up to two weeks due to broken tree limbs and downed trees. Practically all of the damage done to the electric power and telephone systems by the storm was a result of trees damaged by ice.

[31] PSNH. (June 17, 2009). Data Response PS0012. NEI.

Figure V-7 - Effects of ice laden trees. (Photo source unknown)

Second only to industrial development, invasive pests and diseases are the most imminent threat to trees in New Hampshire. Table V-6 lists the most important tree pathogens and their likely victims.

Table V-6 - Tree pathogens.[32]

Pest	Target	Status
Hemlock Woolly Adelgid	Hemlocks	7 towns in New Hampshire and spreading
Asian Long Horned Beetle	Maples	Central Massachusetts in 2008
Emerald Ash Borer	Ash	Pennsylvania and Great Lakes States
Ash yellows	Ash	Southern central New Hampshire and Massachusetts
Caliciopsis canker	White pine	New Hampshire
Oak wilt	Oak	Central and central eastern US

The occurrence of invasive exotic insects and diseases are often the result of global trade. These pests are unintentionally brought to this country in ship dunnage or wooden packaging material. In New Hampshire, the introduction of alien pests may also occur by firewood being imported by tourists in the summer. This is especially a concern with the insect vectors of oak wilt disease,

[32] New Hampshire Division of Forests and Lands. "Regulated Pests." (n.d.). http://www.nhdfl.org/ (Accessed June 24, 2009).

which may be a U.S. native that turned malignant while developing in the native oak stands of the central states.

All of the above pests and diseases are fatal to their hosts if not detected early. Any resulting dead trees will have an impact on vegetation management costs. The possibility of diseases becoming more widespread in the future, which will lead to an increased number of weakened trees, should be considered by the utilities when planning their vegetation management programs.

Although ice storms occur with some regularity in New Hampshire, trees prone to ice damage continue to re-grow near power lines. This fact, coupled with the possibility of increased damage due to pests and diseases, means that ice-related tree damage is highly likely to recur unless changes are made by the utilities in their vegetation management procedures.

Conclusion: For most United States electric utilities, vegetation management is a major distribution expense, but only two of the four electric utilities in New Hampshire have vegetation management budgets that comprise more than 10% of their distribution maintenance budget.[33]

Figure V-8 shows the percentage of each electric utility's maintenance budget that is spent yearly on vegetation management. Since 2005, each of the four utilities has increased the total dollar amount spent on vegetation management, but only National Grid and PSNH have increased the percentage of their budgets dedicated to vegetation management. Vegetation management normally constitutes a high percentage of a utility's maintenance budget, but only National Grid and PSNH have vegetation management budgets greater than 10% of their distribution maintenance expenses.[34] [35] [36] [37] Unitil and NHEC spend less than 4% of their distribution maintenance budgets on vegetation management.

Both Unitil and NHEC should consider budgeting for a more aggressive vegetation management program. Inspection of the Unitil system revealed many cases where power lines and trees conflicted, and discussions with NHEC revealed that their vegetation management cycles are 10 years for lines in ROWs, seven years for road-side lines, and 3 years for all three phase circuits leaving from all stations and metering points.[38] NHEC's trimming policy is superior to that of the other utilities since they use a ground to sky practice when clearing trees from their ROW.

[33] Appelt, P., Beard, A. (2006). Components of an Effective Vegetation Management Program. 2006 IEEE Rural Electric Conference.
[34] PSNH. (June 17, 2009). Data Response PS0012. NEI.
[35] Unitil. (June 5, 2009). Data Response UT0007. NEI.
[36] National Grid. (June 4, 2009). Data Response NG0017. NEI.
[37] NHEC. (May 29, 2009). Data Response CO0002. NEI.
[38] Ramsey, B. ROW Maintenance Supervisor, NHEC. Interview by Nelson, J. May 6, 2009.

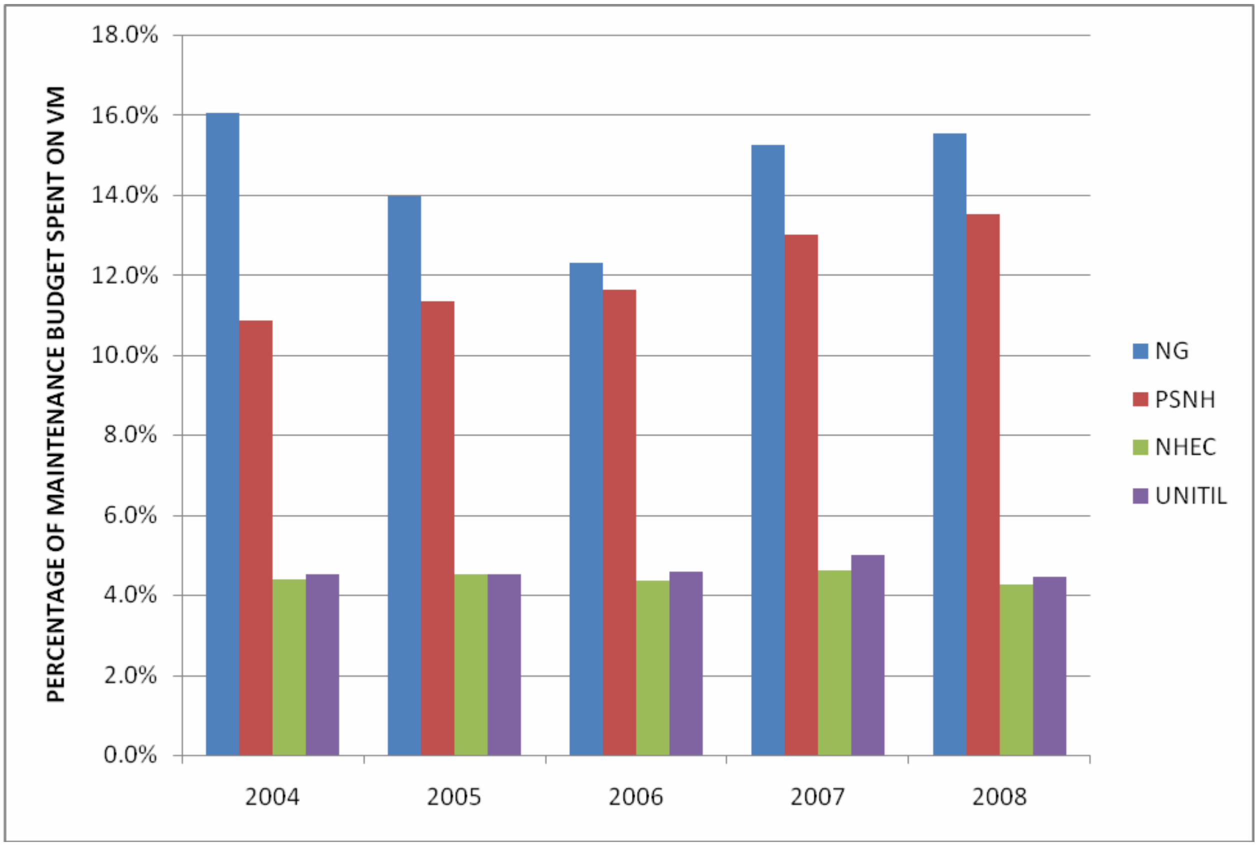

Figure V-8 - Percentage of their distribution maintenance budget each utility spent on vegetation management.

Conclusion: Vegetation Management needs to be improved on the distribution system and in some cases on the transmission and sub-transmission system.

Transmission and Sub-transmission System

An inspection of several transmission line ROWs in New Hampshire revealed the use of the wire-zone border-zone vegetation management practice. This type of management is considered in the electric industry as a best practice. As a result of this type of vegetation management, the number of tree related transmission line outages was small and the impact of those outages was limited.

Figure V-9 shows a Unitil 34.5 kV double circuit sub-transmission line where the wire-zone, border-zone vegetation management practice is being followed. Figure V-10 shows a 115 kV PSNH transmission line (circuit V182) that also has a reasonably well-maintained ROW. However, Figure V-11 shows an adjacent transmission circuit, circuit P145, which has a number of large trees growing under the lines. Figure V-12 shows another view of circuit P145 where the extent of the vegetation management problem may be seen. The vegetation management under this circuit is insufficient and if not improved could result in the trees growing into the lines or major damage if a fire were to occur in the ROW.

Figure V-9 - Example of 34.5 kV Unitil sub-transmission line ROW. (Photo by NEI)

Figure V-10 - PSNH 115kV circuit V182 in Concord, New Hampshire. (Photo by NEI)

Figure V-11 - Northeast view of PSNH 115kV circuit P145 with circuit V182 shown in the background. (Photo by NEI)

Figure V-12 - South view of circuit P145. (Photo by NEI)

Ground to Sky Trimming

At this time the trimming practices used by PSNH, Unitil, and National Grid do not achieve ground to sky clearances around power lines. Ground to sky clearance in a ROW means all trees and branches in the right of way between the earth and the sky are removed during trimming. This would include removing any branches that may be growing over the right of way from trees located outside of the right of way. The trimming practices of PSNH, Unitil, and National Grid do not guarantee ground to sky clearances. It was observed that even freshly trimmed line easements along roads still have canopy branches hanging above the line. One reason for this is that tree trimming crews do not have boom trucks capable of reaching the highest canopy layers which may exceed the 70 foot height limit of a typical boom truck. One instance of this can be seen in Figure V-13 which shows a recently trimmed line with considerable foliage above. The overhanging branches shown here could break in a future storm damaging the conductors below.

Achieving ground to sky clearances would require additional trimming time and the use of cranes to make trimming at a higher level possible. The utilities would incur additional costs that must be included in each utility's vegetation management budget. After one trimming cycle, however, the costs would be reduced since all the branches would be fully accessible from the utility easement making it possible to trim them using conventional boom trucks. The utility would have to ensure that their subsequent trimming cycles were adequate to prevent any branches from extending over the line in the future, or else the original higher cost techniques would have to be repeated.

NHEC has the best vegetation management and line clearance specifications among the four utilities. In most cases[39] NHEC has a practice of ground-to-sky clearances and does not permit vegetation to overhang its lines. NHEC is also least affected by state statutes and municipal ordinances for tree trimming because it requires that its members allow the cooperative to perform reasonable and adequate vegetation management.[40] The utilities not currently trimming their ROWs from ground to sky should implement this requirement during their next vegetation management cycle. It may be impractical for vegetation management practices to be rigorous enough to prevent all trees from falling onto a power line from outside of the ROW, but it is reasonable to require trimming practices sufficient to prevent outages resulting from ice damage to branches growing over lines.

[39] Scenic road statutes and restrictions are one exception.
[40] New Hampshire Electric Co-op. *Handbook for Electric Service*. NHEC. (n.d.). Pg. 27.

Figure V-13 - White pine recently trimmed in Pelham, New Hampshire. (Photo by NEI)

NESC Rule 218 Violations

By following ground to sky trimming practices a number of instances where the National Electrical Safety Code has been violated could be avoided. The National Electrical Safety Code (NESC), IEEE Standard C2, is the minimum code that most utilities, including those in New Hampshire, must meet when building and maintaining their electric systems. It has been adopted by most state commissions including the NHPUC. The 2007 version of the NESC states that the purpose of the code: "… *covers basic provisions for safeguarding persons from hazards arising from the installation, operation, or maintenance of (1) conductors and equipment in electric supply stations, and (2) overhead and underground electric supply and communications lines.*"

The code states that ungrounded bare conductors should not under normal conditions make contact with trees and branches. Rule 218 says: "*Trees that may interfere with ungrounded supply conductors should be trimmed or removed. NOTE: Normal tree growth, the combined movement of trees and conductors under adverse weather conditions, voltage, and sagging conductors at elevated temperatures are among factors to be considered in determining the extent of trimming required.*"

Figure V-14 shows an example of a NESC Rule 218 violation where there is obvious wire to tree contact. This Figure shows substantial, relatively weak, overhang growth above the conductors.

This growth is unsafe, violates the NESC, and is possibly damaging the conductors. While this photograph was taken on Unitil's system, it is not meant to single out Unitil. Similar situations occur on the systems of each utility.

Figure V-14 – NESC Rule 218 violation in Unitil service area. (Photo by NEI)

There are a number of safety and reliability concerns related to the close proximity of trees to overhead power lines. Among these are:

- Damage to the electrical conductor from arcing to the tree branch
- Injury to people, particularly children, climbing trees
- Forest and grass fires damaging the line
- Power outage caused by high-currents from the wires to the trees
- Stray current flowing into the tree

The heavy forest that is characteristic to New Hampshire, and state and local ordinances which restrict vegetation management both contribute to causing this type of NESC violation.

Trees Adjacent to Distribution Lines

There are a number of trees of advanced age located near distribution lines. Due to their size and close proximity to the line, they cannot be effectively trimmed and pose a risk to the line if the tree were to be damaged or uprooted. The tree shown in Figure V-15 is a prime example of a large tree in decline near a power line. Due to its size, it cannot be effectively trimmed using the equipment most utilities have available. This particular tree was marked for removal as a "hazard tree." However, this was not done merely due to its proximity to the power line. In New Hampshire, placing the line at risk is not sufficient cause for a tree to be labeled as a hazard. To be classified as a hazard tree, it must also be either infected or dying in addition to its proximity to the line. Within the state, there are many large healthy trees which pose a hazard to power lines and should be considered for removal.

Figure V-15 - Mature oak to be removed in New Ipswich, New Hampshire. (Photo by NEI)

Trimming Cycle Length

For each utility, there exists an ideal vegetation management cycle. If trimming is done too often, costs become high due to the time and number of people needed. If trimming is done too seldom, then costs become high due to the amount of trimming necessary on each tree. Each utility should choose a trimming cycle length that is the most cost effective when all factors are considered. For most utilities, including those in the Northeast, a four-year vegetation management cycle has been found to be ideal and a four year cycle has been mandated by the electric utility commissions of several states.[41] [42] [43] [44] [45]

[41] Higgins, L. (March 12,2008). *Vegetation Management Program Review*. Hydro One Networks Inc.
[42]Bell, B. (2008). "Industry Perspective on Compliance with the NERC Vegetation Management Requirements of FAC-003-1.". http://www.utilityarborist.org/images/Training/Industry_Perspectives _on_FAC.pdf (Accessed July 28, 2009).
[43] State of Illinois, Illinois Commerce Commission. "Reply Brief 00-0699." (n.d.)www.icc.illinois.gov/e-docket/reports/view_file.asp?intIdFile (Accessed July 28, 2009).
[44] New Jersey Administrative Code. "Vegetation Management Rule 14:5-9.4." (n.d.) http://www.state.nj.us/bpu/pdf/rules/20080227ener.pdf (Accessed August 3, 2009).

One electric utility in the Northeast, Hydro One of Quebec, Canada, performed a study[46] which included the average vegetation management cycle lengths for eight utilities in that region. Figure V-16 shows the results of that study. With the exception of company 47, Hydro One, and company 23, all the utilities shown have vegetation management cycles of around four years.

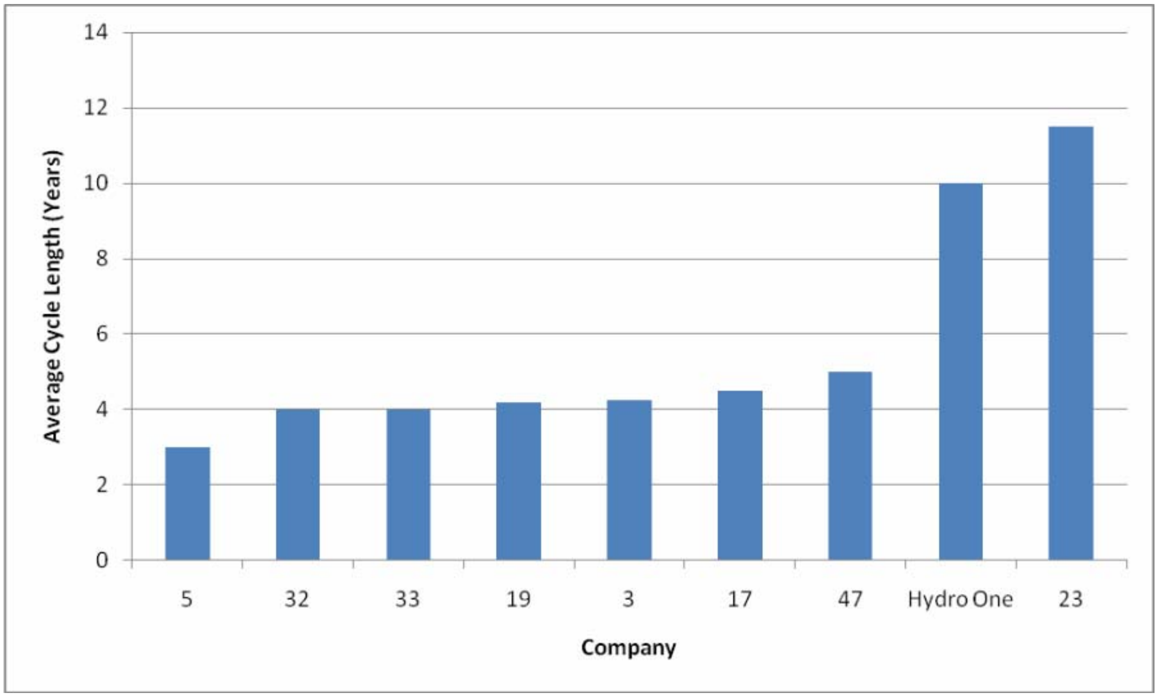

Figure V-16 -Vegetation management cycle lengths for nine utilities.

To achieve an optimum vegetation management cycle, each utility should use empirical data gathered from their system to determine the cycle lengthy expected to produce the most cost effective results. Hydro One did such a study for their system and Figure V-17 shows the results found by that study. The study broke Hydro One's vegetation management costs into proactive and reactive costs. Reactive costs occur whenever vegetation management is done after an incident has occurred. Proactive costs occur whenever routine trimming is done in an attempt to prevent possible future damage. For this particular utility, it appears that the optimum vegetation management cycle is slightly less than six years. Any trimming done in cycles longer or shorter than the optimum will result in unnecessary costs.

[45] Tripp, D. President, SouthEastern Illinois Cooperative. (2007). "Vegetation Management Program. President's Column." 2007. http://www.seiec.com/MC200702.html (Accessed August 3, 2009).
[46] Higgins, L. (March 12, 2008). *Vegetation Management Program Review*. Hydro One Networks Inc.

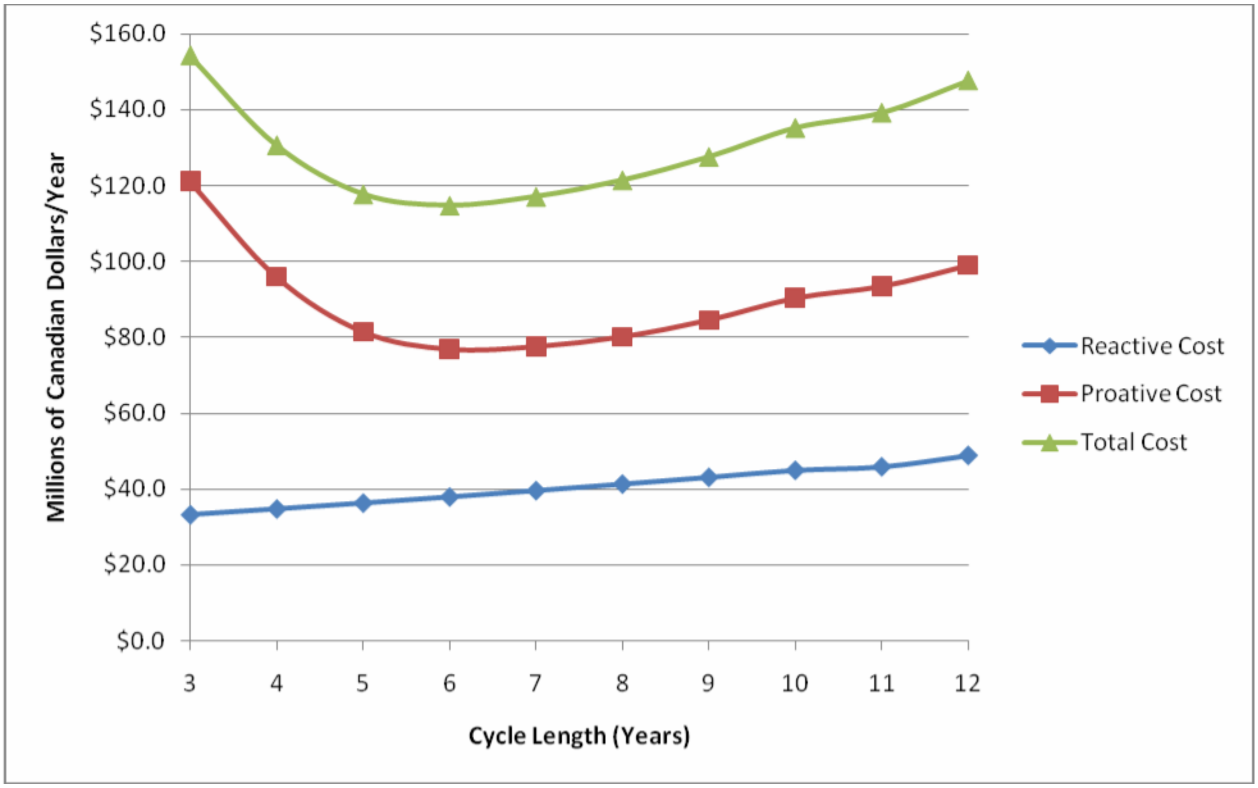

Figure V-17 – Hydro One's total costs of for vegetation management compared to cycle length.

Recommendation No. 4: Each electric utility should establish a more comprehensive vegetation management plan.

- Each electric utility should develop a single vegetation management plan which includes all voltage levels.
- Each electric utility should use a four year trimming cycle unless the utility can show, by using empirical data, that another length is more cost effective.
- Each electric utility should use the wire-zone border-zone method of trimming on all lines transmission and sub-transmission lines and where possible on distribution lines.
- Each electric utility should include in their plan that trimming will be done ground to sky where possible, and where this is not possible a minimum clearance of 15 feet will be maintained above each line, 8 feet on each side of the line, and 15 feet below the line.
- Each electric utility should use specialized equipment or climbers whenever trees are beyond the reach of their standard equipment.
- Each electric utility should institute a basic tree inventory in an attempt to proactively handle trees which may become a future hazard.

- Each electric utility should aggressively monitor their ROWs, identify any trees that might fall from outside the ROW onto the power line, and remove any trees identified as a hazard.

Conclusion: The state laws in New Hampshire, including scenic road statutes, are too restrictive to allow utilities to provide proper vegetation management.[47] However, the laws regarding vegetation management for roads and highways are less restrictive. Extending these laws to apply to vegetation management for power lines should be considered.

The state laws of New Hampshire concerning trees are very restrictive and have hindered the utilities ability to properly manage the vegetation growing near their lines. All of the electric utilities expressed concerns with the limited ability they have in providing proper vegetation management along scenic roads. An article published by the New Hampshire Local Government Center provides examples of the many restrictions a utility faces in New Hampshire when designing a vegetation management program.[48] Some of those issues are:

- "Landowners generally have a right to grow, maintain or cut down their trees as they see fit." There appears to be no liability on the part of a landowner if their trees fall onto a power line causing damage. The same is not true for trees falling onto roadways under according to New Hampshire RSA 236:39 "Liability for Obstruction or Injury to Highway."
- The legislature granted in RSA 33:52 that "Towns may make regulations from time to time concerning the planting, protection, and preservation of the shade and ornamental trees situated within the limits of the town appropriated to public uses."
- The legislature further restricted the vegetation maintenance efforts of utilities when it passed New Hampshire RSA 231:158, which allows cities, towns and villages to designate scenic roads. This restricts the type of trimming that can be done if power lines happen to run along these roads.

In response to the December 2008 ice storm, New Hampshire legislators revised some of the statutes contained by Chapter 231 in order to ameliorate the role legislation played in the damage that occurred.[49] The most notable change is in New Hampshire RSA 231:172. The revised RSA 231:172 will make it much easier for utilities to perform their required trimming.

The legislature has previously taken into consideration the protection of roads and highways from damage caused by trees in New Hampshire RSA 231:139 through 231:156. Appendix C of this report lists the statutes that may affect a utility's ability to manage vegetation. It is important

[47] *New Hampshire RSA* 231:157, 231:158.
[48] Sanderson, P.G. "Trees in the Right of Way: Ice Storm Highlights Uncertainty," February 2009. New Hampshire Local Government Center. http://www.nhlgc.org/LGCWebSite/InfoForOfficials/townandcityarticles.asp?TCArticleID=141 (Accessed September 2, 2009).
[49]. An Act Relative to Procedures for the Trimming, Cutting, or Removal of Trees by Utilities. (May 20, 2009). *New Hampshire Senate Bill 195.*

for the legislature to consider the growing importance of the electric and communication infrastructures when discussing legislation, so that the safe and reliable operations of those systems can be ensured. Communications services such as the Internet, and vital services which are heavily dependent on communications such as fire and police departments, hospitals, nursing homes, and schools, should be considered whenever legislation is proposed which may affect the maintenance of the infrastructure which they depend on. The legislators should not lose sight of the fact that none of these services would be possible without the electric infrastructure which provides them with power.

Another notable change is in New Hampshire RSA 231:145. The original law allowed the removal of hazard trees unless the tree was labeled as "public shade or ornamental." The new law removes this exception and New Hampshire RSA 231:145 now states that any tree posing "unreasonable danger… [to] the reliability of equipment installed at or upon utility facilities" should be considered a hazard tree. Before this change, in some towns such as Lebanon, even uprooted trees in contact with lines or transformers could not be cut without notification delays.

These amendments represent a step in the right direction in achieving the necessary balance between aesthetics and electrical reliability. Although these changes are important, progress should not cease since other statutes still exist, such as those outlined in Appendix C, which restrict effective vegetation management practices by the electric utilities in the state of New Hampshire.

Recommendation No. 5: State and local governments should extend laws regarding vegetation management for roads and highways to include electric and communication corridors. Utilities should be assisted by local and state government to streamline the property owner permission process.

- The NHPUC and the electric utilities should propose appropriate modifications to existing legislation affecting trees adjacent to power lines.
- The New Hampshire government should extend the rights of the electric utility to maintain its service territory and equipment including the right to trim any vegetation that might pose a hazard to electric service or safety.

Conclusion: Better vegetation management education is needed for utilities, municipalities, landscapers, and customers. Many municipalities have no vegetation management budgets or public works departments and rely on utilities for their vegetation management.[50]

Land owners, landscapers, architects, and municipalities continue to plant trees and other vegetation that will eventually conflict with both overhead and underground power lines. The choice and location of trees being planted in many cases displays a lack of planning and an

[50] Sanderson, P.G. Local Government Center of New Hampshire. Interview by Nelson, J. May 28, 2009.

ignorance of the long term effect the trees may have on the future maintenance of the power system. There are already cases where landowners or towns have planted tall species of trees directly below distribution lines to replace trees that were damaged by the ice storm. These trees will inevitably become a problem to the overhead line and will certainly need trimming by the utility at some time. It is a distinct possibility that these same trees will be the ones to cause damage to power lines during a future storm. An informed choice of tree species for use near power lines can provide the necessary beautification and still not adversely impact the electrical system. Figure V-15 is an example of an oak that should never have been allowed to grow so near a distribution line.

Recommendation No. 6: Each electric utility should be required to employ at least one system forester or arborist in their New Hampshire service area.

- Each electric utility should employ a forester or arborist to provide technical support to tree trimming crews.
- Each electric utility should include in its forester's responsibility the requirement to provide education to the public about proper vegetation management and the best species of trees to plant near and under power lines.

Conclusion: The lack of stump treatment in New Hampshire is increasing long term vegetation management costs.

Many trees that are removed in New Hampshire will, within a short period of time, begin sending up new shoots of growth. If not treated, a new tree begins to grow that once again becomes a problem for the power line above. The original investment made to remove the tree is essentially wasted. Proper treatment of the stump would prevent this new growth, but the electric utilities are reluctant to make use of these remedies because of permitting issues related to the use of the necessary herbicides. The lack of this type of stump treatment is resulting in increasing long term vegetation management costs for each utility.

Recommendation No. 7: Each electric utility should expand its vegetation management program to include the judicious use of herbicides for stump treatment.

- Each electric utility should employ an expert or a consultant that can assist with the necessary permitting for stump treatment.

CHAPTER VI

Post Ice Storm Actions and Processes

Chapter Structure

A. BACKGROUND

Post storm actions and processes are those items that a utility should undertake following the completion of storm restoration. These actions should be viewed as a continuation of the overall emergency response efforts, not a separate or distinct set of activities. Examples may include:

- Post storm critiques with action items identified
- Invoice verification for external crews and cost allocations for internal charges from affiliates
- Completion of jobs where temporary repairs were made during the storm restoration

Although it may often be neglected, the post storm phase of an event provides an excellent opportunity for utilities to learn from their experiences. During the actual emergency, management of the restoration effort takes precedence over all other activities. However, once work begins to ramp down management should not lose sight of the next step. Unfortunately, it is during the phase immediately following a major restoration effort that many utilities fail. Factors that may contribute to a utility's lack of effort in completing post storm actions include:

- The desire to return to normal
- The utility's employees are exhausted from many days of overtime.
- The utility's employees have returned to their normal work duties, limiting their availability
- The backlog of normal work which was delayed by the storm restoration effort
- The utility's emergency plan does not require a post storm critique.
- The hesitancy to critique workers who have made sacrifices to work long hours during the restoration

Despite the difficulties, it is imperative that utilities learn from their mistakes and build upon the things they do well.

B. EVALUATIVE CRITERIA

The four New Hampshire electric utilities were evaluated in the areas of planning for post storm operations, and their actions following the completion of the restoration effort. Specific areas of evaluation included:

1. Planning for post storm actions
2. Gathering and use of damage information following the storm
3. The use of post storm critiques and self assessments to gather information for continuous improvement

1. **Emergency Response to an outage does not end with the last customer back in service. Numerous activities remain after the actual restoration is complete. These activities need to be planned for and made part of the emergency response effort.**

- The utility should have a plan for post storm analysis.
- The utility should verify invoices from the contractors.
- The utility should rework any temporary repairs done following the storm.
- The utility should replenish the materials used during restoration.

2. **Information gathered during and immediately after a storm can be invaluable in future events. It may be used to better predict damage and resource requirements, and its use might also help improve system design to withstand similar future events.**

- The utility should collect and archive photographic evidence of damage which occurred on their system.
- The utility should collect, organize, and archive weather information.
- The utility should do a forensic review of damage they experienced.
- The utility should use the data collected to develop specific plans for improvement.

3. **Information gathered from individuals who participated in the storm restoration can be extremely valuable. This information is especially useful if it is gathered immediately following the restoration effort while facts are still clear in the minds of the employees involved.**

- The utility should perform a post storm assessment and critique.
- The utility should standardize its assessment to enable trend analysis.
- The utility should make the post storm assessment procedure part of its emergency plan.
- The utility should base the size and thoroughness of its assessment relative to the size of the event. More people should be included as the event analyzed becomes larger.
- The utility should identify and follow up on actions items.

The following tables indicate the extent to which each of the utilities met the criteria. These tables were not prepared to compare one utility with another. The four utilities are very different and face different problems. These tables were prepared to show where each utility may improve its performance in preparation for the next storm or other disaster. A further explanation for the improvements that are recommended to each of the utilities may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table VI-1- PSNH post ice storm actions and processes evaluation matrix.

1) PLANNING FOR POST STORM ACTIONS	
The utility has a plan for post storm analysis.	○
The utility verified invoices from the contractors.	●
The utility reworked any temporary repairs done following the storm.	●
The utility replenished the materials used during restoration.	●

2) GATHERING AND USE OF STORM INFORMATION FOLLOWING THE STORM	
The utility collected and archived photographic evidence of damage which occurred on their system.	◐
The utility collected, organized and archived weather information.	◐
The utility performed a forensic review of damage they experienced.	○
The utility used the data collected to develop specific plans for improvement.	○

3) POST STORM CRITIQUES AND SELF ASSESSMENTS	
The utility performed a post storm assessment and critique.	◐
The utility standardized its assessment to enable trend analysis.	◐
The utility made the post storm assessment procedure part of its emergency plan.	○
The utility based the size and thoroughness of its assessment on the size of the event including more people as the event analyzed became larger.	○
The utility identified actions items and followed up on these.	◐

Table VI-2- Unitil post ice storm actions and processes evaluation matrix.

1) PLANNING FOR POST STORM ACTIONS	
The utility has a plan for post storm analysis.	○
The utility verified invoices from the contractors.	◐
The utility reworked any temporary repairs done following the storm.	◐
The utility replenished the materials used during restoration.	◐

2) GATHERING AND USE OF STORM INFORMATION FOLLOWING THE STORM	
The utility collected and archived photographic evidence of damage which occurred on their system.	○
The utility collected, organized and archived weather information.	○
The utility performed a forensic review of damage they experienced.	○
The utility used the data collected to develop specific plans for improvement.	○

3) POST STORM CRITIQUES AND SELF ASSESSMENTS	
The utility performed a post storm assessment and critique.	◐
The utility standardized its assessment to enable trend analysis.	○
The utility made the post storm assessment procedure part of its emergency plan.	○
The utility based the size and thoroughness of its assessment on the size of the event including more people as the event analyzed became larger.	○
The utility identified actions items and followed up on these.	●

Table VI-3- National Grid post ice storm actions and processes evaluation matrix.

1) PLANNING FOR POST STORM ACTIONS	
The utility has a plan for post storm analysis.	◐
The utility verified invoices from the contractors.	●
The utility reworked any temporary repairs done following the storm.	●
The utility replenished the materials used during restoration.	●

2) GATHERING AND USE OF STORM INFORMATION FOLLOWING THE STORM	
The utility collected and archived photographic evidence of damage which occurred on their system.	○
The utility collected, organized and archived weather information.	○
The utility performed a forensic review of damage they experienced.	○
The utility used the data collected to develop specific plans for improvement.	○

3) POST STORM CRITIQUES AND SELF ASSESSMENTS	
The utility performed a post storm assessment and critique.	◐
The utility standardized its assessment to enable trend analysis.	○
The utility made the post storm assessment procedure part of its emergency plan.	○
The utility based the size and thoroughness of its assessment on the size of the event including more people as the event analyzed became larger.	○
The utility identified actions items and followed up on these.	●

Table VI-4- NHEC post ice storm actions and processes evaluation matrix.

1) PLANNING FOR POST STORM ACTIONS	
The utility has a plan for post storm analysis.	○
The utility verified invoices from the contractors.	●
The utility reworked any temporary repairs done following the storm.	●
The utility replenished the materials used during restoration.	◐

2) GATHERING AND USE OF STORM INFORMATION FOLLOWING THE STORM	
The utility collected and archived photographic evidence of damage which occurred on their system.	○
The utility collected, organized and archived weather information.	○
The utility performed a forensic review of damage they experienced.	○
The utility used the data collected to develop specific plans for improvement.	○

3) POST STORM CRITIQUES AND SELF ASSESSMENTS	
The utility performed a post storm assessment and critique.	◐
The utility standardized its assessment to enable trend analysis.	●
The utility made the post storm assessment procedure part of its emergency plan.	○
The utility based the size and thoroughness of its assessment on the size of the event including more people as the event analyzed became larger.	○
The utility identified actions items and followed up on these.	●

C. TASKS

In order to assess the post storm actions of each utility, a variety of information was assembled and reviewed. A number of data requests were submitted to each utility and the data responses were subsequently analyzed. Interviews were conducted with engineers, managers, and executives from each of the utilities. Additionally, directors of town emergency operations and the New Hampshire Division of Homeland Security and Emergency Management were interviewed. Customer comments that were collected by the NHPUC regarding the storm were also examined and analyzed. Lastly, public statements collected after the storm during hearings held by the NHPUC and the New Hampshire Division of Homeland Security and Emergency Management were also extensively used in the analysis for this report.

D. FINDINGS AND CONCLUSIONS

Conclusion: None of the New Hampshire Electric utilities are adequately recording weather data or developing damage prediction models.

None of the electric utilities make use of forensic weather data**.** Forensic weather data is defined as actual documented weather measurements. If it had been collected, this data could have been evaluated to determine why the events caused the damage that occurred. This analysis would include determining the stresses on structures and trees that resulted from the actual ice and wind loads that were experienced. Understanding both the species of tree involved in the damage as well as the types of loads and stresses that caused limbs and trees to break and fall onto power lines would also be included in the evaluation. Estimating the forces that caused the failures on the system will help to determine if the structures were performing as predicted or if modifications to design specifications are required. To perform this type of analysis, accurate weather data needs to be recorded and archived.

There is a great deal of anecdotal evidence concerning ice loadings on trees and utility structures that occurred due to the ice storm.[1] [2] [3] [4] Yet none of the utilities endeavored to record actual ice levels or where those levels occurred, and then correlate this data with loading assumptions made during the design of their power line structures.[5] [6] [7] [8] There is also anecdotal evidence that much of the damage to the system was caused by falling trees and limbs, yet none of the utilities

[1] Hybsch, R. Director of Customer Operations, PSNH. Interviewed by Fowler, M. June 4, 2009.
[2] Lynch, H. Disaster Recovery Executive, NHEC. Interviewed by Fowler, M. June 17, 2009.
[3] Letourneau, R. Director Electric and Gas Operations, Unitil. Interviewed by Fowler, M. May 1, 2009.
[4] Kearns, R. Director Emergency Planning, National Grid. Interviewed by Fowler, M. June 9, 2009.
[5] Unitil. (March 27, 2009). Data Response STAFF 2-24. NHPUC.
[6] PSNH. (March 23, 2009). Data Response STAFF 2-24. NHPUC.
[7] NHEC. (March 24, 2009). Data Response STAFF 2-24. NHPUC.
[8] National Grid. (March 27, 2009). Data Response STAFF 2-24. NHPUC.

attempted to quantify this damage or separate failures caused by trees from other types of failures. This lack of recorded data makes future analysis difficult.

Three of the four New Hampshire electric utilities have not attempted to use past storm data to try to model the damage that may be caused by a future storm event. PSNH has worked with Plymouth State University to develop a model to forecast damage to electrical systems based on past storm data. Damage projection models do exist for the utility industry but they are in their infancy in terms of sophistication and accuracy. They were developed for hurricane events and therefore tend to focus on the type of damage seen during hurricanes. This limits their value for predicting damage due to less predictable events such as ice storms, tornados, thunderstorms, or lightning. However, no prediction model can be used or developed until the utilities begin to collect and correlate weather data with associated damage.

Recommendation No. 1: Each electric utility should gather and analyze weather and damage information during and immediately following weather events and develop models to predict damage.

- Each electric utility should collect weather and damage information both during and immediately following storms.
- Each electric utility should attempt to collect local weather data from towns, airports, and other local sources, when possible.
- Each electric utility should record more specific data concerning the location of damage and its cause.
- Each electric utility should provide damage assessors, wire watchers, and crews with inexpensive digital cameras and a method to link the photographed damage with the damage location.
- Each electric utility should assign responsibility to an employee for recording and correlating damage, as well as producing a chronology of the damage to the system.
- Each electric utility may decide to use a contractor or retiree to produce the chronology and correlate the recorded photographs and other information gathered.
- Each electric utility should contract with aerial photography firms to record widespread damage from the air.
- Each electric utility should work more closely with municipalities who can collect damage data.
- Each electric utility should analyze the data collected to develop models for predicting future damage.
- Each electric utility should analyze the data collected to improve their existing practices.

Conclusion: All of the New Hampshire Electric utilities reviewed can improve upon their post storm evaluation methods and procedures.

The New Hampshire electric utilities all performed a storm critique of some type following the December 2008 ice storm. However, the extent of these critiques and the documentation that resulted from them vary considerably. PSNH performed a post storm critique which solicited comments from Division and Area Work Center management; however, these comments were not compiled into a report.[9] Unitil performed an extensive post storm critique which was documented and published. The Unitil review contains 28 specific recommendations covering all aspects of the Unitil storm restoration organization and processes.[10] National Grid did not perform a critique specific to its New Hampshire restoration effort, and NHEC performed an informal critique.

The requirement of conducting a post storm critique is not a part of the overall Emergency Operations Plans and procedures of any of the electric utilities. While post storm critiques were performed, they were not part of a normal systematic process. None of the utilities has a defined set of data that will be collected, performance measures that will be reviewed, or a process for storing the data produced by the review.

Conclusion: PSNH does not have a process in place for responding to the incident management system review and does not include the necessary participants in its post storm reviews.

PSNH performed a formal review of its storm restoration performance during the December 2008 ice storm. The review was conducted in February 2009. Although the review is titled "Incident Management System (IMS) Review," it covers a number of topics beyond the structure of incident management. PSNH has requested confidential treatment of this document. Therefore, this appraisal is limited to the conduct of the assessment and its value in future restoration efforts.

The PSNH post storm critique included comments about their adherence to the new IMS processes and opportunities for improvement. The critique could have benefited from broadening the number of participants to include line workers, electricians, and tree crews. The PSNH IMS review included input from the following IMS positions:

- Area Commander
- Southern Division Incident Commander
- Western Central Division Incident Commander
- Seacoast Northern Division Incident Commander
- Planning Chief EOC

[9] Utilities performing post storm critiques usually do not collect these into a special report.
[10] Unitil. (March 25, 2009). Unitil's Response to the 2008 Ice Storm, Self-Assessment Report.

- Logistics Chief
- Safety and Environmental Chief
- Communications Chief

Each participant provided formal comments. These were organized into the following categories:

- Summary (Incident, Position, who the position reports to)
- Organizational Strengths (of the IMS approach)
- Organizational Opportunities
- Overall Comments

The comments and suggestions were candid, and focused on specific items that could be improved or things that were done well. The eight individual comment forms in the IMS review produced over one hundred suggestions. Some of these overlapped and, not surprisingly, many addressed the same opportunities. Examples include:

- Creation of specific positions and to whom they would report within the IMS structure
- Improved functionality of the trouble analysis system and reporting
- Better means of documenting crew resources
- Use of air patrols
- Methods of turning electric system information into information useful to towns

While the PSNH review is a very good template for an after action review, it would be beneficial to expand it to participants beyond the IMS manager and staff level. It would also benefit from expanding beyond a critique of the IMS to an overall critique, which encourages input on issues other than IMS. Issues such as the unproductive use of time while waiting for safety clearances and difficulties with order closeouts are seen by crews and first level supervisors but do not always work their way up to managers. These issues should be included in the review and may come from field employees who are not involved with the IMS.

Recommendation No. 2: PSNH should develop a process for responding to the IMS review and future post action reports and should expand the number of participants in its post storm reviews.

- PSNH should make after action reviews part of their emergency plan.
- PSNH should prioritize the topics resulting from its reviews.
- PSNH should develop a process to accept, reject, or study further suggestions resulting from the review.
- PSNH should assign responsibility for implementing or studying those suggestions accepted or marked for further study.
- PSNH should develop white papers which would describe in detail the costs, benefits, and the steps needed to implement any needed improvements that are identified.

- PSNH should have a second review step using the more detailed information provided in the white papers before deciding to implement or reject an improvement.
- PSNH should assign responsibility along with a schedule, milestones, and budget to implement the improvement.
- PSNH should develop a method to track the progress of the implementation of all suggestions resulting from the review.
- PSNH should expand upon the number of individuals contributing review forms on future critiques to include all those individuals who may have constructive suggestions concerning storm restoration.

Conclusion: Unitil does not include post storm critiques in its Emergency Operations Plan.[11]

Unitil published an extensive self-assessment of its restoration performance during the December 2008 ice storm entitled: "Unitil's Response to the 2008 Ice Storm, Self Assessment Report." This report was released on March 25, 2009, and was written by an outside consultant. The self-assessment identified 28 recommendations in the areas of:

- Preparations and Crew Mobilization
- Damage Assessments
- Power Restoration
- Outage Tracking
- Logistics Support
- Public Communications
- Customer Communications
- Storm Readiness

Unitil has implemented several of the 28 recommendations and is in the process of implementing the remainder.[12] In fact, Unitil had already implemented several of the recommendations before a subsequent ice storm on January 9, 2009, only weeks after clean up from the December storm. During the January ice storm, improvements were noted including more rapid deployment of field forces and additional communications through conference calls with municipal officials.

Unitil has also increased telephone line capacity by 40 percent and later added additional telephone lines. In May, Unitil hired an Emergency Management Director who will be responsible for implementing the recommendations, along with other emergency duties assigned.

Although Unitil did do a post storm review and productively implemented suggestions coming from that review, it does not include the requirement for conducting a post storm review in its Emergency Operations Plan. This plan should include the requirement that a post storm review

[11] Unitil. (Feb 19, 2009). Data Response STAFF 1-1. NHPUC.
[12] Francazio, R. Director of Emergency Planning, Unitil. Interviewed by Fowler, M. May 20, 2009.

should be done and it should describe the methodology to be used for all post storm critiques. It should also assign responsibility for performing these reviews to specific employees.

Recommendation No. 3: Unitil should include post storm reviews in its Emergency Operations Plans.

- Unitil should make post storm reviews a formal part of its Emergency Operations Plan.
- Unitil should design these reviews so the level of detail increases with the severity of the event.
- Unitil should include in its Emergency Operations Plan who will be included in these reviews, when they will occur, and how suggestions resulting from the reviews will be documented.
- Unitil should perform these reviews whenever its Emergency Operations Center is activated or whenever any event requires more than one day for restoring power to all customers.

Conclusion: National Grid has a post storm review process in place.

National Grid routinely performs post storm reviews. It conducted three storm critiques that included New Hampshire and addressed the December 2008 ice storm.[13] Its review of this storm resulted in several actions involving its system in New Hampshire. The National Grid employees who participated in the ice storm critiques include representatives of:

- New England – North
- Energy Solution Services (New England)
- Transmission Control (New England)
- Construction Delivery
- Corporate Affairs (Media Relations and Internal Communications)
- Customer Contact Center (New England)
- Dispatch & Control
- Emergency Planning
- Supply Chain Management (Logistics Group)
- Protection & Telecom Operations Group
- Process & Systems
- Customer Meter Services
- Gas Dispatch

In early January 2009, and following the completion of the restoration effort, Inspections - New

[13] National Grid. (March 27, 2009). Data Response STAFF 2-48. NHPUC.

England, the group responsible for conducting periodic reviews of the system's distribution infrastructure, began an examination of all distribution feeders in New Hampshire affected by the December 2008 ice storm. This group uses a software application to track items that need to be reviewed for possible repair, replacement, or improvement. New England – North Division is responsible for providing oversight to this effort. The Construction Delivery department used the list of items needing replacement to create work packages and assigned an internal project lead to coordinate the work via weekly conference calls with Division personnel.

Approximately three contractor line crews have been working from the Salem Service Center since January 2009, using the report results generated by efforts of the Inspections – New England department. Once items are closed, the completion is noted in the company's graphic information system. As of February 2009, Inspections – New England had completed reviews and repairs of 21 feeders that were affected by the December 2008 ice storm in New Hampshire.

Conclusion: NHEC performs post storm reviews but the reviews are not part of its Emergency Operations Plan.

NHEC performs storm critiques as standard practice and did so after the December 2008 ice storm.[14] NHEC identified 19 specific recommendations requiring OMS enhancements and improvements in AMI, communications, logistics, and resource procurement. No specified implementation plans were developed as a result of these recommendations.

Recommendation No. 4: NHEC should make post storm critiques a part of its Emergency Operations Plan.

- NHEC should make post storm reviews a formal part of its Emergency Operations Plan.
- NHEC should design these reviews so the level of detail increases with the severity of the event.
- NHEC should include in its Emergency Operations Plan a list of employees who will be included in these reviews, when these reviews will occur, and how suggestions resulting from the reviews will be documented.
- NHEC should perform these reviews whenever its Emergency Operations Center is activated or whenever any event requires more than one day for restoring power to all customers.

[14] NHEC. (March 24, 2009). Data Response STAFF 2-48. NHPUC.

CHAPTER VII

Best Practices for Electric Utilities

Chapter Structure

A. BACKGROUND

There is no manual or reference that provides a list of best practices for the electric or telecommunications industries. The best practice for any process is developed on a case by case basis by a utility or group of utilities. For this assessment, a list of "best practices" was developed using information from the New Hampshire utilities, utilities across the country, and past experience. This list includes practices that are successfully used in the utility industry and are appropriate for all utilities to consider when designing and building their systems to resist the effects of future natural disasters. These "best practices" should be a part of each utility's effort to achieve excellence.

The best practices in this chapter are listed separately from the recommendations of this report. The recommendations are there to aid the utilities in following good utility practice and some of those recommendations are similar to the best practices listed in this chapter. Even when not listed within this report's recommendations, the best practices, if followed, will aid each utility in making improvements to their operations and attain a higher that average ranking within the industry. Each utility should compare its practices with those listed here and evaluate where it stands in relationship to the industry.

B. BEST PRACTICES

Emergency Planning and Preparedness

1. A utility should base their emergency operations on the concept of the Incident Command System (ICS), now referred to as the Incident Management System.

The Incident Command System has been adopted throughout the United States and other parts of the world as a method for managing emergencies. ICS (now integrated under the National Incident Management System-NIMS) is universally used by federal, state and local agencies and was originally developed for forest and grassland firefighting.[1] Its use is required in order for these agencies to receive federal funding. Utilities across the United States and Canada are adopting ICS in at least a modified version. In practice the ICS has proven to have a number of attributes that have made it just as useful to utilities as it has been to first responders. Benefits of the system are as follows:

- It is a proven approach having been in existence for nearly 30 years.
- It allows everyone to "speak the same language", thus vastly improving communications with police, fire, and government emergency management personnel.
- Training is readily available through FEMA's Emergency Management Institute for minimal cost.[2]
- It is suited to large scale electric emergencies due to its scalability, flexibility and ability to manage large influxes of resources.

2. A utility should have a dedicated emergency operations organization and facilities.

Utilities have recognized that "emergency operations" is a discipline that requires special training. Just as other areas of a utility require specialized and dedicated staff and facilities, so does emergency operations. The staff of the dedicated emergency operations organization should be permanent and full time. The staff should be responsible for drills, preparation and updates of the emergency plans and training.

Full time dedicated facilities are becoming standard in utilities following best practices. The costs of such facilities are relatively minor compared to even a small storm restoration. The actual makeup of the "storm room" varies by utility and their particular needs.

[1] National Interagency Fire Center. http://www.nifc.gov/. (Accessed August 26, 2009).
[2] Emergency Management Institute. "Integrated Emergency Management Course," May 15, 2008. http://training.fema.gov/EMIWeb/IEMC/. (Accessed August 26, 2009).

3. At the first indication of a storm, a utility should preposition its restoration workforce, which should include damage assessors and crews. The initial damage assessments should begin as soon as possible after a storm has passed and should be used to develop initial restoration time estimates.

In the aftermath of a major storm it is often difficult to move damage assessment personnel into the areas where damage has occurred for various reasons, including downed trees, ice covered roads, snow, flood waters etc. Such conditions can create major delays as utility personnel attempt to investigate damage and begin repairs. A best utility practice would be to pre-position damage assessors and crews in the field prior to the storm. This may result in increasing costs if employees are pre-positioned for a possible storm that does not materialize. However, for the storms that are correctly predicted, prepositioning of crews can help reduce the initial damage assessment time by several hours, and shorten restoration time by hours or even days.

4. A utility should never underestimate the potential damage of a forecasted storm.

A utility should anticipate a "worst case" scenario and be prepared. Underestimating the damaging effects of a storm will result in longer response times and longer outages. In the case of the December 2008 ice storm, none of the utilities correctly estimated the extent of damage which eventually occurred.

5. A utility should have a plan in place to communicate with public officials and emergency response agencies. The utility should open communications early and maintain constant communications throughout the event.

A utility should have a defined set of criteria including estimated storm damage and storm foot print which trigger direct contact with public officials and emergency first responders. These criteria should be consistently followed and should be known to all parties. The communication should be part of a utility's emergency plan. There should be dedicated EOC staff members at each utility whose sole function is to communicate with public officials and first responders.

A utility's response to a major storm should include more than the field work required to restore service to customers without power. It should include establishing and maintaining communications with the news media, public officials, emergency response agencies, and customers in the affected communities. This communication is necessary in order to provide warnings of an impending storm. It is also needed to provide instructions regarding safety and other information to the public during a power outage. In order to complete repairs safely and efficiently, the utility must also coordinate restoration efforts with local fire, police, other utilities, and public works departments. The information provided by this communications plan will aid businesses who must decide when to ask employees to report for work and aid families who need to know if they should find shelters or travel to other locations until the power and phone service is restored.

6. A utility should extensively use "nontraditional" employee resources.

Nontraditional resources are those individuals employed by a utility or contractor who do not normally participate in operations or provide field support. Such resources may also include utility retirees. The tasks to which nontraditional workers may be assigned include such things as wire watchers, crew guides, communicators, or simply delivering lunches to crews. All the employees within an organization, along with retirees and contractors, can be used as nontraditional support during the restoration effort.

In a major storm, one of the greatest challenges is managing the large influx of crews required to accomplish all the work needed for restoration. Managing these nontraditional resources will add to this challenge and a plan must be in place so they can be efficiently used.

7. A utility should have pre-staged materials, which may include such things as storm trucks or storm boxes.

One of the critical elements in the restoration of power after a major storm is getting the materials to the crews in the field. For utilities such as National Grid which has a small service territory in New Hampshire, using materials and supplies in the local operating center may be sufficient. However, when dealing with larger geographical areas, the use of storm trucks or storm boxes may speed restoration of service by quickly delivering repair materials to where they are needed. A storm truck consists of a trailer carrying an inventory of standard storm restoration material. A storm box consists of dedicated, prepackaged storm restoration materials that can be quickly placed on a truck.

System Planning, Design, Construction, and Protection

8. A utility should include 50 year return values for wind and ice loading in their load cases for designing all line structures.

New Hampshire has adverse weather conditions including ice and wind values that exceed the standard construction practices required by the National Electrical Safety Code (NESC). (See Appendix F on Pole Line Construction). In order to provide a robust and reliable system, all lines should be designed to resist the conditions that may be expected to return every 50 years. All structures, regardless of their height, should be designed to meet 50 year return values for wind, and ice with concurrent wind, as defined by the American Society of Civil Engineers (ASCE) standards and the latest edition of the NESC. The NESC, which is the code being followed by all the electric utilities, only requires this criteria for structures above 60 feet, allowing less rigorous criteria (district loading) to be used for structures below 60 feet. Since all structures, no matter their height, could see the 50 year return values of ice and wind, best practice would dictate that the same design methods should be used for structures of any height. All lines should be designed for the following loading conditions:

- NESC heavy district loading

- NESC extreme wind using the maps contained in ASCE 7 and the latest version of the NESC
- NESC extreme ice with concurrent wind using the maps contained in ASCE 7 and the latest version of the NESC

Due to the number of customers that may be affected by a line failure at higher voltages, all lines 35kV class and above should be designed as Grade B as suggested by Rural Utility Services (RUS) Standards. Distribution lines below 35kV should be designed as required by the latest version of the NESC.

9. A utility should use an automatic distribution line high-speed source transfer scheme.

It is becoming common in many distribution systems to loop feeders from one substation to another substation. This is done by connecting one end of the feeder to one substation using a recloser, and the other end of the feeder to a second substation using another recloser. This produces a looped system which makes possible supplying the loads on the distribution feeder from either substation and disconnecting the feeder, or parts of the feeder, from either of the substations when necessary. The result is that if one substation has an outage, customers can still be supplied from the second substation. It is also common practice for switches or reclosers to be placed along sections of the feeder so parts of the feeder can be isolated from the rest when a fault occurs. At times, a switch is placed in the center of the feeder which is normally kept open, isolating the substations from each other, and allowing each substation to feed half of the feeder. When necessary this switch can be closed, and one of the reclosers connecting the feeder to a substation can be opened, making it possible to supply the entire feeder from either of the substations.

In New Hampshire a large number of these looped feeders have open, mechanically operated switches, located at the half-way point on the feeder, which divides the feeder in half and isolates the two substations. If a substation or part of a distribution line is lost, the tie switches can be manually closed to restore power to the rest of the feeder, minimizing the number of customers who experience a power outage. Unfortunately, in most cases this requires that a lineman be dispatched to close the manual switch before power can be restored.

A number of electric utilities are replacing these mechanical line switches with automatic, electrically operated switches, such as a reclosesrs. These electrically operated switches have automatic or communications assisted controls allowing them to isolate faulted sections of the line and restore power to line sections that are still intact. The automatic nature of this scheme, and its ability to be remotely controlled, greatly reduces outage times for customers and improves reliability. The use of this automatic distribution line source transfer method has resulted in Public Service Electric and Gas (PSE&G) of New Jersey being named America's most reliable electric utility for attaining award winning reliability indices.[3]

10. A utility should replace its traditional electro-mechanical relays with microprocessor-based protective relays.

During the past twenty years, the technology of protective relaying has improved dramatically. The use of microprocessor based technology in system protection has reduced many long term failures into short interruptions.[4] Older electro-mechanical relays are analogous to the vacuum tube radios prior to 1960 and should be replaced with devices using modern day technology.

A large percentage of the electromechanical relays still in service have been there for many decades. Electro-mechanical relays have more reliability issues than microprocessor based relays and many are becoming obsolete as virtually 100% of all new relay installations are using microprocessor based relays. In most cases the procurement, installation, and maintenance costs of microprocessor based relays are a small fraction of the cost for equivalent electro-mechanical relays.

Microprocessor based relays provide numerous features not found in electromechanical relays including sequence of events recording, recording fault analysis data, and selectable relay settings that can be switched during storms to provide improved performance for storm related outages. For example, during normal weather conditions, a utility's protection philosophy may be to block a feeder instantaneous relay function. A fault under these conditions would probably be permanent and a lineman would have to be dispatched to repair the problem. Blocking the instantaneous function would allow a downstream fuse to open before the feeder relay opens. This would allow uninterrupted power to most customers while the few customers downstream from the fuse would see power interrupted until a lineman could be dispatched to fix the problem and replace the fuse. During storm conditions, however, most faults would be temporary and caused by lightning. Under these conditions the instantaneous function will be unblocked. This will allow the feeder protection to trip the feeder off before a downstream fuse can open. Since the fault is temporary, when the feeder breaker recloses all customers would see their power return without a fuse having opened. This saves a lineman from having to be dispatched to replace the fuse for a temporary fault that could have been cleared without opening the fuse. This type of logic is easy to implement with microprocessor based relays and nearly impossible with electromechanical relays.

[3] PSEG Press Releases, n.d. "Reliability One Award winner in the Mid Atlantic Regions 2001-2007." http://www.pseg.com/media_center/pressreleases/articles/Attachments/izzoremarks2008shareholdermtg.pdf (Accessed August 26, 2009).
[4] Islam A. and Domijan A."Weather and Reliability." *IEEE-Power Engineering Society General Meeting*, 2007.

11. A utility should install electronically controlled single and three-phase reclosers where appropriate in order to improve system reliability.

Electronically controlled reclosers are an effective and economical device to properly sectionalize major feeders and major feeder taps. Single-pole reclosers with electronic controls contain the technology to isolate only the faulted phase on a three-phase circuit, instead of opening all phases during a single-phase fault. This can reduce the number of customers affected by the fault to 1/3 of the number who otherwise would have been disconnected by a traditional device, which would have disconnected all three-phases for a fault of this type. While single phase tripping technology is not practical in some urban areas with commercial and industrial three phase loads, it is practical for residential and rural lines.

Operations, Maintenance, and Vegetation Management

12. A utility should have an effective Outage Management System (OMS) that works even during major outage events.

Outage Management Systems have become standard in U.S. electric utilities. Unfortunately, many of those systems have not performed well during major storm events. This has caused some utilities to upgrade their equipment to newer OMS that are better able to handle major events.

During the December 2008 ice storm, none of the four electric utility OMSs functioned well during the storm. However, each utility was able to make better use of their OMS during system restoration. The National Grid OMS functioned better than the others, though the system is relatively old. The NHEC OMS operated reasonably well but was underutilized due to limited staff operating the system. The Unitil OMS was probably the best system among the four; however, it was not functioning due to the loss of third party communications lines. The PSNH OMS was the worst performing system of the four electric utilities. (See Appendix G for a more thorough discussion of OMS).

13. A utility should strive for regular inspection of its entire distribution system on a two-year cycle, using a combination of circuit inspection, tree trimming inspection, and pole ground-line inspection.

Many utilities have found that regular inspection of the entire distribution system is important for its proper maintenance. Since the inspection of a distribution line typically involves a circuit inspection, tree trimming inspection, and a pole ground-line inspection, the best utility practice in the industry suggests combining the efforts of these regularly scheduled inspection programs to ensure that the utility performs an inspection of each circuit bi-annually. To make this possible the following processes are used:

- Implementation of a four-year distribution circuit inspection program
- Implementation a four-year vegetation management cycle

- Implementation a 10-year pole ground-line inspection

By properly training the vegetation management personnel to perform a circuit inspection and by properly staggering the four-year circuit inspection program with the four-year vegetation management cycle, the maximum time between having a utility representative inspecting 100% of each distribution circuit is two years. The 10-year pole ground line inspection is one more opportunity for an inspection of the circuit and it could be used for one of the two-year inspection cycles during a particular year.

14. Where practical, a utility should use the wire-zone border-zone electric right of way (ROW) vegetation management practice on sub-transmission lines.

The vast majority of power outages and damage to the electric system in New Hampshire during the December 2008 ice storm was the result of ice laden tree limbs and trees falling onto power lines. Trees located outside of the ROW may have limbs that overhang the power lines. One of these limbs falling on a line would be classified as an outside of the ROW tree event. Proper wire-zone border-zone vegetation management would eliminate this type of damage.

The wire-zone consists of that portion of the ROW immediately under the power line plus 10 feet on each side.[5] Only grasses and low growing shrubs are allowed to grow in the wire-zone. Low growing shrubs and trees fill the border-zone and extend from the edge of the ROW to the natural forest. In addition to better protecting the line from tree related outages, the wire-zone border-zone concept of vegetation management has had a remarkably positive environmental impact on wildlife, providing a good habitat for small mammals, songbirds, amphibians, reptiles, and butterflies.

15. A utility should utilize a four-year vegetation management cycle for clearing trees around power lines.

New Hampshire is the second most heavily forested state in the nation.   A major cause of the December 2008 loss of power to customers was ice laden tree limbs and whole trees falling onto power lines. Based on these two factors alone, each New Hampshire electric utility should take a very aggressive approach to vegetation management.

Where proper vegetation management practices are allowed, the utilities should adhere to a four-year vegetation management cycle regardless of the voltage level of the line in the ROW. Where vegetation management is restricted along scenic roads, a one, two, or three-year cycle may be required. Consideration should be given to placing a surcharge on the electric bills of the municipalities that have these restrictive vegetation management cycles since they add to the cost of the utilities' operations.

[5] Quattrocchi, S. "Achieving the Perfect Transmission Right of Way." *Electric Light and Power*. January/February 2007. http://www.elp-digital.com/elp/200701/?pg=26.

Trimming on a four-year cycle, if properly adapted to local growth rates, should maintain sufficient clearances between trees and conductors to allow maintenance trimming to be performed safely and efficiently. Reducing the interval between trimming operations while striving for sustainable clearance specifications will ultimately reduce annual costs and improve reliability.

16. A utility should adhere to the proper vegetation management practices. These practices include:

- The utility's trimmers should not strip foliage and side limbs from the part of the branch nearest the trunk and leave foliage at the outermost end of the branch. This practice, called "lion-tailing" and illustrated in Figure VII-1, leads to excess weight at the end of limbs and the reduction of limb diameter over time.

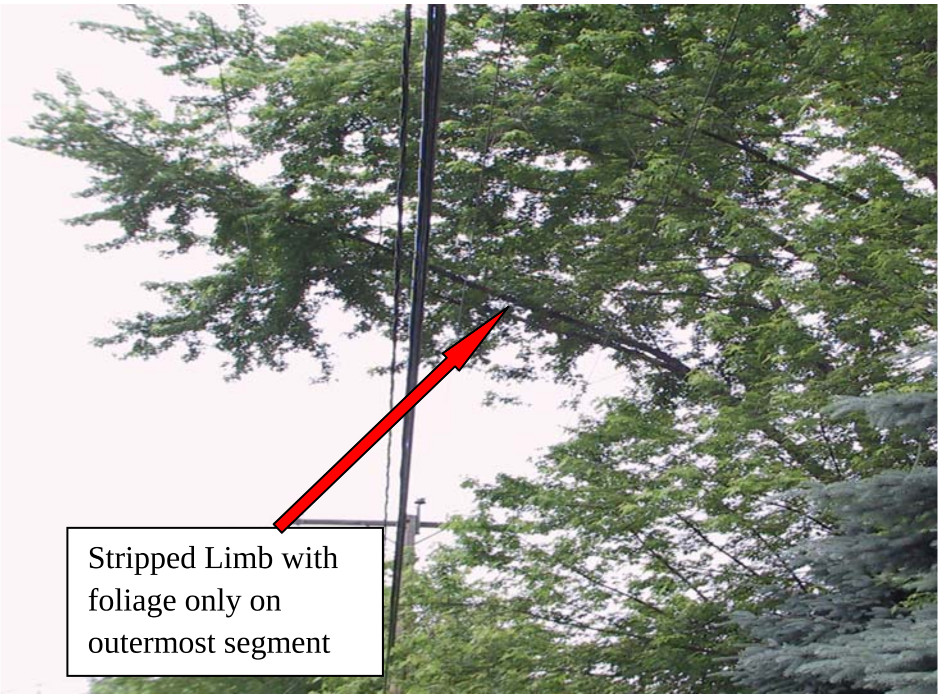

Figure VII-1 - Example of "lion-tailing." (Photo by NEI)

- The utility should use directional pruning to remove live limbs growing toward lines. These should be removed at the point where they connect to the trunk. This encourages growth away from the lines.
- The utility should avoid leaving trees standing with poor stem to crown ratios. The stem to crown ratio is defined as the diameter of the trunk divided by the diameter of the reach of the branches at the widest part of the crown. A high ratio (a narrow crown) leaves a tree that is set up for decline. A low ratio (a wide crown) leaves a tree unstable and subject to failure.

- Before beginning work, the utility should perform a basic hazard evaluation of every tree to ensure workers and the public are safe as well as minimize the probability of property damage from a hazardous tree.
- The utility should create a tree inventory identifying trees along major three-phase circuits. These inventories can help define future vegetation management requirements.
- The utility should review and apply the requirements of the Tree Line U.S.A.[6] program, which requires pruning according to the ANSI 300 standard for utility line clearance.
- The utility should require that lines being worked on are grounded when insulated tools cannot be used or minimum separation distances cannot be maintained.
- The utility should require that each tree contractor working near electrical lines must document its adherence to an electrical hazard awareness program (EHAP).

Post Storm Actions and Processes

17. A utility should both determine the global estimated restoration times and publish that information within 24 to 48 hours.

As soon as possible after an outage occurs, customers need to receive information on the magnitude of the storm, the duration of the storm, and an estimate of the how long customers should expect to be without power. There are several reasons for this practice. Businesses need to know when to ask employees to report for work, families need to know whether to stay home and wait or find shelters or other temporary lodging, homeowners and restaurants need to make provisions for perishable food supplies, and critical care facilities need to plan for maintaining and refueling emergency generators. Developing and publishing the estimated time to restoration early in the response provides customers with necessary information on the duration of the time they will be without power.

18. A utility should have a restoration strategy that targets the restoration of power to the greatest number of customers within the shortest amount of time.

Second only to safety, the most important aspect of storm restoration is efficiency in restoration of service. Efficiency is best measured by the number of customers restored per hour or day. The utility's objective during a major power outage should be to restore service to as many customers as possible within the shortest amount of time even though this might result in isolated groups of customers remaining without power long after other customers have been restored.

19. A utility should not limit its requests for supplemental crews to the local mutual aid groups and other local utilities.

When a major storm is predicted, the search for mutual aid crews should not be limited to only those in the vicinity of the storm. In many cases, local utilities will be reluctant to commit to

[6] Arbor Day Foundation, n.d. "Tree Line U.S.A."http://www.arborday.org/programs/treeLineUSA.cfm (Accessed August 27, 2009).

providing crews to another utility until they are certain that their crews will not be needed for their own restoration work. Each utility should have a plan to expand the search for mutual aid crews well beyond the local area. The utilities should establish agreements and contacts with sources outside their local area well in advance of the next storm.

20. A utility should strive to make sure that all communications are correct and consistent.

During storm restoration it is very important that all communications from the utility to any other entity are correct and consistent. In order to accomplish this, it is mandatory to establish specific sources of information within the utility that are assigned to communicate with the various representatives of the necessary entities. Once established, these personnel assignments and sources of information should not be changed.

21. A utility should implement lessons learned in a timely manner. Implementation plans that include specific tasks and scheduled completion dates should be developed and tracked.

Lessons learned from storm restoration efforts are always more effective when compiled as quickly as possible after the event. The ultimate objective should be to identify policies and practices that were not effective and find ways to improve them. It is important to develop implementation plans and fixed deadlines for specific items that need attention prior the next emergency event.

The following four tables indicate the extent to which each of the utilities incorporates the best practices discussed in this chapter. These tables were not prepared to compare one utility with another. The four utilities are very different and face different problems and issues in operating their systems. The meanings of the symbols used in the tables are:

○	The utility has not implemented the best practice.
◐	The utility has implemented some aspects of the best practice.
●	The utility is meeting the best practice.

Table VII-1 – PSNH best practices evaluation matrix.

1) EMERGENCY PLANNING AND PREPAREDNESS	
1. The utility bases their emergency operations on the concept of the incident command system (ICS) now referenced as the incident management system.	●
2. The utility has a dedicated emergency operations organization and facilities.	◐
3. At the first indication of a storm, the utility pre-positions its restoration workforce which includes damage assessors and crews. The initial damage assessments begin as soon as possible after a storm has passed and the damage assessments are used to develop initial restoration time estimates.	◐
4. The utility never underestimates the potential damage of a forecasted storm.	◐
5. The utility has a plan in place to communicate with public officials and emergency response agencies, and the utility opens communications early and maintains constant communications throughout the storm or event.	◐
6. The utility extensively uses "non-traditional" employee resources.	●
7. The utility has pre-staged materials which may include such things a storm trucks or storm boxes.	◐

2) SYSTEM PLANNING, DESIGN, CONSTRUCTION AND PROTECTION	
8. The utility includes 50 year return values for wind and ice loading in their load cases for designing all line structures.	◐
9. The utility commonly uses automatic distribution line high-speed source transfer schemes.	○
10. The utility replaces its traditional electro-mechanical relays with microprocessor-based protective relays.	◐
11. The utility installs electronically controlled single and three phase reclosers where appropriate in order to improve system reliability.	◐

3) OPERATIONS, MAINTENANCE AND VEGETATION MANAGEMENT	
12. The utility has an effective outage management system (OMS) that works even during major outage events.	◐
13. The utility strives for regular inspection of its entire distribution system on a two year cycle utilizing a combination of circuit inspection, tree trimming inspection and pole ground line inspection.	○
14. Where practical, the utility uses the wire zone-border zone electric ROW vegetation management practice on sub-transmission lines.	◐
15. The utility utilizes a four-year vegetation management cycle for clearing trees around power lines.	○
16. The utility adheres to the vegetation management practices mentioned above.	○

4) POST STORM ACTIONS AND PROCESSES	
17. The utility determines the global estimated restoration times and disseminate that information both within 24 to 48 hours.	○
18. The utility has a restoration strategy that targets the restoration of power to the greatest number of customers in the shortest amount of time.	●
19. The utility does not limit requests for supplemental crews to the local mutual aid groups and other local utilities.	◐
20. The utility strives to make sure that all communications are correct and consistent.	◐
21. The utility implements lessons learned in a timely manner. Implementation plans that include specific tasks and scheduled completion dates are developed and tracked.	◐

Table VII-2 – Unitil best practices evaluation matrix.

1) EMERGENCY PLANNING AND PREPAREDNESS	
1. The utility bases their emergency operations on the concept of the incident command system (ICS) now referenced as the incident management system.	○
2. The utility has a dedicated emergency operations organization and facilities.	○
3. At the first indication of a storm, the utility pre-positions its restoration workforce which includes damage assessors and crews. The initial damage assessments begin as soon as possible after a storm has passed and the damage assessments are used to develop initial restoration time estimates.	◐
4. The utility never underestimates the potential damage of a forecasted storm.	◐
5. The utility has a plan in place to communicate with public officials and emergency response agencies, and the utility opens communications early and maintains constant communications throughout the storm or event.	◐
6. The utility extensively uses "non-traditional" employee resources.	◐
7. The utility has pre-staged materials which may include such things a storm trucks or storm boxes.	◐
2) SYSTEM PLANNING, DESIGN, CONSTRUCTION AND PROTECTION	
8. The utility includes 50 year return values for wind and ice loading in their load cases for designing all line structures.	◐
9. The utility commonly uses automatic distribution line high-speed source transfer schemes.	○
10. The utility replaces its traditional electro-mechanical relays with microprocessor-based protective relays.	○
11. The utility installs electronically controlled single and three phase reclosers where appropriate in order to improve system reliability.	◐
3) OPERATIONS, MAINTENANCE AND VEGETATION MANAGEMENT	
12. The utility has an effective outage management system (OMS) that works even during major outage events.	◐
13. The utility strives for regular inspection of its entire distribution system on a two year cycle utilizing a combination of circuit inspection, tree trimming inspection and pole ground line inspection.	○
14. Where practical, the utility uses the wire zone-border zone electric ROW vegetation management practice on sub-transmission lines.	◐
15. The utility utilizes a four-year vegetation management cycle for clearing trees around power lines.	○
16. The utility adheres to the vegetation management practices mentioned above.	○
4) POST STORM ACTIONS AND PROCESSES	
17. The utility determines the global estimated restoration times and disseminate that information both within 24 to 48 hours.	○
18. The utility has a restoration strategy that targets the restoration of power to the greatest number of customers in the shortest amount of time.	○
19. The utility does not limit requests for supplemental crews to the local mutual aid groups and other local utilities.	◐
20. The utility strives to make sure that all communications are correct and consistent.	◐
21. The utility implements lessons learned in a timely manner. Implementation plans that include specific tasks and scheduled completion dates are developed and tracked.	◐

Table VII-3 – National Grid best practices evaluation matrix.

1) EMERGENCY PLANNING AND PREPAREDNESS	
1. The utility bases their emergency operations on the concept of the incident command system (ICS) now referenced as the incident management system.	●
2. The utility has a dedicated emergency operations organization and facilities.	●
3. At the first indication of a storm, the utility pre-positions its restoration workforce which includes damage assessors and crews. The initial damage assessments begin as soon as possible after a storm has passed and the damage assessments are used to develop initial restoration time estimates.	◐
4. The utility never underestimates the potential damage of a forecasted storm.	◐
5. The utility has a plan in place to communicate with public officials and emergency response agencies, and the utility opens communications early and maintains constant communications throughout the storm or event.	◐
6. The utility extensively uses "non-traditional" employee resources.	●
7. The utility has pre-staged materials which may include such things a storm trucks or storm boxes.	◐
2) SYSTEM PLANNING, DESIGN, CONSTRUCTION AND PROTECTION	
8. The utility includes 50 year return values for wind and ice loading in their load cases for designing all line structures.	◐
9. The utility commonly uses automatic distribution line high-speed source transfer schemes.	○
10. The utility replaces its traditional electro-mechanical relays with microprocessor-based protective relays.	◐
11. The utility installs electronically controlled single and three phase reclosers where appropriate in order to improve system reliability.	◐
3) OPERATIONS, MAINTENANCE AND VEGETATION MANAGEMENT	
12. The utility has an effective outage management system (OMS) that works even during major outage events.	●
13. The utility strives for regular inspection of its entire distribution system on a two year cycle utilizing a combination of circuit inspection, tree trimming inspection and pole ground line inspection.	○
14. Where practical, the utility uses the wire zone-border zone electric ROW vegetation management practice on sub-transmission lines.	◐
15. The utility utilizes a four-year vegetation management cycle for clearing trees around power lines.	○
16. The utility adheres to the vegetation management practices mentioned above.	◐
4) POST STORM ACTIONS AND PROCESSES	
17. The utility determines the global estimated restoration times and disseminate that information both within 24 to 48 hours.	○
18. The utility has a restoration strategy that targets the restoration of power to the greatest number of customers in the shortest amount of time.	●
19. The utility does not limit requests for supplemental crews to the local mutual aid groups and other local utilities.	◐
20. The utility strives to make sure that all communications are correct and consistent.	◐
21. The utility implements lessons learned in a timely manner. Implementation plans that include specific tasks and scheduled completion dates are developed and tracked.	◐

Table VII-4 – NHEC best practices evaluation matrix.

1) EMERGENCY PLANNING AND PREPAREDNESS	
1. The utility bases their emergency operations on the concept of the incident command system (ICS) now referenced as the incident management system.	◐
2. The utility has a dedicated emergency operations organization and facilities.	◐
3. At the first indication of a storm, the utility pre-positions its restoration workforce which includes damage assessors and crews. The initial damage assessments begin as soon as possible after a storm has passed and the damage assessments are used to develop initial restoration time estimates.	◐
4. The utility never underestimates the potential damage of a forecasted storm.	◐
5. The utility has a plan in place to communicate with public officials and emergency response agencies, and the utility opens communications early and maintains constant communications throughout the storm or event.	◐
6. The utility extensively uses "non-traditional" employee resources.	◐
7. The utility has pre-staged materials which may include such things a storm trucks or storm boxes.	◐
2) SYSTEM PLANNING, DESIGN, CONSTRUCTION AND PROTECTION	
8. The utility includes 50 year return values for wind and ice loading in their load cases for designing all line structures.	◐
9. The utility commonly uses automatic distribution line high-speed source transfer schemes.	○
10. The utility replaces its traditional electro-mechanical relays with microprocessor-based protective relays.	◐
11. The utility installs electronically controlled single and three phase reclosers where appropriate in order to improve system reliability.	●
3) OPERATIONS, MAINTENANCE AND VEGETATION MANAGEMENT	
12. The utility has an effective outage management system (OMS) that works even during major outage events.	●
13. The utility strives for regular inspection of its entire distribution system on a two year cycle utilizing a combination of circuit inspection, tree trimming inspection and pole ground line inspection.	○
14. Where practical, the utility uses the wire zone-border zone electric ROW vegetation management practice on sub-transmission lines.	◐
15. The utility utilizes a four-year vegetation management cycle for clearing trees around power lines.	○
16. The utility adheres to the vegetation management practices mentioned above.	○
4) POST STORM ACTIONS AND PROCESSES	
17. The utility determines the global estimated restoration times and disseminate that information both within 24 to 48 hours.	○
18. The utility has a restoration strategy that targets the restoration of power to the greatest number of customers in the shortest amount of time.	●
19. The utility does not limit requests for supplemental crews to the local mutual aid groups and other local utilities.	◐
20. The utility strives to make sure that all communications are correct and consistent.	◐
21. The utility implements lessons learned in a timely manner. Implementation plans that include specific tasks and scheduled completion dates are developed and tracked.	◐

CHAPTER VIII

Telecommunications Companies

Chapter Structure

A. BACKGROUND

This chapter provides an overview and assessment of the respective responses to the December 2008 ice storm of the two New Hampshire telecommunications companies reviewed. The scope of the assessment, as directed by the staff of the NHPUC, was limited to the TDS Companies (Hollis Telephone Company, Kearsarge Telephone Company, Merrimack Telephone Company, and Wilton Telephone Company) and the New Hampshire exchanges operated by Northern New England Telephone Operations, LLC, d/b/a FairPoint Communications-NNE (FairPoint). TDS serves approximately 31,000 access lines in 16 exchanges; FairPoint serves approximately 450,000 access lines in 117 exchanges within the state.[1] [2] TDS and FairPoint are addressed separately, although common themes have been explored with each company. Maps of the territories covered by each of these companies may be found in Chapter I.

B. EVALUATION AND CRITERIA

TDS and FairPoint were evaluated in the areas of effective preparation for prolonged emergencies, efficient and timely response to outages, and restoration of service. Specific areas of evaluation included:

1. Disaster planning and preparation
2. Availability and use of resources
3. Bulk line testing
4. Coordination with electric utilities and local governments.

[1]TDS. (August 10, 2009). Data Response TE0045. NEI.
[2] FairPoint. (August 10, 2009). Data Response TE0040. NEI.

1. **Preparation for emergency response starts with a plan. This plan should describe the policies and procedures required to prepare for and respond to a given storm or other disaster. This plan should include methods for**:
    - Identifying the potential for natural disasters
    - Communicating within the company
    - Communicating with outside entities
    - Preparing the company to respond as rapidly as possible.

2. **Preplanning is necessary to ensure a sufficient work force is available and can be effectively used during a widespread disaster. The following issues must be evaluated:**
    - How and when were existing workforces within the state utilized?
    - How and when were contractor forces and out-of-state work forces utilized?
    - How was the productivity of work forces maximized?
    - How were trouble reports handled? Were they handled individually or were mass sweeps used where work crews concentrated on restoring geographic areas?
    - How were service orders and routine work scheduled during the restoration efforts?
    - How were technicians moved from one work location to another as areas became accessible after roads were cleared and electrical work was completed?
    - How was overtime handled?
    - How productive were workers during the restoration process?

3. **Bulk line testing plays an important role during the restoration of telephone service. This capability allows lines to be tested before the customer reports a trouble condition. It can also identify locations where multiple customers are likely to be out of service. In particular the important issues are:**
    - What capabilities did each telephone company have for bulk line testing?
    - How productive were the bulk line testing efforts?

4. **Communication and coordination with the electric companies that operate in jointly affected areas is critical to timely telecommunications restoration efforts. Telecommunications workers generally do not enter jointly affected areas until the electric company has communicated to them that the area has been declared safe. Telecommunications personnel are neither trained nor equipped to respond to the possibility of electrocution from downed power lines. It is important to know:**
    - What coordination issues existed with the affected electric utility?
    - Did the coordination efforts between the electric and telecommunications companies adversely impact the restoration efforts of telecommunications and electric service?

- Were there any access and communications issues with other entities such as state and local public officials, firefighters, first responders, and other emergency personnel?

The following two tables indicate the extent to which each of the utilities met the criteria. These tables were not prepared to compare one utility with another. The two utilities differ in corporate structure and territory service area, experienced different amounts of damage to their systems and, as a result, faced different problems. These tables were prepared to show where each utility may improve its performance in preparation for the next storm or disaster. A further explanation for the improvements that are recommended for each utility may be found in the findings and conclusions section of this report. The meanings of the symbols used in the tables are:

○	Improvement is needed as stated in the report
◐	Adequate with minor improvements suggested as stated in the report
●	Effective with no improvements noted.

Table VIII-1 - Evaluation Matrix - FairPoint

1) DISASTER PLANNING AND PREPARATIONS	
The potential for natural disasters was identified.	◐
Efficient methods were used to communicate within the company.	●
Efficient methods were used to communicate with outside entities.	◐
The company was prepared to respond as rapidly as possible.	◐
2) AVAILABILITY AND USE OF FORCES	
Existing workforces within the state were used effectively.	◐
Contractor forces and out-of-state work forces were used effectively.	◐
Productivity of work forces was maximized.	●
Trouble reports were handled effectively.	●
Service orders and routine work were scheduled effectively during restoration efforts.	○
Technicians were effectively moved from one work location to another as areas became accessible, once roads were cleared and electrical work was completed.	●
Overtime was handled appropriately.	●
3) BULK LINE TESTING	
The company has facilities for bulk line testing.	●
The bulk line testing effort was effective.	○
4) COORDINATION WITH ELECTRIC COMPANIES/LOCAL AUTHORITIES	
The utility effectively coordinated with the local electric utility.	○
Communications with electric utilities did not adversely impact the restoration efforts of telecommunications and electric service.	○
Communications were effective with other entities, such as state and local public officials, firefighters, first responders, and other emergency personnel.	●

Table VIII-2 - Evaluation Matrix - TDS

1) DISASTER PLANNING AND PREPARATIONS	
The potential for natural disasters was identified.	●
Efficient methods were used to communicate within the company.	●
Efficient methods were used to communicate with outside entities.	●
The company was prepared to respond as rapidly as possible.	◐

2) AVAILABILITY AND USE OF FORCES	
Existing workforces within the state were used effectively.	●
Contractor forces and out-of-state work forces were used effectively.	●
Productivity of work forces was maximized.	●
Trouble reports were handled effectively.	●
Service orders and routine work were scheduled effectively during restoration efforts.	●
Technicians were effectively moved from one work location to another as areas became accessible, once roads were cleared and electrical work was completed.	●
Overtime was handled appropriately.	●

3) BULK LINE TESTING	
The company has facilities for bulk line testing.	○
The bulk line testing effort was effective.	○

4) COORDINATION WITH ELECTRIC COMPANIES/LOCAL AUTHORITIES	
The utility effectively coordinated with the local electric utility.	○
Communications with electric utilities did not adversely impact the restoration efforts of telecommunications and electric service.	○
Communications were effective with other entities, such as state and local public officials, firefighters, first responders, and other emergency personnel.	○

C. TASKS

In conducting this assessment, TDS and FairPoint executives, managers, and engineers were interviewed. Additionally, a number of data requests were submitted to each utility and each data response was reviewed and analyzed.

Focus was placed on the storm chronology and the emergency preparedness, planning, operation, and restoration efforts of each company. In an effort to develop a set of suggested best practices, an examination was made of each company's performance.

As an aid in evaluating the companies' responses to the December 2008 ice storm, the TDS Field Services Disaster Recovery Plan (TDS Plan) and the FairPoint Disaster Plan (FairPoint Plan) were reviewed. In addition, work force availability during the restoration was analyzed in detail. This analysis included an examination of the number of available technicians during November 2008, December 2008, and January 2009, compared with the same period in 2007 and 2008.

The ability to perform bulk line testing prior to customer trouble reports was examined with both companies. Bulk line testing was also discussed with an outside technical expert from the manufacturer of one of the switches commonly used in the New Hampshire system.

D. FINDINGS AND CONCLUSIONS – TDS

Conclusion: The TDS Field Services Disaster Recovery Plan has several significant deficiencies.

Before a utility can respond to a widespread customer service outage, it must prepare a plan to cover such an emergency. The utility's response when the emergency develops would begin with consulting this plan. TDS considers its plan to be proprietary and confidential, so it is addressed here only in general terms.

Plan Elements

The TDS plan establishes a command center, defines a command structure, and defines and assigns responsibilities for handling the emergency response. The local Field Service Managers (FSMs) are key to effective coordination and conduct of emergency operations. The FSMs set up Command Centers in the field and act as overall coordinators. The plan directs that communications be established with the media, the NHPUC, the customers, and the local authorities to the extent possible. Priorities for storm damage restoration are identified and appear to be consistent with established industry practices.

Plan Shortfalls.

Despite its strengths, there are areas where the TDS plan does not address issues critical to its successful application. These are:

- No provision is made for communication and coordination with the electric utilities, which is an essential element in recovering from a natural disaster such as this ice storm.[3]
- No provision exists to supply specific reference material for coordination and liaison with the electric utilities.[4]
- No provision is made for the training necessary to apply the plan.
- No provision is made to update or review the plan according to a formal time line.[5] While it is true that the plan is updated annually and after each disaster event, the plan itself does not define the times or the procedures for this to occur.[6]
- No provision is made for a procedure to review and update the various emergency contact lists that are required to provide information for contacting employees, government officials, contractors, and suppliers during an emergency.
- No provision is made to list electric utility contacts in the plan.[7]

Recommendation No. 1: TDS should revise its Field Services Disaster Recovery Plan to include training requirements and requirements for reviews and updating. This revision should include the following:

- Require that personnel be periodically trained in the requirements and responsibilities included therein. Even though the majority of the personnel involved in this restoration effort were very experienced, periodic re-training would be optimal.
- State specifically when, by whom, and by what method the plan will be updated. This revision should be done at least annually, after each major event, and by a cross functional team that includes the Local FSMs.
- Require periodic reviews to ensure that the lists of contacts included in the plan are as current as possible. Since the utility appears most vulnerable in this area, this review should be completed prior to the winter season.
- Require coordination with the electric utilities whose facilities are located in the TDS service area and include a list of contact information so that communication may be established.

[3] TDS. (March 20, 2009). Data Response STAFF 1-1. NHPUC.
[4] TDS. (May 22, 2009). Data Response TE0032. NEI.
[5] TDS. (March 20, 2009). Data Response STAFF 1-1. NHPUC.
[6] TDS. (March 20, 2009). Data Response STAFF 1-2. NHPUC.
[7] TDS. (March 20, 2009). Data Response STAFF 1-1. NHPUC.

Conclusion: TDS's preparation for the December 2008 ice storm was efficient and effective.

For its disaster recovery plan to be useful, a utility must have a way to determine when a storm is imminent so it has time to put the plan into effect as far in advance as possible. The first indication that a natural disaster such as the ice storm may be approaching is often given in forecasts provided by entities such as the National Weather Service. Staying abreast of current and forecasted weather allows utilities to recognize that a storm may have the potential for causing major system damage.

TDS tracks weather patterns and events in its Network Monitoring Operations Center (NMOC) located in Wisconsin. The NMOC provides advanced technical support for network management operations and monitors all network elements which have remote alarm capability. When a weather event appears imminent, the NMOC notifies local field management to begin the communications process and gather local information. The NMOC management then begins an assessment of the availability NMOC employees with the requisite technical expertise in the areas likely to be affected.

The Technical Customer Operations Center (TCOC) is responsible for repair calls for voice, internet, and television customers in all thirty states in which TDS operates. The TCOC is notified of an imminent threat, along with the Network Operations Center-Trouble Resolution (NOC-TR), which is responsible for determining the type of dispatch needed at the local level.[8] These centers also begin an assessment of their available resources and the overtime needed to handle the anticipated increase in call volume and customer outages.[9] As the probability of a major system disruption becomes more likely, communications between the NMOC, the TCOC, the NOC-TR, and field management forces increase to keep everyone informed of the situation.

An emergency response team is put together under the auspices of the Emergency Operations Center (EOC). The EOC consists of the center managers, the local FSMs, government affairs personnel, communications staff, and the appropriate Executive Vice President (EVP). The EOC is chaired by the Advanced Technical Support Manager or his designee. The participants may vary as the situation changes.

Communication is primarily accomplished through conference calls that are held three times per day for the duration of the restoration effort. The primary function of the EOC is to ascertain what resources the FSMs require and when they require them, and then to make those resources available. The local FSMs, the Regional FSM, and the EVP determine the availability of personnel resources. The FSMs are the key to this process, and every effort is made to accommodate their needs.[10]

[8] Corso, M. Manager-Advanced Technical Support, TDS. Interview by Satterfield, J. May 27, 2009.
[9] Fermanich, B. Manager-TCOC, TDS. Interview by Satterfield, J. May 27, 2009.
[10] Corso, M. Manager-Advanced Technical Support, TDS. Interview by Satterfield, J. May 27, 2009.

At the local level, preparation is also started as the probability of damage from an approaching weather pattern appears more likely. During the December 2008 ice storm, generators were located, fueled, and tested to ensure they would operate correctly. When commercial power is interrupted for an extended period, these generators are used to power the subscriber line carrier (SLC) sites and remote central offices (COs), which are not normally generator equipped. The SLC systems and the remote COs are equipped with batteries. However, the battery life varies depending on their condition and the volume and duration of customer calls. TDS has 102 SLC sites in New Hampshire with 28 stationery generators and 44 portable generators available to serve them.[11] TDS also has 6 COs and 10 remote COs in its New Hampshire serving area. Local technicians are contacted to determine their availability for overtime work and contacts are made by the local FSMs with their peers in Maine and Vermont to alert them that assistance might be required.[12] [13]

Conclusion: Overall, TDS's ice storm restoration effort was efficient and effective.

TDS efficiently moved its work force into areas needing restoration and relocated them as necessary. Workers from outside the state and contractors from outside the company were obtained and efficiently deployed during the restoration effort. Restoring customer service was given top priority and workers concentrated on restoring storm damage rather than handling other types of routine work or installation service orders. Overtime was assigned as needed.

Restoration was initiated with a review of the storm situation and damage, starting with the operations centers and concluding with field activities. An analysis of call volumes made to the TCOC during December 2008 revealed that, during the first eleven days of the month, the number of offered calls averaged 30.3 per day with an average speed of answer (ASA) ranging from 13 seconds to one minute and 11 seconds. ASA is defined as "the average amount of time a customer is waiting in the call queue until they speak with an advisor."[14] From Day 2, Friday, December 12, to the end of the month, there was an average of 117.8 calls per day. ASA ranged from a low of 23 seconds to a one day high of six minutes and 58 seconds, with the highest call volume occurring on Day 3, Saturday, December 13, with 44 received calls.[15]

Tests are not conducted on the customer line when a repair call is received at the TCOC. Instead a trouble ticket is created and referred to the NOC-TR where tests are made on the line and decisions are reached about whether an outside dispatch, inside dispatch (central office), or no dispatch is appropriate. The local FSM is sent the information and then dispatches the correct technician.

[11] TDS. (May 19, 2009). Data Response TE0037.7. NEI.
[12] Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[13] Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[14] TDS. (May 28, 2009). Data Response TE0035.8. NEI.
[15] TDS. (March 20, 2009). Data Response STAFF 1-11. NHPUC.

In a major outage such as caused by the ice storm, when calls are received at the TCOC, primary outage tickets are created to cover specific locations such as a SLC site failure or a damaged or cut cable that would result in multiple customer outages. As more customers call in to report service disruptions, those reports are associated with primary outage tickets. A system is used that can group the customer trouble reports by their addresses to the address ranges covered by the primary ticket. When a field technician reports to the Field Service Technician Contact Center (FSTCC) located in the NOC-TR that a cable has been repaired or a SLC site restored, the primary ticket is closed along with all the associated customer trouble reports. To ensure that customers' troubles have been repaired, automatic calls are made to the reporting customers, with positive verification required that service has been restored. If a customer cannot be reached by the automated call system, the customer is called by a representative in the Customer Contact Center (CCC) located in the TCOC. If the customer still cannot be reached, or indicates the trouble has not been satisfactorily corrected, the trouble is re-dispatched. During a major restoration effort, inbound calls are given priority and the outbound verification calls are delayed.[16]

The NMOC increases its alarm monitoring capability for the impacted area. As alarms are detected from equipment in the impacted area, referrals are made to the NOC-TR for dispatch. The TCOC is also notified so a primary ticket may be created if needed. Direct communication with the field may also be done from this center.[17] [18]

As the ice storm began, field technicians and the local FSMs began to respond. The first efforts, began early on Day 2, Friday, December 12, and were directed at supplying the SLC sites and remote COs with portable generators. Since there were not enough generators for all locations, a rotation and fueling plan was worked out. Offices already equipped with stand alone generators were visited to insure proper operation of the batteries and the generators. During this restoration effort, there was no central office or remote CO failures. Two SLC sites failed due to severely poor accessibility that did not allow deployment of a generator. Initial field assessments were difficult and delayed because of blocked roads. As the situation improved each day, more areas became accessible. At times, however, some roads which had formerly been opened were once again closed.[19] [20]

During the first EOC conference call on the morning of Day 2, Friday, December 12, the local FSMs were asked about their needs. This inquiry prompted a crucial management decision. If borrowed forces were brought in too early and could not gain needed access, then resources would be wasted. If resources were brought in too late, customer service restoration would be unduly delayed. Throughout this event the FSMs were provided with the manpower resources

[16] Snomalski, E. Data Analyst, TDS. Interview by Satterfield, J. June 19, 2009.
[17] Corso, M. Manager-Advanced Technical Support, TDS. Interview by Satterfield, J. May 27, 2009.
[18] Fermanich, B. Manager-TCOC, TDS. Interview by Satterfield, J. May 27, 2009.
[19] Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[20] Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.

they requested. Technicians were moved from location to location within the state as access became available and trouble areas were cleared. Eight technicians were moved from Merrimack and New London to Wilton. Later in the restoration effort, eight technicians were moved from new London and Wilton to Hollis.[21] Personnel were brought in from outside the state starting as early as Day 3, Saturday, December 13 and ending Saturday, January 3, 2009. In total, there were over 800 hours worked by forces from outside the state in December and over 50 hours in January. These forces were a combination of FSTs and managers working as technicians. There were three technicians and one manager brought in from Vermont and six technicians and two managers brought in from Maine.[22] In addition, there were 133 available contractor days starting on Day 2, Friday, December 12, 2008, and lasting until Day 24, January 3, 2009.[23] Contractor forces were used primarily for replacing poles on solely owned routes and putting up drops in area sweeps.[24] [25]

In addition to borrowed forces and contractors, overtime was worked by the existing TDS forces in New Hampshire. There are a total of 27 field service technicians and two assistant field service technicians (these personnel assist the Local FSMs with the clerical aspects of their positions) permanently assigned to TDS in New Hampshire. A comparison was made of hours worked by these forces between November and December 2007 and January 2008 (the year prior to the storm), and the same period in years 2008 and 2009 (the year of the storm). This analysis is displayed in Table VIII-3.

Table VIII-3 – Hours worked by permanent forces in November and December 2008 and January 2009 compared to the prior year.[26]

Month	Total ABD* Hours	Average ABD* Hours/ Tech/Day	Total SSH** Hours	Average SSH** Hours/Tech /Day	Total Hours	Average Hours/Tech /Day
Nov 2007	5132.1	8.43	281.5	1.08	5413.6	6.22
Nov 2008	4617.0	8.38	326.6	1.02	4943.6	5.68
Dec 2007	4744.0	8.17	348.5	1.05	5092.5	5.66
Dec 2008	5947.4	9.32	1481.9	5.67	7429.3	8.26
Jan 2008	5310.5	8.32	255.5	1.01	5566.0	6.19
Jan 2009	5145.8	8.45	417.8	1.44	5563.6	6.19

**ABD = Average Business Day*
***SSH = Saturday, Sunday, Holiday*

21 TDS. (March 20, 2009). Data Response STAFF 1-23 Attachment C. NHPUC.
22 TDS. (March 20, 2009). Data Response STAFF 1-23 Attachment C. NHPUC.
23 TDS. (March 20, 2009). Data Response STAFF 1-20 Attachment C. NHPUC.
24 Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
25 Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
26 TDS. (May 26, 2009). Data Response TE0026. NEI.

As can be seen from the above table, the total hours increased by 45.9 percent between December 2007 and December 2008. A similar increase may be seen in the average hours per technician per day. The average hours per technician per day will yield a more valid figure for comparison purposes since the months differed in the number of business days. Average ABD hours per technician per day increased 14 percent between December 2007 and December 2008, reflecting the limited amount of daylight available in which to work safely before or after a normal work day. However, the comparable number of average SSH hours per technician per day increased more than five-fold when comparing December 2007 to December 2008. Technicians typically worked an average of ten or more hours per day during this event both on business days and weekends. The hours per technician per day in the table above are averaged over the total force and reflect technician days off that are required to ensure safety and work quality. Since the existing permanent workers were already working nearly the maximum allowable hours during business days, the only hours available for extra work were on weekends and holidays. For that reason the increase in hours for each technician came mainly on the weekends and holidays. The total hours worked when both permanent and temporary workers are considered increased by about 3,000 hours comparing December 2007 to December 2008.[27]

Available work force is an important component in a major storm restoration, and equally important is how these forces are used. The use of field forces was reviewed by analyzing the number of service orders worked and troubles cleared. Service orders dispatched were reviewed for November and December 2008 and January 2009. Figure VIII-1 displays the results of this analysis.

[27] TDS. (March 20, 2009). Data Response STAFF 1-23. NHPUC .

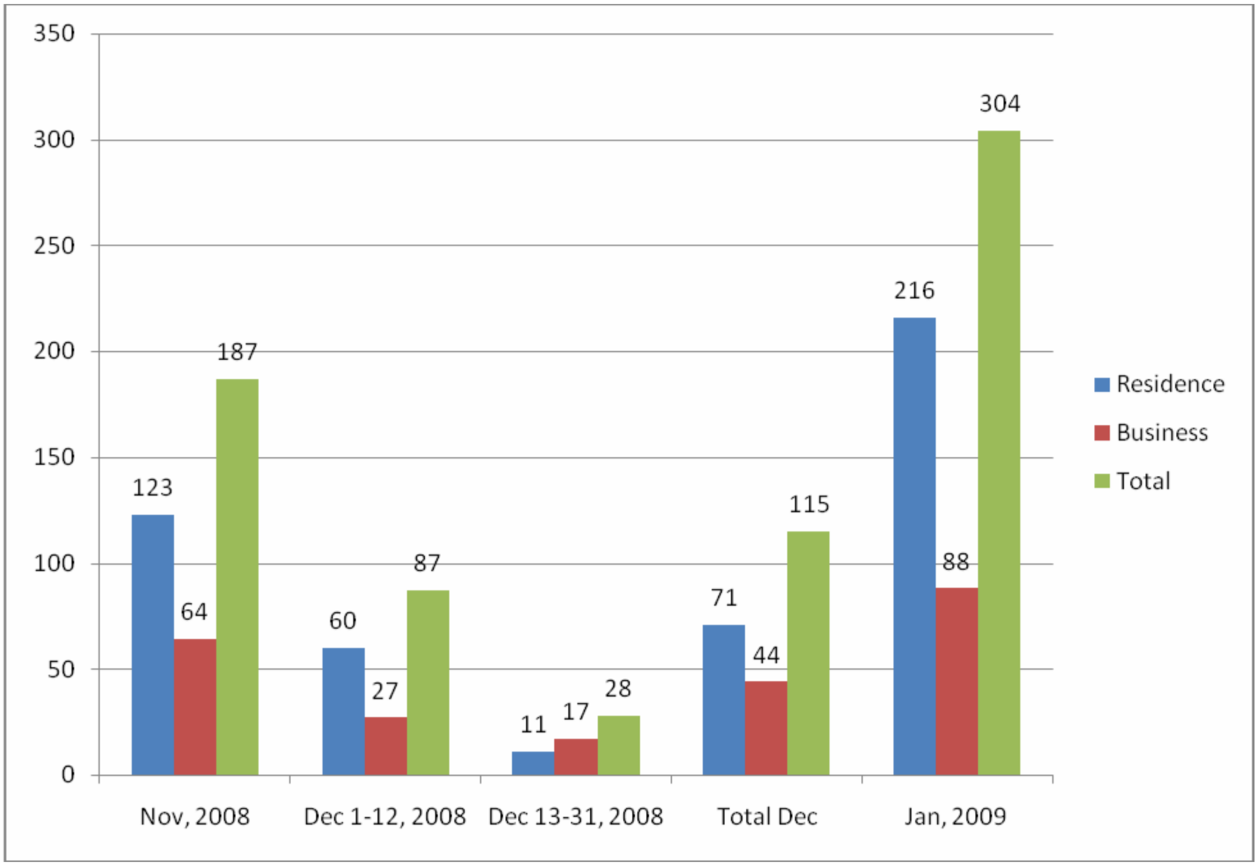

Figure VIII-1 - Service orders dispatched – TDS.[28]

A review of Figure VIII-1 shows that prior to the storm (December 1-12) the month of December was on track to be a typical month for dispatched orders. After the storm (December 13-31) the number of dispatched orders drops dramatically as forces concentrated on service restoration. Note that the number of orders worked in January 2009 increased significantly, likely due to filling the backlog of orders that were not completed the month prior during storm restoration.

An analysis of the number of trouble tickets cleared for November and December 2008 and January 2009 was done and these months were compared to the same period one year earlier. Figure VIII-2 summarizes this analysis.

[28] TDS. (June 2, 2009). Data Response TE0038. NEI.

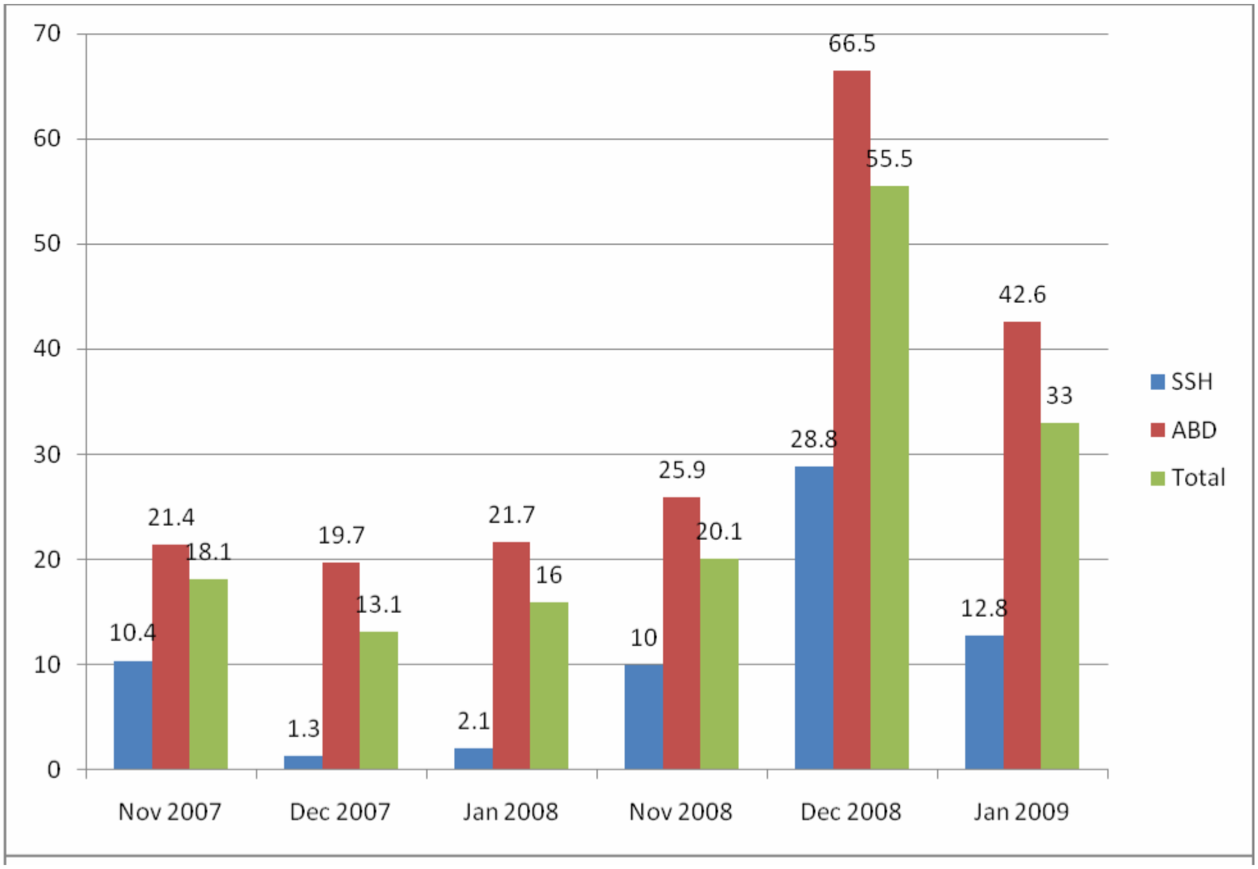

Figure VIII-2 - Average number of trouble tickets cleared per day-TDS.[29] [30]

When reviewing Figure VIII-2 it is apparent that December 2008 shows an increase in service outages caused by the ice storm. December 2008 tickets cleared increased by more than four times over December 2007. The comparable Saturday-Sunday-Holiday (SSH) figures increased by more than 22 times, reflecting the additional hours worked on weekends and holidays. Even though it is difficult to quantify exactly the total number of troubles cleared due to some troubles being cleared without trouble reports being issued, it may still be noted that the number of reported troubles cleared increased more than five fold between December 2007 and December 2008, while hours increased by approximately 62 percent.

Since the technicians perform so many functions, a pure trouble-cleared productivity analysis cannot be accurately done. Moreover, rather than responding to individual customer trouble reports, TDS used mass sweeps. These consisted of clearing all trouble conditions that could be seen in an area once that area became accessible. Technicians were instructed to clear all the problems they could see on a street to which they were dispatched. Nonetheless, a comparison of the increase in hours versus the increase in trouble tickets cleared provides a strong indication

[29] TDS. (May 28, 2009). Data Response TE0023. NEI.
[30] TDS. (May 28, 2009). Data Response TE0024. NEI.

that productivity degradation was not a factor during the recovery. TDS considers that the last customer outage associated with the December 2008 ice storm was restored on Day 24, Saturday, January 3, 2009.[31]

As part of the overall review of the restoration, an analysis was made of the routes carrying umbilicals from host offices to the remote COs. It should be noted that no remote COs were lost during this outage, and the survivability of the umbilicals was essential to the proper functioning of the remote switches. TDS considers the information it furnished to be confidential, but it indicates that most of the facilities are using fiber optic technology, and the larger remote COs are served by diverse routes with fully protected ring architecture. With the increase in planned routes this year, all remote COs will have diversity among themselves and with the rest of the world.[32] [33]

During the restoration, tree trimming crews cut or nicked some of the telephone cables while clearing debris. These damaged cables are subject to future water intrusion if not promptly repaired. After the storm they were identified using existing proactive maintenance and repaired.

In some cases telephone cables were erroneously pulled into the area on the poles reserved for higher voltage conductors. While these problems were corrected, they still took time away from customer restoration efforts and created safety hazards. It was also discovered that some of the replacement poles were not properly guyed to resist the telephone cable loads.[34] [35] The proper guying of these poles should be checked as part of the utility's ongoing maintenance effort.

Conclusion: TDS is effectively preparing for the next major outage.

As restoration efforts were being completed, preparation was already underway for the next major outage. The Centers are reviewing data and budget information from this storm and others around the country to adjust staffing levels to improve readiness. They are working to develop systems that will allow standardized reports down to street level. This will allow technicians to be more readily put on sweeps and be involved in mass closing of trouble areas. However, this system will continue to depend on customer trouble reports to allow grouping of troubles.[36] [37]

At the local level, equipment is being placed at some SLC sites (e.g., power cords, security devices, etc.) that will speed up generator placements. Further, the number of generators in New Hampshire is being increased. Even though during the December 2008 storm review there was no indication of battery neglect, batteries at the SLC sites are undergoing routine maintenance which includes replacement if their output is low. Sites are also being routinely checked for

[31] TDS. (March 20, 2009). Data Response STAFF 1-28. NHPUC.
[32] TDS. (May 26, 2009). Data Response TE0035.6. NEI.
[33] Kidder, C. Geographical Architecture, TDS. Interview by Satterfield, J. May 27, 2009.
[34] Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[35] Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[36] Fermanich, B. Manager-TCOC, TDS. Interview by Satterfield, J. May 27, 2009.
[37] Corso, M. Manager-Advanced Technical Support, TDS. Interview by Satterfield, J. May 27, 2009.

proper bonding and grounding. CO generators and remote CO generators (where equipped), as well as all CO batteries, are routinely tested to insure viability during a major power outage.[38] [39]

Conclusion: TDS in New Hampshire does have the capability to conduct bulk testing of customer access lines. [40]

Bulk testing of customer lines before a customer trouble is received is dependent on the existence of equipment in the central offices that will interact with the test system to perform tests on customer lines. Such a system typically works at night and has the ability to test a number of customer lines to provide reports on those that appear to be in trouble. Bulk testing is not totally conclusive since inside wiring and portable telephone problems may also be identified as trouble conditions in the telephone network. However, bulk testing provides a good indication of where major outages may be located and could be an aid in quicker restoration. A conversation with a manufacturer expert verified that the capability for bulk testing does exist, although bulk testing was not used during the December 2008 ice storm restoration. TDS advised that were reviewing the possibility of utilizing this feature during future outages.

Recommendation No. 2: TDS should use its bulk line testing capability during the initial phases of a major restoration effort.

- Bulk line testing will assist in identification of areas of severe customer outages allowing technicians to be more effectively used from the very start of the restoration effort. This can also aid in coordination with the electric utilities and local authorities as they prioritize their own restoration efforts.

Conclusion: Coordination and communication with local governments and the electric utilities during the response to the December 2008 ice storm was not effective.

TDS's response to the storm took longer than necessary due to the lack of a plan for effective communication and coordination with local governments and the four electric utilities. The communications that did occur was largely by happenstance. It took place between telecommunications technicians and electric company technicians, local officials, or first responders encountered in the field. There was no official coordination between the electric utilities and TDS during the storm restoration although unsuccessful attempts were made to contact PSNH by telephone.[41] TDS employees traveling to work took note of cleared areas and furnished this information to management. Likewise, telecommunication employees working in areas near electric utility employees or tree trimming crews might make contact with them to gather information which they then gave to management.[42] [43] Formal procedures and processes

[38] Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[39] Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[40] TDS. (October 16, 2009). Email, Michael C. Reed, Manager, State Government Affairs.
[41] TDS. (May 22, 2009). Data Response TE0033. NEI.
[42] Raymond, E. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.
[43] Harmon, D. Local FSM, TDS. Interview by Satterfield, J. June 19, 2009.

for communication were not established for sharing information or for coordinating restoration efforts. Customer restoration would have been greatly advanced by effective communication and coordination between the utilities enabling telecommunications workers to get safe and quick access to the impacted areas.

Recommendation No. 3: TDS should establish a forum whereby local TDS management and electric company management meet regularly to coordinate operations and plan for emergencies.

- TDS managers should meet with electric utility managers and local government officials at least annually (preferably biannually) to discuss communication, coordination, and mutual problems, both ongoing and those relating to emergency restoration.
- TDS should identify key sites where power and telephone service are critical.
- TDS should place a person in the EOC from the predominant electric company in the affected area during an outage. That person should have access to up to date electric company information and be able to furnish it to the TDS EOC on a timely basis. This individual can also be a conduit for communication from TDS to the electric company.
- TDS should establish an industry forum for the purpose of creating an internet site that can be utilized to provide current information on restoration efforts. This might include such things as areas cleared of downed power, roads that have become accessible, etc. Since the electric companies are at the forefront of most restoration efforts associated with an event such as the December 2008 ice storm, it would seem logical for them to take the lead in keeping the site current. Access by other involved parties, such as telecommunications companies and cable companies, should be encouraged. As communications and coordination are improved, restoration time and safety will likewise be improved.

E. FINDINGS AND CONCLUSIONS – FAIRPOINT

Conclusion: FairPoint Communications should improve its Disaster Response Plan.

The 117 exchanges located in FairPoint's service area were purchased from Verizon Telecommunications effective March 31, 2008. At the time of the December 2008 ice storm, FairPoint was in a transition period and still operating on Verizon's legacy systems. The transfer of the network and operational support systems was not completed until the end of January 2009; consequently, FairPoint's Disaster Response Plan was not fully operational at the time of the storm. The company is currently conducting an in-depth audit of the plan to ensure that post-cutover system and organizational changes are incorporated.[44] FairPoint's plan was reviewed to determine its applicability in a situation similar to the December 2008 ice storm.

FairPoint considers its plan to be confidential and proprietary, so it is addressed here in general terms. The plan is a structured document that addresses potential outages resulting from severe weather, single building incidents, or work force disruptions. It includes annual updating to allow for changes that may occur in the various aspects of the business. The plan contains a number of contact lists that must be kept current. The plan also includes provisions for tests and exercises to validate its effectiveness. Departmental plans, accessed through hyperlinks from the main plan, are used for responses to major outages such as the ice storm.[45]

Generally, FairPoint's plan has much strength and appears to be a usable document. However, there are areas that need to be improved. Among these are:

- The plan does not identify who is responsible for conducting training and exercises.
- The plan is unclear in defining the responsibility for updating and reviewing the major departmental plans, which are vital to an effective response to an event such as the ice storm.
- The plan does not provide for review and updating after a major outage or event.

Recommendation No. 4: FairPoint should revise its Disaster Response Plan to better focus on responsibility for training, exercises and updating.

- FairPoint should revise its plan to identify who is responsible for the training, exercises, and mock drills.
- FairPoint should revise its plan to fix responsibility for reporting the results of the exercises and updating the plan with lessons learned.
- FairPoint should revise its plan assign responsibility for updating the departmental plans.

[44] Matherly, A. Director-Risk Management, FairPoint. Interview by Satterfield, J. July 2, 2009.
[45] FairPoint. (March 20, 2009). Data Response STAFF 1-1. NHPUC.

- FairPoint should revise its plan to provide for a formal updating process after a major outage. A major outage is classified as one that reaches the two highest levels of severity using the color codes included in the plan.

Conclusion: FairPoint's preparation for the December 2008 ice storm was efficient and effective.

The FairPoint Disaster Response Plan is important for strategy, policy, and general procedures, but the tactical response to an emergency begins with the identification of a potential major event. At FairPoint, weather channels and various weather related internet web sites are monitored by managers in the centers involved in customer restoration, including the Repair Resolution Center (RRC), the Dispatch Resource Center (DRC), and the Network Operations Center (NOC). The RRC is responsible for receiving calls from customers that have experienced a service outage. The DRC coordinates the dispatch of the appropriate technician to perform the necessary repair work. The NOC performs surveillance on all network elements with remote alarm capability. Field operations managers who are responsible for the Central Office, installation and maintenance department, and construction department also monitor the weather using similar sources.

As a result of this monitoring, senior management recognized that the December 2008 ice storm would likely have a major impact on customer service; however, the extent of damage was difficult to anticipate. As the storm approached the state, personnel at centers and in the field were contacted to determine their availability to work overtime. Technicians were advised to fuel their vehicles and stock up on supplies they might need. Supply Chain Management was advised to stock up on items likely to be required for the restoration. Portable and truck-mounted generators were tested and fueled.[46] [47] [48] These generators are used to power subscriber line carrier (SLC) sites in the event of an extended power failure. The SLC sites are equipped with batteries, but battery life is limited and depends on call volume and battery condition. At the time of the ice storm there were 1,119 Remote Terminal sites in operation throughout the State of New Hampshire and FairPoint maintained 29 portable and 293 truck-mounted generators.[49] All remote central offices (COs) are equipped with backup generators and fuel levels for the generators located at these COs were checked. FairPoint had 124 COs and 96 remote COs that served New Hampshire customers at the time of the storm. A listing of central office switches by type is shown below in Table VIII-4.

[46] Powell, D. Director of Operations, Dispatch Resource Center; FairPoint. Interview by Satterfield, J. June 15, 2009.
[47] Aubrey, S. Director-Central Office Operations, FairPoint. Interview by Satterfield, J. June 15, 2009.
[48] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.
[49] FairPoint. (June 5, 2009). Data Response TE0037.7. NEI.

Table VIII-4 - Number of FairPoint Central Office switches by type[50]

Type	Number
DMS 10	5
DMS 100	1
Nortel CS2K Softswitch	1
5ESS Tandem	2
5ESS Stand Alone	5
5ESS Host	14
5ESS RSM	92
5ESS EXM	1
5ESS ORM	3
Total	124

FairPoint also has large capacity portable generators for use in central offices in the event a fixed backup generator fails. As the storm approached, communication between centers and field operations regarding storm preparations increased.[51] [52] [53]

The emergency response was controlled by the Emergency Operations Center (EOC), headed by the Senior Vice President of Operations and Engineering for Maine, New Hampshire, and Vermont. Others participating in the EOC were:

- The Director of Operations, Dispatch Resource Center;
- The Director-Central Office Operations;
- The Director of Operations-Installation and Maintenance, and Construction;

[50] FairPoint. (August 10, 2009). Data Response TE0042. NEI.
[51] Powell, D. Director of Operations, Dispatch Resource Center; FairPoint. Interview by Satterfield, J. June 15, 2009.
[52] Aubrey, S. Director-Central Office Operations, FairPoint. Interview by Satterfield, J. June 15, 2009.
[53] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.

- The Manager, Outside Plant Engineering-Support;
- The Manager, Central Office Engineering;
- The Manager-Proactive Maintenance Field Forces;
- A representative from the logistics support group (Supply Chain);
- The Vice President-Government Relations for New Hampshire.

A representative from Corporate Communications was available as needed for contacts with the external media. No one from FairPoint company headquarters participated in the EOC. Throughout the restoration, the EOC used twice daily conference calls as their primary method of communication. The first organized conference call was held on Day 2, Friday, December 12, at approximately 9:00 a.m. Prior to this there were many calls between the Senior Vice President for Operations and Engineering and her staff to determine their readiness and to obtain initial damage assessments.[54]

Conclusion: FairPoint should not have diluted its restoration efforts by working unrelated service orders, even though the overall restoration effort is considered effective.

FairPoint has a union contract that specifies the amount of overtime that can be worked in the absence of a declared emergency. Management did not declare an emergency during this restoration since there were no problems getting adequate overtime. There were occasions when arranging sufficient overtime on weekends and holidays was a problem, but ultimately the necessary hours were obtained. Initially some construction forces were used to respond to customer service outage reports. However, since repairing the large numbers of downed and damaged cables was a major part of the restoration effort, construction forces were redirected to this task as soon as possible. Personnel in the proactive maintenance group (a group that works on trouble indicators before the customer is aware of a potential outage) with prior installation and maintenance background were moved into customer trouble repair positions to respond to customer trouble reports. Technicians were moved in from other states and were relocated within the state as trouble areas were cleared and others became more accessible. Contractors saw some use, primarily in replacing downed poles, but the union contract limited this to some degree.[55]

The overall manner in which restoration was accomplished was explored by NEI in the course of this review, starting with an examination of the centers and ending with the work done in the field. This included both a review of the central office and outside operations. At the time of the storm, FairPoint was using an Automatic Call Distributor (ACD) configuration for calls into the RRC. Incoming calls were distributed to the Customer Service Attendants (CSAs) that are

[54] Mead, K. Senior Vice President-Operations and Engineering, FairPoint. Interview by Satterfield, J. June 16, 2009.
[55] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.

plugged into the system. When the number of calls exceeded the number of available CSAs, the calls were placed in a queue. This center operates twenty-four hours a day, seven days a week using three shifts. Workers are assigned overtime to handle the higher than normal call volumes that are expected when a large numbers of customers are out of service due to severe weather.[56] An analysis of call volumes to the RRC revealed that typical call volumes for December 1 to 11 were 1,263 calls daily. From December 12 to 31 the average daily calls increased to 2,373, with the two highest days being Day 2, Friday, December 12 when 5,731 calls were received, and Day 5, Monday, December 15 when 4,317 calls were received.[57]

The average speed of answer (ASA) is measured starting with the time a customer is placed in queue and ending with their call being answered by a CSA.[58] For a normal month such as November 2008, the average ASA is 10 seconds; however, for December 2008, the average ASA was 153 seconds, or just under two minutes.[59] The two days with the longest ASA following the storm were Day 2, Friday December 12, when the ASA was 243 seconds, and Day 3, Saturday, December 13, when the ASA increased to 255 seconds.

In December 2008, FairPoint was still operating using the Verizon legacy systems. Consequently, as repair calls were completed by the CSAs, they were entered into a system called V-Repair. This system, using Mechanized Loop Testing (MLT), conducted tests on the reported customers' lines and determined where troubles could be handled best. Troubles were then routed to a system called Work Force Administration-Dispatch Out (WFA-DO) or Work Force Administration-Dispatch In (WFA-DI), depending on whether the trouble condition was thought to be in the outside plant network (DO) or the central office, or should be handled by a dispatch center (DI).

When WFA-DO detects more than three customer trouble reports in a 100 cable pair complement, the system builds a multiple trouble report. Once the multiple trouble report is cleared, all individual troubles associated with it are cleared also. All trouble reports cleared in a day are sent to the Sky Creek Company, a contracted vendor whose automated system places calls to the customers to verify that service has been restored. Business customers are called by a representative from the FairPoint customer service center in Burlington, Vermont.

The Dispatch Resource Center (DRC) monitors WFA-DO, WFA-DI, and WFA-Control (WFA-C) to determine the volume of work in a particular area and the number of hours needed to handle it. These systems can dispatch technicians in two ways. The technician can be given a single work dispatch followed by another when the first is completed, or the technician can be "bulk loaded" by being given the entire day's projected work on the initial download of customer troubles and installation orders. To optimize their efficiency during the ice storm restoration, the

[56] Astle, B. Manager-Repair Resolution Center, FairPoint. Interview by Satterfield, J. June 30, 2009.
[57] FairPoint. (March 20, 2009). Data Response STAFF 1-11. NHPUC.
[58] Astle, B. Manager-Repair Resolution Center, FairPoint. Interview by Satterfield, J. June 30, 2009.
[59] FairPoint. (June 29, 2009). Data Response TE0040.4. NEI.

DRC bulk loaded the construction and proactive maintenance technicians and the majority of its regular technicians. It also handled closeouts when the technician completed work on customer trouble reports. The DRC has 66 administrative assistants and 8 managers assigned during normal operations. During the restoration, the DRC used its normal force and assigned overtime as required to support the field work, allowing it to remain in operation as long as technicians were working.[60]

The NOC operates twenty-four hours a day, seven days a week all year long and monitors all equipment with remote alarm capability down to SLC system level. On Day 2, Friday, December 12, alarm monitoring and surveillance was increased for the areas affected by the storm by assigning overtime and shifting geographic coverage responsibilities (the center covers the states of Maine, New Hampshire, and Vermont). Alarm indications were referred to operations personnel so technicians could be dispatched. This was done for alarms occurring in the outside plant network and the central office, as well as large customer installations with premise equipment monitored by the NOC. The NOC also monitors dial tone delay (DTD) during a storm restoration, although DTD was not a problem during this storm.[61]

During restoration efforts, CO operations personnel visited the COs to insure that generators were fueled and functioning properly, and technicians worked extended hours to provide the necessary support. The technicians also maintained equipment, such as switches, multiplexers, and fiber optics terminals located in the central office building, and worked closely with outside workers on trouble reports that required work in the CO. During this storm, 45 COs in New Hampshire were operating using power supplied by generators. Fuel became a major concern because some of the COs were without commercial power for up to ten days. Lists of offices operating on emergency power were provided to the electric companies and they responded by restoring them when possible.[62]

On Day 2, Friday, December 12, the first morning after the storm, field forces were mainly concerned with assessing the damage and moving portable generators to the SLC sites that were accessible. The first EOC conference call was held on the morning of Day 2, Friday, December 12, when the field managers communicated their understanding of the extent of the damage even though the damage assessments had just begun. After the first two days it was decided that more generators were needed, so approximately 50 were moved from northern New Hampshire and Maine into the most affected areas.[63] Of the 1,119 SLC sites, FairPoint estimated that 150 failed because access could not be gained before the batteries were exhausted.[64] For the first two days

[60] Powell, D. Director of Operations, Dispatch Resource Center; FairPoint. Interview by Satterfield, J. June 15, 2009.
[61] Smee, J. Vice President-Network Operations, FairPoint. Interview by Satterfield, J. July 7, 2009.
[62] Aubrey, S. Director-Central Office Operations, FairPoint. Interview by Satterfield, J. June 15, 2009.
[63] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.
[64] FairPoint. (June 29, 2009). Data Response TE0040.5. NEI.

the construction technicians helped clear customer trouble reports. However, due to the amount of damage requiring their specialized attention, they soon changed to replacing and splicing cable.63 Starting Day 5, Monday, December 15, forces were moved from other states into New Hampshire to assist in the restoration. Figure VIII-3 shows the number of technician days worked each week by technicians from outside of New Hampshire.

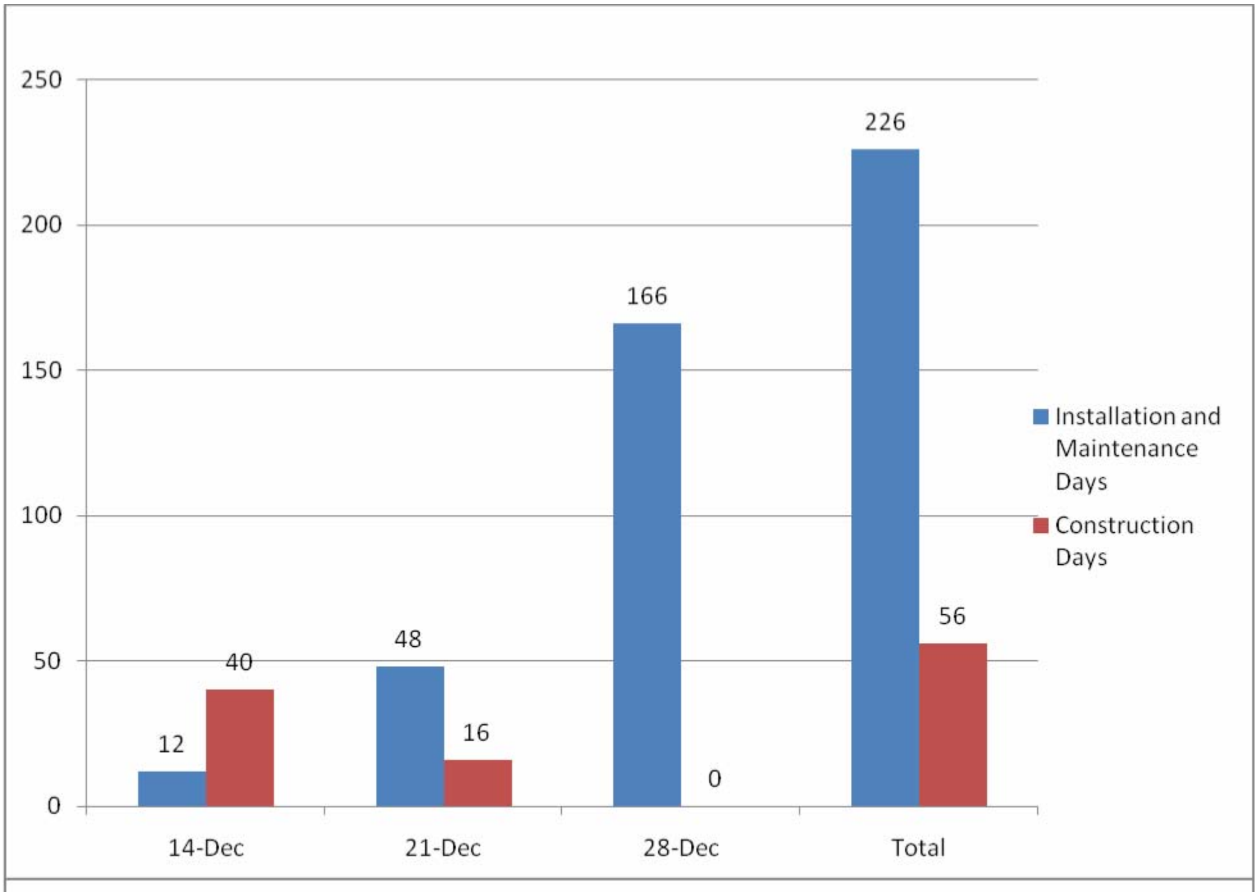

Figure VIII-3 – Technician-days worked per week by technicians from outside of New Hampshire. December 2008.[65]

As restoration proceeded, some areas were restored while others became accessible. This resulted in workers being relocated within the state as needed. Proactive maintenance forces were used throughout the effort to help clear customer trouble reports rather than attend to their regular duties. Splice Service Technicians (SSTs) were relocated from their normal work locations to other areas in the state. In general, forces were moved from north to south since the southern portion of the state was the hardest hit and the damage in the north could be repaired more quickly. Figure VIII-4 shows the number of proactive maintenance technician days and the

[65] FairPoint. (June 5, 2009). Data Response TE0007. NEI.

number of SST days used during the storm. The proactive maintenance technician days shown on the chart are the number of days during which the proactive maintenance technicians were working on storm restoration rather than their normal duties. The SST days shown on the chart are the number of technician days during which SSTs were working in areas of the state other than their normal areas of operation.

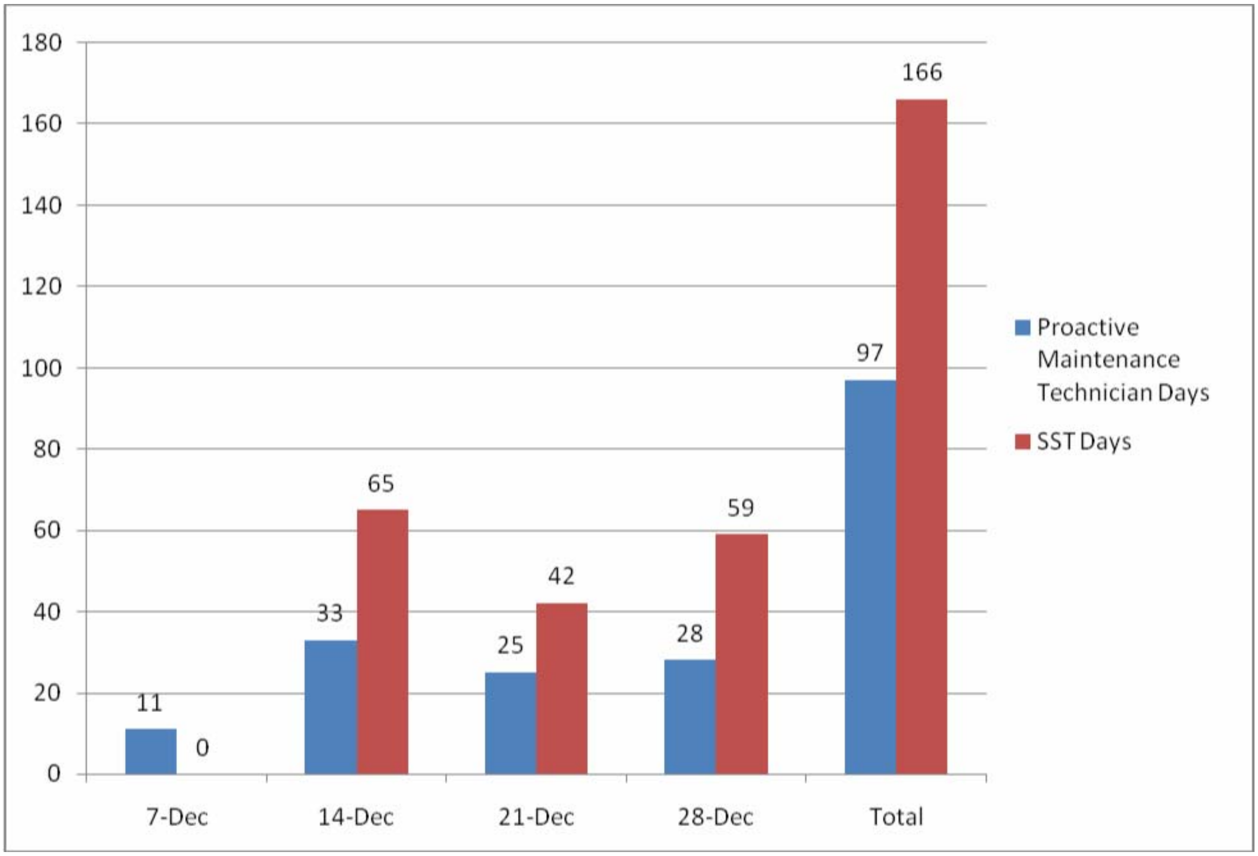

Figure VIII-4 - Proactive maintenance technician days and SST days for the weeks shown. December 2008[66]

FairPoint also engaged contractors starting as early as Day 1, Thursday, December 11. A total of 80 trim crews and 13 ground crews were used from that day through Day 21, Wednesday, December 31.[67] The contractors were mainly used for tree trimming and setting poles.[68]

[66] FairPoint. (June 5, 2009) Data Response TE0008. NEI.
[67] FairPoint. (March 20, 2009). Data Response STAFF 1-24. NHPUC.
[68] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.

Productivity indicators during the restoration period were reviewed. True productivity is impossible to measure since technicians were instructed to repair any drops they came across as they were dispatched on other, unrelated trouble calls. The approach used was that technicians entered an area as soon as it was accessible and cleared all the problems they could see. This method reduced restoration time by minimizing travel time and the issuing of additional dispatch orders. In an effort to improve customer relations, technicians were directed to repair troubles for customers that approached them while they worked on other problems. The DRC was informed about some of these repairs, but in many cases the technician did not call in these additional troubles.[69] Figure VIII-5 provides a comparison of productivity for SSTs by comparing the number of jobs performed in an eight-hour day in November and December 2007 and January 2008, with the jobs performed per day during the same periods in 2008 and 2009.

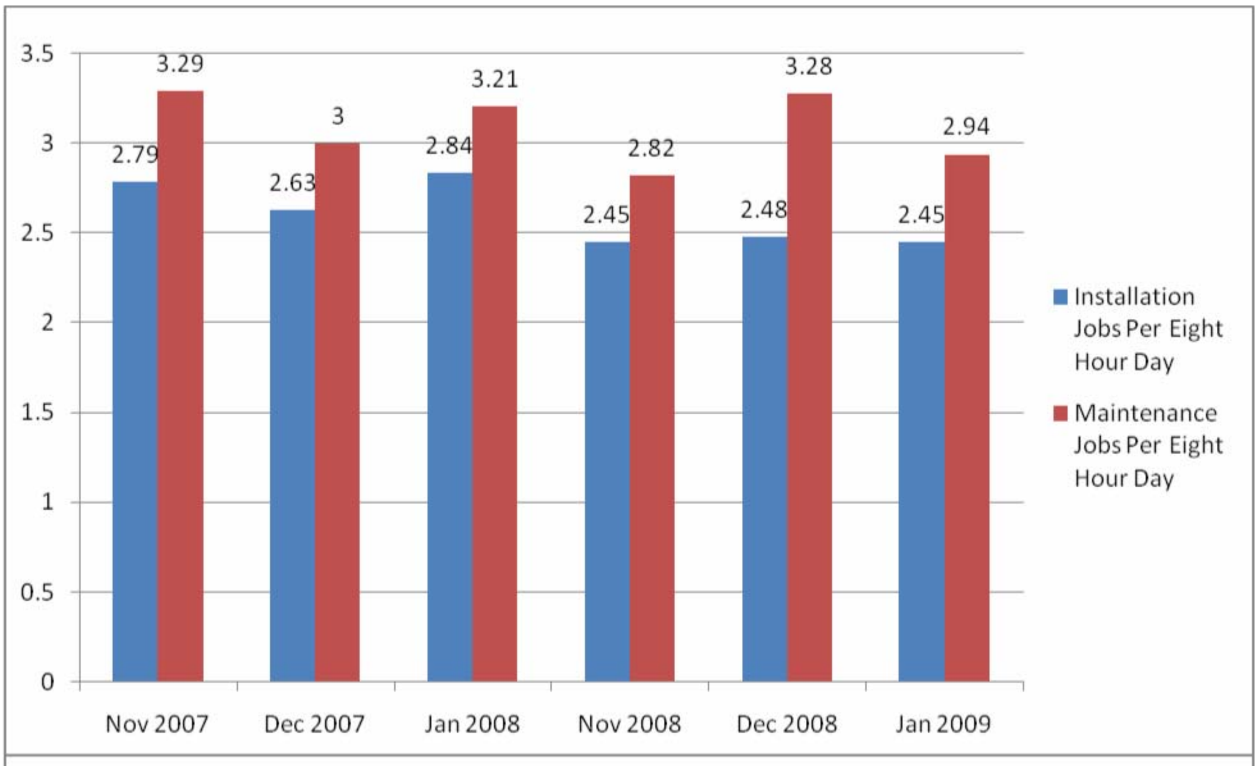

Figure VIII-5 - Installation and maintenance jobs per eight-hour day.[70] [71]

As may be seen in Figure VIII-5, productivity measured by maintenance jobs per day improved in December 2008 compared with December 2007 and November 2008. With due consideration

[69] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.
[70] FairPoint. (June 5, 2009). Data Response TE0009. NEI.
[71] FairPoint. (June 5, 2009). Data Response TE0010. NEI.

to the caveats mentioned previously, it may be seen that productivity definitely improved during the restoration.

Assigning overtime also was used extensively to expedite restoring customer service. Figure VIII-6 provides a comparison of overtime hours worked by installation and maintenance, and construction technicians during November and December 2007 and January 2008, compared with the overtime hours worked during the same months in 2008 and 2009.

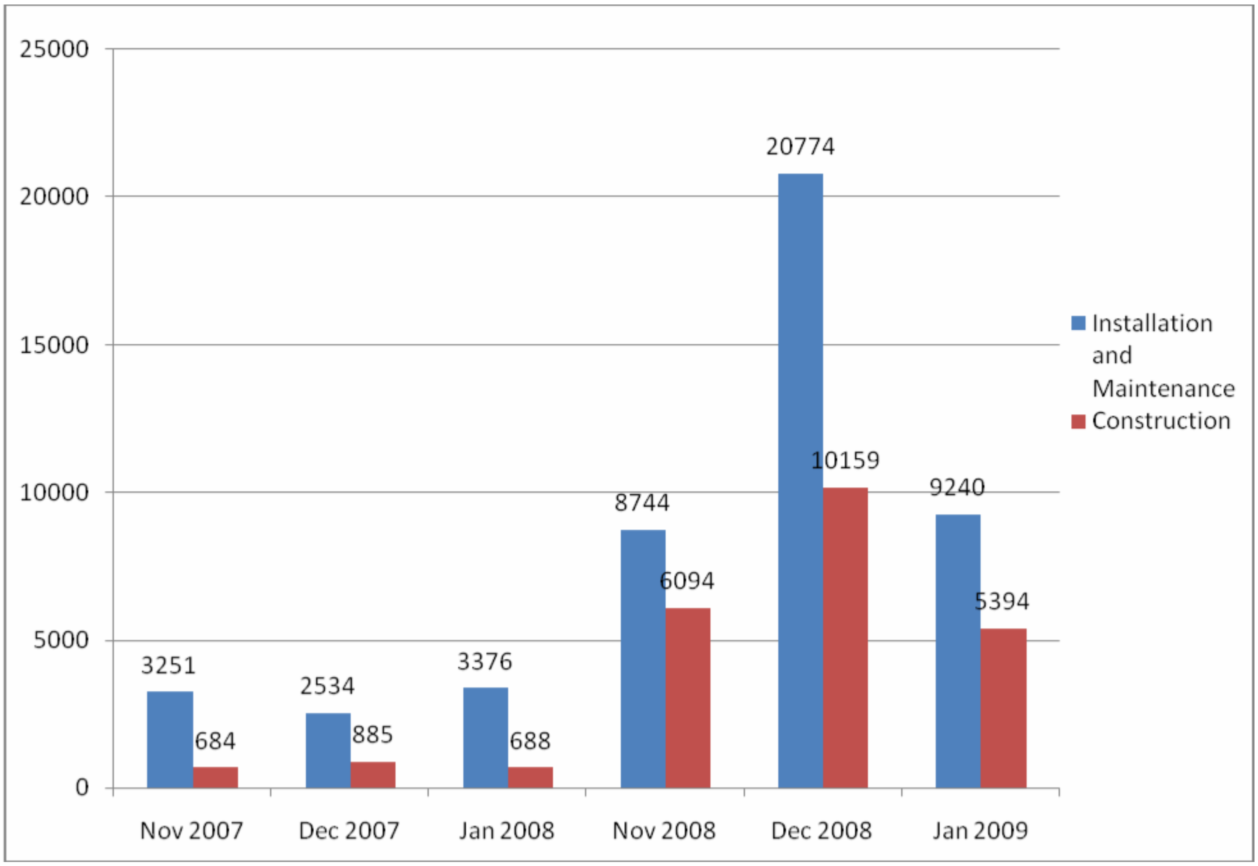

Figure VIII-6 – Technician overtime hours[72] [73]

During December 2007 there were 313 SSTs and 73 construction technicians assigned to New Hampshire. During December 2008 there were 356 SSTs and 65 construction technicians assigned.[74]

[72] FairPoint. (June 5, 2009). Data Response TE0012. NEI.
[73] FairPoint. (June 5, 2009). Data Response TE0013. NEI.
[74] FairPoint. (March 20, 2009). Data Response STAFF 1-19. NHPUC.

Using a 40 hour work week and 4.33 weeks per month, 313 SSTs would have approximately 54,211 base hours in a month. Given the December 2007 overtime hours of 2,534, this equates to an overtime rate of approximately 4.7 percent. Using a similar calculation for December 2008, 356 SSTs would have approximately 61,659 base hours and 20,774 hours of overtime which is an overtime rate of approximately 33.7 percent.

FairPoint's Outside Plant (OSP) Engineering organization in New Hampshire assisted in the restoration by providing nine experienced engineers to help with damage assessment. In total there were 41 employees that assessed the damaged areas. In addition to the engineers, managers from the installation and maintenance department, and construction department were used.[75] The engineering department assisted the restoration effort by making contact with the electric companies when requested by field workers and by placing support personnel in construction centers to expedite engineering work orders (EWOs). They also issued blanket EWOs to cover areas with major damage. In some instances, EWOs were not issued before work was done, and records were updated after technicians had already performed the needed emergency work.

The engineering department maintains an electronic log of poles replaced in their maintenance areas and uses E-mail to notify other users when they can move their pole attachments. This database is used to record pole replacements by the electric utilities and track the progress of work by intermediate attachers. E-mail is also used to notify the electric utilities when FairPoint has completed its work. During the restoration, spreadsheets were used to record storm replacement information and the database was updated to reflect the new status of equipment after restoration was considered complete.[76]

The availability of workers and how they are utilized are important considerations during restoration from a large-scale service disruption. Toward that end, it is useful to compare the number of service orders for new or additional service during the restoration period with the number of orders during non-emergency periods. During November 2008 there were 104 service orders per day. During December 2008 there were 113 per day and for January 2009 there were 112 per day.[77] These months appear nearly equal, even though December was when the major restoration effort was underway. Figure **VIII-5** shows that there were 2.48 average installation jobs worked per eight hour day during December 2008. If there were 113 installation orders worked per day in December and they were worked at a rate of 2.48 installations per eight-hour day, then 45 technician-days, or 360 technician-hours, were required to handle them. While it is never possible to stop all service order work because of emergency orders, it may be seen that for every service order that could have been deferred, 1.32 additional customer trouble reports could have been cleared based on the productivity numbers from Figure VIII-5.

[75] FairPoint. (March 20, 2009). Data Response STAFF 1-29. NHPUC
[76] Laprise, S. Manager-OSP Engineering-NH South, FairPoint. Interview by Satterfield, J. June 16, 2009.
[77] FairPoint. (June 2, 2009). Data Response TE0038.2. NEI.

The impact on overall restoration time caused by working on service orders can be determined by a similar calculation. If no service orders had been worked between Day 3, Saturday, December 13 and Day 21, Wednesday, December 31, then 2,834 additional maintenance jobs could have been done in December after the storm. Assuming 113 installation jobs per day, 19 days, and 1.32 maintenance jobs that could have been worked per installation job, then 113x19x1.32=2,834.

To determine the impact this had on overall restoration time, the number of maintenance jobs done per day must be calculated. Figure VIII-5 shows that it took 3.23 hours for an installation job (8 hours/2.48 installation jobs per eight hour day) and 2.43 hours for a maintenance job (8 hours/3.28 maintenance jobs per eight hour day). There were a total of 3,207 installation jobs during December 2008,[78] which took a total of 10,358 hours (3,207 installation jobs x 3.23 hours per installation job). From Figure VIII-6 it can be determined that the total SST hours worked during December 2008 was 82,433 (61,659 base hours + 20,774 overtime hours). Since 10,358 hours were used for installation jobs, the remaining 72,075 hours (82,433-10,358) would have been used for maintenance jobs. Given the 2.43 hours to complete a maintenance job, approximately 956 maintenance jobs were completed per day on average in December 2008 (72,075 hours/2.43 hours per maintenance job/31 days). By applying the 956 maintenance jobs per day to the 2,834 maintenance jobs that could have been completed if no installation jobs had been worked, the overall restoration time could have been reduced by approximately three days (2,834 maintenance jobs that could have been worked/956 maintenance jobs per day=2.96 days). As noted earlier, it is not possible to stop working on installation jobs entirely, but this analysis gives an indication of the impact to restoration time caused by FairPoint continuing to work on these types of orders.

FairPoint considers that the last customer without service due to the December 2008 ice storm was restored on Day 25, Sunday, January 4, 2009.[79] If FairPoint had decided to stop working on installation jobs completely during storm restoration then the final customer may have been restored to service on Day 22, Thursday, January 1.

The routes carrying umbilicals from the host COs to the remote COs was reviewed. While no remote COs were lost during this storm due to power outage or loss of the host to remote links, the survivability of the umbilicals is essential to the proper functioning of the remote switches. An analysis of the routing for the umbilicals indicates that 74 of the 96 remote COs are currently served via fiber ring technology from their host CO. The remaining offices can only be served via a linear optical path, or folded topology, meaning there is no route diversity. Each of the remote COs not on a fiber ring is currently served using sheath or carrier (equipment) level

[78] FairPoint. (June 2, 2009). Data Response TE0038.2. NEI.
[79] FairPoint. (March 20, 2009). Data Response STAFF 1-28. NHPUC.

diversity or both. [80] FairPoint has extensive procedures in place to ensure that diversity is maintained as rearrangements are made in the outside plant.[81]

Recommendation No. 5: FairPoint should focus on restoring customer service during a large-scale restoration effort.

- FairPoint should divert resources from installation to restoration during a large scale outage. During this restoration, the number of dispatched service orders hardly varied from the preceding and the succeeding months. There were 3,365, 3,207, and 3,253 service orders for new or additional service (installation jobs) for November and December 2008 and January 2009 respectively.[82] It would be expected that during a major restoration the number of installation jobs would be significantly reduced. It would also be expected that the month following the critical restoration period, the number of installation orders would increase significantly as those delayed by the restoration effort would be done. Clearly, this did not happen during the restoration effort from this storm.

Conclusion: FairPoint is effectively preparing for the next major outage.

As the restoration was completed, FairPoint began preparing for the next major event. More portable generators were procured for use at the SLC sites and to provide backup for the CO generators.[83] [84] The operations support systems were upgraded since they will be of major importance for efficient restoration from the next major outage. The systems now in place were not used during December 2008 when the Verizon legacy systems were still being used. All Verizon legacy systems were replaced in January 2009 by newly developed FairPoint systems. These systems, while state of the art, are undergoing refinements to make them even more usable. These upgrades will be important during the next major event when increased volumes of customer calls and trouble reports are expected.[85]

In the NOC, the new collection and display system, NETCOOL, has been updated to include an address table for the remote terminals. This will allow technicians to be more effectively dispatched.[86]

The FairPoint Communications Disaster Response Plan is now completely in place. This plan has been improved since December 2008, but it is still new. Consequently, FairPoint recognizes

[80] FairPoint. (June 29, 2009). Data Response TE0040.6. NEI.
[81] FairPoint. (June 29, 2009). Data Response TE0040.7. NEI.
[82] FairPoint. (June 2, 2009). Data Response TE0038.2. NEI.
[83] Pouliot, D. Director of Operations-Installation and Maintenance and Construction, FairPoint. Interview by Satterfield, J. June 15, 2009.
[84] Aubrey, S. Director-Central Office Operations, FairPoint. Interview by Satterfield, J. June 15, 2009.
[85] Powell, D. Director of Operations, Dispatch Resource Center; FairPoint. Interview by Satterfield, J. June 15, 2009.
[86] Smee, J. Vice President-Network Operations, FairPoint. Interview by Satterfield, J. July 6, 2009.

the need for training, exercises, and mock drills to make the plan effective. Contact lists are a major part of the plan and are updated monthly to ensure they are kept as current as possible.[87]

Conclusion: FairPoint should have conducted bulk testing of customer lines during the restoration effort.

Bulk testing on customer access lines before the customer reports a trouble condition can be done by FairPoint with the type of central office switch commonly used in New Hampshire. The system typically runs at night. It tests the cables chosen and provides an indication of potential trouble conditions. The tests are not totally conclusive because inside wire conditions and portable telephone troubles can also be misidentified as trouble conditions within the telephone company's network. However, the test does provide indications of where major outages may exist and this could be an aid to quicker restoration. Bulk testing was not done during this restoration because of the possibility of false trouble indications being generated.[88]

Recommendation No. 6: FairPoint should use its bulk testing capability during the initial phases of a major outage restoration effort.

- Using bulk testing will provide indications of where major outages are located. Such information will give focus to the early use of the work force. It can also aid in coordination with the electric companies and local authorities as they prioritize their restoration efforts.

Conclusion: Coordination and communication with the electric utilities was inadequate although coordination with local authorities was effective.

Improved communications and coordination between FairPoint and the electric utilities would have allowed FairPoint to respond more quickly during restoration of service. Communications between the FairPoint construction team and the electric utilities were handled at the local levels. Although there were no formal regularly scheduled calls between FairPoint and the electric utilities, there were multiple daily communications between the companies to pass information, prioritize work, and communicate work plans for the following day.[89] However, there were still situations encountered where SSTs were turned away from an area by the electric companies.[88] This resulted in lost time since the telecommunications technicians had to be rerouted and then return at a later date.

Coordination of pole replacements in areas maintained by FairPoint was done through the office of the OSP Engineer. This coordination was effective, as was coordination with local authorities.[90] Coordination with local authorities was handled through the office of the Vice

[87] Mead, K. Senior Vice President-Operations and Engineering, FairPoint. Interview by Satterfield, J. June 16, 2009.
[88] Powell, D. Director of Operations, Dispatch Resource Center; FairPoint. Interview by Satterfield, J. June 15, 2009.
[89] FairPoint. (March 20, 2009). Data Response STAFF 1-25. NHPUC.
[90] Laprise, S. Manager-OSP Engineering-NH South, FairPoint. Interview by Satterfield, J. June 16, 2009.

President of Government Affairs-NH, which was closely involved throughout the restoration effort with the operations managers that were directing technicians and operations personnel. There was little delay in contacting local authorities.[91]

Recommendation No. 7: FairPoint should negotiate to add additional elements of communication and coordination with the electric utilities during storm restoration.

- FairPoint should negotiate with the electric utilities to allow a FairPoint representative to be located in their EOC during any large-scale restoration effort. Following this storm, contacts with the electric utilities were largely done at the local level. If a FairPoint representative were to be located in the EOC, this person could provide FairPoint workers and the DRC with current information about cleared areas. This person could also be the conduit for information flowing from FairPoint to the electric company.
- FairPoint should establish an industry forum for the purpose of creating an internet site that can be utilized to provide current information on restoration efforts. This might include such things as areas cleared of downed power, roads that have become accessible, etc. Since the electric companies are at the forefront of most restoration efforts associated with an event such as the December 2008 ice storm, it would seem logical to coordinate closely with them in keeping the site current. Access by other involved parties, such as telecommunications companies and cable companies, can be as open or as limited as desired. As communications and coordination are improved, restoration time and safety will likewise be improved.

[91] Shea, K. Vice President, Government Affairs-NH, FairPoint. Interview by Satterfield, J. June 15, 2009.

CHAPTER IX

Recommendations, Priorities, and Cost Estimates

Chapter Structure

A. BACKGROUND

This report has developed a number of recommendations designed to help the utilities improve their response to future storm events. This chapter summarizes those recommendations and also includes a chart that rates each recommendation. The ratings are based on the anticipated effectiveness of a recommendation, compared to the costs required for its implementation.

B. COST BENEFIT OVERVIEW

The December 2008 ice storm resulted in approximately $154 million of recordable property damage in the state of New Hampshire. If other economic factors were known such as loss of income, revenue, and profit due to disruptions of electric power, the total economic impact to the state would be much higher.

The CRREL report determined that a storm of the same magnitude as the December 2008 ice storm should be expected to return on average every ten years. In addition, the CRREL report shows a considerable history of ice storms in New Hampshire for over fifty years. The description in the CRREL report [1] of the January 1998 ice storm provides sufficient information to conclude that the January 1998 ice storm was more severe than the December 2008 ice storm. The 1998 ice storm also did more damage to the NHEC system than did the December 2008 ice storm.[2] However, the 1998 storm affected the less populated areas of northern New Hampshire and, therefore, the impact to the electrical infrastructure was not as severe as the December 2008 ice storm. If the 1998 storm had occurred in the same geographical area as the 2008 storm, a much larger amount of damage would undoubtedly have occurred.

An economic analysis can be performed to determine the costs and benefits which can be expected from the recommendations included in this report. Included in this analysis is the probability of another ice storm and the amount of damage that might result. In this analysis it

[1] See Appendix D.
[2] NHEC. (February 19, 2009). Data Response STAFF 1-49. NHPUC.

was assumed that damage from a fifty year return storm would be double that of the ten year storm that occurred in December 2008. Using this assumption and the determination that the current electrical infrastructure is not designed for a fifty year storm, 50% of the damage would be tree related and 50% would occur to the power system infrastructure. While the December 2008 ice storm has a probability of recurrence of one in ten years (0.1), the probability of the fifty year storm is 0.02.

The annual cost for the damage caused by the ten year and fifty year storms determined by the following calculations are assumed to be independent and additive. The annual cost is based on the annual probability of the incident multiplied by the estimated damage as shown in equation IX – 1.

The total damage to the four electric utilities from the December 2008 ice storm is provided in Chapter II, Table II-5 and is approximately \$83.2 million. This amount will be referenced as $Cost_1$, which reflects damage caused mainly by vegetation. $Cost_2$ is then the expected additional cost due to failure of lines, poles, cross arms and other hardware and structures due to ice and wind from a fifty year storm causing forces exceeding the design of the equipment. Equation IX-1 should give the annual cost needed to pay for storm damage due to storms occurring every 10 years that were equal to the December 2008 storm, and storms occurring every 50 years that would cause twice the damage of the December 2008 storm. Equation IX-1 does not include the time value of money.

$$
\begin{aligned}
AC &= P_1 \cdot Cost_1 + P_2 \cdot Cost_2 \qquad \text{Equation IX-1}^{3} \\
&= 0.1 \cdot \$83.2 \text{ million} + 0.02 \cdot \$83.2 \text{ million} \\
&= \$9.984 \text{ million}
\end{aligned}
$$

Where,

AC = Annual Cost

P_1 = Probability of a 10 year storm or 0.10

$Cost_1$ = Damage to the system related to trees

P_2 = Probability of a 50 year storm or 0.02

$Cost_2$ = Damage to the system caused by ice and wind

[3] DeGarmo, E.P., Sullivan, W.G., Bontadelli, J.A. (1984). *Engineering Economy* (8th Edition). New York, NY. MacMillan, pgs 474-476.

Collectively, the four electric utilities should expect an annual cost of $9.984 million due to future ice storms and as a result could spend $9.984 million annually to prevent the damage to their systems expected to occur due to 10 year and 50 year ice storms.

The total annual costs were allocated among the four electric utilities based on the percentage of the total number of meters each utility has, as shown in Table IX-1.

Table IX-1 – Annual cost allocation.

Utility	Allocation to Each Utility	Total Annual Cost for 10 year and 50 year Ice Storms	Vegetation Related Cost	System Infrastructure Related Costs
NHEC	6.93%	$692,000	$577,000	$115,000
National Grid	7.81%	$780,000	$650,000	$130,000
PSNH	73.83%	$7,371,000	$6,142,000	$1,289,000
Unitil	11.43%	$1,141,000	$951,000	$190,000
Totals	100.00%	$9,984,000	$8,320,000	$1,664,000

In addition to the 10 year return and 50 year return ice storms, it would be reasonable to assume that other types of storms and natural disasters would increase the estimated annual cost shown in Table IX-1.

Returning to the results from Equation IX – 1, $8.32 million of the $9.984 million in damage (83.33%) is tree related. The other $1.664 million (16.67%) is system infrastructure related damage. It follows that 83.33% of any investment made by a utility to prevent future storm damage should be directed towards reducing tree related outages, and only 16.67% should be directed toward strengthening the infrastructure of the system. Column four in Table IX-1 shows the vegetation related costs associated with the ice storms and column five shows the system infrastructure related costs expected from ice storms. From this analysis it may be seen that most of the money spent by the utilities to prevent ice storm damage should be spent on vegetation management. This conclusion is consistent with many of the other conclusions and recommendations included in this report.

C. RECOMMENDATIONS, PRIORITIES, AND COSTS

The chart below summarizes the recommendations included in this report. It includes three columns titled: benefit, priority, and cost. The benefit column shows the level of benefit for future storm response that the utilities can expect by implementing the recommendation. The priority column lists the relative importance and effectiveness of the recommendation. The cost column provides a cost range for implementing the recommendation. If the cost for implementing the recommendation is an on-going annual cost, the word “annual” is included with that particular cost range. The specific criteria for each of the rankings are discussed below.

Benefits

The following are the definitions of the benefit levels assigned to each recommendation:

High: The recommendation will provide a significant improvement and is cost effective.

Medium: The recommendation will provide a significant improvement, but may be expensive to implement, or the recommendation would provide a reasonable improvement and is cost effective.

Low: The recommendation will provide a reasonable improvement, but would be expensive to implement.

Priorities

The following are the definitions of the priority levels assigned to each recommendation:

High: Implementation would result in significant improvements that will strengthen the power system, improve restoration times, and improve communications. These recommendations should be implemented as soon as possible.

Medium: Implementation would result in meaningful improvements that will strengthen the power system, improve restoration times, and improve communications. Implementation should begin within 12 months.

Low: Implementation would result in improvements that will strengthen the power system, improve restoration times, and improve communications. Benefits are modest or difficult to measure. Implementation should begin within than next 24 months.

Cost Estimates

The following is a list of the cost estimate levels for each recommendation:

High: Implementation cost is estimated to be greater than $2.5 million.

Medium: Implementation cost is estimated to be greater than $100,000 but less than $2.5 million.

Low: Implementation cost is estimated to be less than $100,000 but greater than $10,000.

Minimal: Implementation cost is estimated at $10,000 or less, or the cost of implementation should be included within the normal cost of conducting business according to good utility practices.

Table IX-2 – Summary of recommendations, priorities, and costs.

Recommendation	Benefit	Priority	Cost
II-1 Unitil should adopt a storm restoration strategy that is based on achieving restoration for the largest number of customers in the least amount of time.	High	High	Minimal
II-2 Each electric utility should improve the systems and processes it uses to develop damage assessments and communicate ETRs to customers during storm restoration efforts.	High	High	Low
II-3 Each electric utility should adopt storm restoration procedures that require the process of procuring additional crews to begin at the first indication of an impending storm and include utilities and contractors beyond the local area.	High	High	Minimal
II-4 Each electric utility should improve procedures for communications with state and municipal government officials and emergency response agencies during major storms.	High	High	Minimal
II-5 Each electric utility should modify emergency planning procedures in order to implement a more effective means of estimating resource requirements.	High	Medium	Minimal
III-1 Each electric utility should include post-storm critiques and lessons learned should be included in their Emergency Operations Plan.	High	High	Minimal
III-2 Each electric utility should include a contingency for coincidental emergencies in their Emergency Operations Plan.	High	Medium	Minimal
III-3 Each electric utility should have its representatives make contact in person with the emergency directors of each of the towns in its service territory to gather information on critical customers within those towns. This should be done within 60 days after the publication of this report.	Medium	High	Minimal

Recommendation	Benefit	Priority	Cost
III-4 Each electric utility should expand its emergency response plans to include procedures for communicating with telephone and cable companies so vital telecommunications can be restored as quickly as possible.	High	Medium	Minimal
III-5 Each electric utility should arrange for security services as part of its emergency plan.	High	Low	Minimal
III-6 Each electric utility should develop a method for collecting and archiving data following emergency events and use this data to develop a predictive damage model for use in future storm planning.	Medium	Medium	Low
III-7 Each electric utility should expand emergency readiness drills beyond the individual companies.	Medium	Medium	Low
III-8 Each electric utility should fully implement the Incident Command System (ICS) concept and Unitil should adopt the IMS as its new structure for emergency management.	Medium	High	Low
III-9 PSNH should dedicate an emergency response area solely for the purpose of managing outage events; Unitil should continue with their plans for a dedicated EOC; NHEC should explore options for building a dedicated EOC or obtaining a mobile command center.	Medium	Medium	Medium
III-10 PSNH should purchase an Outage Management System and deploy the system within 12 months of acquiring and implementing a GIS, and Unitil should continue with its present plans for installing an OMS.	Medium	Medium	High
III-11 Each electric utility should identify and train additional damage assessment personnel and have them activated prior to the storm.	Medium	Medium	Medium

Recommendation	Benefit	Priority	Cost
III-12 Each electric utility should develop a mechanism for quickly assessing global damage and providing restoration times in order to allow customers and government to take prompt appropriate action.	Medium	High	Minimal
III-13 Each electric utility should expand its available resource pool to reach across the boundaries between cooperative and investor owned utilities (IOU), and consider using resources from other sources.	Medium	Medium	Minimal
III-14 Each electric utility should work with the community first responders to develop a process for "batching" wires down calls during a major emergency.	High	Medium	Minimal
III-15 Each electric utility needs to expand its communications program to better educate their customers about the restoration process.	Medium	Medium	Medium
III-16 Each electric utility should better define the methods it uses for communications with government officials during emergencies. .	High	Low	Minimal
III-17 Each electric utility should file their Emergency Operating Plans with the State Homeland Security and Emergency Management Office (state EOC) and work with the state to define thresholds which would trigger communications with the EOC.	High	High	Minimal
IV-1 PSNH should inspect the condition of the static wire on Line 367, compare it with the original design, and present a report to the NHPUC.	Medium	High	Minimal
IV-2 NHEC should upgrade their substation SCADA back-up power systems to provide reliable power for a minimum of eight hours.	Medium	High	Medium
IV-3 Each electric utility should perform a review of distribution loads supplied by sub-transmission lines.	High	High	Minimal

Recommendation	Benefit	Priority	Cost
<u>IV-4</u> Unitil should investigate the failure of the Iron Works Substation transformer and correct any deficiencies on their system that could result in failures in the future.	High	High	Minimal
<u>IV-5</u> Each electric utility should plan on replacing existing electro-mechanical relays with microprocessor based relays that feature event reporting ability.	Medium	Low	High
<u>V-1</u> PSNH should abandon their existing OMS system in favor of a modern fully integrated GIS based system, Unitil should continue on the path they have begun and choose an OMS, and National Grid and NHEC should continue on with their plans for their OMS.	Medium	Medium	High
<u>V-2</u> Each electric utility should include provisions for rapid restoration of communications in their disaster recovery plans.	High	High	Minimal
<u>V-3</u> Each electric utility should ensure that all its poles, including joint use poles, are being properly inspected.	High	High	Med/High
<u>V-4</u> Each electric utility should establish a more comprehensive vegetation management plan.	Medium	High	Medium
<u>V-5</u> State and local governments should extend laws regarding vegetation management for roads and highways to include electric and communication corridors. Utilities should be assisted by local and state government to streamline the property owner permission process.	High	High	Low
<u>V-6</u> Each electric utility should be required to employ at least one system forester or arborist in their New Hampshire service area.	Medium	Medium	Low (Annual)

Recommendation	Benefit	Priority	Cost
V-7 Each electric utility should expand its vegetation management program to include the judicious use of herbicides for stump treatment.	Medium	High	Medium
VI-1 Each electric utility should gather and analyze weather and damage information during and immediately following weather events and develop models to predict damage.	High	Medium	Minimal
VI-2 PSNH should develop a process for responding to the IMS review and future post action reports and should expand the number of participants in its post storm reviews.	High	Medium	Minimal
VI-3 Unitil should include post storm reviews in its Emergency Operations Plans.	High	Medium	Minimal
VI-4 NHEC should make post storm critiques a part of its Emergency Operations Plan.	High	Medium	Minimal

APPENDIX A

List of Terms

Appendix A provides a summary of terms and acronyms used within the report:

ABD	Average Business Day
AC	Alternating Current
AMI	Automated Metering Infrastructure
AMR	Automated Meter Reading
Ampere	A unit of measure for electrical current flow.
ANSI	American National Standards Institute
ASA	Average Speed of Answer
ASCE	American Society of Civil Engineers
ASD	Allowable Stress Design
ASOS	Automated Surface Observing System
AVL	Automatic Vehicle Locator
CAIDI	Customer Average Interruption Duration Index $= \frac{\text{Sum of All Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$
Circuit breaker	A device used to isolate a short circuit or fault on the system.
CCC	Customer Contact Center
CIS	Customer Information System
CO	Central Office

COF	Call Overflow
CRREL	Cold Regions Research Engineering Laboratory
CSA	Customer Service Attendants
CSR	Customer Service Representative
CT	Current Transformer
DA	Distribution Automation
DC	Direct Current
DI	Dispatch In
Dielectric	An insulating material normally placed around a conductor.
Distribution	Voltage levels below 69 kV.
DO	Dispatch Out
DRC	Dispatch Resource Center
DRED	New Hampshire Division of Resources and Economic Development
DTD	Dial Tone Delay
Easement	Right-of-way granted to public utility to run lines on or under private property.
EOC	Emergency Operations Center
ETOR/ETR	Estimated Time of Restoration
EVP	Executive Vice President
EWO	Engineering Work Order

Fault	An abnormal condition on a power system caused by various conditions, such as when: • a conductor makes contact with the ground (ground fault) • two conductors make contact with each other (line-to-line fault) • all three conductors make contact with each other (three-phase fault).
FEMA	Federal Emergency Management Agency
FCR	Fixed Charge Rate
FERC	Federal Energy Regulatory Commission
FSM	Field Service Manager
FSTCC	Field Service Technician Contact Center
Fuse	A protective device, used in an electric circuit, containing a conductor that melts under heat produced by an excess current, thereby opening the circuit.
GIS	Geographic Information Systems
Ground Fault	A system condition where one or more conductors make contact with the earth or ground.
IBC	International Building Code
ICS	Incident Command System or Incident Command Structures
IEEE	Institute of Electrical and Electronics Engineers
in.	Inch
IOU	Investor Owned Utility
Kilo-Volt (kV)	1000 Volts

Kilo-Volt- Ampere (kVA)	1000 Volt – Amperes, a measure of electric capacity based voltage and current.
Level One (State EOC)	Normal Operations. The operations section is staffed and operational daily from 0800 to 1600 hours Monday through Friday. An off-hours duty officer system is available all other times including night, holiday and weekend coverage. The state EOC was at Level One on Day 1, Thursday, December 11, 2008 at 11:00 a.m.
Level Two (State EOC)	A Low Intensity Event. Communications and Information & Planning Sections monitor the event, collect information, and notify appropriate staff. Selected assistance may be required from NHHSEM staff. The state EOC went to Level Two on Day 1, December 11, 2008 at 4:30 p.m.
Level Three (State EOC)	A High Intensity Event. The event requires, or is likely to require, a limited response from the state, or has the potential to result in significant loss of life, property damage, or disruption of vital public safety infrastructure. The EOC is activated, the state Emergency Operations Plan is implemented. Rapid Needs Assessment Teams are alerted for possible mobilization. The state EOC escalated to Level Three at 7:00 a.m. on Day 2, Friday, December 12, 2008.
Level Four (State EOC)	A complex, high intensity event or is likely to occur. The event has all the attributes of Level Three, but is more complex, either because a larger geographic area is affected, or because the potential effects are greater. It is likely to result in a Presidential Disaster Declaration. The state EOC is activated for the duration of the event. The entire NHHSEM staff is placed on standby and selected members report to the EOC. Rapid Needs Assessment Teams (RNATs) are deployed as required (in accordance with the Rapid Needs Assessment Team Plan). The state EOC elevated to Level Four on Day 10, Saturday, December 20, 2008.
LLC	Limited Liability Company
LRFD	Load and Resistance Factor Design

MAIFI	Momentary Average Interruption Frequency Index $= \frac{\text{Total Number of Customer Momentary Outages}}{\text{Total Number of Customers Served}}$
MLT	Mechanized Loop Testing
MPH	Miles Per Hour
National Grid	Granite State Electric d/b/a National Grid
NCDC	National Climatic Data Center
NEC	National Electrical Code
NEMAG	New England Mutual Assistance Group
NEPPA	Northeast Public Power Association
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NG	National Grid, d/b/a Granite State Electric in New Hampshire
NHEC	New Hampshire Electric Cooperative
NHHSEM	New Hampshire Homeland Security and Emergency Management
NHPUC	New Hampshire Public Utilities Commission
NIMS	National Incident Management System
NMOC	Network Monitoring Operations Center
NOC	Network Operations Center

NOC-TR	Network Operations Center – Trouble Resolution
O/H	Overhead
Outage	An electric utility customer without power due to storm damage
OMS	Outage Management System
OSP	Outside Plant
Phase	Major electric circuits consist of three individual circuits, each of which is identified as a "Phase." Such a circuit is called a three phase circuit. However, in residential and small commercial areas, single phase and double phase circuits may exist. These phases often times are referenced by letters or numbers such as "A Phase", "B Phase", and "C Phase", or "Phase 1", "Phase 2". and "Phase 3."
PSA	Public Service Announcement
PSF	Pounds per Square Foot
PSNH	Public Service Company of New Hampshire
PT	Potential Transformer
Recloser	An electric distribution line device with control equipment to sense and trip for abnormal conditions, as well as automatically restore power for momentary faults.
ROW	Right-of-way – area dedicated for placement of utility power lines and equipment. This may include utility, state or municipal right-of-way.
RNAT	Rapid Needs Assessment Teams
RRC	Repair Resolution Center
RSA	Revised Statutes Annotated

RUS	Rural Utility Service
SAIDI	System Average Interruption Duration Index $= \frac{\text{Sum of all Customer Interruption Durations}}{\text{Total Number of Customers Served}}$
SAIFI	System Average Interruption Frequency Index $= \frac{\text{Total number of Customer Interruptions}}{\text{Total Number of Customers Served}}$
SCADA	Supervisory Control and Data Acquisition
Sectionalizer	An electric distribution device that acts like a switch and is used to isolate sections of a distribution or transmission line or system.
Short Circuit	A specific type of system fault that involves two or more conductors coming into contact with each other, thus creating high electrical currents.
SLC	Subscriber Line Carrier
SSH	Saturday, Sunday, & Holiday
SST	Splice Service Technician
Sub-Transmission	The voltage levels that fall outside of the normal transmission criteria level and are used to transfer power to distribution substations. The voltage levels are typically 34.5 kV or 44 kV in New Hampshire.
TCOC	Technical Customer Operations Center
Three Phase Fault	A system condition where all three of the “hot” conductors make contact with each other.
Transmission	Voltage levels 69 kV and above, usually resulting in more rigorous design, operation, and maintenance criteria.

Triplex Service	A three conductor electrical circuit supplying power to an electric customer. The three conductors normally consist of two insulated "hot" wires wrapped around a "bare" neutral wire.
Unitil	Unitil Energy Systems, Inc
UVMP	Utility Vegetation Management Plan
U/G	Underground
Voltage	The electrical pressure on an electric system with the units of volts.
VMP	Vegetation Management Plan
VT	Voltage Transformer
Wire-Zone Border Zone	This is a vegetation management practice on electric ROWs. The "wire-zone" consists of that portion of the ROW immediately under the power line and extends 10 feet on each side. In the wire zone, only grasses, shrubs, and low-growing shrubs are allowed. Low growing shrubs and small trees fill the border zone and extend to the edge of the ROW.

APPENDIX B

Overhead to Underground Conversion

Chapter Structure

A. INTRODUCTION

Over the last decade, major ice storms, wind storms, thunderstorms, and hurricanes have caused billions of dollars of damage to overhead electrical systems across the country. These incidents in turn have affected millions of customers. For example, during a 2002 ice storm, approximately two million or 24% of the 8.5 million residents in North Carolina lost power.[1] Likewise, an estimated 63% of the 1.3 million residents in New Hampshire were without power during the December 2008 ice storm. These are but two examples of incidents that resulted in the consideration of replacing overhead electrical systems with underground ones. With the extensive amount of damage caused by these storms, and the resulting repair and replacement costs, it is only natural to contemplate placing an overhead system underground.

B. OVERHEAD TO UNDERGROUND CONVERSION

There has been a definite trend among utilities across the United States to place new distribution systems underground, especially in residential areas. Many municipalities have passed ordinances requiring this. In turn, property developers and ultimately home owners must pay for the differential costs for placing these systems underground. The main reason for this has been aesthetics, with reliability being of secondary importance. While underground construction can improve reliability by minimizing damage due to high winds, falling trees, and ice and snow storms, it is not immune to all types of damage. For example, damage due to hurricanes, flooding, lightning, earthquakes, rodent, and human damage may be worse for underground

[1] North Carolina Public Utilities Commission. (November 2003). *The Feasibility of Placing Electric Distribution Facilities Underground*.

construction than for overhead construction. It is true, however, that for a storm such as the one that occurred in New Hampshire in December of 2008, any part of the system that was placed underground would have been impervious to the types of damage seen.

To better understand the requirements to convert an overhead distribution line to underground, one needs to understand the construction of both. The overhead distribution line typically uses two or more "bare" conductors (conductors covered with no rubber or plastic insulation). Air, which is a good insulator (dielectric), surrounds the conductor and allows the heat resulting from the electric current flow to easily dissipate into the surrounding atmosphere. This keeps the conductor below the temperature at which it would be damaged. Overhead type construction has been used for many decades. Due to the requirements of the Rural Utility Service, the construction methods are somewhat standardized and are similar in all parts of the United States. For this reason, bare conductors and installation hardware are widely available and relatively cost effective to install. In order to hold the bare conductors in the air, they are attached to wood, steel, or concrete poles at several hundred foot intervals. The conductors are insulated from the pole by being held in place by polymer or porcelain insulators. These can be mounted directly to the pole or on cross arms which are in turn mounted to it. Safety results from the height the conductors are mounted above the ground rather than the presence of rubber insulation on the conductors. Since air is used as the insulator, continuous rubber insulation on the conductor is not necessary. The result is that this type of construction is very cost efficient and highly durable. Figure B-1 illustrates a typical type of overhead distribution line construction.

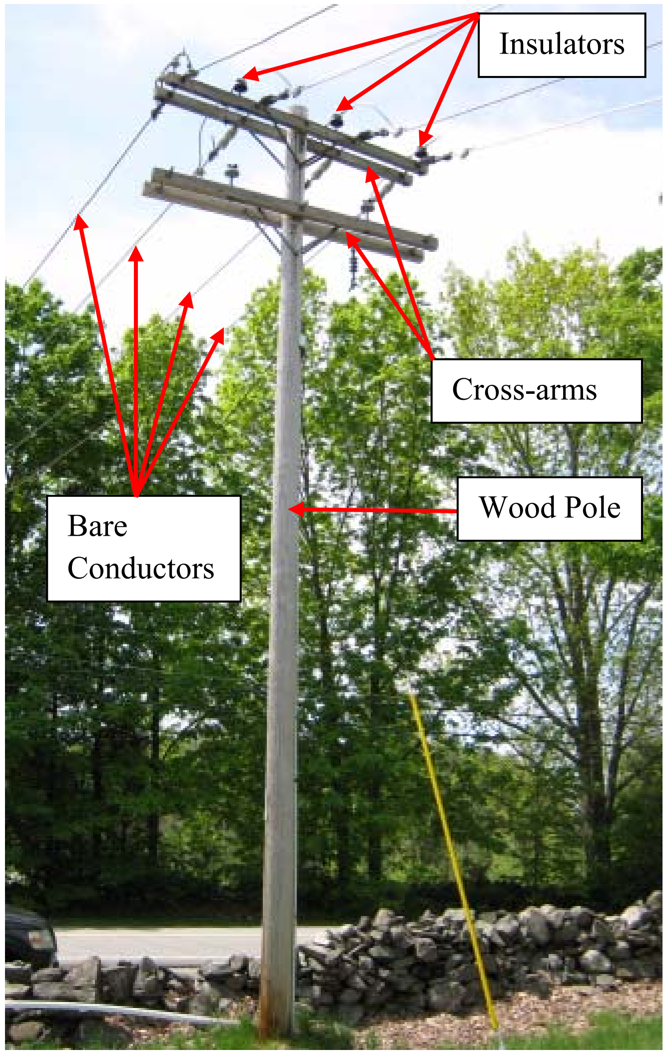

Figure B-1-Typical distribution line bare consisting of conductors attached to insulators mounted on a cross-arm attached to a wooden distribution pole. (Photo by NEI-Location Unknown)

Placing an electrical conductor underground is a much more complex and costly undertaking. First of all, an un-insulated bare conductor cannot be placed underground. While overhead conductors are placed many feet apart from each other and located high above the ground, underground conductors are placed very close together and within a few inches of surrounding earth. It is common in some areas to directly bury conductors. In direct burial, a narrow trench is dug, sometimes only large enough to place the conductor in, and soil is placed directly around it. A direct bury installation is shown in Figure B-2.

Figure B-2-Installing direct buried cable. (Photo courtesy of Southwire)

Another common construction is to bury a pipe (conduit) in the earth and install the electrical conductors inside this pipe. The pipe provides some protection for the conductors and makes future replacement easier than would be possible with the direct burial method. In both cases, since the conductor may be directly in contact with the earth, or directly in contact with a pipe, it cannot be merely a bare conductor (as in the case of overhead conductors). It must instead be covered in some type of insulation. The metal conductor and the various layers of insulation and shields which are necessary constitute an electrical cable. In the case of direct buried cable, the central metal current carrying part of the underground cable may be only an inch or so (the thickness of the insulation) away from surrounding earth. In the case of cables installed in pipe, the metal part of the conductor may only be a slightly further from surrounding earth (the additional distance caused by the thickness of the pipe wall). A typical installation of underground cable in conduit is shown in Figure B-3.

Figure B-3 – Typical underground conduit and cable. (Photo by NEI)

These differences between overhead and underground construction mean that the electrical quantity of capacitance may be up to 75 times higher for an underground line than it will be for an equivalent overhead line. Higher capacitance has the effect of limiting the practical length of a power line. Since capacitance is relatively low for an overhead line, it has little effect on how long the line may be. The higher capacitance of the underground line, however, severely limits its length. Due to the lack of devices capable of switching the capacitive current, the line capacitance limits the length to approximately 15 miles for a typical 35kV underground line. For a 345kV line, the absolute length limit is 26 miles at which point the capacitive current flowing exceeds the current carrying capacity of a typical cable. Currently no 345kV line in the world is longer than 20 miles.

At lower voltages there are other constraints that limit line length more than capacitance. For that reason, typical voltages for an underground distribution line may be in the 7,000 to 15,000 volt range. The conductors must be designed to handle these voltage levels and all of the problems associated with the long term use of the cable. A typical overhead line life is considered to be approximately 50 years. In contrast, underground cable life is usually considered to be 30-40 years.[2] The installation conditions greatly affect an underground cable's life. Variations in ambient temperature, loading, and soil moisture conditions all affect the life of an underground cable. A typical underground cable is shown in Figure B-4. Note all of the components of the underground cable namely:

- The electrical current carrying conductor in the center.
- A conductor shield surrounding the conductor.
- The electrical insulating material.
- A semi-conducting material (semicon) surrounding the insulation to uniformly distribute the electric charge.
- Concentric wires which are typically used for the neutral or return circuit.
- An outer jacket used to protect the concentric neutral and cable.

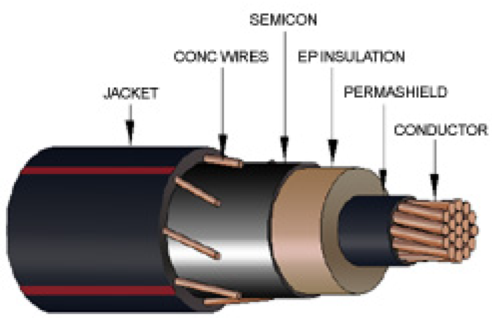

Figure B-4: Typical Underground Distribution Cable. (Courtesy of Kerite)

This complex and relatively expensive cable must then be placed underground. Figure B-5 shows the construction of an underground distribution line in a new residential area where construction in previously undisturbed ground is relatively simple. Typical underground construction involves the following:

- Excavating a trench that is approximately four feet deep and wide enough for the electric power cables
- Installing the cables in plastic (PVC) or steel conduit, which can make future replacement easier than if the cable is direct buried without conduit
- Properly spacing the conduits so heat generated by the cables can be dissipated.
- Carefully backfilling the trench around the conduits with clean, rock free dirt, sand, or concrete
- Placing the top layer of soil, grass, asphalt or concrete

[2]Rudasill, C.L. and Ward, D. J. (July 1997). "Distribution Underground Cable Evaluation." *IEEE Transactions on Power Delivery*. Vol. 12,No. 3.

Figure B-5 - Conduit and Trench for Underground Distribution
(Photo by NEI-Grand Prairie, Alberta)

Pulling electric power cables into underground conduits requires special equipment. In addition, the length of cable that can be pulled is limited to runs typically less than 1,000 feet. Therefore, above grade switching cabinets or below grade man-holes are required at least every 1,000 feet for access to the power cables during installation and future maintenance.

The fact that the underground cable is hidden from sight and difficult to access makes it more difficult to replace than overhead power lines. While the number of outages due to the distribution system may be far fewer with underground than with overhead lines, the duration of an outage will be far longer with underground systems. If cable damage occurs underground, special equipment and training is needed for linemen to locate the problem. In contrast, the same type of problem may be located in a few minutes by a lineman doing a physical inspection of an overhead line. After the damage in the underground line is located, it may take many hours or days to dig up the line to expose the cables for splicing, or remove the existing damaged cable to replace it with a new one. Alternatively, with an overhead line, the problem may be repaired in a relatively short period of time since all the conductors and hardware are above ground and easily accessible.

If special design techniques are not used, simply placing a line underground may result in more outage time for the customers than would be experienced if the line were overhead. It may take up to 10 times longer to repair a problem on an underground line than it would on an overhead line. To help resolve this issue, two techniques are commonly used. The first is to install an additional empty conduit next to each line. This allows new cable to be pulled into the spare conduit and connected to restore power to the customer. Afterwards, the old damaged cable is removed from the original conduit. Since this process may still take many hours, the second technique, referred to as a looped system, is often used to minimize outage time for customers fed by an underground system.

Most overhead distribution systems in the United States are radial systems and operate at 12.47kV[3]. A typical radial distribution system shown in Figure B-6 has only one path for current to flow from the source to the customer. If a line is disabled, the resulting outage for all of the customers on that line may persist until the line is replaced. This may take considerable time.

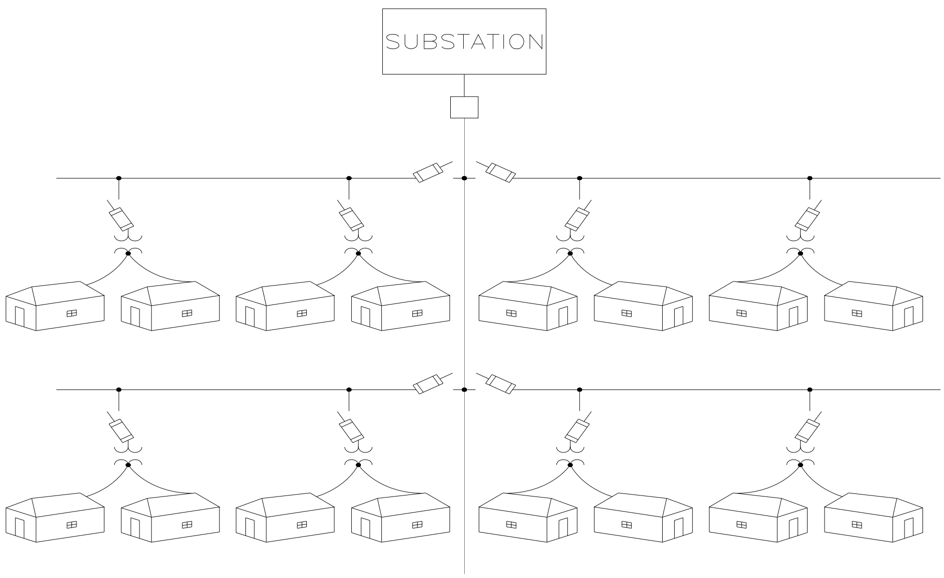

Figure B-6 - Typical radial distribution system.

To expedite power restoration to customers when an underground system is installed, a looped system, rather than a radial system, should be installed. There are several types of looped systems which may be used. One possible type is shown in Figure B-7. With this type of system, power can flow from the source to any customer using either of two different routes. The route used can be changed by opening and closing switches throughout the system. In the event an underground cable fails, linemen can quickly reconfigure the switches in the system to restore power to all customers. Afterward, the linemen can replace the damaged cables without interrupting power to any of the customers, which makes the longer repair time less important.

[3] Willis, H.L. (2004). *Power Distribution Planning Reference Book*, 2nd Edition. Marcel Dekker, New York, NY.

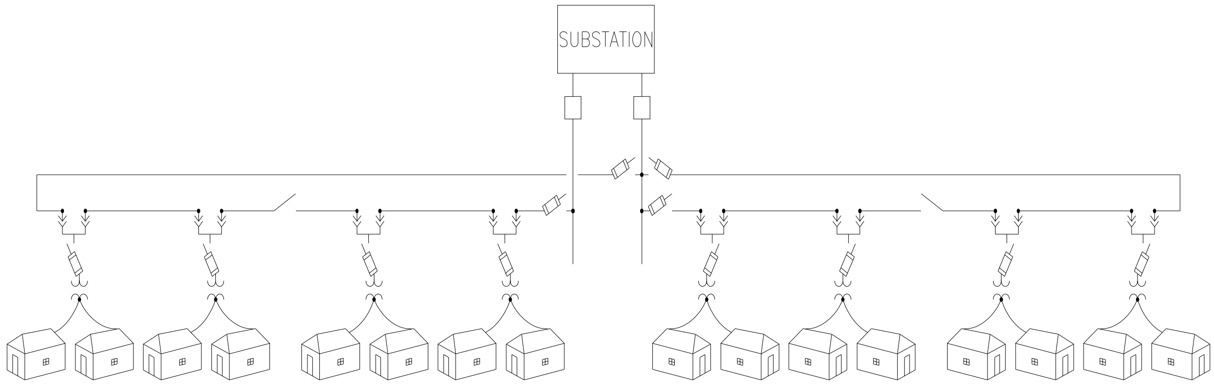

Figure B-7-Looped distribution system.

If an underground distribution system is installed for the sole purpose of reducing outage times, a looped distribution system is necessary. From a reliability standpoint it makes little sense to install underground distribution if a radial system must be used, since it may in actuality increase rather than decrease total outage times.

The placement of a new underground distribution line in a new area is more expensive than installing an overhead line, but is a relatively simple and cost effective process compared to that of moving an existing overhead line underground. If this is planned, several other factors must also be addressed, including:

- Placing lines underground means the utility must obtain new easements from customers and must receive indemnifications for any incidental damage that may occur during the placement of underground lines such as damage to trees.
- The utility will also have some restoration costs for customer property, and these costs may vary greatly from one customer to another.
- Soil conditions can severely impact costs. The shallow level of rock which exists in some areas of New Hampshire may increase the costs of underground construction.
- Overhead lines may have considerable life left and may not need to be replaced for decades.
- While there are many different methods that have been used to fund an overhead to underground conversion, one of the methods is simply incorporating the costs into electrical rates. If this alternative is chosen, the increased cost of underground construction may greatly increase the electrical rates of the customers involved. Some sources predict it could increase rates by 110-150%.[4] [5] [6]

[4] Florida Public Service Commission. (March 2005). *Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida*.
[5] North Carolina Public Utilities Commission. (November 2003). *The Feasibility of Placing Electric Distribution Facilities Underground*.

According to data supplied by the New Hampshire utilities,[7] [8] [9] [10] in good soil conditions, the cost of a 34.5 kV line may be in the range of $2,000,000 per mile. If built in granite, that cost could increase by another $500,000 per mile. The cost of an underground distribution line may vary greatly depending on:

- Soil conditions
- Urban versus rural
- Three phase versus single phase
- Cable in conduit versus direct buried
- Concurrent construction with other underground utilities and road work
- Main feeder construction versus lateral construction
- Type of equipment required.

Some utilities have reported construction as low as $200,000 per mile for some single-phase lines.[11] However, the four New Hampshire utilities have provided numbers ranging from as low as $500,000 per mile to $3 million per mile. Under the best conditions, such as no adverse soil or installation problems, the work can be coordinated with the work of other city departments (e.g., road construction), right-of-ways are easily obtainable, and restoration of customer's property is minimal, the average cost per customer in any of the published reports amounts to $3,000. A rough cost calculated by some of the data provided by the New Hampshire electric utilities places that figure in excess of $40,000 per customer. A $3,000 investment using a 15% fixed charge rate would increase the average electric bill by $450 per year or $37.50 per month. On the other hand, the $40,000 figure would increase the average cost by $6,000 per year or $500 per month.

Due to the increased cost and complexity of retrofitting an overhead system to become an underground system, it is less reasonable to consider underground construction in an existing situation. While in all likelihood the cost of placing electrical systems underground will be more expensive than installing them overhead, even in new construction, the differential costs between overhead and underground construction are modest enough that they may be acceptable. The same justification may not apply to installing the system in an established area since the difficulty and differential costs will be much greater.

One other issue that should be discussed is that of timing. To convert the entire electric overhead system in the State of New Hampshire to underground could easily take over 40 years to

[6] Infrasource Technology. (February 28, 2007). *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion, for Florida Electric Utilities*.
[7] PSNH. (June 3, 2009). Data Response GN0001. NEI.
[8] Unitil. (May 27, 2009). Data Response GN0001. NEI.
[9] National Grid. (May 29, 2009). Data Response GN0001.NEI.
[10] NHEC. (June 4, 2009). Data Response GN0001.NEI.
[11] City of Fort Collins. (April 28, 2009). Colorado Municipal Utility Conversion from Overhead to Underground, Presentation for the IEEE Rural Electric Power Conference.

accomplish. Considering delays that could come due to permitting, weather, and easement acquisition, the construction time could equal the average cable life of 50 years. This would mean that as soon as all the cable was replaced the project of replacing aged cable would begin. So construction or maintenance on the underground system would become perpetual.

C. UTILITY COST SUMMARY[12]

Table B-1 is a summary of data that was provided by each of the four electric utilities. The data requested from each utility were identical; however, the responses from some of the utilities were not consistent due to the fact that some data was not available due to record keeping and accounting practices. In order to provide more accurate data, the utility may have been required to take a large amount of time and cost to obtain that information. Therefore, in order to provide some continuity of data from one utility to another, assumptions were made by NEI in order to complete the values needed for analysis. Each utility was given the opportunity to review the data and changes were made where requested.

The intent of this data was not to develop detailed cost estimates for the conversion of overhead to underground. Such an effort to provide detailed costs would take a considerable amount of time and money. The results from the data in Table B-1 provide a “ball park” estimate based on numbers independently obtained from each utility. These numbers are used in the main body of the report that discusses the costs of overhead to underground conversion of the electric distribution system. As discussed in the main body of the report, the transmission system was not adversely impacted by the December 2008 ice storm. That fact. along with the major technical and economic issues involved in converting the transmission system from overhead to underground, lead to the conclusion that the costs associated with placing the overhead transmission system to underground was not deemed worthy of further analysis.

Table B-1 provides the following high-level cost estimates for placing the overhead distribution system to underground:

- The first row of the table covers the installation of the underground electric system for each utility. Included in these costs are the conversions of each electrical substation for an underground versus overhead exit along with the cost for the underground sub-transmission line or distribution line.
- The second row of the table covers the cost of removing the overhead sub-transmission line or distribution line along with the present value of the overhead line. It should be noted that the existing overhead system throughout the State of New Hampshire is in relatively good condition and is designed for a perpetual life with proper maintenance.

[12] All costs discussed in this section are expressed in 2008 dollars, unless otherwise noted.

- The third row of the table covers the costs of converting overhead electric services from the distribution lines to each customer. Included in these costs would be the excavation from the new underground distribution system through each customer's property to the respective meter. In all likelihood, many customers would be required to personally hire an electrician to perform part of this work.
- The fourth row of the table provides the estimated cost per utility for the conversion of the overhead sub-transmission and distribution system. The estimated range in costs is $1.4 billion for National Grid on the low end to $33.6 billion for PSNH on the high end. The total for all four utilities is $43 billion.
- The fifth row lists the approximate number of customers for each utility.
- The sixth row is a high-level cost estimate per customer for the conversion of the distribution system from overhead to underground.
- The seventh row is a high-level cost estimate for the monthly increase of electricity costs based on each utility recovering the investment and replacement of the system in perpetuity using a simple fixed charge rate[13] of 15%.[14] [15]

The interesting fact is that the average cost per customer was in a similar range.

[13] Fixed Charge Rate is a term used by an electric utility to determine the annual, perpetual cost of an investment that needs to be recovered and includes such things as depreciation, rate of return, taxes and insurance. For example, a 15% fixed charge on a $1000 investment means that an electric utility would need to recover in rates $150 per year or $12.50 per month.
[14] Fixed Charge Rate (FCR) of 15% is chosen with the following formula ($FCR=d/[1-(1+d)^{-N}]$) where 'd' is the discount rate and 'N' is the number of years of payment. We assume d=0.15 from Figure 12.7 (Anders, George J.; Rating of Electric Power Cables; Page 358; 1997.). We assume N=40 for a safe period of payments based on the average lifespan of an underground cable system .
[15] Lai, Loi Lei. (2001). *Power System Restructuring and Deregulation*, 3rd Edition. John Wiley and Sons. New York, NY. Page 299.

Table B-1 – New Hampshire electric utility high level overhead to underground cost summary.

	NG	NHEC	PSNH	Unitil
U/G Distribution Costs - Lines and Subs (millions)	$1,288	$3,845	$29,946	$1,664
Overhead Removal Costs (millions)	$55	$364	$305	$627
U/G Service Costs (millions)	$90	$903	$3,360	$562
Total Cost (millions)	$1,430	$5,110	$33,610	$2,850
Number of Customers	41,156	70,422	492,000	41,264
Average Cost Per Customer	$34,746	$72,563	$68,313	$69,140
Average monthly electric bill increase[16]	$434/mo	$907/mo	$854/mo	$864/mo

National Grid[17] [18] [19] [20] [21] [22]

The National Grid responses for overhead to underground conversion data are shown in Table B-2, Table B-3, and

Table B-4. Their assumptions and comments included:

- No overhead removal costs were provided. Therefore, the removal costs provided by PSNH were used for the cost of removal.
- A $38 million net value was provided for overhead assets. The $38 million stranded costs were included as part of the cost of removal.
- No mileage breakdown was provided to rural versus urban areas, therefore the following assumptions were used:

[16] Repayment period of 40 years.
[17] National Grid. (May 29, 2009). Data Response GN0001.NEI.
[18] National Grid. (May 29, 2009). Data Response GN0002.NEI.
[19] National Grid. (May 29, 2009). Data Response GN0003.NEI.
[20] National Grid. (May 29, 2009). Data Response GN0004.NEI.
[21] National Grid. (May 29, 2009). Data Response GN0005.NEI.
[22] National Grid. (May 29, 2009). Data Response GN0006.NEI.

- 23 kV – Urban 20% and rural 80% of the 9.7 miles
- 15 kV – 10% 3-Phase Urban, 40% 3 Phase rural, 10% 1 or 2 Phase urban and 40% 1 or 2 phase rural.

Table B-2 – Cost of Overhead to underground conversion-National Grid.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
23 kV Sub Trans	9.7[3]	$2,800,000[1]	$5.432
		$1,800,000[2]	$13.968
15 kV			
	833[4]	$2,800,000[1]	$233.24
		$1,800,000[2]	$599.78
1 & 2 Phase		$1,000,000[1]	$83.30
		$750,000[2]	$249.90
Subtotal Lines	**342.7**		**$1,285.62**
Substation Modifications	**Qty**	**Cost Per Unit**	
23 kV Sub Trans	34	$50,000	$1.70
15 kV Dist	21	$50,000	$1.05
Subtotal Subs	**55**		**$2.75**
Total Subs & Lines			**$1,288.37**

[1] Urban [2] Rural
[3] Assume 23 kV: 20% Urban and 80% Rural
[4] Assume 15 kV: 10% – 3φ Urban, 40% 3φ Rural, 10% ½ φ Urban, 40% ½ φ Rural

Table B-3 - Stranded cost and cost of removing overhead electric distribution-National Grid.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
23 kV –Sub Trans	9.7[3]	$30,000[1] $26,000[2]	$0.058 $0.202
15 kV	833[4]	$30,000[1] $26,000[2]	$2.499 $8.663
1 & 2 Phase		$15,000[1] $13,000[2]	$1.250 $4.332
Distribution Stranded Cost			$38.00*
Total	**842.7**		**$55.004**
[1] Urban [2] Rural [3] Assume 23 kV: 20% Urban and 80% Rural [4] Assume 15 kV: 10% – 3φ Urban, 40% 3φ Rural, 10% ½ φ Urban, 40% ½ φ Rural National Grid did not provide removal costs. Therefore, PSNH Estimates were used			

Table B-4 - Cost of underground service to the customer- National Grid.

Type of Service	No of Services	Cost of U/G Service	Total Cost (millions)
3 Phase Commercial	16,000[1,3] 7,600[2,3]	$15,000 $15,000	$48.00 $22.80
120/240 Volt Commercial And Residential	16,000[1,3] 7,600[2,3]	$1,000 $1,000	$12.80 $6.08
Totals	**70,422**		**$89.68**
[1] Urban [2] Rural [3] Assume: 20% Commercial and 80% Residential			

NHEC[23] [24] [25] [26] [27] [28]

The NHEC responses for overhead to underground conversion data are shown in Table B-5,

[23] NHEC. (June 4, 2009). Data Response GN0001..NEI.
[24] NHEC. (June 4, 2009). Data Response GN0002 .NEI.
[25] NHEC. (June 4, 2009). Data Response GN0003. NEI.
[26] NHEC. (June 4, 2009). Data Response GN0004 .NEI.
[27] NHEC. (June 4, 2009). Data Response GN0005. NEI.
[28] NHEC. (June 4, 2009). Data Response GN0006. NEI.

Table B-6, and Table B-7. The NHEC data was complete and no additional assumptions were required.

Table B-5 - Cost of Overhead to underground conversion-NHEC.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
34.5 kV – Sub Trans	5[1]	$1,433,000	$7.165
	36[2]	$992,000	$35.712
15 kV			
	65[1]	$2,876,000	$186.940
	584[2]	$1,776,000	$1,037.184
1 & 2 Phase			
	277[1]	$1,148,000	$317.996
	2,491[2]	$904,000	$2,251.864
Subtotal Lines	**3,458**		**$3,836.861**
Substation Modifications	**Qty**	**Cost Per Unit**	
34.5 kV Sub-Trans	34	$88,000	$2.992
15 kV Dist	75	$71,000	$5.325
Subtotal Lines	**109**		**$8.317**
Total Lines and Subs			**$3,845.178**
[1] Urban [2] Rural			

Table B-6 - Stranded cost and cost of removing overhead electric distribution-NHEC.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
34.5 kV – Sub Trans	5	$100,000[1]	$0.50
	36	$100,000[2]	$3.60
15 kV			
	65	$115,000[1]	$7.475
	584	$125,000[2]	$73.00
1 & 2 Phase			
	277	$110,000[1]	$30.47
	2,491	$100,000[2]	$249.10
Total	**3,458**		**$364.145**
[1] Urban [2] Rural			

Table B-7 - Cost of underground service to the customer- NHEC.

Type of Service	No of Services	Cost of U/G Service	Total Cost (millions)
3 Phase Commercial	822[1]	$32,000	$26.304
	1,823[2]	$28,000	$51.044
120/240 Volt Commercial And Residential	4,230[1]	$15,000	$63.45
	63,547[2]	$12,000	$762.564
Totals	**70,422**		**$903.362**
[1] Urban [2] Rural			

PSNH[29] [30] [31] [32] [33] [34]

The PSHN responses for overhead to underground conversion data are shown in tables Table B-8, Table B-9, and Table B-10. Their assumptions and comments included:

- No line lengths were provided, therefore the numbers in the tables have been assumed.

[29] PSNH. (June 3, 2009). Data Response GN0001. NEI.
[30] PSNH. (June 3, 2009). Data Response GN0002. NEI.
[31] PSNH. (June 3, 2009). Data Response GN0003. NEI.
[32] PSNH. (June 3, 2009). Data Response GN0004. NEI.
[33] PSNH. (June 3, 2009). Data Response GN0005. NEI.
[34] PSNH. (June 3, 2009). Data Response GN0006. NEI.

- The following percentages were used for calculating underground construction distances: 15 kV – 10% 3 Phase Urban, 40% 3 Phase rural, 10% 1 or 2 Phase urban and 40% 1 or 2 phase rural.
- The number of overhead customers that exist was not provided. With 492,000 meters, it was assumed that 400,000 were overhead services.
- With regard to new services for undergrounding, the following assumptions were made: 70% Urban and 30% rural; and 10% Commercial and 90% residential

Table B-8 - Cost of Overhead to underground conversion-PSNH.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
34.5 Sub-Trans[3]	814	$4,000,000	$3,256.00
34.5 Sub-Trans[4]	302	$2,000,000	$604.00
34.5 Dist	3,919	$2,000,000	$7,838.00
15 kV Dist	7,698[5]	$3,000,000[1]	$2,309.40
		$1,500,000[2]	$4,618.80
15 kV 1 & 2 Phase		$1,000,000[1]	$769.80
		$500,000[2]	$1,539.60
Subtotal Lines	**12,733**		**$29,935.60**
Substation Mods	**Qty**	**Cost Per Unit**	
34.5 kV	186	$30,000	$5.58
15 kV	164	$30,000	$4.92
Subtotal Sub	**350**		**$10.50**
Total Lines and Subs			**$29,946.10**

[1] Urban [2] Rural [3] On ROW [4] Along Street
[5] Assume 15 kV: 10% – 3φ Urban, 40% 3φ Rural, 10% ½ φ Urban, 40% ½ φ Rural

Table B-9 - Stranded cost and cost of removing overhead electric distribution-PSNH.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
34.5 Sub-Trans[3]	814	$30,000	$24.42
34.5 Sub-Trans[4]	302	$26,000	$7.85
34.5 Dist	3,919	$30,000	$117.57
15 kV Dist	7,698[5]	$30,000[1]	$23.094
		$26,000[2]	$80.059
15 kV		$15,000[1]	$11.547
1 & 2 Phase		$13,000[2]	$40.30
Total	**12,733**		**$304.84**

[1] Urban [2] Rural [3] On ROW [4] Along Street
[5] Assume 15 kV: 10% – 3φ Urban, 40% 3φ Rural, 10% ½ φ Urban, 40% ½ φ Rural

Table B-10 - Cost of underground service to the customer- PSNH.

Type of Service	No of Services[1]	Cost of U/G Service	Total Cost (millions)
3 Phase Commercial	28,000[2]	$30,000	$840.00
	12,000[3]	$30,000	$360.00
120/240 Volt Commercial And Residential	324,000[2]	$5,000	$1620.00
	36,000[3]	$15,000	$540.00
Totals	**400,000**		**$3.360**

[1] Assuming 400,000 O/H Services out of 492,000 meters, 70% Urban and 30% rural; and 10% Commercial and 90% residential
[2]Urban [3]Rural

Unitil[35] [36] [37] [38] [39] [40]

The Unitil responses for overhead to underground conversion data are shown in Table B-11, Table B-12, and Table B-13. The Unitil data was complete and no additional assumptions were required.

Table B-11 - Cost of Overhead to underground conversion-Unitil.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
35 kV – Sub Trans	22[1] 88[2]	$2,500,000 $2,000,000	$55.00 $178.00
15 kV **3 Phase**	105[1] 420[2]	$3,000,000 $2,200,000	$315.00 $924.00
15 kV **1/2 Phase**	150[1] 400[2]	$500,000 $250,000	$75.00 $100.00
Subtotal Lines	**1,235**		**$1,647.00**
Substation Mods	**Qty**	**Cost Per Unit**	
34.5 kV **15 kV**	65 105	$100,000 $100,00	$6.50 $10.50
Sub Total Subs	**170**		**$17.00**
Total Subs & Lines			**$1,664.00**
[1] Urban [2] Rural			

[35] Unitil (May 27, 2009).Data Response GN0001. NEI.
[36] Unitil (May 27, 2009).Data Response GN0002. NEI.
[37] Unitil (May 27, 2009).Data Response GN0003. NEI.
[38] Unitil (May 27, 2009).Data Response GN0004. NEI.
[39] Unitil (May 27, 2009).Data Response GN0005. NEI.
[40] Unitil (May 27, 2009).Data Response GN0006. NEI.

Table B-12 - Stranded cost and cost of removing overhead electric distribution-Unitil.

Distribution Voltage Level	Miles of Distribution	Cost Per Mile	Total Cost (millions)
35 kV – Sub Trans	22[1] 88[2]	\$350,000 \$350,000	\$7.70 \$30.80
15 kV 3 Phase	105[1] 420[2]	\$650,000 \$650,000	\$68.25 \$273.00
15 kV 1/2 Phase	150[1] 400[2]	\$450,000 \$450,000	\$67.50 \$180.00
Total	**1,235**		**\$627.25**
[1] Urban [2] Rural			

Table B-13 - Cost of underground service to the customer- Unitil.

Type of Service	No of Services	Cost of U/G Service	Total Cost (millions)
3 Phase Commercial	2,160[1] 1,475[2]	\$22,080 \$25,275	\$47.692 \$37.281
120/240 Volt Commercial And Residential	33,920[1] 3,691[2]	\$12,550 \$13,780	\$425.696 \$50.862
Totals	**41,246**		**\$561.531**
[1]Urban [2]Rural			

APPENDIX C

New Hampshire Revised Statutes Pertaining to Vegetation

Chapter Structure

A. INTRODUCTION

The delivery of electricity over power lines is an extremely important aspect of modern day life. Two options for reducing power system outages in future storms similar to the December 2008 Ice Storm:

- Placement of the power lines underground
- Better control of vegetation management

Appendix C shows the revised statutes in New Hampshire that pertain to vegetation. Most of these statutes apply to roads, but do not apply directly to the electric utility industry. However, after the December 2008 ice storm the New Hampshire legislature took the responsibility to see that additional rights are extended to electric utilities by amending RSA 231:145 and RSA 231: 172. These amendments were passed on July 16, 2009 and enacted on September 14, 2009.

B. SUMMARY OF VEGETATION MANAGEMENT RELATED LAWS

RSA 231-139 Tree Wardens

- The selectmen or other citizens of any town may nominate for appointment by the director, division of forest and lands, department of resources and economic development, as town tree warden one or more persons by them known to be interested in planting, pruning and preservation of shade and ornamental trees and shrubs in public ways, parks and grounds. After investigation the director may choose and appoint from the persons recommended as above prescribed one competent person to be the tree warden for said town who shall serve for one year or until a successor is appointed as hereinbefore provided. The director shall have the power in the exercise of his discretion to remove any tree warden from office. It shall be the business of the tree warden to perform the duties hereinafter specified and he shall be allowed such compensation for services and expenses as the selectmen may deem reasonable.

RSA 231-140 Control of Trees

- Towns shall have control of all shade or ornamental trees situated within the limits of their highways which have been or may be acquired by gift or purchase, or planting by or with the advice of the tree warden, or by condemnation by the tree warden.

RSA 231:141 Acquisition of Trees

- It shall be the duty of the tree warden to examine the trees growing within the limits of highways and to designate from time to time such as may be reasonably necessary for the purpose of shade or ornamentation and to acquire them in the name of the municipality as hereinafter provided, if it can be done, either by gift or by purchase if at a fair price and funds either public or private are available. Failing in this, he may take said trees, including the right to maintain the same as shade trees, for the use of the town or city by appraising the fair value of the same and by causing to be served upon the owner thereof a notice of such taking, which notice shall state the number of each variety of tree so taken, the location of the same as near as practicable, and the value thereof as fixed by him, or by a committee selected for the purpose, and also by filing a copy of such notice as attested by him with the town clerk. If the owner shall be satisfied with the value stated in such notice, the tree warden shall cause the same to be paid to him forthwith. If the owner shall be dissatisfied, he may, within 30 days after said notice has been served upon him, but not afterwards, apply to the selectmen to assess his damages. Such proceedings shall thereupon be had, including the right of appeal, as are provided in the case of assessment of damages in laying out of highways by selectmen; and thereupon such damages, if any, may be awarded as shall be legally and justly due to the landowner.

RSA 231:142 Marking of Trees Acquired

- The trees so acquired shall be marked for identification in such manner as the state forestry commission shall approve. The tree warden shall keep a record of such trees, such record to show the approximate location, name of abutting landowner, variety and approximate diameter and date of acquisition. The tree warden or his authorized agent shall represent the interest of the public at any hearing whenever a public service corporation shall desire to cut or remove any shade or ornamental tree in accordance with RSA 231:172, or may have caused damage to such trees.

RSA 231:143 Appropriation

- Such sums of money as the town may appropriate, or as are available, may be used to carry out the provisions of RSA 231:139-142.

RSA 231:144 Removal of Trees

- Whoever desires the cutting and removal in whole or in part of any public shade or ornamental tree may apply to the tree warden, who shall give a public hearing, upon the application, at some suitable time and place, after publishing and posting notices of the hearing in 2 or more public places in town and also upon the tree or trees which it is desired to cut and remove; provided, that the tree warden may, if he deems it expedient, grant permission for such cutting or removal, without a hearing, if the tree in question is on a public way outside of the residential part of the town limits, such residential part to be determined by him. No tree within such residential limit shall be cut by him, except to trim it, or removed by him, without such hearing. The decision of the tree warden shall be subject to review by the selectmen of towns or the governing bodies of cities.

RSA 231:145 Removal of Certain Hazardous Trees

- **Before July 16, 2009:** Notwithstanding the provisions of other sections of this subdivision or any other provision of law, the commissioner of transportation on class I and III highways, and state maintained portions of class II highways, and the mayors of cities and the selectmen of towns and the county commissioners for unorganized places on class IV, V and VI highways and town maintained portions of class II highways may declare any tree, either alive or dead, situated within the limits of highways, roads, or streets to be a public nuisance by reason of danger to the traveling public or spread of tree disease. After such declaration by such authority and notice to the abutting landowner on whose property such tree is located the said authority shall within a reasonable time remove the same without compensation or cost to the abutter. However, no such declaration and notice shall be required when the delay entailed by such declaration and notice would pose an imminent threat to safety or property. The provisions of this section shall not apply to public shade or ornamental trees. Nothing in this subdivision shall be construed to relieve the public utility companies of their accepted responsibility of tree trimming and tree removal for the protection of their lines, or for the construction of new lines, or to alter the provisions of RSA 231:150-182 in any manner. The aforesaid state and municipal authorities may require of the public utilities owning lines which pass through or near a tree or trees which are condemned for removal as a public nuisance to assist in their removal at their expense by either the temporary removal of their lines or by causing to be removed at their expense the top portion of said tree or trees from a point below their lines.
- **After July 16, 2009:** Notwithstanding the provisions of other sections of this subdivision and subject to the provisions of RSA 231:157 and RSA 231:158, the commissioner of transportation on class I and III highways, and state maintained portions of class II highways, and the mayors of cities and the selectmen of towns and the county commissioners for unorganized places on class IV, V, and VI highways and town maintained portions of class II highways may declare any tree, either alive or dead, situated within the limits of highways, roads, or streets to be a public nuisance by reason of unreasonable danger to the traveling public, spread of tree disease, or the reliability of equipment installed at or upon utility facilities authorized under RSA 231:160 or RSA 231:160-a. After such declaration by such authority and notice to the abutting landowner on whose property such tree is located the said authority shall within a reasonable time remove the same without compensation or cost to the abutter. However, no such declaration and notice shall be required when the delay entailed by such declaration and notice would pose an imminent threat to safety or property. Nothing in this subdivision shall be construed to relieve the public utility companies of their accepted responsibility of tree trimming and tree removal for the protection of their lines, or for the construction of new lines, or to alter the provisions of RSA 231:150-182 in any manner. The aforesaid

state and municipal authorities may require of the public utilities owning lines which pass through or near a tree or trees which are condemned for removal as a public nuisance to assist in their removal at their expense by either the temporary removal of their lines or by causing to be removed at their expense the top portion of said tree or trees from a point below their lines.

RSA 231:146 Notice

- Notice to the abutting landowner of a tree declared a public nuisance shall be given by delivery at his place of residence or by sending by registered mail to his last known address and it shall clearly state the intention of removal of such tree. He may appeal to the superior court as to the validity of such declaration within 30 days of delivery or mailing of said notice, and shall be entitled to a speedy hearing. The final judgment upon every appeal shall be a decree dismissing the appeal, or vacating the declaration complained of in whole or in part, as the case may be; but in case such declaration is wholly or partly vacated the court may also, at its discretion, remand the matter to the said department, city, county, or town for such further proceedings, not inconsistent with the decree, as justice may require. Following expiration of the aforesaid 30-day period of appeal, or following waiver of said right of appeal, the abutting landowner is relieved of any liability or responsibility in connection with the tree or trees declared a public nuisance and similarly is relieved of any liability or responsibility in connection with any stump or stumps left remaining.

RSA 231:147 Injury or Defacement of Trees

- It shall be unlawful to cut, destroy, injure, deface, or break any public shade or ornamental tree; or to affix to any such tree a play bill, picture, announcement, notice, advertisement, political or otherwise, or other device or thing, or to paint or mark such tree, except for the purpose of protecting it and under a written permit from the tree warden; or to negligently or carelessly suffer any horse or other beast to break down, injure or destroy a shade or ornamental tree within the limits of any public way or place.

RSA 231:148 Trees Donated

- Whenever any party, at a proper time of the year, shall present to a town well grown nursery trees, the tree wardens may set out such trees in the highways, cemeteries, commons, schoolhouse yards and other public places, as indicated by the donor, and protect the same at the expense of the town.

RSA 231:149 Public Ownership

- Any young shade or ornamental tree planted within the limits of a public highway by the tree wardens or by any other person or persons, with the approval of the selectmen or the mayor, or any young seedling tree or sprout left within the limits of the highway as specified in RSA 231:150 and designated by the tree warden to be preserved for its future value as a shade tree, shall become the property of the municipality; provided, that the abutting landowner, having been notified of the intention of the town to take and preserve such young tree, shall make no written objection to the tree warden within 30 days from the date of such notification.

RSA 231:150 Clearing Highways

- Mayors of cities, selectmen of towns and county commissioners for unorganized places shall annually, and at other times when advisable, cause to be cut and disposed of from within the limits of town maintained highways all trees and bushes that may cause damage or pose a safety hazard to such highways or to the traveling public; provided however that no tree which has a circumference of 15 inches or more at a point 4 feet from the ground shall be removed in the absence of notice to the abutter in the same manner as provided in RSA 231:145 and 231:146, except when the delay entailed by such notice would pose an imminent threat to safety or property. Shade and fruit trees that have been set out or marked by the abutting landowners or by the town tree wardens, and young trees standing at a proper distance from the highway and from each other, shall be preserved, as well as banks and hedges of bushes that serve as a protection of the highway, or that add to the beauty of the roadside.

RSA 231:151 Improvements by Abutter

- The selectmen of a town or the highway department of a city may contract with any owner of land abutting a public highway to cut, trim and improve the roadside growth along said owner's property, and for all such work properly done in carrying out the provisions of RSA 231:150 and approved by the tree wardens, may allow and cause to be paid to such owner such sums as in their judgment, with the advice of the tree wardens, justly represent the value to the town of the improved condition of the roadside.

RSA 231:152 Burning Brush

- Whenever any trees or brush cut along the highway are disposed of by burning, the cut trees or brush shall be removed a safe distance from any adjoining woodland or from any tree or hedge designated or desirable for preservation, and such burning shall be done with the permission of the forest fire warden. All trees or brush thus cut from within the limits of the highway shall be disposed of within 30 days from the cutting thereof.

RSA 231:153 Disposal of Brush

- If any cut brush has been left within the limits of any public highway for a longer period than 30 days the director, division of forests and lands, department of resources and economic development, may complete the removal or disposal of such brush and assess the costs thereof against the party authorizing or causing such nuisance. If the said costs are not paid within a reasonable time they may be recovered in an action brought by the attorney general upon complaint of the director.

RSA 231:154 Taking Tree Rights

- When any highway shall be laid out damages may be assessed to the abutting owners to provide for the maintenance or planting, from time to time, within the limits of such highway, of such shade and ornamental trees as may be necessary for the preservation and improvement of such highway. Damages may be assessed to abutting owners on any existing highway upon petition therefore, and such proceedings had as in the laying out of highways by selectmen to provide for the maintenance and planting from time to time, of such trees within the limits of such highways as may be necessary for the preservation and improvement of the same. When such damage shall be assessed and paid there shall be, in addition to the right of travel over such highway, a public easement to protect, preserve and renew the growth thereon for the purposes aforesaid.

RSA 231:155 State Supervision

- On all class I and III highways, and state maintained portions of class II highways, the commissioner of transportation shall have under his supervision the planting, acquisition, maintenance and removal of all trees and vegetation and the same powers relative thereto as conferred by this subdivision or any other law upon the cities and towns on highways under their jurisdiction. The commissioner shall make such rules and regulations for the purposes hereof as shall, in his judgment, seem for the best interests of the state.

RSA 231:156 Penalty

- Any person who violates any provision of this subdivision or any rule or regulation thereunder made by the commissioner of transportation shall be guilty of a violation if a natural person, or guilty of a misdemeanor if any other person. Any person shall be liable for all damage occasioned thereby.

RSA 231:157 Scenic Roads; Designation

- Any road in a town, other than a class I or class II highway, may be designated as a scenic road in the following manner. Upon petition of 10 persons who are either voters of the town or who own land which abuts a road mentioned in the petition (even though not voters of the town), the voters of such town at any annual or special meeting may designate such road as a scenic road. Such petitioners shall be responsible for providing the town clerk with a list of known property owners whose land abuts any of the roads mentioned in the petition. The town clerk shall notify by regular mail within 10 days of the filing all abutters along the road that lies within the town that a scenic road petition has been filed for and that an article to designate such road as a scenic road will appear in the warrant at the next town meeting. The voters at a regular town meeting may rescind in like manner their designation of a scenic road upon petition as provided above. Notice to the abutting landowners shall also be given as provided above. Each town shall maintain and make available to the public a list of all roads or highways or portions thereof within the town which have been designated as scenic roads. Such list shall be kept current by updating not less than annually and shall contain sufficient information to permit ready identification of the location and extent of each scenic road or portion thereof, by reference to a town map or otherwise.

RSA 231:158 Effect of Designation as Scenic Road

I. As used in this subdivision, "tree" means any woody plant which has a circumference of 15 inches or more at a point 4 feet from the ground.

II. Upon a road being designated as a scenic road as provided in RSA 231:157, any repair, maintenance, reconstruction, or paving work done with respect thereto by the state or municipality, or any action taken by any utility or other person acting to erect, install or maintain poles, conduits, cables, wires, pipes or other structures pursuant to RSA 231:159-189 shall not involve the cutting, damage or removal of trees, or the tearing down or destruction of stone walls, or portions thereof, except with the prior written consent of the planning board, or any other official municipal body designated by the meeting to implement the provisions of this subdivision, after a public hearing duly advertised as to time, date, place and purpose, 2 times in a newspaper of general circulation in the area, the last publication to occur at least 7 days prior to such hearing, provided, however, that a road agent or his designee may, without such hearing, but only with the written permission of the selectmen, remove trees or portions of trees which have been declared a public nuisance pursuant to RSA 231:145 and 231:146, when such trees or portions of such trees pose an imminent threat to safety or property, and provided, further, that a public utility when involved in the emergency restoration of service, may without such hearing or permission of the selectmen, perform such work as is necessary for the prompt restoration of utility service which has been interrupted by facility damage and when requested, shall thereafter inform the selectmen of the nature of the emergency and the work performed, in such manner as the selectmen may require.

III. Designation of a road as scenic shall not affect the eligibility of the town to receive construction, maintenance or reconstruction aid pursuant to the provisions of RSA 235 for such road.

IV. Designation of a road as a scenic road shall not affect the rights of any landowner with respect to work on his own property, except to the extent that trees have been acquired by the municipality as shade or ornamental trees pursuant to RSA 231:139-156, and except that RSA 472:6 limits the removal or alteration of boundary markers including stone walls.

V. A town may, as part of a scenic road designation under RSA 231:157 or as an amendment to such designation adopted in the same manner, impose provisions with respect to such road which are different from or in addition to those set forth in this section. Such provisions may include, but are not limited to, decisional criteria for the granting of consent by the planning board or other designated municipal body under paragraph II, or protections for trees smaller than those described in paragraph I, designated for the purpose of establishing regenerative growth along the scenic road.

VI. Any person who violates this section or any local provision adopted under this section shall be guilty of a violation and shall be liable for all damages resulting therefrom.

RSA 231:172 Cutting Trees

- **Before July 16, 2009:** No such licensee shall have the right to cut, mutilate or injure any shade or ornamental tree, for the purpose of erecting or maintaining poles or structures or installing wires or other attachments or appurtenances thereto, without obtaining the consent of the owner of the land on which such tree grows or the payment or tender in full of damages therefore determined as provided in this section. If the consent of such owner cannot be obtained, the selectmen, upon petition, after notice to the owner and hearing, shall determine whether the cutting or mutilation is necessary and if determined to be necessary, they shall assess the damages that will be occasioned to the owner thereby. Upon highways which have been designated scenic roads pursuant to RSA 231:157 and RSA 231:158, cutting shall be further restricted as set forth in those sections or any local provisions adopted thereunder.
- **After July 16, 2009:** I. No licensee shall have the right to cut, prune, or remove any shade or ornamental tree, for the purpose of erecting or maintaining poles or structures or installing wires or other attachments or appurtenances thereto, without obtaining the consent of the owner of the land on which such tree grows. The receipt of a license to erect and maintain such equipment pursuant to RSA 231:160 and RSA 231:160-a includes consent to cut, prune, or remove shade or ornamental trees growing on land located within the public right-of-way that pose an unreasonable danger to the reliability of equipment installed at or upon licensed utility facilities. Nothing in this section shall affect the right of the landowner to the cordwood or timber that results from the activities of a licensee under this subdivision.

  II. A licensee shall provide notice in writing at least 45 days in advance of any non-emergency cutting, pruning, or removal of shade or ornamental trees that is scheduled to take place on a landowner's property. The notice shall, at the option of the licensee, be given in person, or sent separately by ordinary mail, and not included in or as a part of a utility bill or other regular communication, to owners of affected land using the name and address that appears on municipal tax records for the property, or sent separately by electronic mail, and not included in or a part of a utility bill or other regular communication, if the landowner has established regular electronic mail communication with the licensee.

(a) The notice shall provide the name and contact information of a representative of the licensee who may be contacted to schedule personal consultation regarding the activities.

(b) For the purposes of this section, the owner shall be deemed to have consented to the activities if he or she fails to affirmatively request personal consultation within 45 days of the mailing of such notice.

(c) If, after personal consultation with the licensee, the owner refuses to consent to the activities, the selectmen, upon petition, after notice to the owner and licensee, and hearing, shall determine whether the cutting, pruning, or removal is necessary and, if determined to be necessary, assess the damage to the owner.

III. Upon highways which have been designated scenic roads pursuant to RSA 231:157 and RSA 231:158, cutting, pruning, or removal shall be further restricted as set forth in those sections or any local provisions adopted thereunder.

IV. Nothing in this section shall be construed to require notice to or consent from the owner of land in the event that the owner, or a predecessor of the owner, has granted an easement which provides legal authority for the utility to remove, cut, prune, or trim trees or vegetation on the owner’s land.

APPENDIX D

The December 2008 Ice Storm in New Hampshire

Kathleen F. Jones
Cold Regions Research and Engineering Laboratory
Hanover, New Hampshire 03755

Chapter Structure

A. INTRODUCTION

The December 11-12, 2008 ice storm caused long power outages in New Hampshire and the surrounding states. Difficulties in restoring power were attributed to the abundant trees in the region affected by the storm and the large area that the storm covered. Many utilities had to restore power to customers in their own service area and did not have the personnel to also help other utilities with whom they had mutual aid agreements. This report was commissioned by NEI

Electric Power Engineering for their storm response analysis for the New Hampshire Public Utilities Commission.

The severity of this ice storm can be quantified in terms of the equivalent radial glaze ice thickness R_{eq}, and the return period of storms resulting in R_{eq}s that were seen in this event determined. The shape of the ice that forms on the branches and twigs of trees and on the wires of power distribution lines, and conductors and shield wires of power transmission lines varies depending on the local weather conditions, the orientation of the line to the wind direction, any heat generated in the wire/conductor by the current, any rotation of wires as ice accretes, and any change in orientation of twigs and branches as ice accretes. The equivalent radial thickness of the ice on a wire is the thickness it would have if the actual shape was redistributed to make the ice uniformly thick around the wire. R_{eq} does not vary with the wire diameter (Jones 1998), so it can be used to determine the weight of ice per unit length W on wires or branches of any diameter:

$$W = \rho\pi\left(R_{eq}d + R_{eq}{}^2\right) \qquad (1)$$

The equivalent radial ice thickness is not measured at weather stations, and is not typically reported. Forecasters or weather observers sometimes report the thickness of ice on the ground or another horizontal surface. These reported thicknesses can include ice pellets and snow as well as freezing rain because these types of precipitation often occur in the same weather event. There are often many reports of the maximum dimension D_{max} of ice accreted on a branch or wire. This will include icicles, which form in conditions where the heat of fusion is removed relatively slowly (low winds, temperature near freezing) when impinging rain drops freeze as they start to drip off. Note that

$$\begin{aligned} R_{eq} &= 0.5\left(D_{\max} - d\right) \text{ for round accretion cross sections} \\ R_{eq} &< 0.5\left(D_{\max} - d\right) \text{ for non-round accretion cross sections} \end{aligned} \qquad (2)$$

Data from weather stations is used to estimate R_{eq}. The map in ASCE Standard 7 *Minimum design loads for buildings and other structures* (ASCE 2005) is based on the analysis of historical weather data using the Simple ice accretion model (Jones 1998) with hourly weather data. The ice load maps in ASCE Standard 7 are also being adopted by ASCE Manual 74 (ASCE in press). Values for long return periods were determined by fitting the generalized Pareto distribution, using the method of probability weighted moments, to a sample of the largest ice thicknesses, grouping the weather stations into superstations to reduce sampling error. This approach for mapping ice thicknesses and concurrent gust speeds is described in detail in Jones et al (2002). R_{eq} can also be estimated directly from a freezing-rain sensor using the Automated Surface Observing System one-minute, page 2 data (Ryerson and Ramsay 2007). For this analysis of the December 2008 ice storm, both methods are used. Alan Ramsay provided equivalent radial ice thicknesses from the freezing rain sensor.

In the next section the freezing rain storm forecasts are summarized, a map of the total precipitation for December 11-12 is presented, the footprint of the ice storm is delineated, and equivalent radial ice thicknesses are calculated from weather data. A description of the storm damage is provided in Section 3, along with damage footprints and descriptions of previous storms in the region from http://cmep.crrel.usace.army.mil/ice. Finally in Section 4 the return period of storms in this region with similar ice thicknesses is estimated.

B. PRECIPITATION, ICE STORM FOOTPRINT, AND R_{EQ}

The December 2008 ice storm was part of a larger system that brought precipitation ranging from rain to freezing rain to snow to ice pellets to the northeastern United States. Forecasts for freezing rain were issued from the Taunton, Massachusetts, Gray, Maine, and Albany, New York, forecast offices for the region affected by the storm. Portions pertaining to New Hampshire are summarized here:

- The forecast from Taunton, Massachusetts at 5:10 pm on December 10 mentions the likelihood of heavy ice pellets or freezing rain occurring in portions of the interior of the forecast region on Thursday (December 11) and Thursday night. The forecast states that the potential for a major ice storm exists, but the most likely locations of 1 or 2 inches of ice (all ice amounts in forecasts are on a horizontal surface; they are not equivalent radial ice thicknesses) is not known and will be sensitive to the depth of the subfreezing layer of air. If the subfreezing layer of air is cold enough or thick enough the precipitation will likely fall as ice pellets, decreasing the severity of icing on structures. Light freezing rain with significant icing is expected on Thursday at Hartford CT, Westfield and Worcester MA, and Manchester NH, with some ice pellets at Manchester. An ice storm warning is issued for Massachusetts (forecast zones 2-4, 8-12, 26) with a winter storm warning issued for New Hampshire (forecast zones 11, 12, 15).
- The forecast from Albany, New York, at 12:43 am on December 11 issues an ice storm warning and flood watch for Massachusetts (forecast zones 1-25) and a winter storm warning for portions of Vermont (forecast zones 13-15)
- The forecast from Gray, Maine at 7:12 am on December 11 warns of heavy accumulating ice with power outages expected across portions of Maine and New Hampshire. Freezing rain is expected to approach one inch over interior sections, with power outages and downed tree limbs becoming a significant problem in some communities. It is suggested that high precipitation rates tonight might slow the accretion of ice compared to a steady long period of light freezing rain. Hefty ice accumulations are also expected across

portions of the coast. The situation will be monitored closely in case shifts in the pattern imply coastal ice accretions of greater than one-half inch.

- The forecast from Taunton, Massachusetts issued at 4:28 pm on December 11 issues an ice storm warning for western Massachusetts and southern New Hampshire; a winter weather advisory and flood watch for eastern, northeastern and western Massachusetts; and an ice storm warning and flood watch for central and eastern Massachusetts.

Freezing rain began essentially simultaneously in Massachusetts and New Hampshire with freezing rain first observed at Jaffrey, Concord, and Manchester between 6 am and 9 am (LST), and at Lebanon at 6 pm on December 11. At Whitefield and Berlin freezing rain began almost a day later, between 3 and 5 am on December 12. At many of these airport locations freezing rain was preceded by ice pellets. At higher elevations in the area, that precipitation might also have been freezing rain instead of ice pellets because of the thinner layer of overlying cold air. The end of freezing rain is difficult to determine because stations in the region most severely affected stopped transmitting data during the storm, presumably because of power outages. In general freezing rain and ice pellets ended some time on December 12.

Daily accumulated water-equivalent precipitation is measured and archived for hundreds of cooperative weather stations and hourly weather stations in the region. At most stations precipitation is measured early in the morning (typically 0700) each day. For those stations the storm precipitation is taken as the sum of the measured amounts from the mornings of December 12 and 13. At about 20% of the stations precipitation is measured sometime between the late afternoon and midnight. For those stations the storm precipitation is taken as the sum of the measured amounts from the evening hour on December 11 and December 12. Those accumulated precipitation amounts are shown in Figure D-1 as a contour plot. The locations of the weather stations that provided data for this map are shown in Figure D-2. Precipitation is heaviest in eastern Connecticut, Rhode Island, and southeastern Massachusetts, and generally decreases toward the north and west. Some of the small scale variation shown on the map may be due to variation in the measurement time from station to station. But some of the variation is likely because of power outages at hourly weather stations because of the ice storm. For example, the bulls eye in the middle of Massachusetts comes from the Worcester weather station where no data was archived from 0700 December 12 through 1300 December 13.

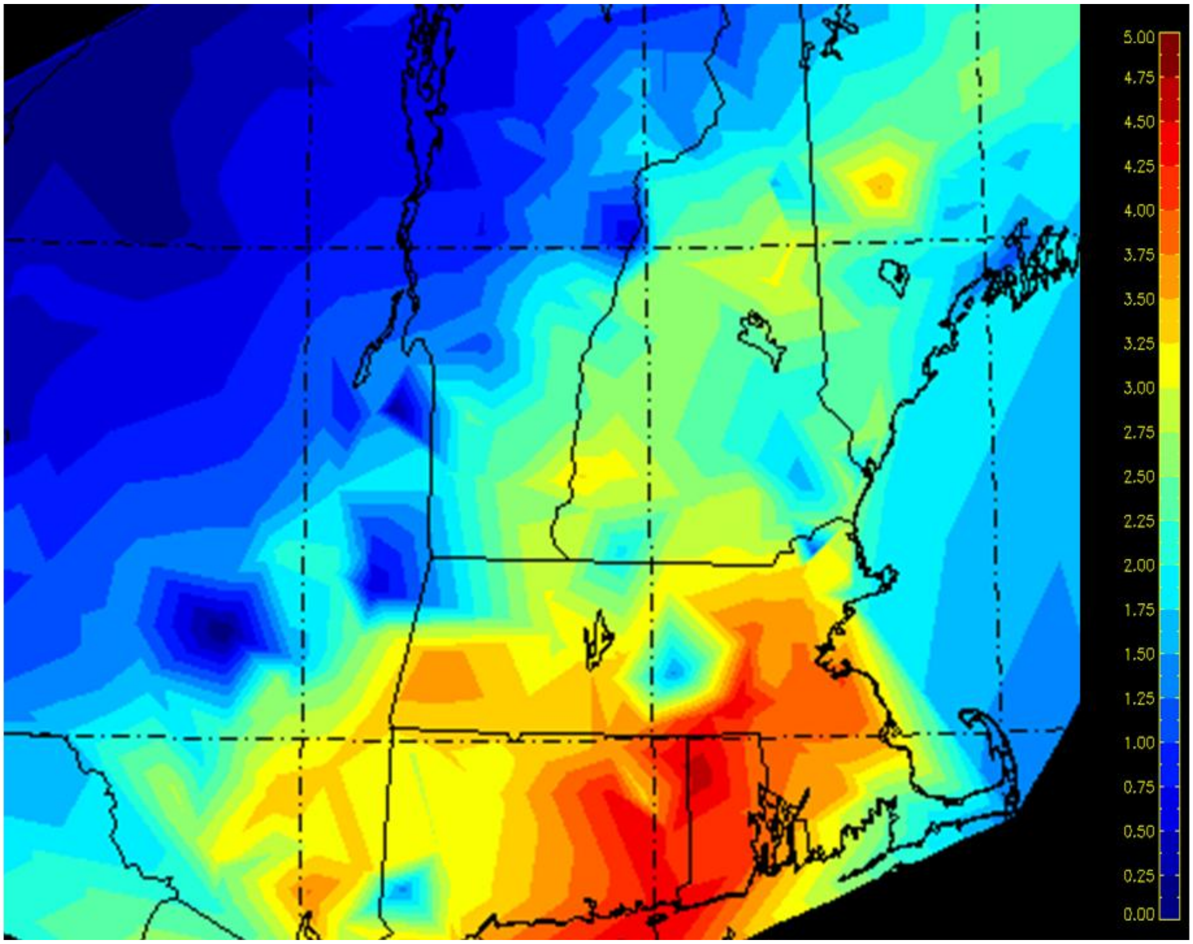

Figure D-1 – Accumulated precipitation (inches) December 11 to 12, 2008.

The precipitation fell as freezing rain for part of this two-day period in only a portion of the region with significant precipitation. Information on damage associated with the ice storm was compiled from newspaper articles from the Portland *Press Herald*, Augusta *Kennebec Journal*, Concord *Monitor*, White River Junction *Valley News*, Rutland *Herald*, Albany *Times-Union*, *New York Times*, Pittsfield *Berkshire Eagle*, Springfield *Republican*, Worcester *Telegram Gazette*, and the *Boston Globe* as well as from the Taunton and Albany storm compilations. Areas where trees, power lines, or communication towers were damaged by the ice or a combined ice and wind load are included in the damage footprint. In many storms much of the damage to distribution lines and transmission lines in narrow right-of-ways is from ice-covered trees and branches falling on wires and conductors (Jones 1999). Locations where the storm caused slippery roads but no other effects are not included. The storm footprint in Figure D-3 extends from northwestern Connecticut, western Massachusetts, and east central New York across southern Vermont and the upper Connecticut River valley, the southern half of New Hampshire and the northern two-thirds of Massachusetts, and into Maine. The storm also affected an area around Wilkes Barre and Scranton Pennsylvania. The power outages reported in

Rhode Island during this period were likely due to high winds and flooding rather than ice as temperatures there remained above freezing.

Some of the stations shown in Figure D-2 are airport stations with hourly weather data. Most of the hourly stations are Automatic Surface Observation System (ASOS) stations, with no human observers. The stations have battery backup for only one-half hour, so in lengthy power outages, which are common in significant freezing rain storms, data may not be collected for a portion of the storm. A few ASOS stations are augmented by observers who can continue to make measurements and record data even when the power is out. The weather elements that are measured at these stations that are required for the Simple ice accretion model are precipitation type, precipitation amount, and wind speed. The more detailed CRREL ice accretion model (Jones 1996) also uses air temperature and dew point data in a heat balance calculation to determine how much of the impinging precipitation freezes. The Simple model assumes that it is cold and windy enough that all the precipitation that impinges on a cylinder (e.g. wire, conductor, cable, branch, twig) freezes to it. When the two models differ, the Simple model R_{eq} may represent more severe conditions in the vicinity of the airport. In both models, in any hour with freezing rain, all the precipitation is treated as if it were freezing rain. In many hours the local conditions indicate different precipitation types, typically freezing rain and ice pellets or freezing rain and snow occurring at various times. Assuming all the precipitation is freezing rain in these hours is intended to represent what might be occurring at higher elevations or locations with a different upper air temperature profile in the vicinity of the station. Both models determine the accretion of ice on a horizontal cylinder with axis perpendicular to the wind direction. There will be less ice on horizontal cylinders that are parallel to the wind direction or on vertical cylinders. At hourly weather stations with freezing rain sensors, R_{eq} can also be estimated from the detailed sensor data that is archived by the National Climatic Data Center (NCDC).

Simple model R_{eq}s at 10 m (33 ft) above ground and freezing rain sensor R_{eq}s at 2 m (7 ft) above ground for the thirty stations with archived hourly weather data in and near the ice storm footprint are provided in Table D-1. There was no archived data for the Bedford MA or Rochester NH stations. Precipitation type is not recorded at the Milton MA station. Freezing rain was not observed in this storm at the three Connecticut stations and two of the Massachusetts stations in Table D-1. At seven stations where there was freezing rain, the calculated R_{eq}s are low because of data missing from the archive from power outages or data transmission errors. Note the generally lower values from the icing sensor than are provided by the Simple model with its conservative assumptions. Icing sensor response is within 20% of a specified standard, with a flat distribution between those limits. Time series of the weather data as well as modeled equivalent radial ice thicknesses and values determined from the freezing rain sensor are provided for Worcester MA and Concord NH in Figure D-4 and Figure D-5, respectively. In the second panel the type of precipitation uses the codes Z for freezing rain, I for ice pellets, R for rain, and S for snow.

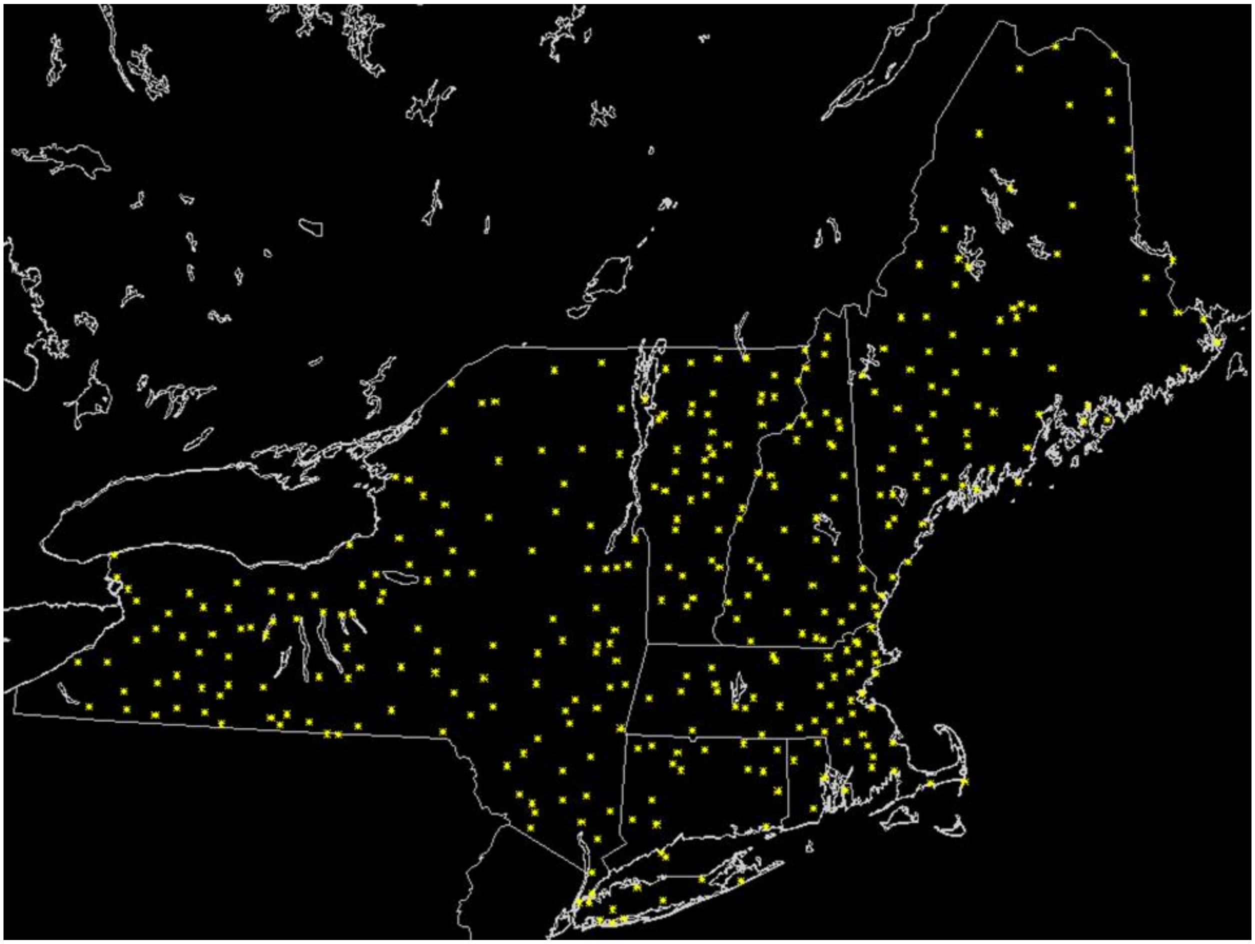

Figure D-2 - Weather Stations for Figure D-1

The largest modeled R_{eq} in this storm is 22.7 mm (0.9 in.) in Augusta ME. For seven hours of the storm the precipitation at the Augusta weather station was a mixture of freezing rain and ice pellets. As ice pellets bounce off objects, the equivalent radial thickness of ice on wires and twigs would accumulate to 0.9 in. only at locations near Augusta where the precipitation was actually all freezing rain.

In Albany NY R_{eq}=20.6 mm (0.8 in.), with ice pellets and freezing rain for five hours.

In Massachusetts ice thicknesses were more than 16.2 mm (0.6 in.) and more than 17.0 mm (0.7 in.) at Lawrence and Worcester, respectively. Data is missing at the height of the storm, so these should be considered lower bounds on R_{eq} in the vicinity of these two stations. Ice pellets and freezing rain occurred in the same hour for five hours at Lawrence and three hours at Worcester.

Modeled ice thicknesses in Vermont are relatively low with 3.9 mm (0.2 in.) at Bennington. Precipitation amounts are missing at Springfield for the entire storm, and there is no data at all after 1000 UTC on December 12 so that area with likely significant icing is not represented by the weather station data.

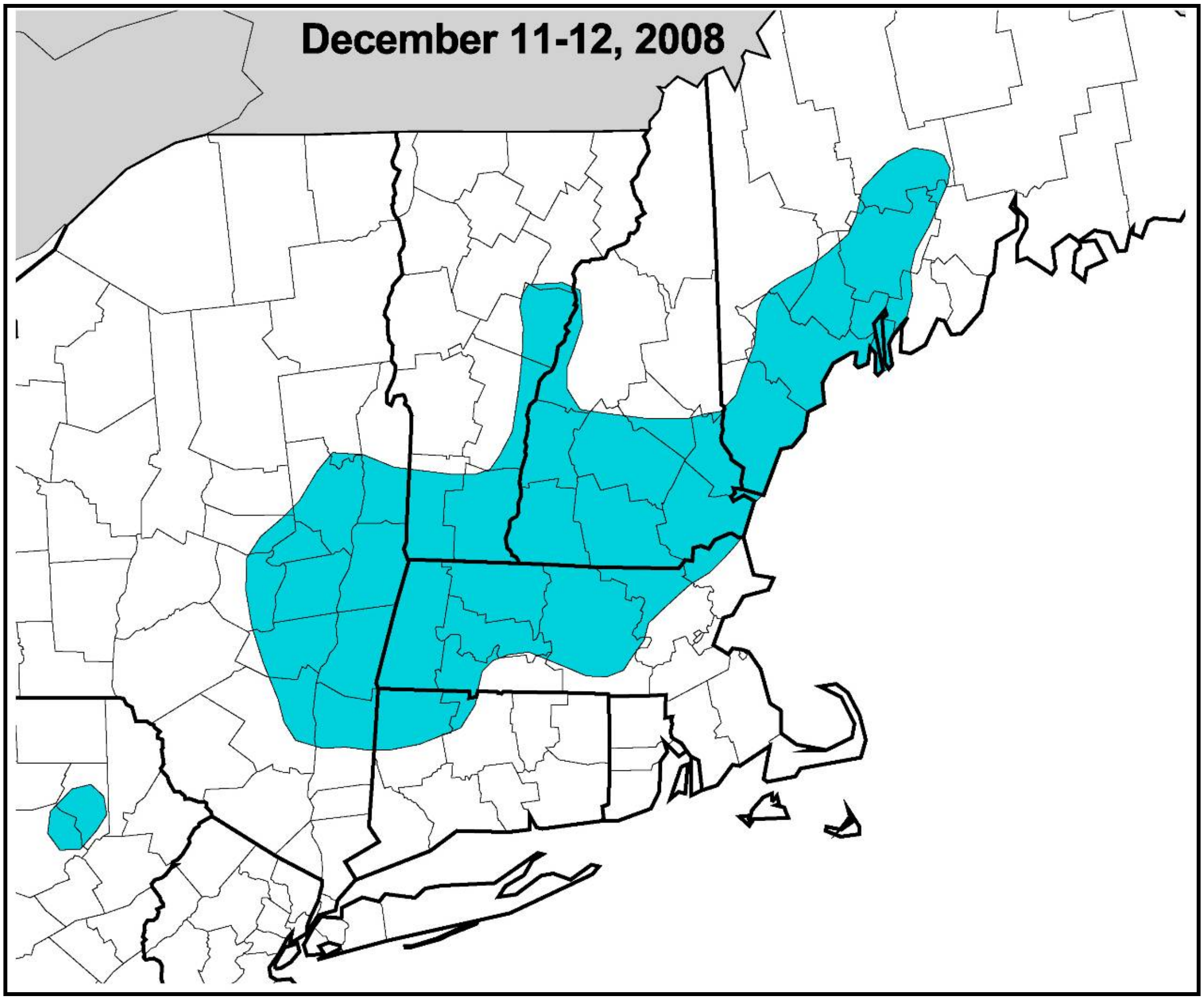

Figure D-3 - Ice storm footprint; region with damage to trees, power lines, and communication towers.

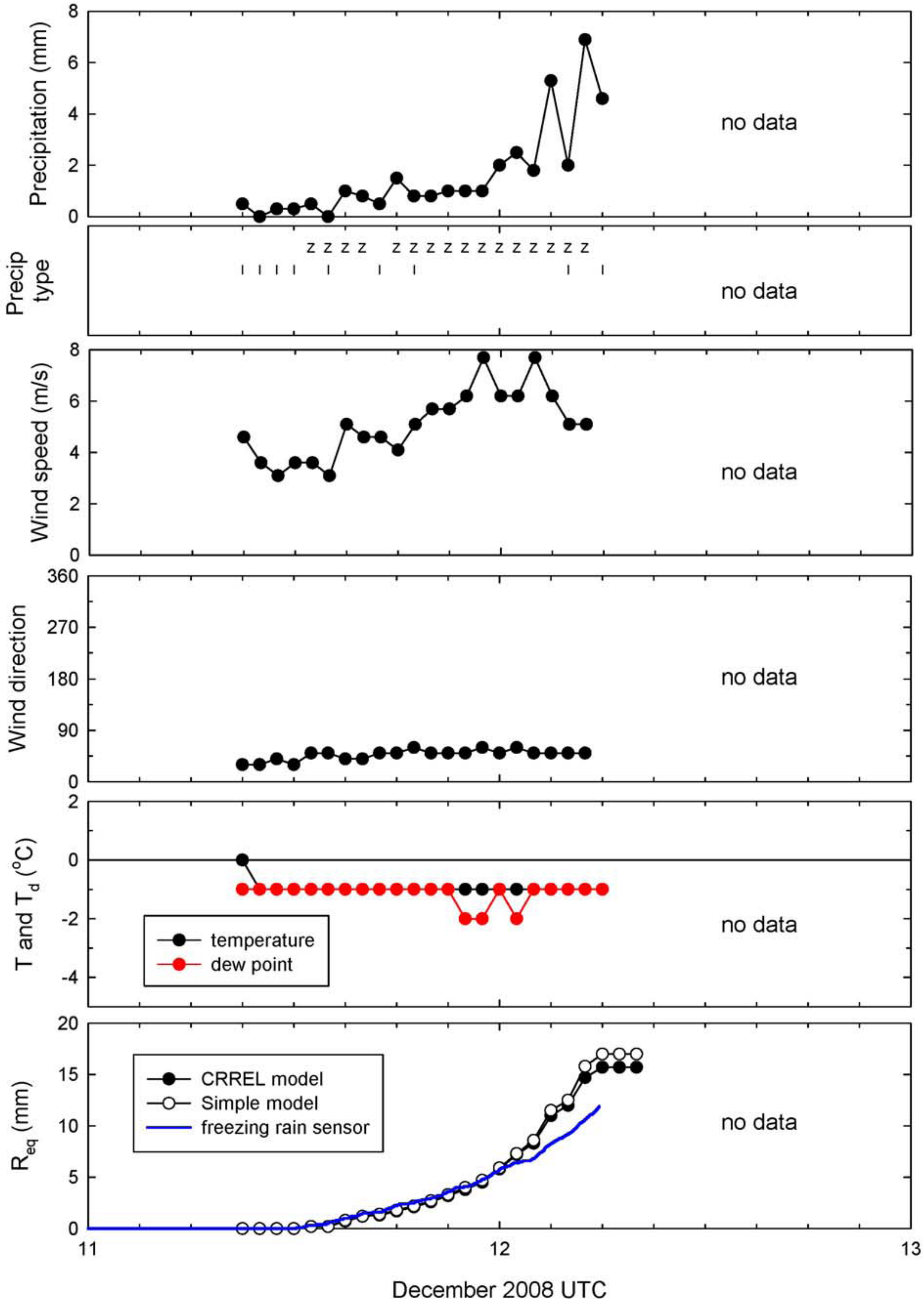

Figure D-4 - Storm time series for Worcester, Massachusetts. Equivalent radial ice thicknesses from the CRREL and Simple models and from the freezing rain sensor are in the bottom panel.

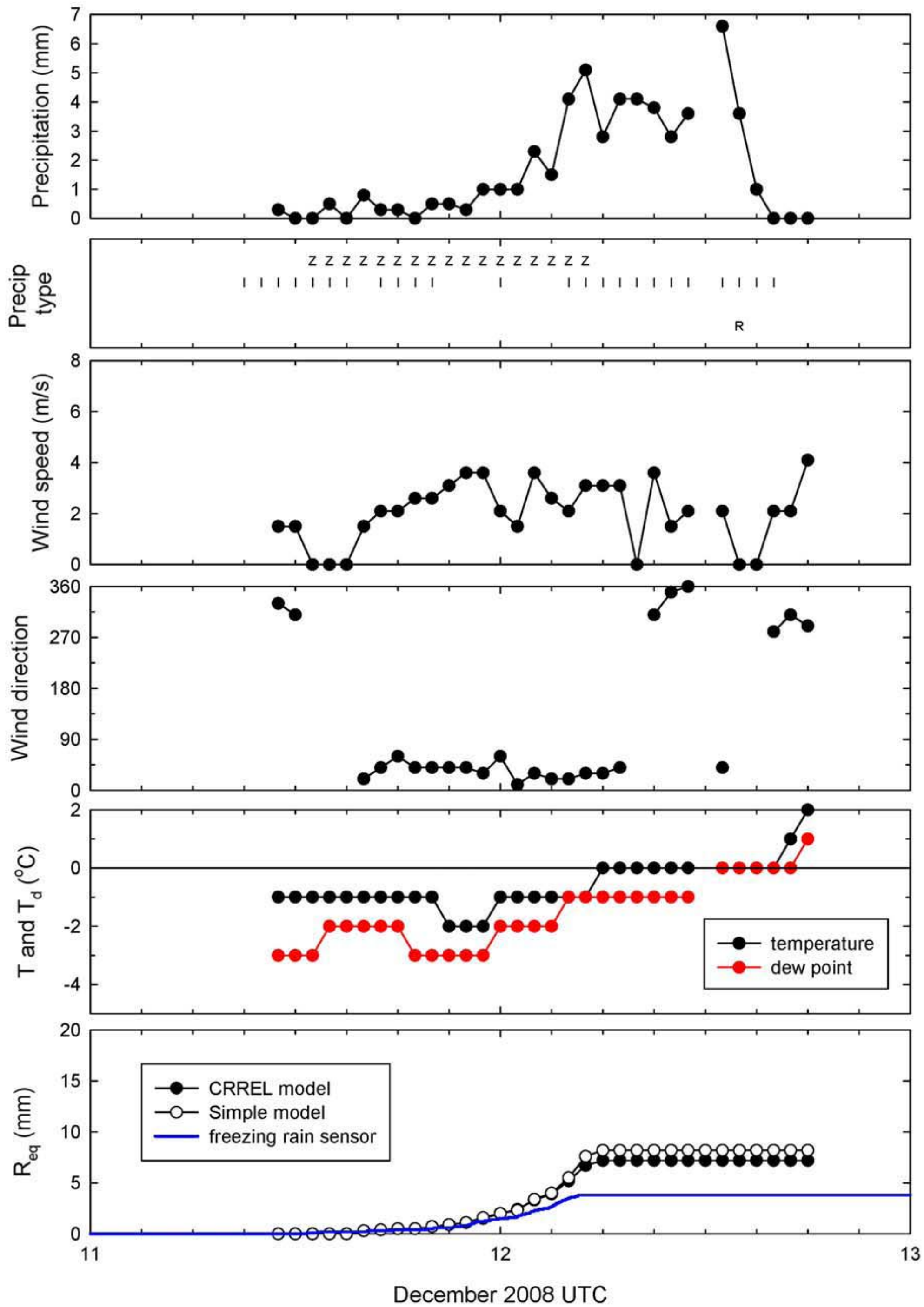

Figure D-5 - Storm time series for Concord, New Hampshire. Equivalent radial ice thicknesses from the CRREL and Simple models and from the freezing rain sensor are in the bottom panel.

Table D-1 - Equivalent radial ice thickness at stations with hourly weather data.

Station		Simple model R_{eq} (mm)	Hourly data comments (times are UTC)	Sensor R_{eq} (mm)	Freezing rain sensor comments (times are UTC)
HARTFORD	CT	-	no freezing rain until December 17	-	
WILLIMANTIC	CT	-	no freezing rain until December 17	-	
WINDSOR LOCKS	CT	-	no freezing rain until December 17	-	
BEVERLY	MA	-	no freezing rain until December 17	-	
FITCHBURG	MA	3.2+	no data 12/0400 to 2200	0.8+	missing data
LAWRENCE	MA	16.2+	no data 12/0800 to 2000	3.8+	missing data
NORWOOD	MA	-	no freezing rain until December 17	-	
ORANGE	MA	3.5+	no data 12/0900 to 2000	1.0+	missing data
PITTSFIELD	MA	1.1		2.5+	data ends 12/12 at 0332
WESTFIELD	MA	0		0	
WORCESTER	MA	17.0+	no data 12/0700 to 13/1300	12.2+	ASOS power off from 12/1100
AUGUSTA	ME	22.7		5.7	
FRYEBURG	ME	14.5		4.2	
PORTLAND	ME	12.4		6.7	
WISCASSET	ME	10.3+	no data 12/1000 to 2100	-	missing data for entire event
BERLIN	NH	6.1	missing 12/1400	2.5	
CONCORD	NH	8.2	no data 12/1200	3.8	
JAFFREY	NH	9.8+	no data 12/0700 to 17/1700	1.6+	missing data
LEBANON	NH	7.1		4.7	
MANCHESTER	NH	13.2		4.3+	ASOS power off from 12/1600
WHITEFIELD	NH	7.5	freezing rain reported for 6 hours with $T>0^oC$	2.5	out of calibration
ALBANY	NY	20.6	missing 12/1000	6.1	
BINGHAMTON	NY	4.4		4.7	
GLEN FALLS	NY	6.9		2	
MONTGOMERY	NY	5.3	wind data missing for 11 hours	2.5	
POUGHKEEPSIE	NY	0.1		0	
SYRACUSE	NY	0.7		-	no icing sensor
WILKES-BARRE	PA	0.5	freezing rain reported for 20 hours with $T>0^oC$	0.3	out of calibration
BENNINGTON	VT	3.9		3.3	
SPRINGFIELD	VT	0+	no data 12/1000 to 13/1600; missing precip data	0.8+	missing data

The largest modeled ice thicknesses in New Hampshire are 13.2 mm (0.5 in.) at Manchester and more than 9.8 mm (0.4 in.) at Jaffrey. As hourly data for Manchester continued after the power outage that ended the freezing rain sensor data prematurely, some of the weather data there was apparently recorded by human observers. On December 14 the CRREL Ice Storm Team measured R_{eq}=14 mm (0.6 in.) on a twig (Figure D-6a) from the top of a birch tree bent over under the weight of ice by the parking lot at Temple Mountain State Reservation (Figure D-6b), about 4 miles east of Peterborough on Route 101, and 7 miles northeast of the Jaffrey airport. There was substantial tree damage in the area, with trees and branches on wires (Figure D-6c). The air temperature was still below freezing at this location at an elevation of about 1500 ft, two days after the freezing rain storm, and the ice appeared to be intact. This was the largest measured ice thickness in the team's survey of the region between Manchester and Keene, New Hampshire. In some areas the ice was already melting so that the ice samples at those sites provide only a lower bound on R_{eq}. Simple model ice thicknesses from Table D-1 are mapped in Figure D-7. Wind speeds during the storm were low to moderate. At locations where temperatures remained cold (e.g. higher elevations) following the freezing rain, the wind blowing on ice-covered trees and wires might have added to the damage. In general wind-on-ice loads do not appear to be significant in this event.

Figure D-6 - CRREL Ice Storm Team Site 9:
a) Ice sample with R_{eq}= 14 mm
b) Icicle covered Temple Mountain sign and wires, with ice-covered trees in the background
c) Route 101 headed toward Peterborough; wires sagging, trees on wires, and broken pole in road.

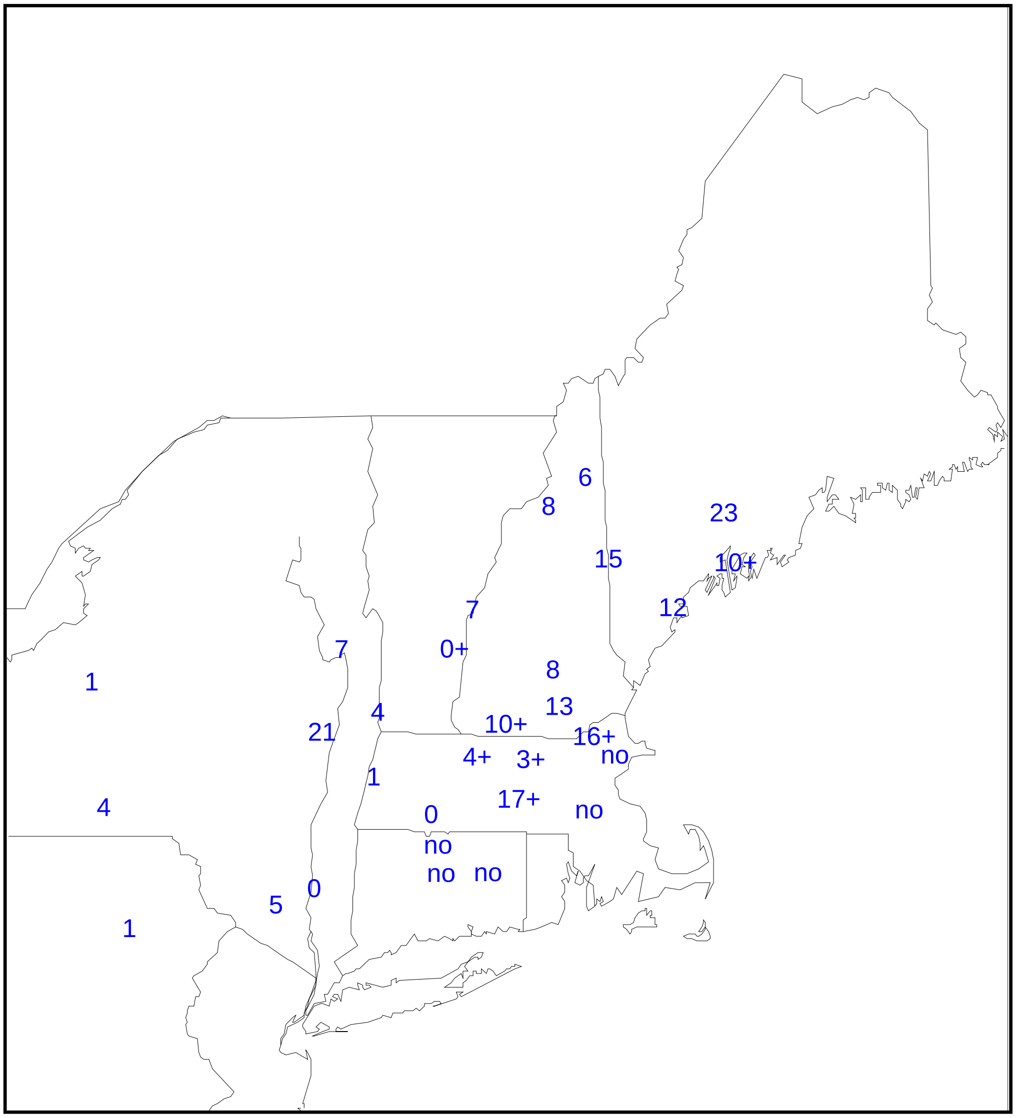

Figure D-7 - Equivalent radial ice thicknesses R_{eq} (mm) for December 11-12, 2008 at hourly weather stations from the Simple ice accretion model: "no" indicates that no freezing rain was observed; "+" indicates that weather data was not recorded for some hours of the storm so the mapped value is a lower bound.

C. DAMAGING ICE STORMS IN THE REGION

The December ice storm damage is summarized below from the newspaper reports listed in Section 2 along with summaries and damage footprints of previous damaging ice storms in this region from http://cmep.crrel.usace.army.mil/ice in reverse chronological order. The ice thicknesses in these summaries are those reported in *Storm Data* (NOAA 1959-present) and the newspaper reports used in the summaries. They are not equivalent radial ice thicknesses.

December 12-14, 2008

11,000 utility customers in Pennsylvania lost power in freezing rain storm; utility poles to WYOU transmitter in Scranton were downed on December 11.

Worst ice storm in 21 years (October 4, 1987) in New York's Capital Region; 229,000 (or 311,000) National Grid, NY State Electric and Gas, and Central Hudson customers without power; outages down to 141,000 (December 13), 42,000 (December 15), 2,000 (December 17); ice more than 1/2 inch thick; extensive damage for National Grid; Amtrak cancelled service between the Capital Region and New York City because of trees blocking the track; basements flooding; phone and cable TV outages also; high winds on December 15 caused more outages; National Grid replacing 350 poles and resetting 772,000 ft of wire.

326,000 National Grid, Unitil, NStar, Western Massachusetts Electric Co., and municipal utility customers lost power in the worst ice storm to hit central Massachusetts in years; in western MA freezing rain in the higher elevations above about 1400 ft felled trees and power lines; outages down to 200,000 (December 13), 95,000 (December 16), 36,000 (December 17), 8000 (December 19); some without power for 10 days; many who lost power also have no water; snow on December 17 slowed down restoration work and caused more outages; telephone poles snapped like toothpicks; tree limbs tangled with downed power lines turned streets into obstacle courses; 1500 National Guard troops helped to clear fallen trees from roads and performed aerial assessments of the damage; 20,000 Charter Communications cable TV customers in central MA still without service on December 16; Verizon phone customers also lost service; widespread disruption of commuter rail leaving North Station because of signal systems down and trees blocking tracks; tree damage in Worcester compounded by the need to control downed limbs infested with the Asian Long-horned beetle; schools cancelled because of lack of electricity and closed roads; minor flooding.

Ice storm clipped Connecticut leaving 16,500 Connecticut Power and Light customers in small northwest CT towns at higher elevations without power; 4,400 still without power on December 13.

In Vermont this was the second most costly storm in the 78-year history of Central Vermont Public Service; 35,000 utility customers lost power with 6,500 still out on December 14; ice up to 1 inch thick and multiple trees down on every line; more than 45 snapped poles; dozens of state and local roads closed.

Up to an inch of ice across the southern half of New Hampshire downed trees and wires and left 440,000 Public Service of NH, Unitil, NH Electric Coop, and National Grid customers without power; largest outage in NH history; 175 National Guard soldiers deployed to help clear debris and evacuate residents; outages down to 300,000 (December 13), 138,000 (December 15), 44,000 (December 18); unprecedented storm damage for PSNH, with many central power lines damaged, and entire systems needing to be rebuilt; Monadnock, Nashua, and Derry regions hard hit; PSNH crews had strung 55 miles of wire by December 18; PSNH doubled its spending on tree trimming to $13 million last year.

Worst ice storm in a decade in Maine left 220,000 utility customers without power for days; most outages since the January 1998 ice storm when 270,000 customers lost power; outages down to 30,000 (December 15), 8,000 (December 16); 70% of homes and businesses in York County lost power; tree branches encrusted in ice up to 1 inch thick ripped off and fell on power lines causing heavy damage to the electrical distribution system; not much wind; Central Maine Power had to replace 125 poles; outages disrupted the state's fuel distribution when storage tanks could not be pumped; Amtrak cancelled service between Portland and Boston because of branches on the tracks; CMP doubled its tree trimming budget this year to $18 million but 75% of the trees that fell on the power lines were outside the trim zone (8 ft on either side of the wires and 15 ft above and below).

6000 National Grid customers in Rhode Island lost power; these outages were likely from the strong coastal winds.

January 4-10, 1998

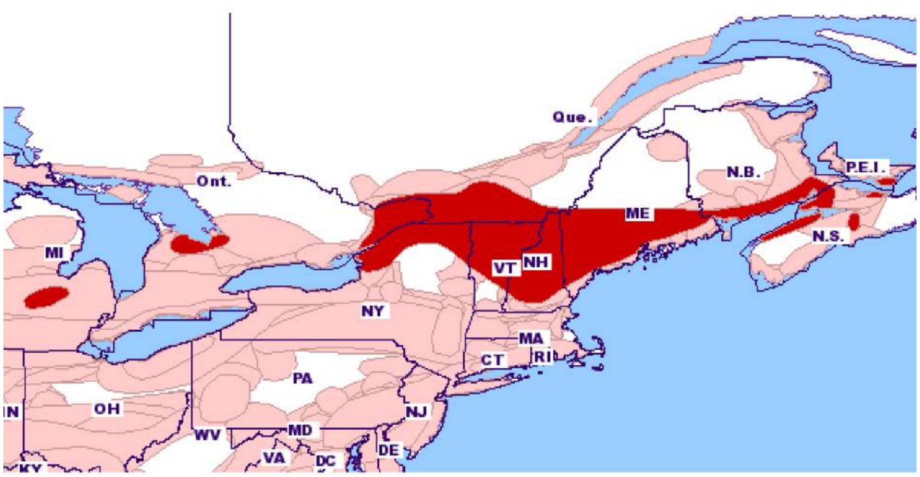

Figure D-8 - January 4-10, 1998 Ice Storm

Freezing rain in Michigan cut power to 2300 Consumers Energy customers.

Freezing rain in Owen Sound region of Ontario; 1.5 inches of ice causing power lines to sag 10 to 15 feet; ice-covered branches on wires caused extensive outages.

Ice storm in eastern Ontario knocked out power to 232,000 utility customers, with 300 transmission line towers damaged; Ontario Hydro had 149,000 customer outages, 36 municipal utilities outages causing an additional 122,000 customer outages, along with 100 towers damaged, 10,750 poles broken, and 2150 transformers damaged; three 115 kV lines that supply Glocester, Greely, Russell, Manotick, and Navan disabled; 90% of Metcalfe without power starting Jan 6 and still without power on Jan 10; much of Ontario Hydro's rural system has to be rebuilt from the ground up; 1000 poles in VanKleek Hill area have to be replaced; 67,700 Hydro Quebec customers in the Outaouais lost power, from the Pontiac to Low; rural region to the east of Ottawa still paralyzed by the power outage on Jan 11 with 15,000 still without power on Jan 12; hundreds of 1000s of trees destroyed; 1000s of fallen trees blocking city streets in Ottawa, where large trees shattered like fragile crystal; highway 417 towards Quebec closed because of electric wires and tree branches fallen on the road; 2000 military personnel sent to clear roads for hydro crews; emergency declared.

Worst ice storm of the century in Quebec; dozens of transmission lines collapsed; ice thickness three or four times the wire diameter in some places; 20 mm of ice on trees and wires near Victoriaville; 300 transmission line towers down, including dozens toppled like dominoes near Ste. Julie; high-tension line at the bottom of the St. Lawrence River near Montreal; 1,393,000 Hydro Quebec customers lost power with 800,000 without power on Jan 9, 590,000 out on Jan 13, 400,000 on Jan 15; 1000 towers toppled and 24,000 poles downed; another report says 100 large lattice towers and 500 smaller lattice towers will have to be replaced; two of the three transmission lines on the North Shore collapsed; all but one of the five transmission lines feeding Montreal went down; seven towers of 735 kV line near Drummondville came down like dominoes closing Highway 20; some of the system will have to be totally rebuilt; 14,000 Hydro Sherbrooke customers lost power; many roads closed in Estrie region because of flooding or trees and wires in the road; five of the dozen prisons, with 1500 detainees altogether, had no power for more than 48 hours; almost everyone in the "triangle of darkness" formed by Granby, Boucherville, and Saint-Hyacinthe lost power and 170,000 customers there still without power on Jan 16; Iberville was without power from Jan 5 until Jan 25 and residents were burning 700 cords of firewood daily; at least 14,000 trees in Montreal uprooted or severely damaged with no fewer than 21,000 trees damaged by the ice; hardly a sugarbush is intact, with tubing buried under fallen branches; 30% of maple trees affected; 5500 dairy producers in Quebec and Ontario had to dump 13.5 million liters of milk; two water treatment plants in Montreal lost partial power; parts of Montreal without water; city subway system shut down temporarily; four Montreal bridges closed and areas in front of tall buildings were roped off; major businesses like IBM and Alcan closed; Rolling Stones concert in Montreal cancelled when falling ice tore holes in the fabric roof of the Olympic Stadium; Quebec relies on electricity for 41% of energy consumption; 4000 military personnel sent to clear roads for Hydro Quebec crews.

Major ice storm in New York crippled a 9700 square mile area; tens of 1000s of trees damaged; roads closed by ice and downed trees; foot to 18 inches of snow on Jan 15 slowed repairs; Gouverneur prison used as shelter; storm knocked out power to 130,000 utility customers with 116,500 still out on Jan 12 and 61,000 on Jan 18; 99,600 Niagara Mohawk customers lost power, with 59,000 still without power on Jan 15, and 10,000 poles down; New York State Electric and Gas still had 15,000 customers without power on Jan 15; Massena Electric department had lines damaged by huge trees coming down; 75% of Jefferson County without power; Fort Drum without power from Jan 8 to Jan 11, but 1200 families in the off-post military housing still without power on Jan 14; farmers in Clinton County shared three truck-sized portable generators so they could milk their cows; 249th Engineer Battalion installed more than 50 FEMA-supplied generators where needed (e.g. hospital, nursing home, Indian reservation) National Guard called out to help with storm cleanup; federal disaster declaration; flooding followed ice storm, with the Black River flooding in Watertown, Carthage and Philadelphia.

Ice storm in Vermont; more precipitation in four days than the average total for January; 33,200 utility customers lost power; power lines and tens of 1000s of trees snapped from weight of ice; tree damage compared to the 1938 hurricane; farmers unable to milk cows; 6500 utility customers across the state still without power on Jan 13; in Pittsburg and Errol the ice on trees and wires had not melted on Jan 14; Citizens Utilities had 1/2-inch-diameter wires as big as coke bottles with accreted ice--the weight broke poles or pulled them out of the ground; poles came down like dominoes; CU had 1400 customers without power from Guildhall to Norton; all customers in Grand Isle County were reconnected by Jan 18; Vermont utilities had 9000 customers still without power on Jan 10; 13,000 Central Vermont Public Service customers lost power with 8,000 still out on Jan 8; 10,000 Green Mountain Power customers lost power with 5000 still out on Jan 10; 10,000 Burlington Electric Department customers lost power; Central Vermont Public Service 46 kV line and Green Mountain Power transmission line down, so one-quarter of Addison County was without electricity; electric distribution system in Isle La Motte and Alburg needs to be rebuilt from the ground up; some Bell Atlantic customers lost phone service (2000 from South Burlington office) elevation difference noted in many areas including St. Johnsbury; in Strafford area, ice damage began at about the 1700-ft level and increased in severity with elevation, with damage mostly confined to summits and south and southeast facing slopes; Windsor County Forester observed that eastern and southern hillsides above 1500 ft were most severely affected; thousands of trees, some of them a century old, were toppled or crippled; trees in South Reading looked like they were run over by a lawnmower; Granby was like a war zone; century-old sugar maples splintered in Tunbridge; some of heaviest tree damage was in Orange and Windsor counties; in Burlington 25% of the public trees (crabapples, pine, green ash, black walnut) either toppled or will have to be cut down, and another 25% were damaged; in the Champaign Islands maples, cottonwoods, and apple trees were hard hit; 90% of trees on the

University of Vermont campus were damaged; 60% of the 5000-mile-long state trail system was crippled by fallen trees; tree tops and tubing in sugarbushes damaged; worst storm in a long time for CVPS.

Severe ice storm in New Hampshire knocked out power to 67,586 utility customers; sugar bush and timber damage; damage generally occurred in areas between 1000 and 2000 ft above sea level where ice accreted 1 to 3 inches thick on trees and power lines; large differences in ice accretion occurred with small differences in elevation; little icing in some town centers (e.g. Laconia, Pittsfield, New Durham, Hanover, Colebrook, Stewartstown, Stratford, Enfield, Croydon, Lyme, Cornish, Plainfield, Grantham), but heavy icing with tree damage in the surrounding hills; 250 poles, 80 crossarms and 430 transformers had to be replaced; New Hampshire utilities still had 34,500 customers without power on Jan 10; entire town of New London without power; most of Newport without power on Jan 10; 55,000 Public Service of New Hampshire customers lost power with 43,000 out Jan 9, 30,000 on Jan 10, 15,500 on Jan 11, 11,500 on Jan 12, 1150 on Jan 14, and a handful on Jan 18; more than 11,000 New Hampshire Electric Coop customers lost power with 10,000 out on Jan 9, 6000 on Jan 11; 1000 on Jan 14, 150 on Jan 18; DC transmission line from Quebec to Massachusetts damaged along its route through New Hampshire; aerial survey estimated that 5% of the forest was severely damaged with birches and maples at elevations around 1200 ft hit the hardest; south and, perhaps, east facing slopes in Grantham area were hit the hardest; 2 million of the 5.5 million acres of forest had at least some damage; 900 trees down across the trail from Pinkham Notch to Tuckerman Ravine on Mt. Washington, but temperatures remained above freezing at the summit and down to halfway on the auto road; 100s of blowdowns in the White Mountains National Forest; still ice on trees at higher elevations on Jan 24; 300-ft-tall radio tower in Laconia coated with 1 to 1.5 inches of ice collapsed; 2310 phone customers lost service; 16 communities declared a state of emergency; federal disaster declaration for all except Rockingham County; National Guard called up; worst ever ice storm for some old-timers. Another freezing rain storm on Jan 24 hit Manchester, Nashua, and Rochester and surrounding towns with scattered outages cutting power to 31,000 PSNH customers.

Severe ice storm in Maine, followed by single-digit temperatures on Jan 12, knocked out power for 365,000 utility customers; winds gusting to 35 or 40 mph and temperatures in the mid-teens slowed efforts to restore power to the utility customers still out on Jan 14; one third of outages lasted for more than a week and some had no power for three weeks; some summer homes may not get power until spring; ice accreted up to several inches thick on trees and power lines; half-inch guy wire in Bar Harbor was covered by ice that was 9 inches in diameter; 3200 poles, 1.2 million feet of wire, 1600 crossarms, and 2100 transformers had to be replaced (note that these totals are less than the estimates for CMP alone); 291,500 Cental Maine Power customers lost power with 212,000 customers still out on Jan 10, 185,000 on Jan 11, 142,000 on Jan 12, 98,000 on Jan 14, 82,775 on Jan 15, 47,000 Jan 18, 14,183 on Jan 20, 3200 on Jan 22, 1500 on Jan 23; longest outages were in the Augusta, Lewiston and Bridgton districts with 17 days required for restoration of power; had to replace 2 to 3 million feet (several 1000 miles) of cable/line, 2,500 poles, 4000 crossarms, 5250 transformers; 50,000 Bangor Hydro Electric customers lost power with 20,000 still out on Jan 12, 6700 on Jan 14, 6600 on Jan 15, 3782 on Jan 16, 1400 on Jan 18, 100 on Jan 20; 8-mile section near Deblois of H-frame 115 kV transmission line serving downeast Maine cascaded, so Indeck woodfired plant in Jonesboro brought online to help provide power to the 10,000 customers in the area using the lower voltage Route 1 line, which had also been damaged; industrial generators also brought in; Indeck (asking 6 cents/kwh) and Bangor Hydro (offering 3.8 cents/kwh) at odds over cost of power from plant, power ultimately provided at cost as needed; 10,000 of Eastern Maine Electric Coop's 12,000 customers lost power with a few hundred still out on Jan 14; major part of the state's transmission system was patched together by Jan 12; most gas stations along the Maine Turnpike closed on Jan 13 with no power for the pumps; almost every road in Acton blocked by fallen trees with limbs encased in <u>2 inches</u> of ice; a line of 12 poles along route 201 in Gardiner knocked to the ground by fallen trees and branches; Maine Public Radio responsible for doing emergency broadcasts, but had no emergency generator, so was off the air for four days; public television was off until Jan 15; still outages in rural Otis, Mariaville, North Ellsworth and Bucksport on Jan 20; a dozen streets, down from 100 on Jan 9, in Waterville still blocked by trees and power lines on Jan 20, with work slowed by two days of snow; only minor damage to phone system, with one low-hanging wire severed by tractor-trailer rig and another burned through by a live power wire; Bell Atlantic using backup generators, maintained by 87 people, to keep the system's battery power on line; also had damage to more than 6000 local phone lines; relatively light damage attributed to the company's improving the reliability and survivability of the infrastructure over the past ten years, with stranded cables that can withstand 10,000 psi stresses; State Cable customers lost service in the ice storm from power outages to the system, broken cable drops to houses, and damaged transmission lines; still 4900 without service on Jan 15; seven communication towers collapsed; top 70 feet of WEZQ tower on Blackcap mountain fell off; 300-foot tower of 104.7 The Bear on Mount Waldo came down because of heavy icing; trolley service disrupted; extensive timber damage; worst devastation in 33 years for Bangor city forester; 200 city trees in Bangor will have to be removed; birch trees with 6- to 9-inch trunk diameters bent to the ground; pine trees splintered; major event to the forests, particularly in southern Maine; greatest toll was in hardwood stands, worse where foresters had thinned the trees to encourage growth; 2.1 million of the state's 19 million acres of forest had the worst damage, with moderate damage to 2.5 million acres and light damage to 5.9 million acres; National Guard and Brunswick Naval Air Station loaned CMP flood lights so the line crews could work at night; additional tree and power line crews and trucks flown in by Air Force; the power system was fragile after repairs had been made because of all the damaged trees near the lines; rash of generator thefts from homes, businesses, telephone switching stations, and utility company buildings; thefts of equipment from CMP trucks; CMP trims branches on a five-year cycle; worse than hurricanes Gloria (1985) and Bob (1991); compared to Dec 19, 1929 ice storm; worse than the flood of '87 or the hurricane of '68; National Guard and public works employees helped with tree clean up; federal disaster declaration for the entire state. Another devastating freezing rain storm with gusts to 25 mph on Jan 24 hit the Portland, Brunswick, and Alfred districts cutting power to 75,000 CMP customers, with 12,000 still without power on Jan 25, and 1000 on Jan 26; 1 or 2 inches of ice on top of the wires with 4-inch long icicles; 90% of Wells without power; Cousins and Littlejohn Island hard hit; Prince's Point Road hit with long outages in both storms; little damage to poles.

Ice storm in New Brunswick cut power to 28,000 New Brunswick Power customers, 2500 for four days; heavy build up of ice snapped main feeder lines; St. John Energy still had 500 customers without power on Jan 14; several poles toppled outside St. George where there was no power; St. George and St. Andrews declared state of emergency; hardwood tree damage.
Ice storm in Nova Scotia cut power to 20,000 Nova Scotia Power customers; power outages in the Annapolis Valley lasted three days for 500 customers in rural areas; severe apple tree damage feared.

Ice storm in Prince Edward Island knocked out power to a few hundred (or more) Maritime Electric customers for 10 to 12 hours; high winds to 130 km/hr caused wires to gallop and slap together, also pulled down poles.

On Jan 16 new ice storm hit Connecticut knocking out power to 16,200 utility customers.

November 19, 1986

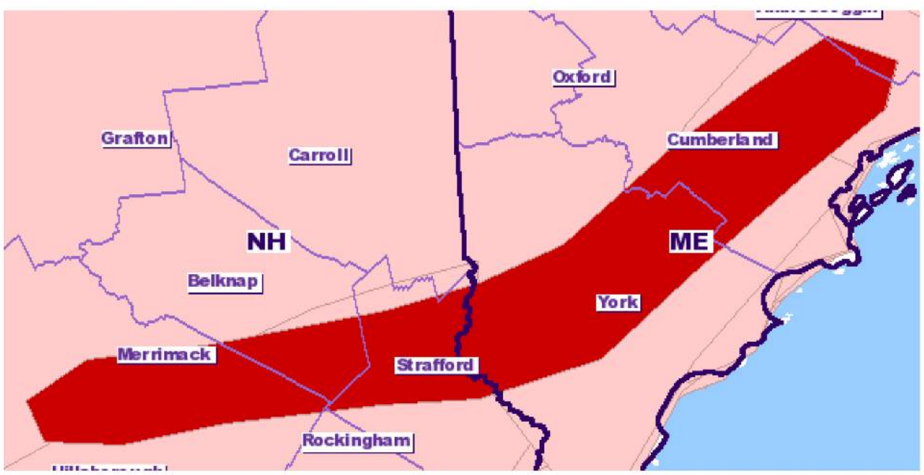

Figure D-9 - November 19, 1986 Ice Storm

Snow and freezing rain storm in New Hampshire loaded branches which broke onto utility lines; scattered power outages; 700 in the Lakes Region without power for up to 7 hours; 3200 in Manchester without power for a few hours; 1000 in Milton without phone service for up to 12 hours.

Narrow swath of freezing rain in Maine raised havoc with trees and power lines; ice-laden branches broke onto power lines; 12,000 utility customers were without power.

January 3-7, 1986

1 inch of ice on trees in Maine in sleet and freezing rain storm caused weekend-long power outages.

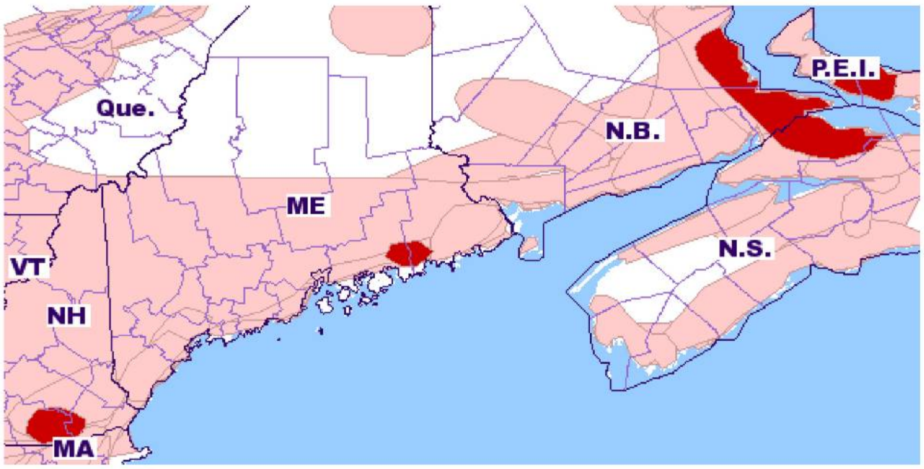

Figure D-10 - January 3-7, 1986 Ice Storm

Freezing rain in New Hampshire caused power outages for 100s.

Power out for several 1000 customers in New Brunswick; drifting snow and high winds made repairs difficult.

Snow, freezing rain, and wind left 1000s without power in Nova Scotia for up to four hours.

Worst ice storm of winter in Prince Edward Island caused massive outage; winds to 120 km/hr; wires galloping and poles down on main transmission line; power not restored for 10 to 12 hours; phones out in some areas.

Not mapped: 10,000 without power in Cape Breton at some time during the weekend.

January 31 – February 4, 1982

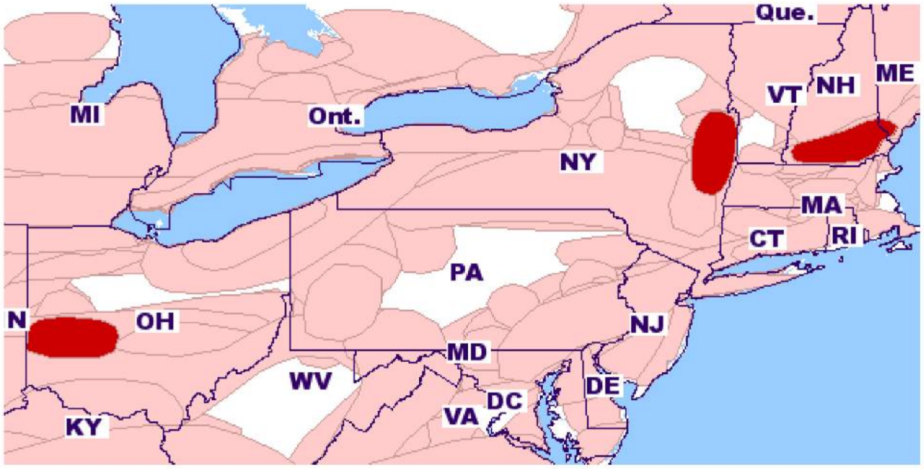

Figure D-11 - January 31 - February 4, 1982 Ice Storm

Wet snow, sleet, rain, freezing rain, and wind storm in Ohio caused power outages; broken trees and ice on wires broke wires; 17,000 Dayton Power and Light customers without power; no power or water in New Paris; outages lasted up to three days.

Heavy ice and tree branches pulled down power lines in eastern New York; 11,000 Niagara Mohawk customers in Columbia County lost power for up to nine hours; Troy hardest hit; one of the better ice storms in the past ten years.

Widespread power outages in New Hampshire in rain, freezing rain and snow storm.

Ice and broken tree limbs caused outages in Maine according to *Storm Data* but no outages were reported in the *Portland Press Herald*.

January 4-9, 1979

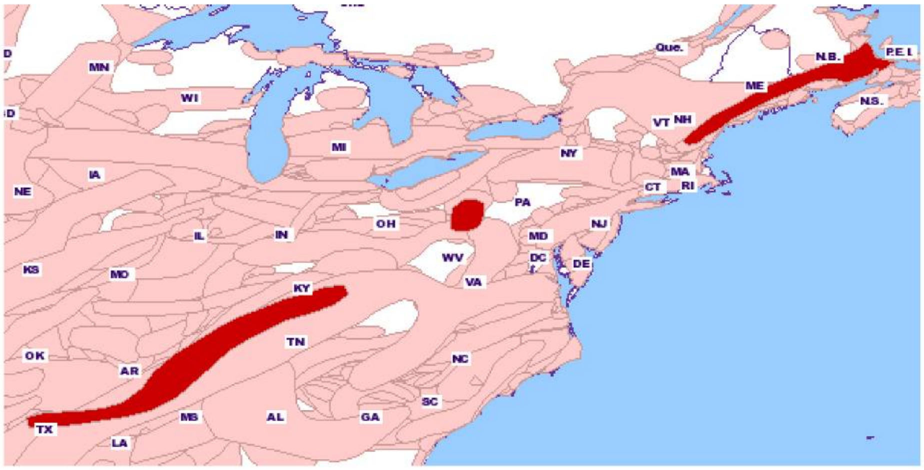

Figure D-12 - January 4-9, 1979 Ice Storm

Power and phone outages from ice-laden trees falling on wires over large parts of Whatcom County in Washington; three Puget Power substations that had been restored once went out again.

Second ice storm in a week in Texas caused scattered brief power outages.

Up to <u>3 inch</u> ice accumulations in Arkansas; Arkansas Power and Light had 80,000 customers without power at the height of the storm; with many still out two weeks later; 3.5 millions acres of timber damaged; one of worst ever ice storms in the state.

Up to <u>2 inches</u> of ice in Mississippi snapped limbs and broke wires and poles a few feet above ground level; 30,000 customers had no power for several days; Cleveland and Clarksdale blacked out for a day; very cold following storm; governor declared state of emergency in nine counties; Tennessee Valley Authority had outages caused by ice; extensive damage to forests and orchards.

Freezing rain caused power and phone outages and damaged trees in Tennessee; Tennessee Valley Authority had outages caused by ice.

Freezing rain in Kentucky caused power outages; ice-covered wires and tree limbs snapping wires; 50% of Warren Rural Electrical Cooperative customers in eight counties were without power for up to two days; major transmission line in Lexington knocked out by ice on the wires; phone service out for hundreds of South Central Bell customers; two poles that were cut down for firewood caused outages near London; worst ice storm ever.

Freezing rain caused power outages over most of western Pennsylvania.

<u>1 to 2 inches</u> of ice accumulated on trees and wires and caused a major power disruption in New Hampshire.

Heaviest ice storm in many decades in Maine coated trees and power lines with more than 2 inches of ice; 45,000 customers were without power for an extended period; moderate damage to fruit trees.

Widespread outages in New Brunswick from freezing rain; over an inch of freezing rain in Fredericton weighted trees with ice; four elm trees fell on one power line in the Fredericton district; 32 communities blacked out; some without power for two days; phones out of service for some in Moncton; not as bad as the Groundhog Day storm a couple of years ago that had cold temperatures and high winds.

December 5-21, 1977

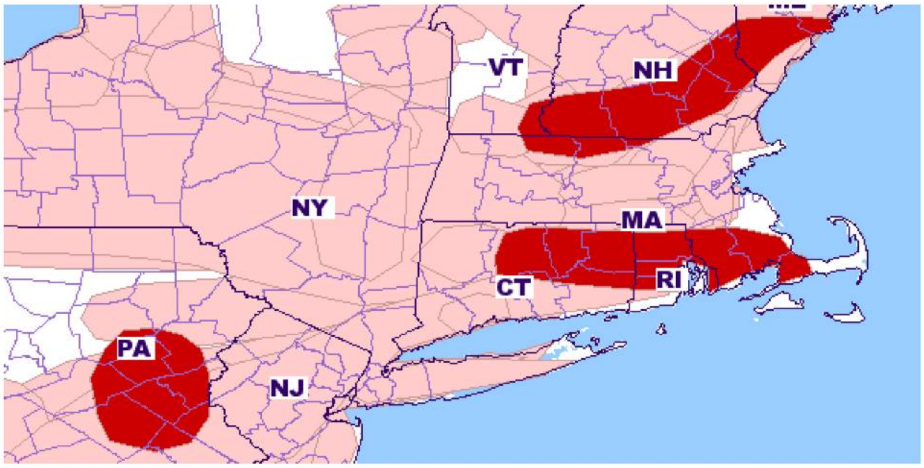

Figure D-13 - December 5-21, 1977 Ice Storm

Considerable buildup of ice from freezing rain in Pennsylvania's Lehigh Valley and northern Schuylkill Valley; trees bent and broken by ice broke power lines; 35,000 utility customers without power, some for a considerable period.

Ice from freezing rain broke tree limbs and power lines in Connecticut.

Ice broke power lines in Rhode Island.

Freezing rain broke power lines in Massachusetts.

Freezing rain caused some electrical blackouts in Vermont.

Freezing rain coated trees in New Hampshire; birch trees leaned and evergreen tree branches broke on power lines causing outages that lasted for hours.

Freezing rain, sleet and snow in Maine; Central Maine Power had scattered outages, many in rural areas; sleet jumping added to outage duration.

December 21-31, 1975

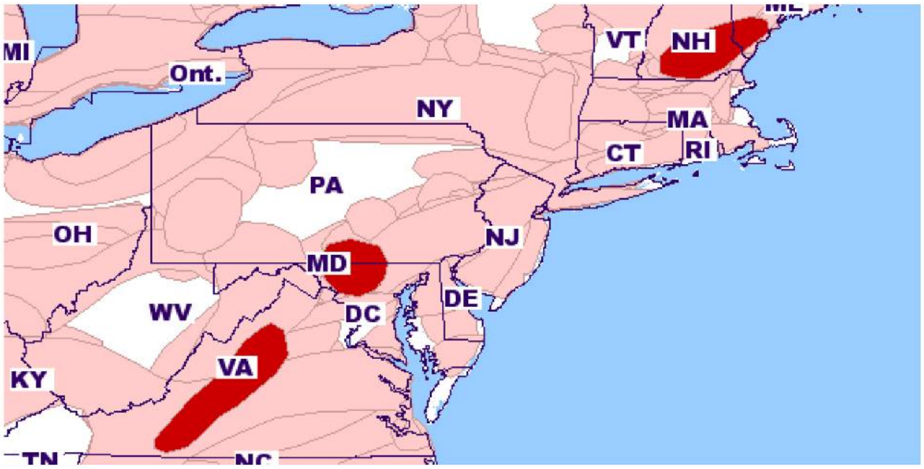

Figure D-14 - December 21-31, 1975 Ice Storm

Freezing rain in Virginia caused power outages; ice laden branches snapped off ripping down power lines; 1/2 inch of ice on objects in Charlottsville-Lynchburg area; bent trees and broken branches damaged power lines in southwestern Virginia, with outages lasting up to 82 hours; one of the most severe ice storms in recent years in that area.

Freezing rain in Maryland produced ice laden tree branches that snapped phone and power lines as they broke; service interrupted.

Heavy freezing rain in Pennsylvania downed many trees and power lines resulting in numerous power outages.

Heavy ice accumulations in New Hampshire caused tree damage and power outages.
Fallen tree limbs knocked out power in Maine.

January 28, 1973-February 3, 1973

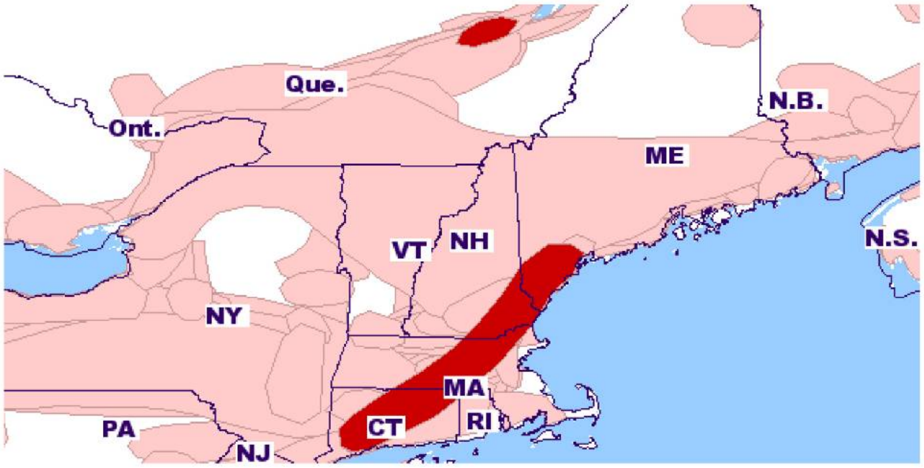

Figure D-15 - January 28, 1973-February 3, 1973 Ice Storm

Wind and ice felled trees and power lines in two storms in Connnecticut; 8500 customers were without power for various periods in the first storm; the second storm caused some outages.

Some power outages in Rhode Island from glaze and wind.

Freezing rain in Massachusetts resulted in ice thicknesses of up to 1 inch; wind blew down ice-laden branches that damaged utility lines.

Freezing rain in New Hampshire; limbs of ice-covered trees broke and cut utility wires. Scattered damage in Maine from limbs of ice-covered trees falling.

Freezing rain in greater Quebec City and east caused heavy damage to the power and phone lines on the north shore of the river; 2-inch-thick ice in some regions; 1 inch of ice on phone poles; outages caused by ice-covered trees falling on wires; 32,000 customers without power for a couple of days.

December 14-28, 1973

Numerous power outages in Maryland from freezing rain icing trees that then fell on power lines.

Ice from freezing rain broke large tree limbs and power lines in Delaware; outages lasted more than four days for homes and poultry farms; National Guard called out.

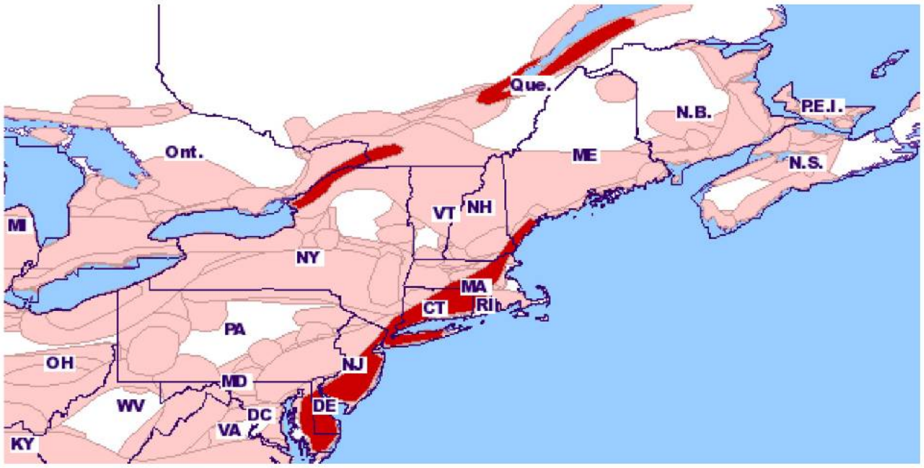

Figure D-16 - December 14-28, 1973 Ice Storm

Howling sleet and freezing rain storm in New Jersey; power failures in most counties from ice-weighted trees snapping; astronomical damage to trees.

1 inch of ice with long icicles on trees and wires in severest ice storm in many years in New York; trees and limbs fell on ice-coated wires; many communities without electricity; fallen trees obstructed streets and highways; three people electrocuted by fallen power lines.

Freezing rain in Connecticut caused ice buildup on trees resulting in greater damage than in the 1938 hurricane; power lines broken by ice and trees; 269,000 Connecticut Light and Power Company (worst storm in 20 years) customers without power, with outages lasting longer than one week; Hartford resident killed by falling tree limb; emergencies declared in Hartford, Middlebury, Vernon, and Middletown; National Guard activated to clear fallen trees; worst ice storm in history.

Freezing rain in Rhode Island covered exposed objects with thick ice and caused widespread broken trees and branches and utility failures; 100,000 customers without power at one point; roads blocked by trees.

Freezing rain in Massachusetts downed 100s of trees and utility lines; 80,000 Boston Edison customers without power for up to 24 hours; state of emergency in Marlborough; 80% of Sudbury without power; 123,000 in central Massachusetts lost power; 206-foot-tall radio tower in Framingham downed by weight of ice; most severe icing since December 1968 or longer.

Freezing rain and snow caused rash of power outages in New Hampshire.

Freezing rain and snow in Maine caused hours-long power outages; no power in Wells; most outages caused by ice-covered branches falling on wires.

Niagara Mohawk in northern New York along Lake Ontario and Seaway had scattered outages in sleet, rain and freezing rain storm from frozen switches and ice-covered branches falling on wires; thick ice on trees and wires in Massena.

75,000 Hydro-Quebec customers without power in Quebec City, Quebec and east to Mont Joli and Gaspe from freezing rain storm; gusty winds to 25 mph after storm; severe outages in Mont Joli region, where state of emergency was declared, caused by weight of ice and by branches falling on wires; many without power for up to six days; water filtration system out in Ste. Foy; 18 poles down near Ile Verte; irreparable damage to 1000s of trees; some relatively short outages to 200,000 in Montreal (pole knocked down by truck, circuit breakers tripped) and Ottawa; worst ice storm since 1961, worst of the century in the lower St. Lawrence region.

December 30, 1972- January 1, 1973

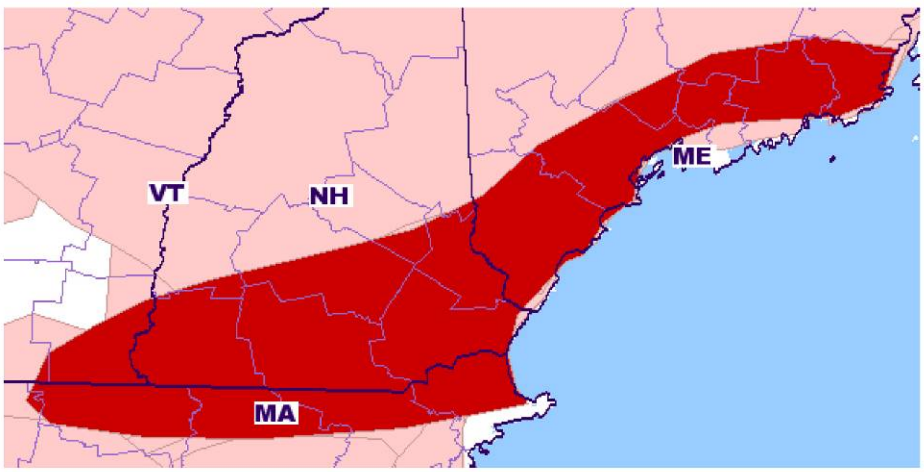

Figure D-17 - December 30, 1972 - January 1, 1973 Ice Storm

Severe icing from freezing rain in Massachusetts caused serious tree damage and power outages; ice accumulated to 1/2 to 3/4 inch thick; maples in one area suffered 50% loss.

Serious ice storm in Vermont; much tree damage, especially to maples, and utility outages.

Serious ice storm in New Hampshire with ice accumulation up to 1/2 inch and more; much tree damage from weight of ice; utility outages.

In Maine severe ice storm broke tree limbs and caused utility outages.

December 22, 1969- January 17, 1970

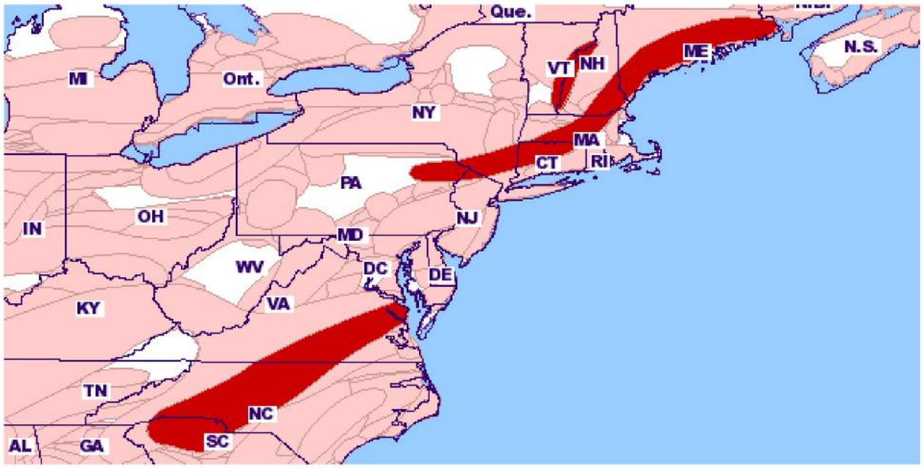

Figure D-18 - December 22, 1969- January 17, 1970 Ice Storm

Freezing rain, snow, and wind caused power failures in Pennsylvania.

Moderate utility damage in scattered areas in New York from freezing rain, with outages lasting up to 48 hours.

Two freezing rain storms in Connecticut, the first with high winds caused extensive power failures; power and communication lines knocked out in second storm also.

A severe ice storm in Massachusetts; trees and limbs weighted with ice broke and downed utility lines; widespread power outages; cars damaged by falling limbs; in the northeaster that followed heavy snow and ice on trees broke trees and limbs, causing utility outages.

Noreaster in Vermont caused freezing rain along the Connecticut River and in the Northeast Kingdom; ice built up to more than 2 inches with local reports of 3 to 6 inches on wires and twigs; devastated forests and utility lines described as "havoc unbelievable"; prolonged utility outages, up to a week or more; most severe ice storm in 40 years for the utility companies in the Connecticut Valley area where ice remained in the northern sections for up to six weeks.

Freezing rain in southern New Hampshire caused heavy icing and widespread power failures; in second ice storm spectacular glazing in north coated twigs and wires with 1 to 2 inches of ice; trees and limbs broken by thousands with devastation comparable to the 1938 hurricane; power out for the second time in a week in some areas.

Worst ice storm in many years in Maine followed a few days later by a northeaster; in the first storm 1000s of trees toppled and took utility wires with them; snow, sleet, and freezing rain in the second storm damaged 1000s of trees causing devastation like the 1938 hurricane; utility wires downed for the second time in a week in some communities.

Freezing rain in Virginia damaged utilities; 50,000 customers of Virginia Electric and Power Company in Richmond and 62,000 overall without power; heavy ice damaged trees and shrubs; power outage in Richmond caused loss of water pressure and sewage overflows into nearby creeks; wires and trees snapping up as ice melted caused more outages; some customers without power for three days.

Trees and power and phone lines damaged in North Carolina from a great deal of freezing rain; trees fell on power lines; outages lasted from a few hours up to two days.

Trees and power and phone lines damaged by freezing rain in South Carolina.

December 21, 1968-January 18, 1969

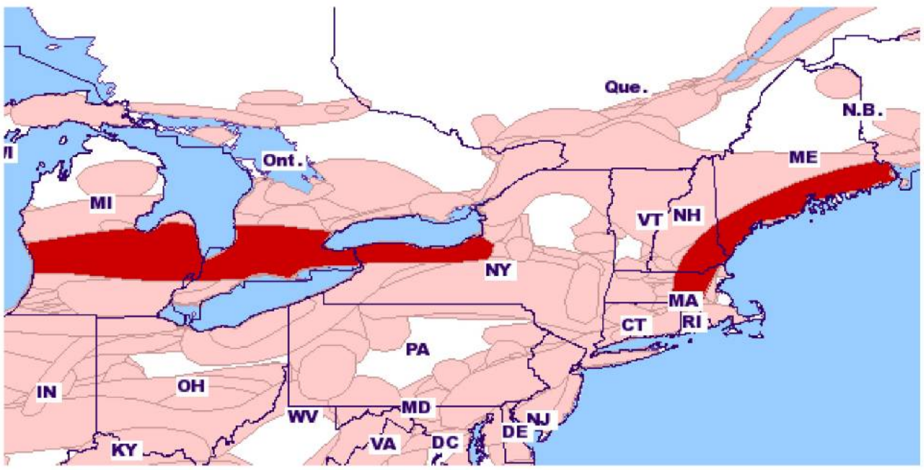

Figure D-19 - December 21, 1968-January 18, 1969 Ice Storm

Falling trees and power lines in Astoria, Warrenton, and Hammond, Oregon from freezing rain; communications out to Cape Disappointment; trees and power lines down along Highway 30; no power or phones in community north of Washougal; armor coat of ice and numerous outages in Portland after snow; first silver thaw there since December 1964.

Ice-covered trees caused outages in North Bend and Prescott, Washington.

1 to 2 inches of ice from freezing rain in Michigan; worst damage in history for utilities in Lapeer and Sanalac Counties; three to four mile stretches of poles and wires on the ground; trees broke under weight of ice; major disaster for Detroit Edison; many in rural areas without power for more than three days; whistle at St. Johns fire department froze.

Worst ice storm in 20 years for Ontario Hydro in Simcoe, Ontario; almost a crisis in Niagara Falls; up to 0.5 inch of ice in outlying areas of Hamilton; up to 3 inches of ice in Simcoe area with residents still without power after four days; not as bad in Stoney Creek area as the storm 11 months ago, with outages lasting only 30 hours in this storm.

Freezing rain with 1/4 to 1/2 inch of ice in New York crippled counties from Niagara Falls to Oswego area; power and phone lines disrupted; worst from Niagara to Rochester with 300 lines down in Niagara County.

24 hours of freezing rain resulted in the worst ice storm since 1921 in the area just west of Boston, Massachusetts; 1/2 inch of ice or more on exposed surfaces; 100,000 without power, some for an extended time.

Ice broke trees in Maine causing utility outages.

Up to 1/2 inch of ice from freezing rain broke branches and caused utility failures in New Hampshire.

Extremely heavy ice accumulations from freezing rain in interior Rhode Island caused considerable damage.

December 25, 1967-January 19, 1968

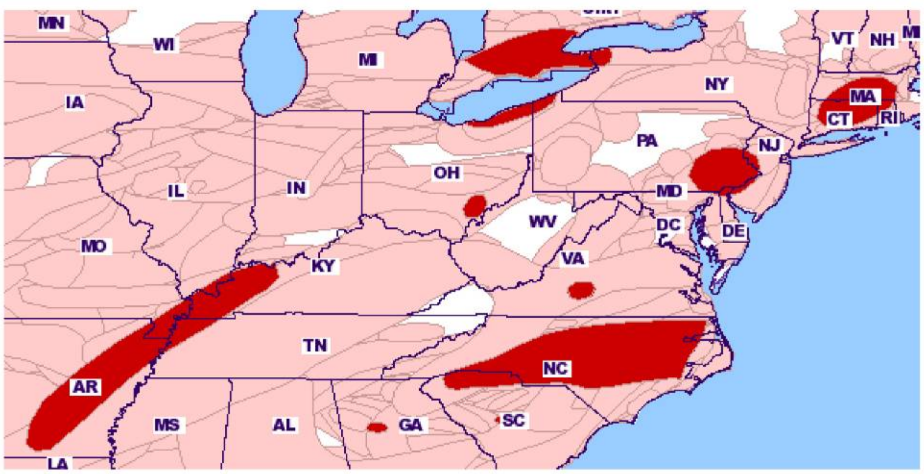

Figure D-20 - December 25, 1967-January 19, 1968 Ice Storm

Worst snow and ice storm in living memory in London, Ontario, with outages lasting more than 5 days in some areas; most power outages were caused by ice covered trees breaking on wires; birches and willows hard hit; phones out in some areas; TV tower south of Alymer collapsed; former head of London PUC compared it to the March 1922 storm that blacked out most of the city; worst ever ice storm for Toronto Hydro crippled city.

Freezing rain coated trolley wires with ice in Cleveland, Ohio; power lines toppled mostly in north central and southeast counties; worst storm of the season.

Gusty sleet storm in southeastern Pennsylvania broke overhead wires; power outages in Erie from ice-covered branches falling on wires.

Weight of ice and snow broke many utility lines in Kentucky; residents without power or phones.

Power out in northwest Tennessee for up to nine hours.

55,000 outages for Arkansas Power and Light customers from glazing; 15,000 Southwest Bell customers in 20 cities lost phone service in the storm.

Freezing rain damaged trees and caused outages in Connecticut.

Two episodes of freezing rain caused outages in Massachusetts, up to 1/2 inch ice damaged trees and utility lines.

Widespread but little damage to trees and utilities in Virginia.

2 to 3 inches of ice but luckily no wind in North Carolina; several counties without power or phones for one to five days; worst power failure in Charlotte's history with 40,000 of Duke Power's 114,000 customers without power; 50% of Goldsboro without power; one of the worst ever ice storms for Carolina Power and Light, and far worse than Hurricane Hazel in 1954; 73% of Southern Pines without power, problems caused almost exclusively by longleaf pines falling in massive numbers; no gas available along I-75 from Smithfield to almost Fayetteville; large chunks of ice falling from 1400-ft WCTU-TV tower punched holes in the roof of the studio; REA chairman calls it the worst ice storm since 1942.

Freezing rain coated a power line that fell on phone cable on Paris Mountain, South Carolina; worst ice storm in 37 years in Greenville; worse than hurricane Hazel; power and phone lines in Greenville are much less vulnerable than they were at Christmas 1945 when an ice storm knocked out power to 70% of the city.

Ice accumulations from freezing rain broke a main feeder line in Marietta, Georgia; outages in metro Atlanta also from ice-covered branches falling on wires; some customers without power for two days.

January 4-19, 1962

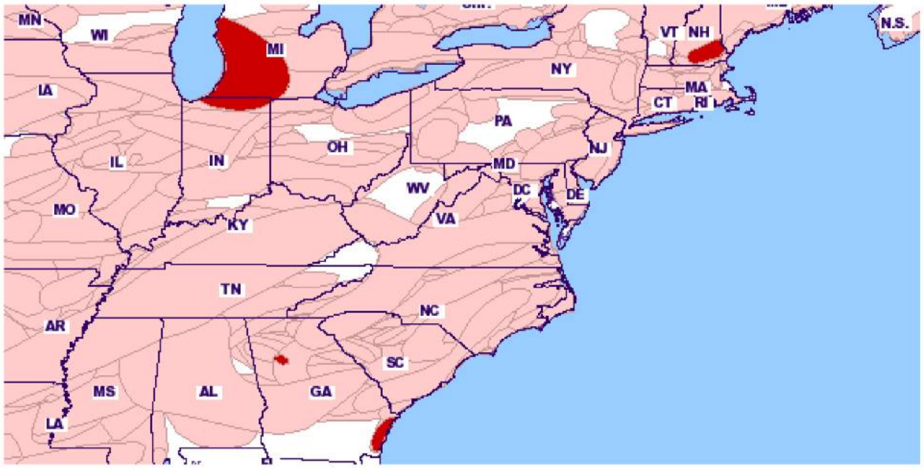

Figure D-21 - January 4-19, 1962 Ice Storm

One of the most severe and sustained ice storms in history in the Muskegon, Michigan, area; Consumers Power Company had primary lines out in at least ten parts of the county, but had them back in service within five hours.

In Indiana westerly winds to 31 mph broke ice-covered wires; phone and power lines down from weight of ice and ice-covered trees falling on wires.

Unusually severe glazing on trees and wires in New Hampshire caused some power and phone outages; great damage to trees and shrubs; worst ice storm in 30 years.

Worst ice storm in recent memory in Massachusetts and Maine, but no mention of tree or power line damage in the *Boston Globe* or the *Portland Press Herald*, disagreeing with *Storm Data*.

Southeast coastal Georgia paralyzed by unusual ice storm for several hours; phone and power lines damaged by falling ice covered trees; in Atlanta area wires broken by ice-covered trees, power restored by afternoon; Atlanta Transit using ice breakers on trolley wires.

Ice coated trees in the Hilliard area in Florida, but no reports of damage.

January 1-2, 1961

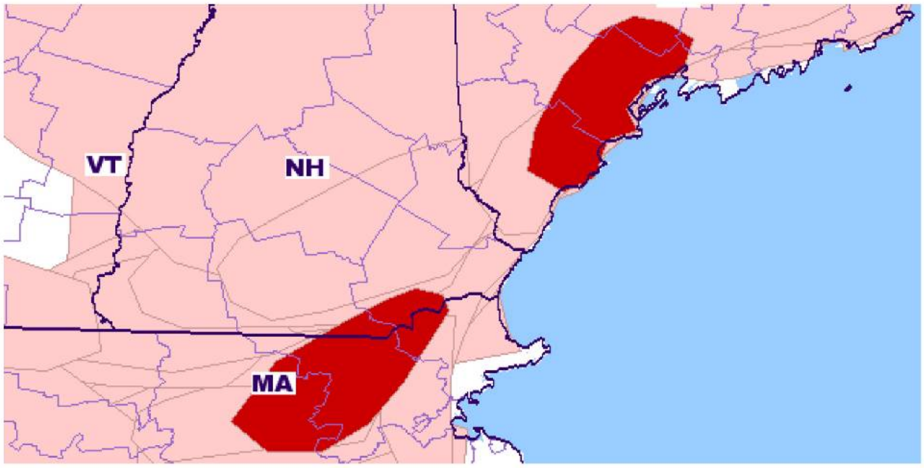

Figure D-22 - January 1-2, 1961 Ice Storm

Power lines broken by ice on wires or ice-covered trees falling on wires in Massachusetts.

Snow, rain, and sleet in New Hampshire; power outage in Salem.

Snow, rain, and sleet storm in Maine; power lines snapped under heavy coating of ice over a widespread area; tree limbs damaged wires; roads closed because of live wires; New England Telephone and Telegraph had minor damage.

December 23, 1959 - January 6, 1960

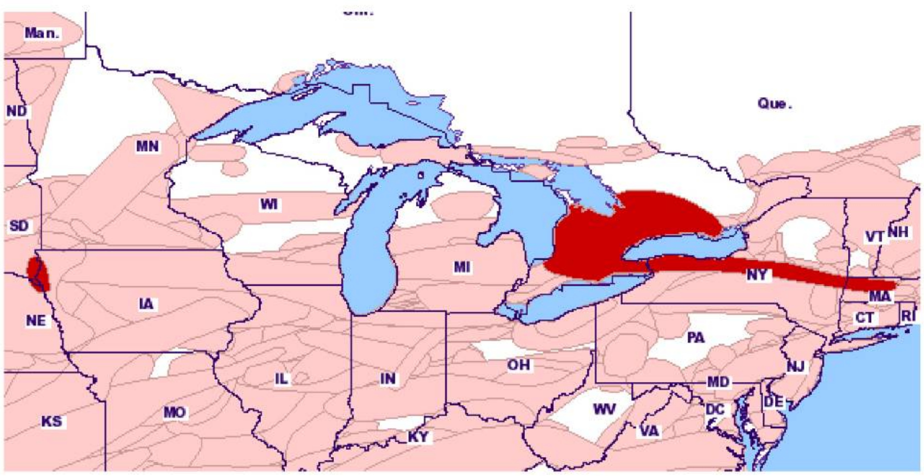

Figure D-23 - December 23, 1959 - January 6, 1960 Ice Storm

Extensive damage to trees and wires from glaze and strong winds to 25 mph in South Dakota; 40 communities without phones for more than 24 hours.

0.5 to 0.75 inches of ice in Ontario; long stretches of poles on the ground; phone, telegraph and power out; poles upside down; trees split open with poplar, birch and willow trees taking a beating; 220 kV line between Barrie and Kitchner severed, 115 kV line between Niagara and Hamilton out, 115 kV line outside London and three of four 115 kV lines from Owen Sound to Hamilton down; one week to restore power in Orangeville; worst sleet storm in years; worst in 20 years for Bell Telephone.

Worst sleet storm of major proportions in western New York since 1936; strong winds off Lake Ontario contributed to heavy icing of trees and wires; most severe ice storm of record in Rochester area with more than 40,000 utility customers without electricity--some still out on January 1--and 4500 customers without phone service; in Buffalo worst in 30 years for Niagara Mohawk, winds whipping wires, worst tree damage since 1929, 115 kV line down; 1.5 inches of ice on wires and trees in parts of Schoharie County; Warsaw in Wyoming County isolated; ice still on trees and wires on December 31.

Heavy ice and snow in Massachusetts brought down branches breaking overhead wires.

January 28 – February 6, 1951

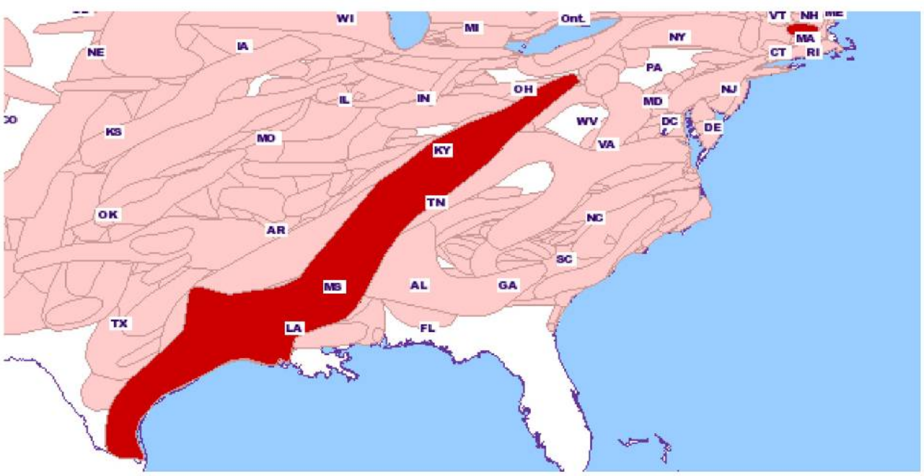

Figure D-24 - January 28 – February 6, 1951 Ice Storm

Ice storm pounded Rio Grande Valley; highlines snapped by ice; 272 phone circuits in San Antonio unusable and situation deteriorating; long distance and telegraph circuits from Houston and south out.

Southern Bell suffered the worst ice storm damage ever across Louisiana, Mississippi, Alabama, Tennessee, and Kentucky; more than 80,000 telephones out of service and 3,174 long distance circuits out of commission; service back to normal within 10 days.

Heavy icing and thunderstorm winds in Louisiana broke power and phone lines and trees; forests and pecan trees heavily damaged; 60% of phone lines to Monroe out.

Mississippi Power and Light extremely hard hit in all 44 counties; 49 towns isolated by phone and telegraph outages, expect some customers to be out for 3 to 4 weeks; severe timber damage from ice and wind, century-old oaks shattered; worse than 1915 and 1932 storms; 800 of 1000 poles between Jackson and Meridian down.

Wind and ice damage in Alabama.

Most devastating winter storm in recorded history in Middle and West Tennessee; outages lasted more than 1 week in rural areas; 80K out in Nashville area nearly shuts down industry.

Tennessee Valley Authority had 31 transmission line failures in south central Kentucky, middle Tennessee, northwest Alabama, and north Mississippi; heaviest ice was in the Tupelo and Nashville areas; switches covered by thick ice and some were damaged.

Trees and power lines down in Kentucky.

In Ohio snow and freezing rain in southeast quarter of state heavily damaged trees and power lines.

Worst sleet and ice storm in years in Massachusetts; some ice-coated trolley wires snap; ice on phone wires in central and western parts of the state.

APPENDIX E

System Protection

Chapter Structure

A. TRANSMISSION SYSTEM PROTECTION

The discussion of transmission line protection begins with the definition of a transmission line. A transmission line is defined by the location of the circuit breakers or other sectionalizing devices that isolate the line from other parts of the system and include sections of bus, overhead conductor, underground cable, and other electrical apparatus that fall between these circuit breakers.

The fundamental concepts of zones of protection and overlapping zones of protection need to be addressed. A protection zone is defined as the area a relay or set of relays are responsible to protect. For a transmission line this zone is normally bounded by the circuit breakers and current transformers (CTs) that connect to the relays at each end of the line. Overlapping zones of protection is the practice of using CTs located in Zone A to provide current inputs to relays protecting Zone B and vice versa, as represented in Figure E-1. Overlapping zones ensure that equipment located at the edges of a zone is protected.[1]

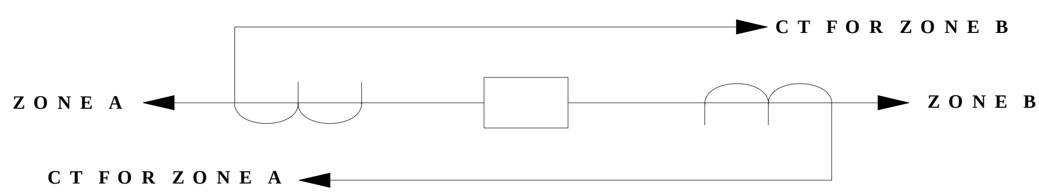

Figure E-1 - Overlapping zones of protection.[2]

One of the more important design considerations in transmission protective relaying is reliability. Relaying reliability included two things: dependability and security. Dependability is defined as

[1] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.
[2] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.

the degree of certainty that a relay will operate correctly. Security is defined as the degree of certainty that a relay will not operate incorrectly.[3] A balance between dependability and security needs to be reached. Dependability is the easier of the two to obtain by providing redundant relays, fail-safe designs, and thorough testing of protection schemes. Security is harder to obtain, but can be improved through the use of high quality equipment, self-checking relays, and avoiding overly complicated protection schemes.

Standard transmission line protection methods may include phase overcurrent, ground overcurrent, phase distance, ground distance, and pilot system relaying. Overcurrent protection (phase and ground) on transmission lines is often controlled by a directional element that determines which direction current on the system is flowing in order to distinguish between faults within a zone of protection as opposed to an external fault. This selectivity is important to ensure only the faulted section of the line is isolated, allowing the rest of the system to operate normally. Over current protection must be used carefully as it may create coordination issues with other protection devices or schemes. Coordination and selectivity determine the ability of a protection scheme to distinguish where a fault is in the system and then take action in the proper sequence to remove the faulted line without isolating more of the transmission system than is necessary.[4] As line lengths increase and more zones of protection are added, coordinating between the many zones becomes difficult.

Distance relaying (phase and ground) is commonly used in transmission line protection. It is capable of approximately determining the location of a fault and determining if the fault is within the relay's zone of protection. During a fault, the distance relays determine the fault location by measuring voltage and current to calculate the apparent impedance to the point of the fault and then compare it to the fixed impedance of the transmission line. Since the relay is calculating the apparent transmission line impedance there may be some error. Therefore, the standard practice for setting distance relays is to set a zone 1 to trip instantaneously if a fault occurs within 80-90% of the transmission line length, and zone 2 is set to trip with some time delay if a fault occurs within120% of the line length. Standard distance relaying allows for easy coordination between transmission line sections, but does not allow for high speed tripping on the entire line. The delays necessary for coordination may result in greater damage to the line during a fault than if the whole line could be tripped instantaneously for any fault along the line. Further complicating the use of distance relaying are multi-terminal and tapped transmission lines which can affect the apparent impedance of the line due to network changes.[5]

[3] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.
[4] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.
[5] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.

To provide high speed tripping on 100% of the protected line, pilot schemes are used. Pilot schemes use communications channels to transmit information between the local and remote relay terminals. The communication method used may be power line carrier, which transmits a high frequency signal on one or more of the transmission line conductors, standard telephone lines, or fiber optic cables. The two most common classes of pilot schemes are directional comparison, and current comparison or line differential. The directional comparison schemes use fault current direction information transmitted between the two terminal relays to determine the fault location. The current comparison schemes compare the currents at each end of the transmission line. The two currents should normally be nearly equal. If the difference between the measured currents at each terminal is too great, the relays determine that a fault has occurred and act to remove the fault from the line. The advantage of these types of schemes is they remove the line from service when a problem occurs without delay or loss of security.

The use of automatic reclosing of breakers to restore service prevents long outages due to temporary faults such as tree contacts or lightning strikes[6]. If a breaker trips open, a timer will reclose the breaker after a short period of time. If the fault has disappeared the breaker will stay closed and the customers affected will see no further interruption of power. If the fault still exists after reclosing, the breaker will once again trip. If this occurs a preset number of times, the breaker will no longer attempt to reclose, and will "lock out" preventing the breaker from being automatically closed again. In this case, a crew is normally dispatched to patrol the line and determine the cause of the fault. Once the issue causing the fault is repaired the line is re-energized manually. Reclosing uses a shot counter to determine the number of times a breaker is reclosed after the initial fault detection. A shot is defined as a cycle where the breaker is tripped open, waits some defined time, and is closed again. Commonly, transmission lines incorporate one or two shots of reclosing to attempt to clear a fault and a distribution line may use up to four shots before locking out. A delay time may be anywhere from a few cycles based on the breakers trip and close speeds up to several seconds depending on the transmission line characteristics as well as environmental factors such as frequency of lightning strikes. Reclosing can be done for all three phases and at higher voltages single-phase reclosing is used to limit the interruption of power flow on all three phases.

Protective relays are devices that measure some quantity, such as voltage or current, and if the relay determines that the measured quantity is abnormal the relay acts to open a circuit breaker to remove the cause of the abnormality. In the past all protective relay were electromechanical, meaning they use electromagnetic forces to rotate a metallic wheel or impart a force on a cantilever beam to cause an electrical contact, or switch, to close resulting in the tripping of a circuit breaker. Creating the logic necessary to implement the protection schemes used often required multiple electromechanical relays, as seen in Figure E-2, each with its own specific

[6] *IEEE Guide for Protective Relay Applications to Transmission Lines*, IEEE Std. C37.113-1999. (1999). New York, NY. IEEE.

function. Still in use today, electromechanical relays are quickly being replaced by more modern solid state and microprocessor based relays. These are based on computer technology and a single relay can be programmed with logic to perform the functions of multiple electromechanical relays. The ability to be programmed means they are more flexible than electromechanical relays, and the use of electronics rather than moving parts results in greater reliability. Because of the much smaller size and complexity of the new relays, it has become standard practice to install a primary relay with a secondary protective relay as back-up to the first in case of failure. Microprocessor based relays are capable of recording pre and post fault data that can help to determine the cause of a fault and if the protection functioned as expected. Modern distance relays can also provide a relatively accurate fault location that will help direct crews appropriately to begin the line inspection. Electromechanical relays do not have these analysis tools.

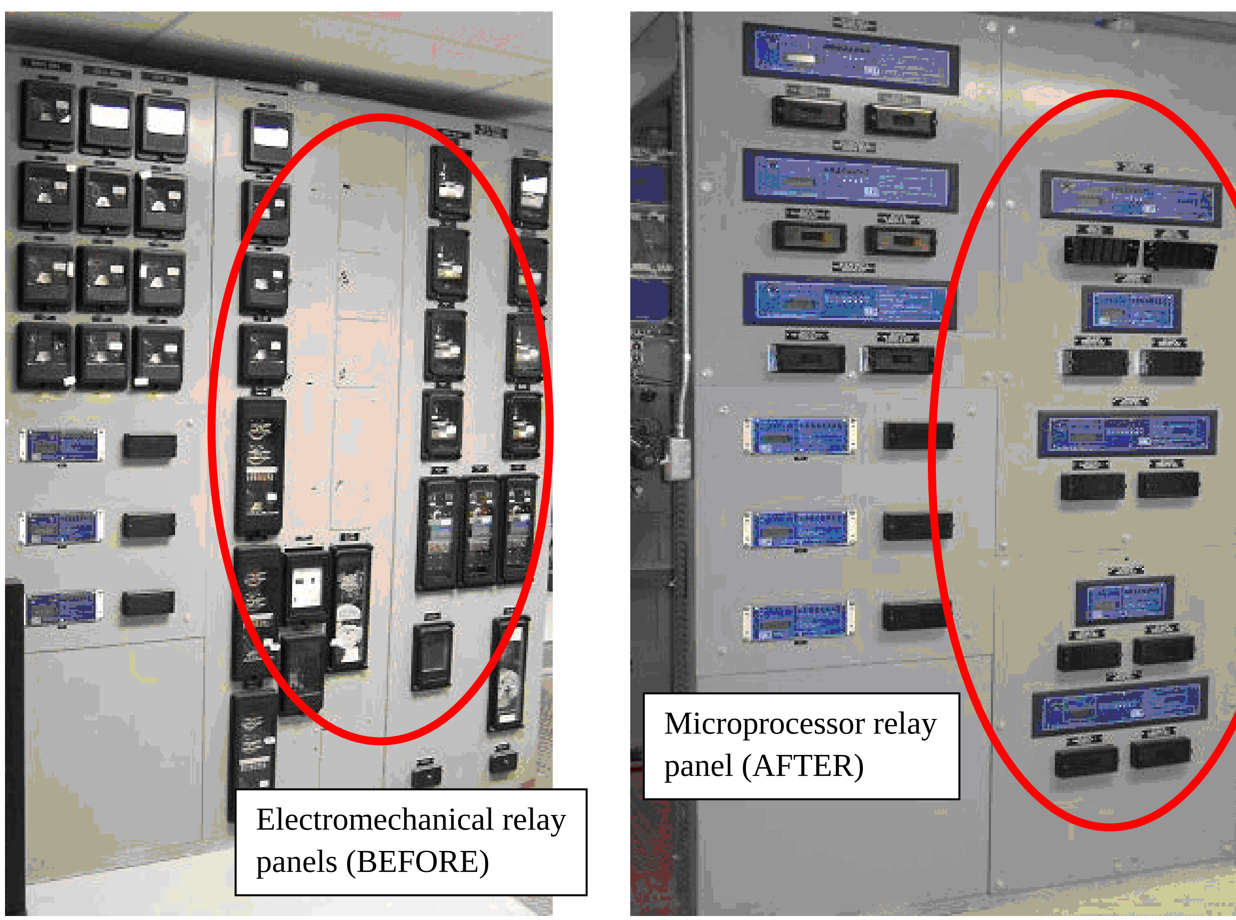

Figure E-2 – The electromechanical relays on left were replaced with the microprocessor based relays on the right. (Photos by NEI)

During the December 2008 ice storm, the causes recorded for transmission line protection operations were documented as being: “trees in line”, “static wire failed and caused fault”, and "no cause found upon inspection". The first two causes resulted in permanent faults. The result was that the breakers protecting these lines tripped and locked out. The "no cause found upon inspection" group was likely due to momentary contact with vegetation or by conductors touching each other due to galloping or line jumping. During these momentary faults, the transmission line protection would have opened breakers to clear the fault and then automatically reclosed the breakers to re-energize the line.

B. DISTRIBUTION SYSTEM PROTECTION

A distribution system is typically a radial system with power lines radiating outward from a single distribution substation. The main power lines normally have multiple taps called laterals which provide power to individual customers. As seen in Figure E-3, a distribution line is similar to a tree in that a main trunk line splits into smaller feeders called laterals that in turn split again to feed individual customers.

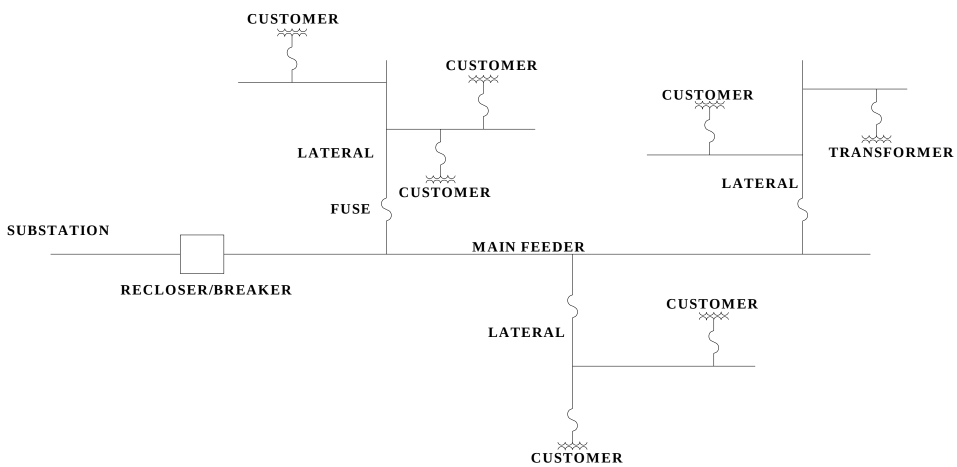

Figure E-3 - Typical radial distribution line[7]

The radial lines may have tie points where they connect to adjacent lines through normally open switches. This allows switching to be done so loads can be fed from more than one line making it possible to take equipment out of service for repair if necessary without interrupting power to customers.

Weather events such as lightning, rain storms, snow storms, or high winds may only affect a small section of the distribution system and likely a single distribution circuit. The distribution system protection will try to react in such a way that temporary faults can be cleared then

[7] *IEEE Guide for Protective Relay Applications to Distribution Lines,* IEEE Std. C37.230-2007. (2007). New York, NY.IEEE.

restored using automatic reclosing. If permanent faults occur, the system protection will attempt to sectionalize the system to keep as many customers with service as possible.

If a fault occurs on a line it can present a hazard to the general public and utility personnel, and may damage other equipment.[8] To disconnect a line where a fault has occurred, a number of devices may be used including circuit breakers, reclosers and fuses. Breakers are typically found in substations and are used in cases where very large fault currents are possible. Breakers will typically have their own current transformers for sensing current, and an external protective relay to monitor current and trip the breaker under abnormal conditions. Reclosers are smaller units allowing them to be mounted on power poles. They act much like a circuit breaker but normally have a lower current interrupting capability. A recloser has its own integral current transformers and is combined with a protective relay that is mounted near the recloser and connected via an umbilical cable. A fuse is the most basic protective element. It is simply an encased metal filament with a known melting point that opens up to disconnect a circuit if too much current passes through it. Fuses are most often used for protecting laterals and taps off of laterals, as well as equipment such as transformers that are connected to laterals.

Faults occur on overhead as well as underground conductors with regularity. They are often caused by weather, equipment failure, vegetation contact, animal contact, and human damage due to digging up cables, vehicle accidents, and vandalism.[9] Fault types that may occur include three-phase, phase-phase, phase-ground, or multiple phases to ground, and protection must be able to sense and properly react to each type of fault. Distribution system protection is predominately over current protection that prevents system components from overloading and damage from short circuit currents.

Sectionalizing and coordination play a vital role in a distribution system's reliability by limiting the number of customers experiencing an outage due to a faulted section of the system. Sectionalizing is the practice of dividing the distribution feeder into smaller sections using devices that can isolate a faulted piece of the system from the remaining system. In order to limit the impact of a faulted section of the system, the standard practice is to use reclosers, fuses, and sectionalizers positioned at strategic locations. Once a distribution feeder has been properly sectionalized to limit wider spread outages, coordination between the sectionalizing devices needs to be developed.

Coordination is accomplished using a concept called inverse time over current (TOC) protection. Any fuse has a known melting time for each level of current flowing through it. If a chart is created showing the time it takes a fuse to melt at each value of current, an inverse time curve is produced as shown in Figure E-4. Electromechanical, solid state, and microprocessor based

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[8] *IEEE Guide for Protective Relay Applications to Distribution Lines*, IEEE Std. C37.230-2007. (2007). New York, NY.IEEE.
[9] *IEEE Guide for Protective Relay Applications to Distribution Lin,* IEEE Std. C37.230-2007. (2007). New York, NY.IEEE.

relays emulate this same inverse time characteristic. This allows breakers and reclosers to coordinate with fuses. Relays are set and fuses are chosen so that the protective device closest to any fault opens first, allowing the remainder of the system to stay energized. This process is known as protective device coordination.

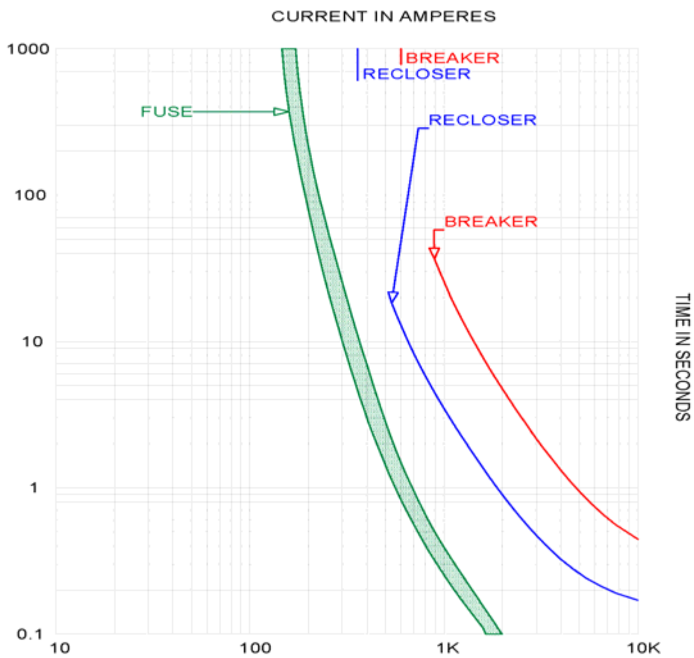

Figure E-4 -Typical inverse time curve for a fuse, circuit breaker, and recloser.

Because most faults are caused by wildlife, wind, and lightning they are temporary in nature.[10] Similar to transmission system protection reclosers or circuit breakers that can be reclosed, are often used to disconnect when a fault occurs and then automatically reclose after a short time. This minimizes the time that customers are without power. Distribution lines may also make use of sectionalizers. A sectionalizer is a device that can disconnect a section of line but is not capable of interrupting fault current. Instead it counts the number of times a recloser disconnects a line by sensing a loss of voltage. If the recloser has tried unsuccessfully to reclose the line a certain number of times, the sectionalizer opens to disconnect a section of line where the fault may have occurred. If the fault occurred on this sectionalized part of the line, the next time the recloser closed it should successfully energize the portion of the line where the fault did not occur. Sectionalizers are an economical means of segregating long distribution lines to limit outages due to faults.

Distribution systems will use one of two protection philosophies when system coordination is planned. Either fuse saving schemes or fuse blowing schemes will be used. A recloser may be programmed to use either a fast operate curve or a slow operate curve. When the recloser opens on its fast operate curve, it will disconnect the line before any fuses on the line have time to blow, saving the fuse. If it operates on its slow curve the fuse will blow first before the line is disconnected by the recloser.

[10] *IEEE Guide for Protective Relay Applications to Distribution Lines*, IEEE Std. C37.230-2007. (2007). New York, NY. IEEE.

If a fuse saving scheme is used, the recloser will be set to use the fast operate curve for one or two attempts, saving the fuse if possible, and then operate on its slow operate curve on its last try to energize the line. If the fault was downstream of the fuse, and was a permanent fault, the fuse will blow before the recloser trips for the final time, allowing power to be restored to the line not affected by the fault. A fuse saving scheme prevents longer outages due to a blown fuse caused by a temporary fault, but may cause more temporary outages to more customers since everyone on the feeder is disconnected instead of just allowing the customers downstream of the fuse to be interrupted.

If a fuse blowing scheme is used, the recloser will always use its slow operating curve. If a fault occurs downstream of a fuse, the fuse will always blow before the recloser opens. This will occur for both temporary and permanent faults. The benefit of this is that only those few customers downstream of the fuse are affected, and most of the customers on the feeder never see their power interrupted. The disadvantage is that the fuse needs to be replaced for all faults, even temporary ones, and the customers being fed through this fuse will be without power until the linemen can drive out to replace the fuse. If the fault was temporary all customers, including those downstream of the fuse, might have been restored after a brief interruption when the recloser opened, if a fuse saving scheme had been used instead of a fuse blowing scheme. Figure E-5 shows typical coordination curves that might be used for fuse saving.

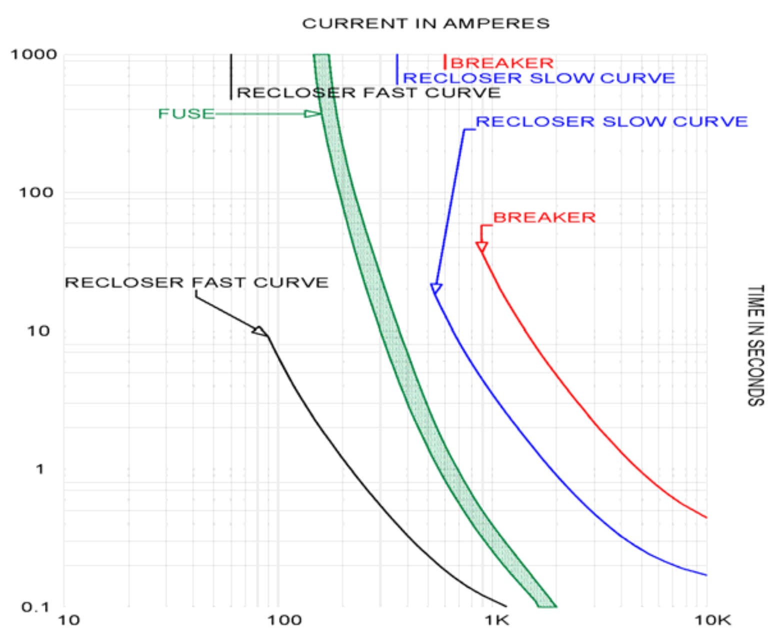

Figure E-5 - Coordination curves for fuse saving.

During the early stages of the December 2008 ice storm, the distribution system functioned as would normally be expected by isolating sections of the system with permanent faults and restoring power to sections affected by temporary faults. As the storm worsened and tree limbs began to break and entire trees began to fall into the distribution lines, the distribution line protection at the substations began to lock out due to the permanent nature of the faults.

C. SUBSTATION PROTECTION

The type of protection used in a substation is often determined by the size and importance of the substation. Normally higher voltage substations with larger transformer sizes require more intricate protection schemes whereas smaller substations may require only minimal protection.

Substation protection schemes are designed to protect the equipment in the substation, the lines supplying the substation's power, and the lines leaving the substation. In most cases, a breaker or circuit switcher is used as the main protective device on the high voltage side of the substation transformer.

Transmission substations have three zones of protection, each utilizing different protection methods (Figure E-6).[11] The first zone is the incoming bus or high voltage bus. The second zone is the transformer zone and the third zone is the feeder bus or low voltage bus. There are several ways to protect the high voltage bus, and the method used is based on the substation configuration. The high voltage bus may be protected by the same relays protecting the transmission line, or it may be protected with a current differential relay that compares current flowing into the bus with that flowing out of the bus. Transformer protection is usually provided by a transformer differential relay that compares the current flowing into the high voltage side of the transformer with that exiting the low voltage side. An over current relay located on the high voltage side of the transformer may also be used to protect the transformer. The low voltage bus may be protected with a differential relay or may simply be protected with an over current relay. The lower voltage lines leaving the substation are each protected using breakers and either overcurrent or distance relaying. Often, automatic reclosing is used on the outgoing lines.

[11] Blackburn, J.L. (1987). *Protective Relaying, Principles and Applications*, 2nd Ed. New York, NY. Marcel Dekker. pg. 28.

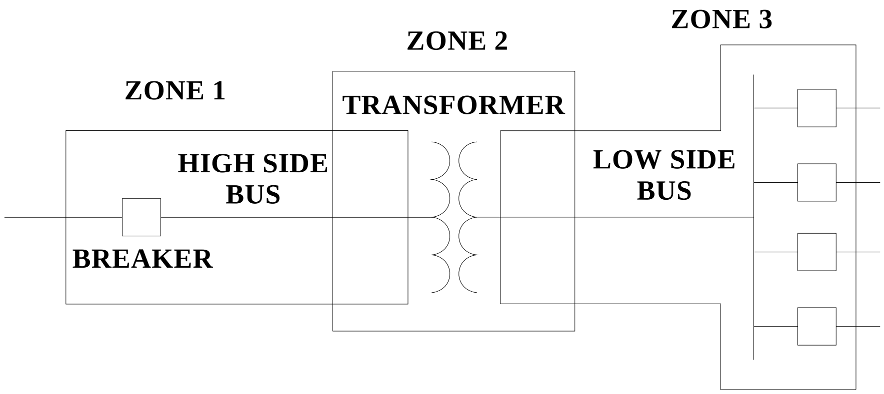

Figure E-6 – Substation protection zones.

Distribution substations are often smaller physically and use a smaller transformer than transmission substations. Protection schemes used in larger distribution substations or substations deemed critical are similar to the schemes used in transmission substations. Smaller distribution substations may simply have a high side fuse protecting the high voltage bus, transformer, and low voltage bus. Reclosers are often used for outgoing feeder protection.

Substation protection is designed to limit the damage that can occur to the equipment located in the substation including the transformer, breakers, reclosers, and buses. It may often be expensive and time consuming to repair or replace equipment in a substation. This means it is very important to limit damage to substation equipment whenever possible. If faults occurring on the electrical system outside of the substation are not quickly removed, they may cause damage to the equipment inside the substation.

In most cases during the December 2008 ice storm, the substation protection used by the New Hampshire utilities worked effectively to prevent damage to critical equipment and disconnect damaged feeders as necessary. Only one protection related failure occurred when a wye-delta-wye power transformer failed due to inadequate protection.

APPENDIX F

Overhead Line Construction

A. LINE CONSTRUCTION AND LOADING

Prevailing laws and practice in most states in the United States require overhead lines be designed, at the very minimum, to meet the National Electrical Safety Code (NESC).[1] New Hampshire Code of Administrative Rules Puc. 306.01 mandates that New Hampshire utilities must use the requirements of the NESC to construct their facilities in accordance with good utility practice. In addition, some states, such as California, have adopted by law their own codes which often refer to NESC requirements.[2] In the United States, most structures (other than transmission and distribution lines) are built according to the International Building Code (IBC), which often defaults to American Society of Civil Engineers (ASCE) standards on such issues as loading and methods. Current practice is to design structures using two well accepted design methods. The first and oldest is the "Allowable Stress Design" (ASD) method, and the second is "Load and Resistance Factor Design" (LRFD), which is the method most commonly taught in colleges and toward which the industry appears to be moving.

The NESC, however, uses neither of these commonly accepted methods. Instead, it historically has used an ultimate stress design method with overload factors used in the loading part of the design to provide the needed factors of safety. This method differs from all other commonly accepted design methods. Loading requirements contained in the NESC are different than those used in any other code. NESC rules for selection of design loads and for safety factors are largely based on successful experience, but have little basis in theory.[3] The more modern methods of design, such as LRFD, have been developed using successful experience as well as structural theory that has become accepted over the years. As a result, the 2007 edition of the NESC contains sections which have begun to include LRFD methodology such as is commonly accepted for other types of construction. It should be noted that the NESC still includes the older historical methods alongside the newer methods and appears to be in a process of transition. However, at this time the requirements of the NESC do not closely match the requirements that an engineer would be obliged to use when designing a habitable structure.

In many cases a power line design produced by strictly following the NESC loading and design criteria will deliver a less capable structure with lower factors of safety than would be produced

[1] Dagher, H.J. "Reliability of Poles in NESC Grade C Construction." *IEEE Rural Electric Power Conference 2001*, Pgs C4/1-C4/6. (10.1109/REPCON.2001.949521).
[2] State of California General Order 95. (January 2006). *Rules for Overhead Electric Line Construction*.
[3] Bingel, N., Dagher, H., et.al. (2003). "Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code." *Transmission and Distribution Conference and Exposition 2003*, Vol. 3.Pgs 1088-1093. (10.1109/TDC.2003.1335100).

if the structure were designed using methods required for other types of structures, such as the those required by the (IBC).[4] There is disparity between the results produced by building under the NESC instead of the IBC. The NESC tries to simplify things for the designer by specifying loading requirements that have been developed for average conditions over a large part of the country, while other codes use more exact data specific for small areas. Problems occur when local conditions vary from those considered average by the NESC. An area with high likelihood of large amounts of wind and ice, such as most of New Hampshire, will see more damage than average. Conversely, an area with lower expectations of wind and ice will see less than average damage on their system. Questions have also emerged as to the reliability of the NESC loading criteria with the development of joint use poles. Loading criteria and design methodology used in the NESC may not adequately anticipate the additional use of the utility's poles by a telephone or cable company.[5] For this reason, many utilities have developed their own standards which more closely match local conditions. In most cases, these standards produce a more robust and realistic design for an area than simply using the criteria in the NESC. In New Hampshire, all four major electric utilities use NESC loading. Only Public Service of New Hampshire uses an additional standard which exceeds NESC requirements for some transmission lines. It must be noted, however, that many utilities across the country have used NESC loading criteria exclusively over the years and have had good success. This is likely due to the fact that the average loading shown in NESC for their region closely matches or exceeds the actual conditions witnessed in their exact location.

The NESC recognizes three grades of construction which may be used in different areas: N, C, and B.[6] Grade N is the lowest strength, has the lightest loading requirements, and the smallest safety factors. Using Grade B construction results in the highest strength and largest safety factors. This results in the heaviest and most costly construction. Grade N may be used for emergency or temporary construction, on private right-of ways below 8.7kV, and for communication cables or cables below 750V. None of the four utilities in New Hampshire presently allow grade N construction on their systems. The NESC allows grade C construction in most other areas except at line, railroad. or limited access crossings where grade B is required. The grade of construction used is based upon the degree of importance and reliability level needed for the line.[7] Lines that are less important may be allowed to be constructed with a lower grade of construction, which has a lower factor of safety and may be expected to suffer more failures during an extreme weather event. For example, a rural single phase line crossing an

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[4] Malmedal, K. and Sen, P.K. (2003).”Structural Loading Calculations of Wood Transmission Structures.” *IEEE Rural Electric Power Conference 2003*.Pgs A3/1 – A3/8.
[5] Bingel, N., Dagher, H., et.al. (2003). “Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code.” *Transmission and Distribution Conference and Exposition 2003*, Vol. 3.Pgs 1088-1093. (10.1109/TDC.2003.1335100).
[6] National Electrical Safety Code. (2007). ANSI/IEEE C2-2007.
[7] Bingel, N., Dagher, H., et.al. (2003). “Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code.” *Transmission and Distribution Conference and Exposition 2003*, Vol. 3.Pgs 1088-1093. (10.1109/TDC.2003.1335100).

open pasture to a stock water tank may be constructed as grade N, especially if privately owned. The failure of this line during a storm might pose an inconvenience but would not normally pose a direct threat to human life. On the other hand, a line crossing an interstate highway or railroad could cause disastrous results if it failed and dropped onto an automobile or train. Additionally, the repair of this line without closing the highway or rail line would be very difficult. For this reason, a line of this type must be built to grade B construction, which has the highest factor of safety of all the grades of construction.

Another design guide commonly used in the United States is the RUS Bulletin 1724E-200, Design Manual for High Voltage Transmission Lines. The specifications in this guide are required for all Rural Electric Co-ops (REC) which borrow funds from the Rural Utility Service (RUS, formerly known as REA). This manual requires Grade B construction for lines 35kV and over while accepting the NESC requirements for other voltage classes and definitions for construction grades. It also has more conservative loading requirement than the minimum required by the NESC. Following this guide will generally produce a more robust design with higher safety factors than those that will occur when using only the NESC.[8] RUS guidelines also recognize that NESC minimum construction may be inadequate for local conditions and that local requirements may supersede those contained on the NESC or RUS documents.[9]

There are other design manuals which are commonly used by designers when deciding how to determine loads and design criteria for overhead transmission and distribution lines. While not reaching the level of model codes or having the weight of either the NESC or RUS documents, they provide guidance that can be referred to and valuable information for the designer. The first is ASCE Manual and Report on Engineering Practice No. 74: Guidelines for Electrical Transmission Line Structural Loading. This manual supplies some of the theoretical basis for the methods suggested for determining wind, ice, and other types of loading. and provides examples that can be referred to in designing overhead line structures. It also provides suggestions for load and strength multiplying factors for various conditions and materials, and describes the probabilistic approach used to determine these factors. This manual is independent of the requirements in the NESC. It is based upon theory and loading data rather than using the legacy methods required by the NESC. This manual is presently being revised, as some of the information included in it is now considered outdated and is being replaced by the information contained in ASCE Standard 7-05.

ASCE Standard 7-05: Minimum Design Loads for Buildings and Other Structures is also of great value in determining loads to place on overhead lines. This manual contains the most up-to-date information available regarding maximum wind speeds and ice loads for each part of the

[8] U.S. Department of Agriculture, Rural Utility Service. (2004). *Design Manual for High Voltage Transmission Lines.* (RUS Bulletin 1724E0200)
[9] U.S. Department of Agriculture, Rural Electrification Administration. (1982). *Mechanical Design Manual for Overhead Distribution Lines*. (REA Bulletin 160-2).

country. It divides the country into much smaller areas than are shown in the NESC district loading maps. The provisions and methods included in ASCE 7-05 are also required when structures are designed using the International Building Code. The ice loading information contained in ASCE 7-05 is prepared, compiled, and updated by the U.S. Army Corps of Engineers Cold Regions Research and Engineering Laboratory (CRREL) located in Hanover, NH. This manual contains historical maximum weather loading information compiled from data collected by the laboratory. It is more up-to-date and provides more realistic weather loading data than that contained in the NESC. It is interesting to note that the 2007 NESC has for the first time included extreme wind maps and concurrent wind and ice loading maps which are derived directly from ASCE 7-05, yet the NESC does not require using either extreme wind or extreme ice with concurrent wind until a structure is taller than 60 ft. This is in contrast to both the ASCE and RUS documents that suggest including these two loading cases in all designs. All structural codes presently used in the United States have either already adopted or are moving toward the loading and weather criteria contained in ASCE 7-05. This can be expected to continue into the future.

Another manual which explains the statistically derived loading and strength methods included in ASCE design manuals is ASCE Manuals and Reports on Engineering Practice No. 111: Reliability-Based Design of Utility Pole Structures. This manual explains and gives examples of the methods described in the ASCE codes use for determining load factors and strength factors.

Every line should be designed for reliability, security, and safety. Security is the ability of a design to prevent the propagation of an initial failure to additional failures; safety means protecting the public at all times and construction personnel during construction and maintenance; reliability is the ability of the line to resist without damage a climatic event with a certain return duration, such as designing a line with the ability to stand up to a storm without damage with a recurrence of 50 years, which is the most commonly used return period for overhead line construction.[10] These objectives are normally accomplished by assuming a design load equal to the maximum ice and wind load which can be expected to occur during the service life of the line. This value is then multiplied by a factor of safety to make sure that the weakest structure in the design can resist the expected loads even after some deterioration due to age and accounting for the variations in material tolerances, which can be large in the case of wood and somewhat less in designed materials such as steel and composites. The two most important climatic conditions of interest in New Hampshire are the amount of ice that can be expected to accumulate on a line, usually stated as radial thickness of ice, and the wind pressure on the line which is a function of wind speed, height, and terrain type. The line should be designed for three load types: The maximum wind pressure the line will be expected to see during its lifetime, the maximum ice load the line will be expected to see, and the combination of the maximum amount

[10]Peyrot, A., Maamouri, M., et al. (1991). “Reliability-Based Design of Transmission Lines: A Comparison of the ASCE and IEC Methods.” *The International Conference on Probabilistic Methods Applied to Electric Power Systems, 1991*. Pgs 97-102.

of ice the line will see in combination with the amount of wind pressure that can be expected during this icing event. The way this information is derived varies depending upon the code the designer decides to use.

After deciding the level of loads to be placed on the line, the designer must next decide upon the safety factors which must be applied. These safety factors vary with types of material. Naturally occurring materials (such as wood) require larger safety factors than engineered materials (such as steel). This is due to the fact that there is a larger variation in strength based on the material. For example, tolerances between the strongest and weakest wood members will vary a much greater degree than those between the strongest and weakest steel or concrete members. The designer will design around some average value of strength of the material and the safety factors will account for the variations around these average values to try to ensure that even the weakest structures will not fail under the design conditions. The combination load and strength safety factors for steel structures may be up to 2.5, whereas the safety factors for wood could be as large as 4.0. Safety factors will also account for the unpredictability of characterizing the loads. Weather loads may be difficult to foresee and the safety factor accounts for this unpredictability. In the most modern method of design, load and resistance factor design, these factors of safety are added by multiplying the loads by a load factor to account for the uncertainty in the loading information, and then multiplying the strength of the material by a strength factor to account for the variation in material strengths. The latest version of the NESC has also begun to take this approach.

In order to optimize the design of an overhead line, loadings must be chosen correctly. This is not easy in practice, especially where ice loading is concerned. Several types of icing may occur on an overhead line depending upon the conditions occurring at the time. Some of these are:

- Glaze ice: Clear ice possibly with icicles, very dense
- Hard Rime Ice: Opaque milky to nearly transparent, may be alternate layers of clear and opaque ice, intermediate density to very dense
- Soft Rime Ice: White, granular, snow-like, weak and low density
- Hoar Frost: White snow-like, irregular crystalline deposits, very brittle and low density
- Snow and sleet: Can melt and re-freeze several times and attain large weights

Icing can occur in cloud during fog or during precipitation.[11] The type and amount of icing that may occur depends on air temperature, water droplet size, water content of the air, wind speed, and local topographic effects near the line. For this reason icing may be highly variable along the length of a line. Due to the high variability of icing, it is impractical to try to determine the exact type of ice that may occur along the entire length of a line. In the United States, the protocol is to design the line for an equivalent radial ice load. This load is normally found from

[11] Ervic, M., Fikke, S.M. (1982). “Development of a Mathematical Model to Estimate Ice Loading on Transmission Lines by Use of General Climatological Data.” *IEEE Transactions of Power Apparatus and Systems, June 1982*. Pgs1497-1503. (10.1109/TPAS.1982.317197).

maps prepared by various groups using both actual historical measurements and theoretical statistical methods.[12] These maps are developed using algorithms developed from research done by groups such as CRREL.

In some areas of the country, the loading described by the NESC and for which most overhead lines are designed (including those in New Hampshire) varies considerably from the loading described in other documents published by ASCE and other sources.[13] [14] The NESC should be considered the minimum mandatory requirement for loading and design. As utilities often recognize, the NESC merely describes conditions that can be expected to occur frequently rather than providing information about the maximum wind or ice that may be expected with a 50 year or 100 year recurrence.

Extreme weather events are described as random variables in probability distributions. The designer must decide on how rare of an event they are willing to design their systems to withstand. The designer of a building which may be expected to have a service life of 100 years or more might design for the largest weather event that may be expected to occur in 100 years. For the power line designer, the expected lifetime of their design is customarily 50 years. Therefore, the designer will design for the weather conditions that may be expected to occur only once every 50 years. The maps given in the NESC showing design loads typically show values of wind and ice which can be expected to occur once in any 50 year period.[15] The return period (RP) of the 2008 storm was 10 years, [12] which means that the magnitude of the storm was not highly unusual. Any lines designed for a storm of a 50 year return period should have weathered the impact of this storm.

In many areas the loading and safety factors in the NESC have produced reliable designs, while in others areas the loading conditions shown in the NESC have proven to be inadequate for local conditions. Because of this fact, utilities often require a stricter minimum loading condition than shown in the NESC, especially if local ice and wind loading data are available and conflict with those shown in the NESC.

Figure F-1 shows the loading criteria required by the NESC. There are only three loading conditions, or districts, defined: light, medium, and heavy loading.[16] These loading districts define both wind and ice loads to be used for structures below 60 ft. in height, and for these

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[12] Jones, K.F., Cold Regions Research and Engineering Laboratory (July 2009). The December 2008 Ice Strom in New Hampshire.

[13] Minimum Design Loads for Buildings and Other Structures. (2005). American Society of Civil Engineers 2005. (ASCE Standard 7-05).

[14] Guidelines for Electrical Transmission Line Structural Loading. (1991). American Society of Civil Engineers 1991. ASCE Manuals and Reports on Engineering Practice No. 74.

[15] Reliability-Based Design of Utility Pole Structures. (2006). American Society of Civil Engineers 2006. ASCE Manual and Reports on Engineering Practice No. 111.

[16] National Electrical Safety Code. (2007). ANSI/IEEE C2-2007.

structures, which would include most distribution lines, this is the only loading case required by the NESC. The loads defined for the three districts are:

- Heavy: 0.5 in. ice and 4 psf. of wind (equivalent to a 40 MPH wind)[17]
- Medium 0.25 in. of ice and 4 psf. of wind (equivalent to a 40MPH wind)[13]
- Light 0.0 in. of ice and 9 psf. of wind (equivalent to a 60 MPH wind)[13]

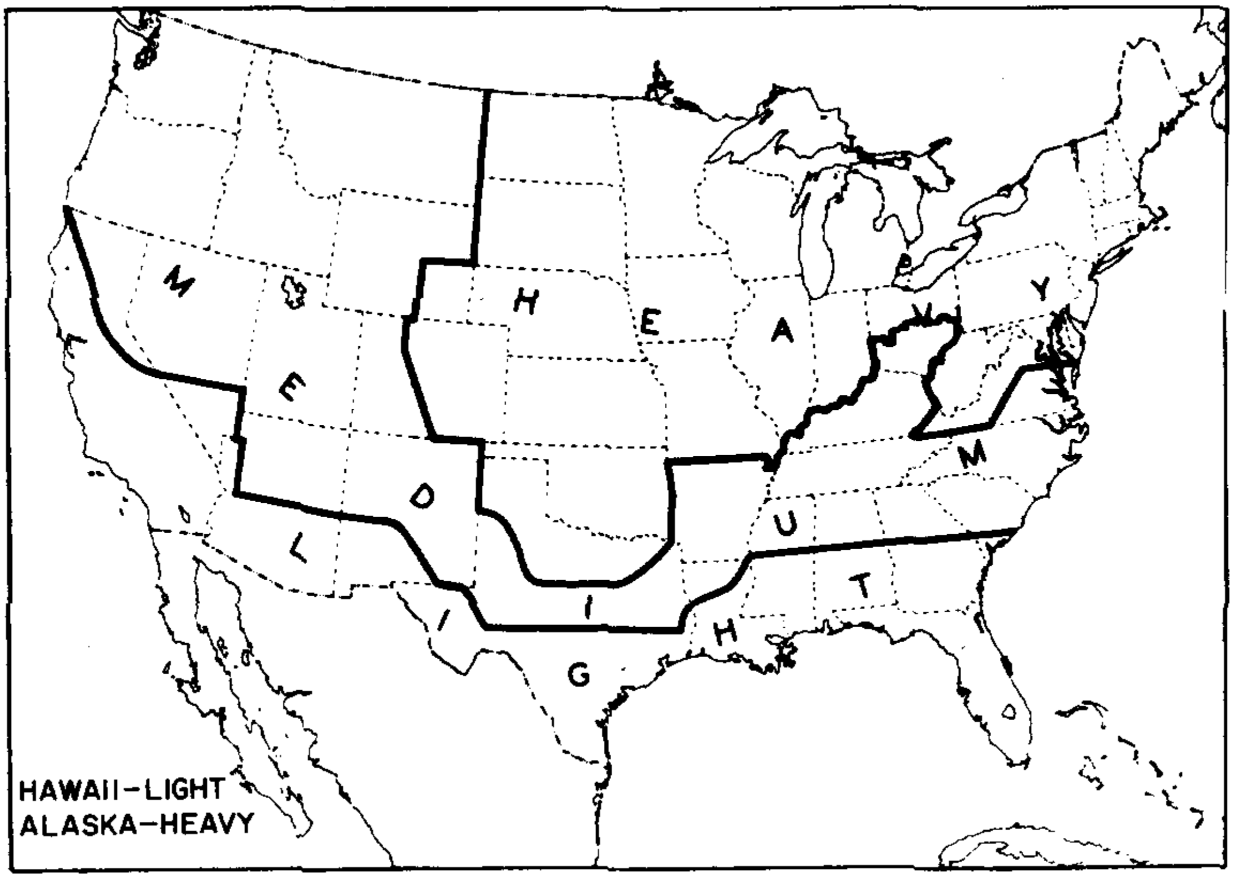

Figure F-1 - NESC loading map.

It may be seen that each of the three loading areas shown in Figure F-1 are quite large. Small variations due to terrain and even geographic location do not affect the loading levels shown in this map. The ice and wind load for New Hampshire, for example, is shown to be exactly the same as that for eastern Colorado, when in reality both icing and wind conditions for New Hampshire are far more severe than they are for eastern Colorado.

If a structure is taller than 60 ft. (which would primarily include transmission structures), the NESC requires that two other loading conditions be examined: extreme wind and extreme ice

[17] Bingel, N., Dagher, H., et.al. (2003). "Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code." *Transmission and Distribution Conference and Exposition 2003*, Vol. 3.Pgs 1088-1093. (10.1109/TDC.2003.1335100).

with concurrent wind. Figure F-2 shows the NESC map for extreme wind contained in the NESC.[18] It may be seen that a wind speed of 90 to 100 MPH is given for New Hampshire with a special wind area for the mountainous area along the New Hampshire and Vermont border. A special wind area means that local wind information must be found and the speeds shown on the map cannot show adequate information for these areas. The wind values for these locations are usually determined from local building departments in cities within the special areas. Officials in these cities have usually determined from experience the wind speeds required for safe design of buildings in their areas. The basic wind speeds shown in Figure F-2 are substantially higher than those required by NESC heavy loading for New Hampshire, which would be the equivalent of a 40 MPH wind. The map in Figure F-2 is taken from the latest data included in ASCE standard 7-05 while the loading in Figure F-1 has been included in the NESC without change for many years.

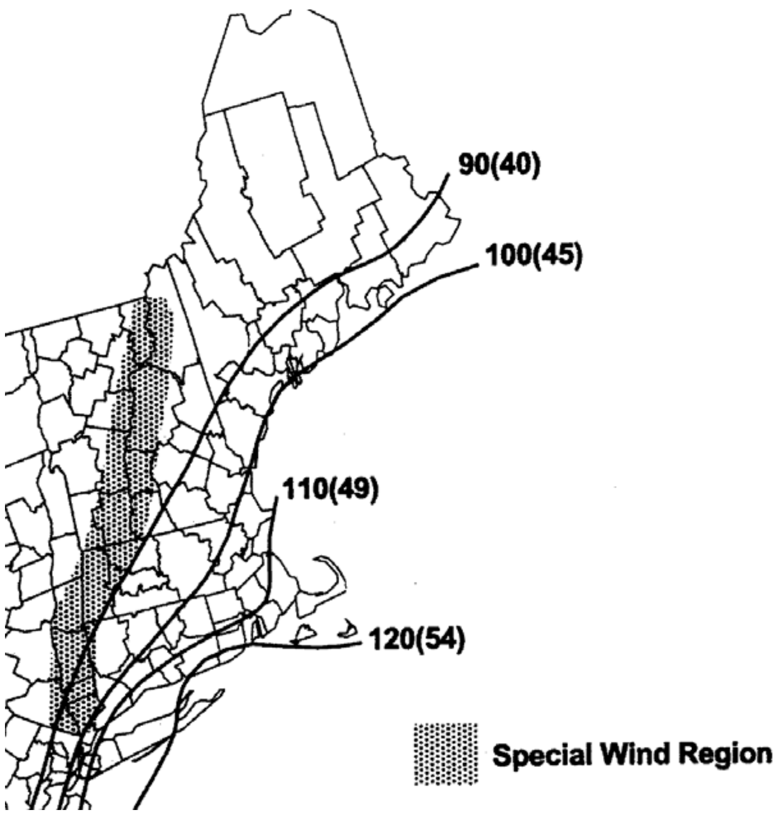

Figure F-2 - Basic wind speed for extreme wind design.

The third loading condition, extreme ice with concurrent wind, is considered by taking information from the map in Figure F-3. This map shows the 50-year return period levels for

[18] National Electrical Safety Code. (2007). ANSI/IEEE C2-2007.

wind and ice for New Hampshire. It is also taken from the latest version of ASCE 7-05.[19] [20] As may be seen in Figure F-3, the ice loading for New Hampshire varies from 0.75 in. with 40 MPH wind, to 1.0 in. with 40 MPH wind, and although not shown in the NESC map, the ASCE map shows a special wind area shown along the Vermont-New Hampshire border. This wind and ice loading shown in Figure F-3 is greater than is required using only the district loading from Figure F-1. For all structures designed using ASCE standards or the International Building Code, the loading shown in both Figure F-2 and Figure F-3 would have to be considered, but the NESC only requires these loads for structures above 60 ft. in height, which would not include most distribution lines that only need to be designed for the loads shown in Figure F-1.

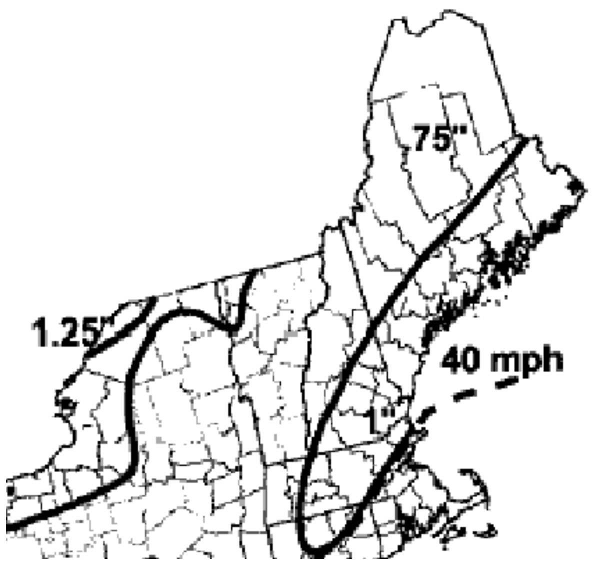

Figure F-3 - Ice and concurrent wind for line design.

It is generally recognized that the loading required in Figure F-1 has produced an adequate design on average when coupled with the safety factors (overload factors) contained in the NESC. For some areas with higher than average icing loads or higher than average wind loads, both of which would be true of New Hampshire, these levels of loading have produced designs with higher than average failure rates. In areas of lower than average wind and ice loads these levels of loading have produced a more robust than necessary design.[21] No design approach is inherently more reliable than another; all design methods make assumptions about loading and

[19] National Electrical Safety Code. (2007). ANSI/IEEE C2-2007.
[20] Minimum Design Loads for Buildings and Other Structures. (2005). American Society of Civil Engineers 2005. (ASCE Standard 7-05)
[21] Bingel, N., Dagher, H., et.al. (2003). "Structural Reliability-Based Design of Utility Poles and the National Electrical Safety Code." *Transmission and Distribution Conference and Exposition 2003, Vol. 3,* Pgs 1088-1093. (10.1109/TDC.2003.1335100).

accept some probability of failure. The art of good design is to reduce the probability of failure while at the same time minimizing the total lifetime cost.[22] If specific and accurate design criteria is available for a region it becomes easier to produce a reliable design without spending too much on overdesign. Overdesigning can occur when an engineer has insufficient loading data available making it impossible to accurately characterize the actual loads that will occur in a certain location. As a result the designer must compensate by using larger safety factors. In the attempt to make sure the structures are adequate the designer will likely produce an overly stout design.

The latest version of the NESC has endeavored to begin addressing the differences in reliabilities that can be seen in lines built according the NESC district loading values from Figure F-1. It has addressed the differences apparent in various parts of the country, by revising the overload factors it uses. The overload factors used for overhead line design before the 2007 version of the NESC were historically derived and often based on subjective criteria including engineering judgment and experience.[18] While the loading and methods historically used in the NESC have proven successful over the years for most of the country, questions have arisen as to their validity due to new methods and materials being used for line construction, including the use of extensive numbers of shared-use poles by electric utilities and communications companies. There is some evidence that as communication under build (as used in the New Hampshire system) has become common, the loading criteria shown in the NESC has become less reliable over the years.

The load and strength factors used in the 2007 version of the NESC are designed for use with both NESC district loading and 50 year repeat period loading as shown in ASCE maps. Even though only NESC district loading cases are required for structures less than 60 ft., it is recommended that the higher wind and ice loading cases required by ASCE data also be taken into account for the design of all structures no matter their height. This should produce a more realistic design for the conditions that can be expected in New Hampshire. Since the system would be designed for loads that can be expected to occur only once every 50 years, it should be easily robust enough to sustain the loads imposed by a storm which can be expected to be repeated every 10 years, such as the one seen in 2008. This would include determining from local sources the actual wind and ice loads which can be expected in the special wind areas shown on ASCE maps rather than relying on loading data from NESC maps.

The question arises as to how the storm of December 2008 compares with the design criteria contained in the NESC and in ASCE standards under which the lines in New Hampshire were designed. The first thing that must be understood is the levels of ice which occurred. The design values of ice and the values contained in the NESC tables are “equivalent radial glaze ice” values. These are not the same values as typically reported in the media or measured by weather

[22] Sayer, B. (2000). “What of the Weather? Wood Pole Line Design & Weather Loadings.” *IEE Seminar on Improved Reliability of Woodpole Overhead Line, (March 8).* Pgs. 1/1-1/8.

stations. Forecasters and weather observers usually report ice accretion on a horizontal surface or on the ground. This might include the thickness of ice pellets and snow in addition to freezing rain. Occasionally the amounts of ice reported include icicles and the ice located on top of branches or wires. To determine the equivalent radial ice it would be necessary to take the average thickness of the same amount of moisture if it were spread evenly over the surface of a conductor. There is no method by which the ice accretions reported by weather stations can be accurately converted to equivalent radial ice as needed for design and analysis of utility structures.[23]

To produce the maps contained in ASCE 7, and to determine equivalent radial ice for this storm, hourly weather data from weather stations is needed. This data must include wind, temperature, dew point, precipitation rate and type among other factors which are used in an ice accretion model developed by the New Hampshire Cold Regions Research and Engineering Laboratory (CREEL) to determine equivalent radial glaze ice values. These values may also be directly measured with freezing rain sensors if a weather station is so equipped. The exact methods used are more completely explained in the CREEL report on this storm contained in Appendix D. Figure F-4 shows the amount of precipitation that occurred in New Hampshire during the storm.

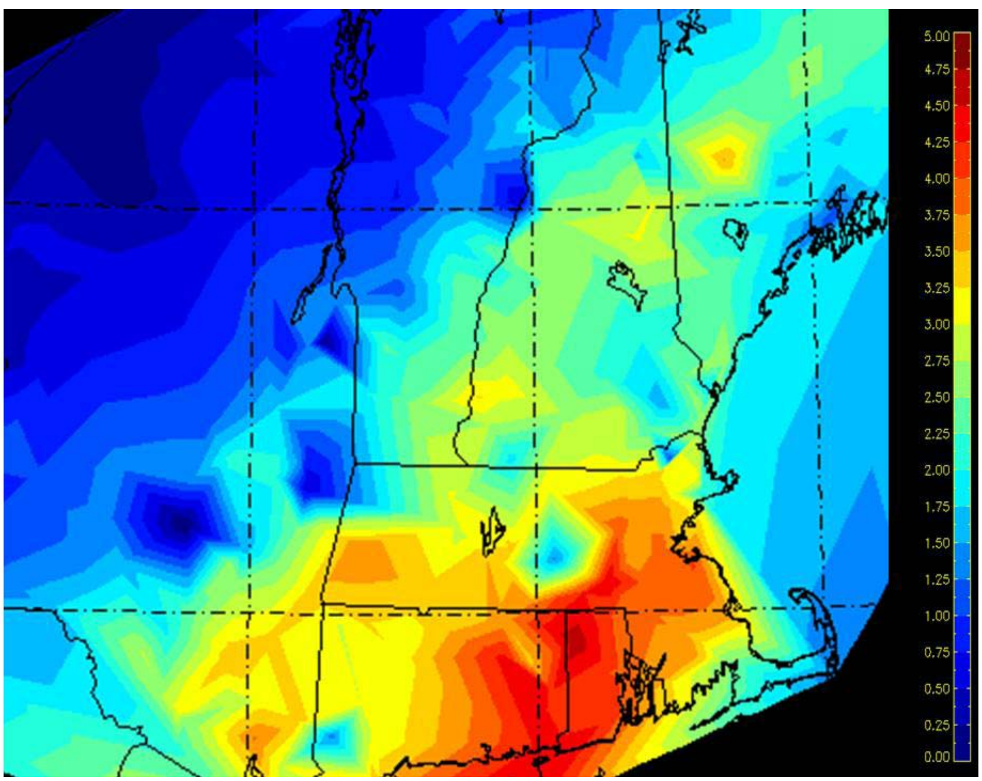

Figure F-4-Precipitation levels as reported by CREEL.

[23] Jones, K.F., Cold Regions Research and Engineering Laboratory. Phone Interview by Malmedal, K. August 5, 2009.

Figure F-5 shows the locations of the weather stations in New Hampshire and nearby. All the stations shown below are automated and all are able to record precipitation levels. However not all the stations shown are capable of recording all of the types of data needed to compute equivalent radial glaze ice using the CREEL model. Only those stations which are labeled in Figure F-5 record all the parameters needed for this computation. There are six labeled stations shown in New Hampshire, one in Maine, two in Massachusetts, and one in Vermont. The values below these stations are the equivalent radial glaze ice in inches as reported in the CREEL report.[24] Not all the stations shown reported complete data. Some data was missing for Fitchburg, MA, Lawrence, MA, and Jaffrey, NH and the values shown should be considered lower limits of ice. Only the station at Manchester has automated data augmented with human observations. Figure F-6 shows the footprint of the area where damage was reported due to ice. Both maps below were developed by CREEL.

[24] Jones, K.F., Cold Regions Research and Engineering Laboratory (July 2009). The December 2008 Ice Strom in New Hampshire.

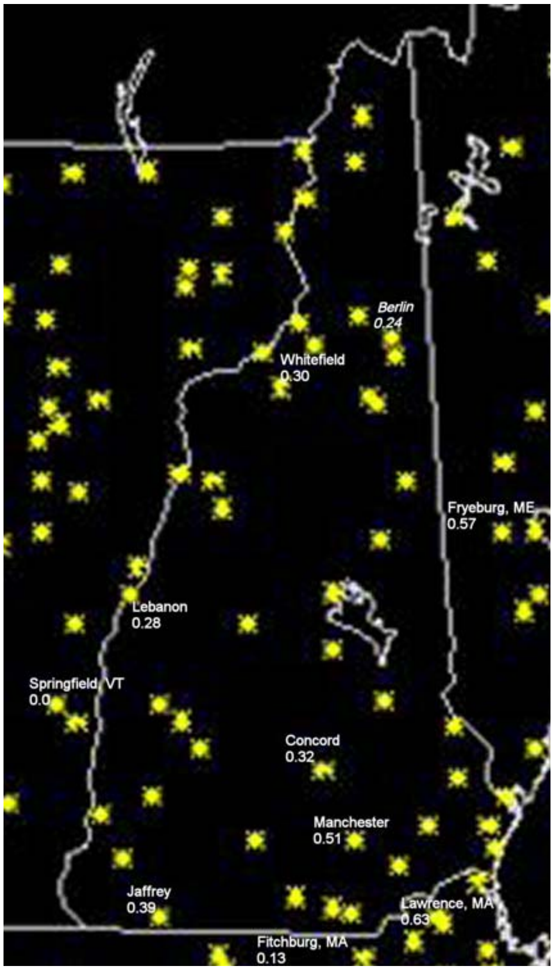

Figure F-5-Weather stations in New Hampshire and the surrounding area and equivalent radial glaze ice in inches.

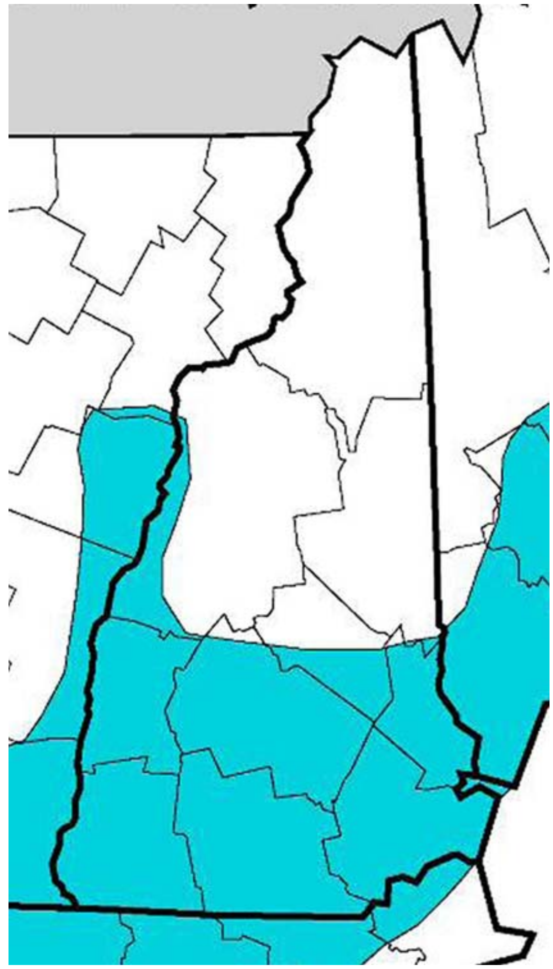

Figure F-6-Ice storm footprint showing area where damage to trees, power lines, and communications towers was reported.

It may be seen in Figure F-5 that the largest equivalent radial ice which occurred at any station in New Hampshire was 0.51 inches. It was also reported by CREEL that winds during the storm were light to moderate and wind on ice should not have been a significant factor in causing damage. The largest wind speed reported was approximately 9 MPH. The largest values for radial ice reported during this storm were reported in Maine with 0.9 inches, and New York where 0.8 inches was recorded. It appears that New Hampshire missed the worst effects of this storm in terms of the amounts of radial ice deposited.

The ice and wind loads recorded during this storm should not have resulted in stresses to the structures in excess of those required for design by the NESC for New Hampshire. It is interesting to note that the stations in the northern part of the state, outside the damage area, recorded nearly the same amount of ice as some of the stations in the area recording damage in the south. Even the relatively low values used for distribution structures below 60ft in height, as shown in Figure F-1, were not exceeded by this storm and the amount of ice and wind seen were far below the 50 year return period values shown in Figure F-3, 0.75-1.0 inch and 40 MPH winds. It can be concluded, therefore, that simple ice and wind loading on the transmission and distribution system should not have caused widespread structural failures in New Hampshire during this storm since the structures should have been designed to handle higher stresses than were seen during this weather event. Since all four New Hampshire utilities are designing their systems to meet the NESC, and the conditions during this storm did not exceed those stated in the NESC, the reasons for the widespread damage during this event do not include deficiencies in design. The reasons for the widespread damage witnessed in New Hampshire during this storm must reside elsewhere.

According to the CREEL report, the return period for equivalent radial glaze ice for storms in New Hampshire is shown in Table F-1. It may be seen that the return period of this storm is approximately 10 years. A storm of this magnitude should be relatively common and the distribution and transmission systems should be expected to experience an event of this magnitude many times during their lifetimes.

Table F-1-Return periods of ice.

Equivalent Radial Ice (inches)	Return Period (years)
0.5	10
0.7	25
0.9	80

Even though this storm did not produce loads exceeding the design loads, it is clear that 50 year levels of ice and wind would exceed the design loads of structures less that 60 ft in height which used only NESC district loading. It is recommended that all structures, regardless of height, be designed for not only district loading but also extreme wind and extreme ice with concurrent wind as is now required in the NESC for structures exceeding 60 ft. in height. This should prevent widespread damage to the distribution system during a weather event with a 50 year return period which the distribution system would be expected to experience at least once during its design lifetime.

Another weather related phenomena which can cause damage to overhead power lines is galloping. Galloping of conductors is a low frequency high-amplitude wind induced vibration that happens in the presence of glaze ice or rime ice deposits, which changes the cross sectional profile of the conductor from circular to some shape that is modified in aerodynamic characteristics.[25] Damage caused by galloping is not primarily due to ice loading itself, but due to the aerodynamic forces imposed on the structures and cables due to the wind acting on the

[25] Electric Power Research Institute, (n.d.) *Transmission Line Reference Book, Wind-induced Conductor Motion*.

deformed shape of the conductor. This causes lift on the conductor which is sufficient to cause large conductor motions. Galloping occurs most commonly with moderately strong steady crosswinds acting on asymmetrically-iced conductors.[26] There is some evidence that some of the damage which occurred on the transmission system during this storm may have been caused by this phenomenon.

Figure F-7 shows the conditions than cause galloping.[25] Ice forms on one side of the conductor, then wind crossing the conductor causes lift that causes the conductor to move up or down. This lift along the entire conductor causes it to move in a vertical direction either up or down, and variations in wind velocity may result in cyclical repetitive conductor oscillation.

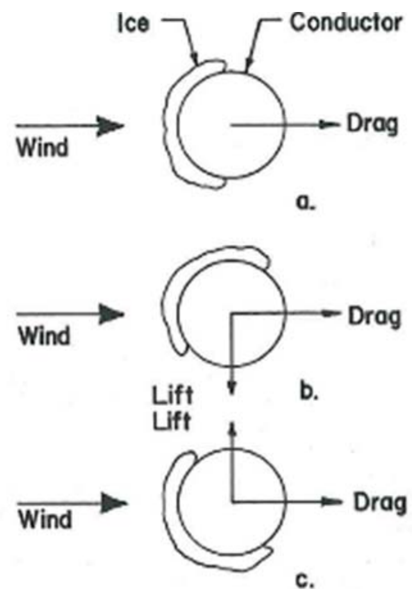

Figure F-7-Conditions causing galloping.[25]

The vertical motion of a conductor between supports that may result from these forces is shown in Figure F-8. Illustrated in this figure is a single mode of motion between supports which is the type that will produce the largest amplitude of motion between the normal location of the conductor and the farthest excursions of conductor location.[27] The conductor movement due to galloping has been known to cause contact between phase conductors and between phase conductors and overhead ground wires resulting in electrical outages and conductor burning and failure. While relatively less common in the United States due to types of construction used, it has been estimated that in England and Wales up to 20% of all line-line or line-ground faults on

[26] Wang, J. (2008). "Overhead Transmission Line Vibration and Galloping." *2008 International Conference on High Voltage Engineering and Applications, Chongqing China, November 9-13, 2008.*
[27] Ratowski, J.J. (1968). "Factors Relative to High-Amplitude Galloping." *IEEE Transactions on Power Apparatus and Systems, Vol 6*. June, Pg. 87.

275 to 400kV transmission lines were caused by line contacts due to galloping[28] and one of the main causes of failure to large extremely high voltage transmission line in China. Galloping has also been known to cause failure of hardware and supporting structures due to the large dynamic forces imposed upon them during galloping, and excessive conductor sag due to stressing the conductors beyond their elastic limits.[29]

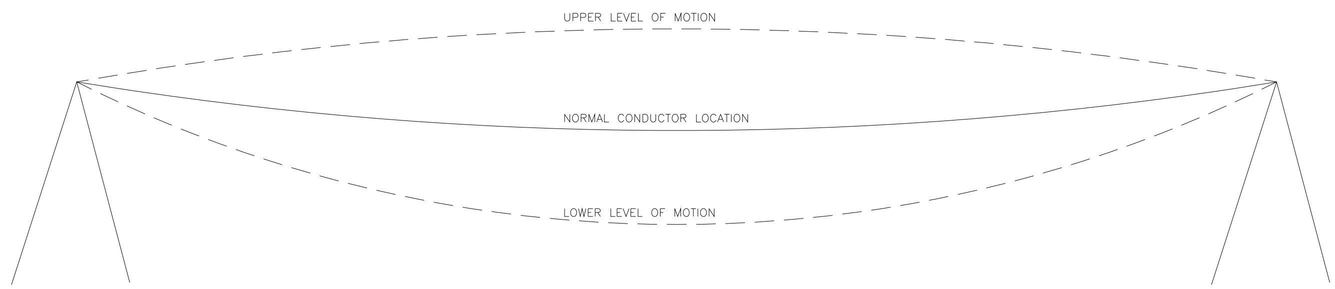

Figure F-8-Conductor motion during galloping, single mode galloping.

The results of a galloping line which caused enough stress in the conductors to greatly increase the conductor sag are shown in Figure F-9. The large amplitudes produced by galloping are usually vertical and may typically range from 0.1 to 1.0 times the sag of the span.[30] Frequencies will vary with the types of construction and are typically between 0.15 Hz and 1.0 Hz.

[28] Rowbottom, M.D. (1981). "Method of Calculating the Vulnerability of an Overhead Transmission Line to Faults Caused by Galloping." IEE Proceedings, Vol. 6, November, 128 Pt. C.
[29] U.S. Department of Agriculture, Rural Utility Service. (2004). D*esign Manual for High Voltage Transmission Lines*. (RUS Bulletin 1724E0200)
[30] Wang, J. (2008). "Overhead Transmission Line Vibration and Galloping." *2008 International Conference on High Voltage Engineering and Applications, Chongqing China, November 9-13, 2008.*

Figure F-9-Excessive sag as a result of galloping. (Photo courtesy of CIGRE)

It is difficult to predict which spans or lines might be susceptible to galloping. The phenomenon has been difficult to study due to the sporadic nature of when and where it might occur.[31] While the precise meteorological conditions that cause galloping are not known, it is thought that in addition to some ice being present, wind speeds greater than15 mph at a minimum angle of 45° to the line direction are needed to produce galloping.[32] It is also thought that spans in excess of 800 feet on structures using suspension insulators with conductors exceeding 1-inch in diameter using older conductors with relatively high tension are most susceptible to galloping. However, under proper conditions, galloping may occur in nearly any span. Galloping with amplitudes of 10 feet has been reported on spans of 300 feet.[33] Anything that produces mechanical dampening such as newer conductor[34] or stiffer mounting methods will tend to minimize galloping.

In the parts of the United States where galloping is expected or historically known to exist, design methods are used to try to minimize the possibility of galloping causing conductors coming into contact with each other. The main method is to increase line-line spacing of conductors.[35] To determine the distances needed to minimize contact due to galloping, research performed by A.E. Davison during the 1930s is used. Davison determined that galloping

[31] Electric Power Research Institute, (n.d.) *Transmission Line Reference Book, Wind-induced Conductor Motion*.
[32] Rowbottom, M.D. (1981). "Method of Calculating the Vulnerability of an Overhead Transmission Line to Faults Caused by Galloping." *IEE Proceedings*, Vol. 6, November, 128 Pt. C.
[33] McDaniel, W. N. (1960). "An Analysis of Galloping Electric Transmission Lines." *Power Apparatus and Systems Part III Transactions of the American Institute of Electrical Engineers, Volume 79,* April, pgs 406-412. (10.1109/AIEEPAS.1960.4500782).
[34] Rawlins, C.B. (1988). "Research on Vibration of Overhead Ground Wires." *IEEE Transactions on Power Delivery*, *Vol 3*, No. 2, April.
[35] Rawlins, C. B. (1981). "Analysis of Conductor Galloping Field Observations-Single Conductors." *IEEE Transactions on Power Apparatus and Systems, Vol.* 8, August, Pg. 100.

conductor loops appeared to remain within an elliptical region and he suggested the dimensions these ellipses would attain. Further research modified the dimension of these ellipses, but the basic method is still the one designers use as one determining factors controlling the minimum distances required between conductors. A typical example of these ellipses is shown in Figure F-10. If the structure is designed so these ellipses do not touch each other, theory states that the probability of contact between either the conductors or the phase conductors and overhead ground wires should be minimized.

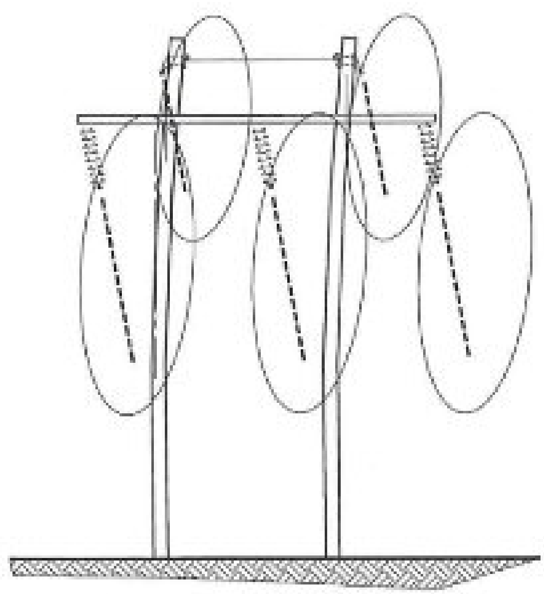

Figure F-10-Galloping ellipses. [36]

When galloping occurs there are mitigating measures which can be added. If a galloping problem is predicted or seen, there are a number of different line dampening technologies that can be included in design or added after a line is completed. There are also types of conductors that can be used which are designed to minimize vibrations including galloping. These conductors are more costly than standard conductors and are usually used only in areas where galloping has been seen historically.

Since predicting which spans will experience the proper conditions to produce galloping is difficult, susceptible spans may only be identifiable after a line is constructed. One method which may be used to identify these troublesome spans is using fault location, which is a feature of many newer protective relays.[37] This can help determine where faults on the system are

[36] U.S. Department of Agriculture, Rural Utility Service. (2004). *Design Manual for High Voltage Transmission Lines*. (RUS Bulletin 1724E0200).
[37] Rowbottom, M.D. (1981). "Method of Calculating the Vulnerability of an Overhead Transmission Line to Faults Caused by Galloping." *IEE Proceedings*, Vol. 6, November, 128 Pt. C.

occurring and whether any spans are experiencing frequent unexplained faults during icing conditions. After these susceptible spans or lines are identified, it may be possible to retrofit them with vibration dampers or other galloping prevention hardware to reduce the possibility of galloping on these spans in the future.

All four utilities are using proper design methods to minimize the possibility of damage and flashover due to galloping. However, there was one shield (overhead ground) wire failure on the transmission system that was unexplained, and two faults whose cause was not determined. Galloping is a possible cause of both of these conditions. No changes in design or overhead line construction are recommended at this time, but the utilities should monitor these locations in the future to determine if repeated failures are occurring which may be attributable to galloping. If these problems become frequent enough, it may be necessary to add vibration dampeners to the spans in question to eliminate galloping damage in the future.

APPENDIX G

Outage Management Systems (OMS)

A. OMS OVERVIEW

General Discussion

With the improvements in technology, Outage Management Systems (OMS) has become a sophisticated tool which can be valuable for improving the efficiency of restoration and communication with customers.[1] OMS integrates with systems that are normally installed for reasons other than outage management, but when working in conjunction with the OMS, they are able to provide information helpful to the restoration effort. Supervisory Control and Data Acquisition (SCADA) systems are an example. They are usually installed to give operators information about the condition of equipment, the status of switches and breakers, and to control the remote opening and closing of breakers. This same SCADA information can be invaluable to operators as they try to restore service after an outage. They can tell which breakers or reclosers have opened and may be able to attempt remotely closing some devices. The dual nature of the systems integrated into the OMS can at times make this integration difficult. The ease of integration into the OMS should be an important part of the utility's thinking when choosing any particular technology.

The modern OMS requires an accurate customer-to-electrical system model to provide accurate predictions of outage locations. It must gather, compile, and display information from a variety of sources including:

- Customer Information Systems (CIS)
- Interactive Voice Response (IVR) systems
- Call Over Flow (COF) systems
- SCADA status information
- Distribution Automation (DA) systems
- Automated Meter Reading (AMR) or Advanced Metering Infrastructure (AMI) systems
- Protective relay fault location information
- Geographic Information Systems (GIS)
- Damage assessment reports
- Automatic Vehicle Locator (AVL) systems

[1] Nielsen, T.D. (2007). Outage Management Systems Real-Time Dashboard Assessment Study. *Conference Proceeding IEEE/PES General Meeting June 2007*. (10.1109/PES.2007.385707).

- Crew reporting information[2]

Figure G-1 shows the architecture of a typical OMS. To manage the available data, the computing power and interface between the information gathering portions of the system and the OMS itself cannot be overwhelmed during a large area outage. This has been a problem historically with OMS. They have performed well with small scale outages, but have failed to operate correctly when large scale outages occur. Recently, newer systems have been shown to be more reliable under large outage conditions. However, the algorithms used might need modification for disaster scale conditions. The predictive algorithms incorporated in OMS try to use outage data to pinpoint a single location of trouble. During a large scale event, the predictive methods used may be inadequate and provide misleading or useless information. With this knowledge, the operators can still obtain useful information with the understanding that some of the conclusions reached by the system will be incorrect. Rather than merely leaving the system algorithms in place to identify trouble locations, human intervention and decision making may be necessary. Newer systems continue to improve in their ability to handle large outages, and several manufacturers claim their systems can handle multiple system outages simultaneously.

The different parts that may be integrated into the OMS are as follows:

- **Customer Information System (CIS):** A computerized system used to track customer information, generate bills, issue service requests, and "manage" customer relationships by providing the utility information about each customer's needs and preferences.
- **Interactive Voice Response System (IVR):** Interactive computer system which can answer telephone calls, route information, compile data, return calls, and call back customers as programmed. It can be linked to record customers' locations and link these with locations in the distribution system.
- **Call Over Flow System (COF):** A system that redirects telephone calls from one answering location to another when volume exceeds capacity. It allows overflow calls to be answered and information tabulated.
- **Supervisory Control and Data Acquisition system (SCADA):** A computer system that gathers data from devices such as protective relays, provides breaker, switch, and re-closer statuses and a means to control these devices remotely, and displays the status of this monitored equipment graphically.

[2] Nielsen, T.D. (2002). "Improving Outage Restoration Efforts Using Rule-Based Prediction and Advanced Analysis." *IEEE Power Engineering Society Winter Meeting 2002*, Vol. 2, January, pp. 866-860.

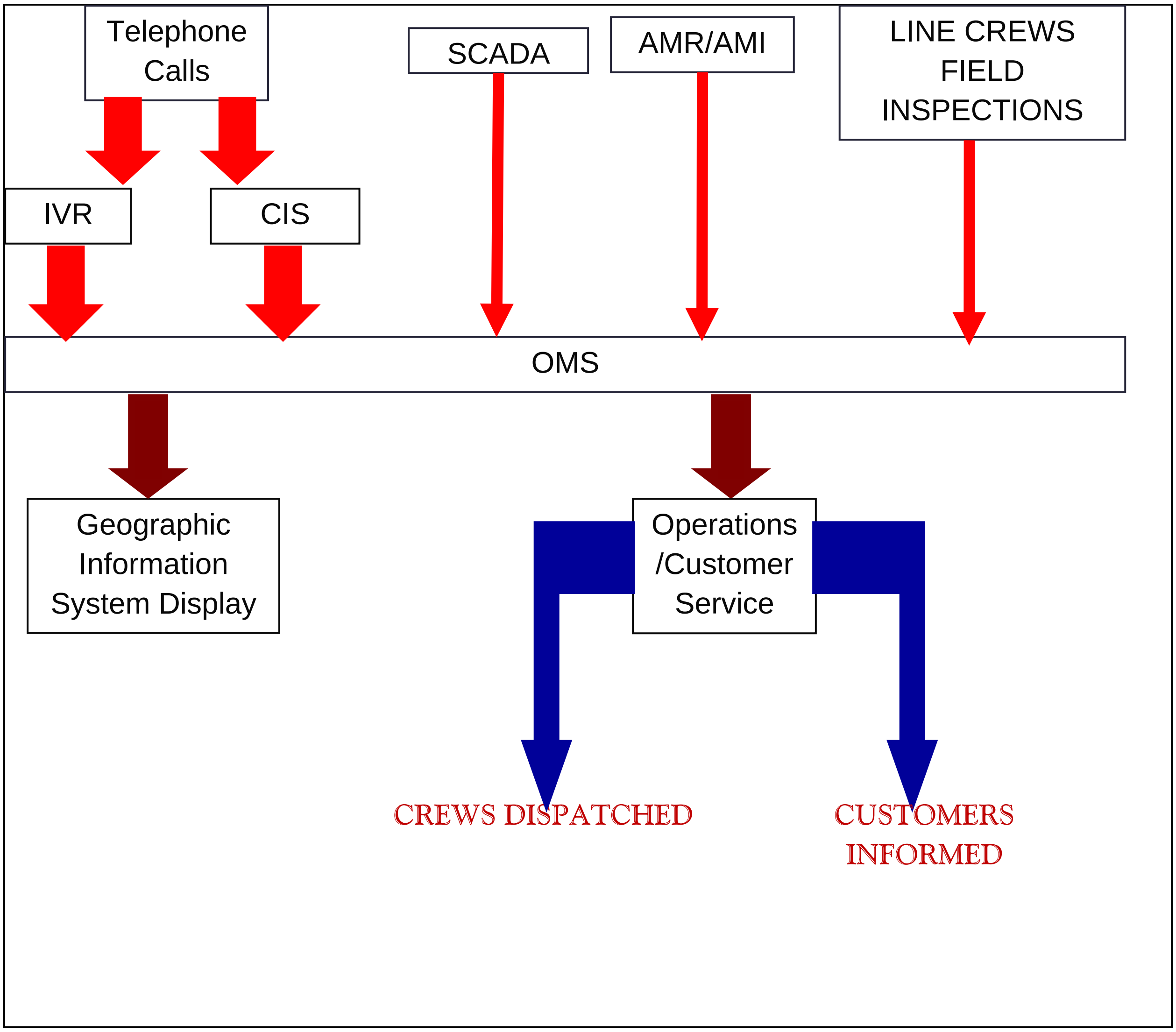

Figure G-1: OMS architecture.

- **Distribution Automation (DA) system:** Computer system which monitors and controls devices on the distribution system. May include monitoring and controlling breakers, re-closers, and distributed generators.
- **Automatic Meter Reading (AMR):** Systems which can remotely read kWh from meters and automatically record the values in a computer data base. Some systems can also send instantaneous values to the system reading the meter. Meter data can be transferred via radio, telephone, or power line carrier.
- **Advanced Metering Infrastructure (AMI):** Includes the same hardware, software, communications, and customer associated systems that are used by AMR systems, but also includes two-way communication to make possible remotely disconnecting customers or in other ways manage demand.

- **Geographic Information System (GIS):** A computer based technology to collect, record, and display geographically referenced or spatially oriented information. Can record the exact locations of utility infrastructure and attach to those records construction information, life, or repair data. Can produce graphic displays which compile and usefully display data concerning components in a power system.
- **Automatic Vehicle Locator (AVL):** Uses global positioning system information to automatically record in near real time the location of vehicles in a utility's fleet. Can display on a GIS based system the location of all line trucks or other vehicles so dispatchers can determine the truck located nearest an outage.
- **Protective Relaying:** Devices on the power system which trip breakers to disconnect parts of the system experiencing malfunctions, such as short circuits or open conductors. The OMS may be informed if a relay has detected a problem on part of the system and has tripped a breaker. This will help the OMS characterize the reason for an outage.

From a technological point of view, the most quickly changing part of the system that can be integrated with the OMS is the metering system. Due to governmental initiatives seen in the last few years that mandate smart grid and smart metering technologies, metering technology and communications have improved dramatically. The trend has been for utilities to install Automatic Meter Reading (AMR) systems or Advanced Metering Infrastructure (AMI) systems.[3] The AMR/AMI technology is usually installed for reasons not relating to outage management since its principal benefits go beyond it. Significant benefits can be seen in customer service due to improved accuracy in meter reading. The increasingly detailed information available from AMR/AMI systems can be beneficial in system planning, load management, asset allocation, and load forecasting.

Integrating the AMR/AMI system with an OMS system, even a simple one, can have definite cost advantages. About 70-75% of outage reports received by a utility are single service outages, nearly a third of which are customer side problems. If the AMI system is integrated with the OMS, the meter can be queried instantly to determine if the problem is on the utility or customer side of the meter. This can avoid sending line crews or trouble-men to the site for a customer side problem. The improved speed and accuracy in response has been shown to decrease average outage durations from 6 to 4 minutes.[4]

One of the worst customer perception problems is caused when a customer reports an outage, the utility takes action to remedy the outage, believes the customer is restored, but the customer is still without power. An integrated AMI-OMS system allows the utility the ability to verify that

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[3] Steklac, I. and Tram, H. (2005). "How to Maximize the Benefits of AMR Enterprise-Wide." *IEEE Rural Electric Power Conference 2005*. (10.1109/REPCON.2005.1436325).
[4] Tram, H. (2008). "Technical and Operational Considerations in Using Smart Metering for Outage Management." *IEEE Transmission and Distribution Conference and Exposition 2008-IEEE/PES Vol. 1*, Issue 21-24, April, Pgs 1-3. (10.1109/TDC.2008.4517273).

the meter is energized without a call to the customer. The OMS can also help identify problems with meters which could otherwise result in inaccurate or missing billing information.

AMR systems come in two basic types. The first requires in-field reading which means personnel must be dispatched to the vicinity of the meters being read and the metering data is transmitted over relatively short-range radio channels. The second type provides centralized meter reading which does not require that personnel be dispatched to the vicinity of the meter. This type may transmit its data via power line carrier to the substation or another point where it is compiled and transmitted to a central location using radio, telephone, or satellite communications channels. The second type can typically be “pinged” during an outage to determine if the meter is on-line. Some modern meters have the ability to be interrogated and can send back voltage and other data. Some AMR systems are limited in their response time, however, and if integration with the OMS is required, the AMR system must be chosen carefully to maximize its benefits to the OMS.

Operational Aspects of OMS

OMS, if integrated with all available systems, can be of great value during both large and small outages. It can provide call based and independently derived data, and in turn, display this data in useful forms to aide operators in making the proper decisions as to where resources can best be allocated. A properly used OMS can also track the restoration efforts by monitoring how many crews are allocated to each outage and where those crews are located. It can also record the time it takes to complete restoration, which can then help project restoration times for all customers as the restoration process progresses.

The OMS system may function in this way during a large area outage:

- Outage Notification
    - Customers call the call center to notify the utility their power is off.
    - The AMI detects the outages and transmits outage messages to AMI network.
    - The customer call is logged into the OMS system.
    - The AMI network sends its outage data to the OMS.
- Outage Verification
    - Damage assessment crews are dispatched and report damage to the call center.
    - Damage assessment crew reports logged into the OMS.
    - OMS orders AMI to periodically “ping” all the meters.
    - OMS provides a graphical display to show operators where outages exist.
    - OMS provides a graphical display of the status of breakers and switches.
    - SCADA system detects which breakers and relays have operated and transmits this information to the OMS.
- System Restoration

  - Operators remotely close breakers/switches and reconfigure the system to restore power where possible using the SCADA and DA systems.
  - Available crews are dispatched to areas where operators decide power can be most quickly restored.
  - Crew locations are tracked with the AVL system.
  - Crew information from AVL is relayed to the OMS network which displays current location and number of crews.
  - Decisions are made to bring in additional repair crews if needed.
  - AMI reports restored meters to the OMS.
  - OMS graphically displays meters as they are restored.
  - OMS system records restoration time for each meter. This information helps operators calculate estimated restoration times for meters still not restored.
  - Estimated restoration times are logged into or calculated by the OMS.
  - OMS sends graphical data to the web-based customer information system that indicates the size of the outage, the number of crews working in each area, and the estimated time for restoration for each customer.
- Restoration Verification
  - AMI detects sustained voltage and transmits message to OMS.
  - IVR call-back system calls customer to notify that power is restored and confirm the customer's power is back on.

The OMS can be integrated with tools dedicated to informing the public of the status of restoration efforts. These would mainly be web based tools that could display the size of outages, allocation of crews to certain areas, and estimated restoration times. These values can be graphically attached to individual meters so customers can obtain up-to-date information on the estimated duration of the outage for their own home or business.

In Figure G-2 and Figure G-3, sample screenshots from an OMS display the way outage information is displayed for easy use by operators. A properly chosen OMS can update this information several times a day, and some of it can be updated in near real time. The OMS can also help prioritize the restoration effort by tracking and displaying critical locations such as 911 systems, fire departments, hospitals, police departments, shelters, etc. so operators can allocate resources to restore critical infrastructure first.

OMS is not a cure-all and does have limitations. Instantaneous information may not always be available since polling time of devices may not provide immediate feedback. Wide area outages may limit the value of the OMS algorithms. During these situations, the OMS may not achieve its real advantages for restoration until a few hours or days after the disaster, or until field information from damage analysts is available and entered into the system. Implementing the OMS is often necessary in stages and this might limit its usefulness in the areas where the infrastructure to support it is not yet in place. OMS is also a major expenditure for a utility and personnel must be dedicated to its implementation.[5] The system model must be kept up to date and the utility's personnel must be dedicated to maintaining the information inputs to the OMS. OMS are often limited in the speed at which they gather input data--40,000 calls per hour is often a limit. When an OMS system is selected, the utility must make sure that the chosen system can gather the quantity of information available from the systems connected to it and respond to the large amount of data available during a wide area outage.

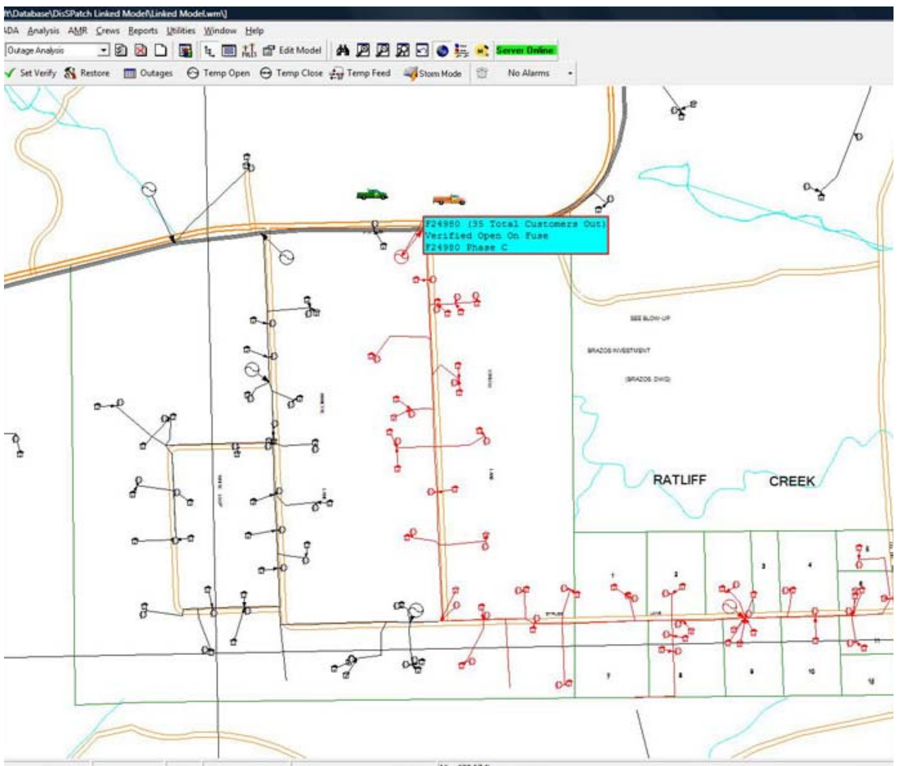

Figure G-2: Typical OMS screen showing customer outages. (Courtesy of Milsoft Utility Solutions)

A modern integrated OMS will require secure communications from the operations centers to the data gathering points. It may also require secure communications between operations centers if a utility has multiple centers. The communications infrastructure used must support a real-time, highly available information platform. The communications system could be the weak link during a disaster, and an OMS may be rendered useless if sufficient attention is not focused on maintaining good communications so data can be reliably sent to the OMS. There are two types of communications systems that a utility may use.[6] The first is an internal network, which is completely owned and controlled by the electric utility, and the second is an external network,

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[5] Blew, D.S. (2001). "Outage Management System: Surviving the implementation." *IEEE Power Engineering Society Summer Meeting, 2001, Vol. 2*, Pgs 994, 995. (10.1109/PESS.2001.970193).
[6] Banks, D.R. (2005). "Telecomm Disaster Recovery Planning for Electric Utilities." *IEEE Rural Electric Power Conference 2005*. Pgs D3/1-D310. (10.1109/REPCON.2005.1436337).

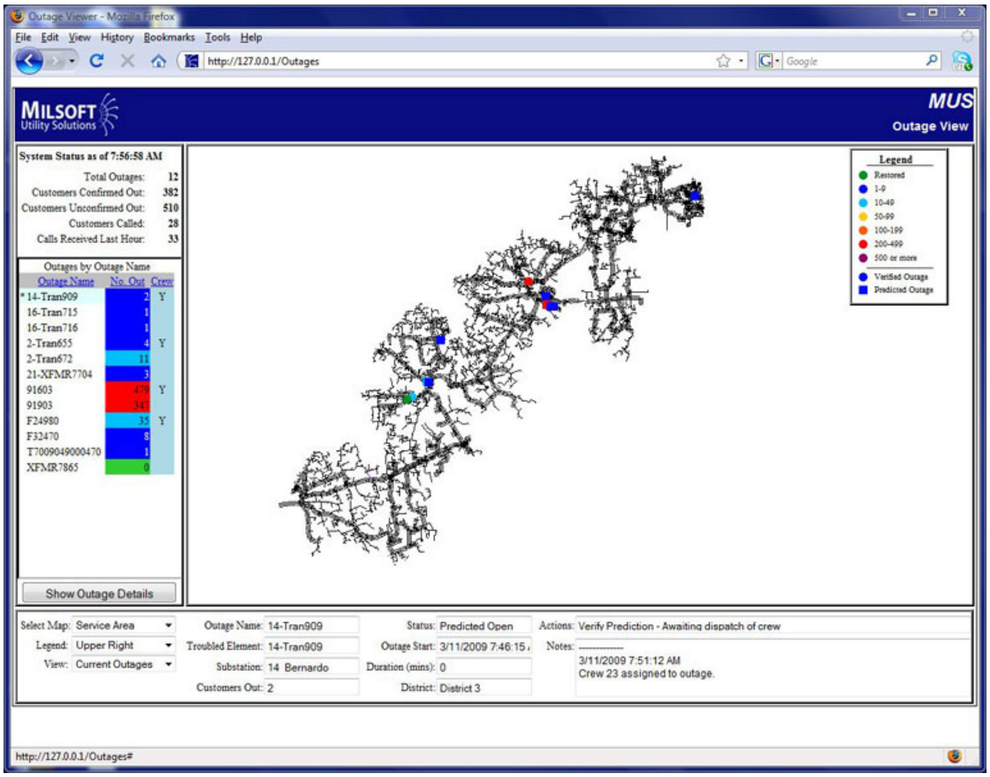

Figure G-3: Typical OMS screen summarizing area outages. (Courtesy of Milsoft Utility Solutions)

which is owned and operated by another company over which the electric utility has little or no control. In the case of the New Hampshire utilities, the communications systems are typically external and controlled by the telephone companies rather than the electric utilities. During the storm, the telephone companies were slow in restoring their systems. Where utilities were depending on information relayed from substations, their efforts were hampered by the lack of telephone communication to these substations.

The electric utilities should develop a telecomm disaster recovery plan that coordinates with their system restoration plan. Successful telecomm disaster recovery might include several options which either prepare for loss of communications by providing a secondary system, or provide for the restoration of the communications system in tandem with the electrical system. Considerations must also be given to supplying emergency power for critical telephone system components, or in other ways insure that critical telephone infrastructure can function for extended periods of time when the electric grid is inoperative. Suggestions which may be considered to improve communications from and to the OMS are:

- Supplying emergency generators to the telephone company to keep central offices, cell phone sites, or other critical systems operating during the outage.
- Providing expanded internal networks such as private optic networks or microwave facilities which can transmit data in the event of a loss of telephone service.
- Providing redundant telecomm service. This is an expensive option but might provide a secondary telephone network in the event the primary network fails.
- Provide telephone carrier diversity. Different companies or different services, such as a wired and wireless service, could both be used to provide redundant carriers and telephone mediums to minimize the possibility of outages.
- Coordinate restoration plans with the telephone company so the communications system can be restored at nearly the same time as the electrical system.

APPENDIX H

New Hampshire Public Utilities Commission Request for Proposal

February 17, 2009

REQUEST FOR PROPOSALS

**NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
REQUEST FOR PROPOSALS FOR CONSULTING SERVICES
TO REVIEW EFFORTS OF NEW HAMPSHIRE UTILITIES FOLLOWING THE
DECEMBER 2008 ICE STORM**

To Prospective Bidder:

The New Hampshire Public Utilities Commission (Commission) is seeking proposals from qualified firms or individuals to provide consulting services to assess utility companies in the area of performance before and after the December 11-12, 2008 ice storm.

Pertinent dates and information:

1. Bidders may submit written inquiries about this RFP by e-mail: To: 2008StormRFP@puc.nh.gov, Subject line: 2008 Storm RFP Inquiry, no later than March 3, 2009. Inquiries and their responses will be posted on the Commission's website as they are received.

2. Proposals must be received by the Commission prior to 4:30 p.m. on March 9, 2009.

3. Submit proposals to:

   ChristiAne G. Mason, Director of Administration
   New Hampshire Public Utilities Commission
   21 S. Fruit Street, Suite 10
   Concord, NH 03301-2429
   ChristiAne.Mason@puc.nh.gov

4. Follow-up conferences/interviews will be scheduled as needed.

5. An Evaluation Team consisting of Commission and/or other qualified personnel will be established to evaluate responses to this bid proposal.

1

I. BACKGROUND

The New Hampshire Public Utilities Commission is an administrative agency with executive, legislative and quasi-judicial powers. The Commission's prime responsibility is as an arbiter between the public utilities and their ratepayers. Proceedings in this regard address such areas as public utility rates, financing, terms and conditions of utility service, quality of service, safety and reliability, eminent domain matters, public utility exemptions from local zoning ordinances, public utility franchises, utility crossings of public lands and waters, wholesale relationships between utilities, rulemakings and consumer complaints.

II. SCOPE OF SERVICES

The Commission is seeking an independent consultant to review the efforts of each of New Hampshire's electric utility companies and two telephone companies with respect to preparation, response and restoration of service following the December 11-12, 2008 ice storm. The electric utilities being reviewed include three investor-owned utilities and one electric cooperative. To the extent that telephone customers were affected by the ice storm or by power outages, the review will also consider telecommunications preparedness and response to the storm. Effective preparation for prolonged emergencies such as a major storm, and efficient and timely outage response and restoration of service are critical to the provision of safe and reliable service. A thorough examination of a utility's management of its emergency planning, preparedness, outage response, and restoration operations is warranted to assess utility performance and identify opportunities for improvement.

The consultant's review is expected to focus, at a minimum, on the following areas:

1. Emergency Planning. A review of the adequacy of a company's overall emergency preparation and response planning, including content and adequacy of emergency plans, training on emergency plans, and plan activation thresholds.

2. Preparedness. A review of operating policies that allow the company to respond to large-scale outage emergencies, including:
   a. Adequacy of overall resources (personnel, equipment and facilities, including those provided by third parties) available for emergency outages.
   b. Procedures for obtaining assistance from other utilities, contractors, equipment providers and the ability to deploy and manage these additional resources.
   c. Collection of data regarding outages and assessment of data accuracy, integrity and use.
   d. Effectiveness of existing systems and procedures to determine the extent of damage, number of customer outages and development of specific estimates of service restoration.
   e. Ability to respond to multiple and simultaneous large-scale outages occurring in different operating areas and procedures for prioritization of outage repairs.

f. Communication plans for customers, local officials, state agencies and the public before and during an emergency outage.

3. Storm Restoration Performance. A review of the utilities overall performance during the December 2008 ice storm including:

    a. Review of whether emergency procedures were appropriately activated and followed.
    b. Effectiveness of managing and deploying overall resources in an optimal manner.
    c. Effectiveness of procedures for obtaining assistance from other utilities and contractors and their management and deployment.
    d. Effectiveness of data collection process for determining the extent of the outage, including number of customers affected and the development of accurate estimates of time for service restoration.
    e. An assessment of all interruption reporting systems.
    f. Effectiveness of reporting relationships established for storm restoration efforts and internal communications protocols.
    g. Effectiveness of communications with customers, local officials, state agencies and the public, generally, including the ability to provide timely and accurate information.

4. System Planning, Design and Protection. A review of distribution and transmission procedures including:
    a. Each utility's planning, design, and construction practices with respect to distribution and transmission systems within New Hampshire as they relate to major storm events.
    b. Assessment of the age and condition of distribution and transmission facilities and determination of any relevant contributing factors to outages that occurred.
    c. Compilation and review of background and reports of known national studies that relate to cost-benefit analyses of underground construction of distribution circuits versus overhead circuits that may be relevant to New Hampshire distribution systems.

5. Operations and Maintenance. A review of utility operations and management practices and if and how those practices were contributing factors, including:
    a. Review of vegetation management procedures and budgets for transmission and distribution lines with emphasis on those areas most affected by the ice storm.
    b. Utility inspections of poles and replacement policy.
    c. Utility inspection practices for their transmission and distribution lines.
    d. Utility inspection practices for theirs substations.
    e. Workforce levels and training with regard to operations and maintenance.

3

6. Post Ice Storm Actions and Processes. Analysis of all post-Ice Storm Action Reviews conducted by electric and telecommunications utilities to quantify and determine any recommended improvements.

7. Best Practices. Identify areas suitable for adoption of best practices, such as latest advances with outage management systems, outage analysis programs, advanced metering and other technical innovations, etc. that would mitigate the effects of storms and increase efficiencies in restoration.

In addition, the selected vendor(s) will take the following key process steps and produce the following required deliverables:

1. The consultant shall conduct a project initiation meeting with the Commission. The purpose of the meeting is to:
    a. Review and refine the scope and task requirements, discuss data requirements, and clarify current data availability and quality;
    b. Review and confirm the schedule for the project, including key milestone dates;
    c. Review and adjust (as necessary) the project approach outlined in the proposal; and
    d. Develop project management and communication protocols to ensure that the information needs of both the Commission and the Consultant are satisfied.

2. The consultant shall prepare and submit to the Commission a detailed memorandum documenting the results of the project initiation meeting. If modifications to the memorandum are needed the Commission will submit a request for modifications to the Consultant within (5) working days of receipt of the memorandum.

3. The consultant may modify the initial draft workplan after giving due consideration to Staff's comments, and must then submit a final draft workplan to Staff for approval. Approval of the workplan by Staff will authorize the consultant to execute the tasks as stated therein.

4. The consultant will provide regular briefings to Staff, as well as biweekly, written reports on the progress of the review, and identify discussion issues germane to the review's success.

5. The consultant will produce a draft report of its findings by July 17, 2009. This initial draft report must provide the results of the consultant's review and recommendations and should be in sufficient detail to support specific findings. The report will be reviewed by the Commission, who will provide comment for a Final Report.

6. The consultant will produce a Final Report of all findings by August 14, 2009. At that time, presentations on the report, both informal and formal, may be convened. To the extent such presentations are required, the contract will be amended to provide

additional funding for such. However, the consultant(s) will be paid at the rate(s) agreed to in this contract.

III. COMPONENTS OF THE PROPOSAL

The following is a list of the information to be provided. Proposals should respond to all areas listed below, in the order listed, and conclude with a separate section on cost.

1. Technical Discussion and Proposed Approach. Bidders are required to submit a proposed work plan, including a description of the techniques and procedures to be utilized, and timeframes in which key products will be delivered.

2. Corporate/Company Information. Bidders must provide the Commission with information concerning its corporate/company history; e.g., how many years in business, corporate officers or company principals, location of branch offices, professional and business association memberships, etc.

3. Personnel Assigned. Bidders must provide the Commission with a list of all personnel who might be assigned to this project, including the project manager (if applicable), and detailed resumes and summaries of each individual, reflecting their relevant experience, training, and the nature of their specific responsibilities. If possible, include a copy of previous analyses reports that the proposed project members worked on. During the course of the work, the Commission must approve any substitutions or changes in personnel assigned to perform the work.

4. References. Bidders must provide the Commission with a list of up to three references for work performed which is similar in scope or content to the one being proposed, preferably within the past 5 years.

5. Statement of Disclosure. Bidders must identify any existing or potential conflicts of interest, including those that arise as a result of relationships or affiliations with utilities. Contractor must disclose any criminal violations within the past 5 years by the bidder and its principals, including personnel who might be assigned to perform work on this project.

6. Detailed Budget Proposal. Bidders must provide the Commission with a detailed cost proposal that identifies the hourly rate for personnel and any associated expenses.

IV. CRITERIA FOR SELECTION

Cost is a consideration but may not be the determining factor in the Commission's decision. In addition to cost, the Commission will consider the following criteria:

1. The qualifications, expertise, and availability of the proposed team assigned to the project, including expertise and experience pertinent to the services requested in Section II of this Request for Proposals.

2. Experience and qualifications in providing similar services in the NorthEast as well as other states or regions and to other utility commissions or regulatory agencies.

3. Ability to perform all of the major disciplines necessary to perform the work and meet specified timeframes.

4. Cost of consulting services and expenses, including the competitiveness of the proposed hourly rates and any proposed discounts or other cost-effective benefits. (The Commission reserves the right to negotiate lower fees or a different fee structure than proposed, with any selected firms.)

5. Overall responsiveness to the requirements of the RFP, including completeness, clarity and quality of the proposal.

6. Potential conflicts of interest.

7. Any other considerations the Commission may deem appropriate in light of its objectives and review of proposals received.

V. GENERAL BID CONDITIONS

1. Bids must be typed. Original and 5 copies of the bid must be submitted, along with an electronic copy in .PDF format. Bids that are incomplete or unsigned will not be considered.

2. The deadline for submitting bids is 4:30 p.m. on March 9, 2009. Bids must be addressed to ChristiAne G. Mason, Director of Administration, New Hampshire Public Utilities Commission, 21 S. Fruit Street, Suite 10 Concord, NH 03301-2429 and via email ChristiAne.Mason@puc.nh.gov.

3. The Commission reserves the right to reject or accept any or all bids, to reject or accept all or any part of any bid, to determine what constitutes a conforming bid, to waive irregularities that it considers not material to the bid, to award the bid solely as it deems to be in the best interest of the State, to contract for any portion of the bids submitted and to contract with more than one bidder if necessary.

4. All information relating to this bid (including but not limited to fees, contracts, agreements and prices) are subject to the laws of the State of New Hampshire regarding public information.

5. Any contract awarded from this Request for Proposals will expire on December 31, 2009. The Commission at any time, in its sole discretion, may terminate the contract, or postpone or delay all or any part of the contract, upon written notice.

6. The selected vendor must agree to maintain confidential all information to which it has access until it is instructed otherwise by the Commission.

VI. CERTIFICATES

Bidders will be required to provide the following certificates prior to entering into a contract:

1.	Secretary of State's Office Certificate of Good Standing ("CGS")	Individuals contracting in their own name do not need a CGS. Business organizations and trade names need a CGS, except for nonresident nonprofit corporations
2.	Certificate of Vote /Authority ("CVA")	Individuals contracting in their own name do not need a CVA. Business entities and trade names need a CVA.
3.	Certificate of Insurance	Certificate of Insurance demonstrating insurance coverage required under the contract specified in Exhibit C.

VII. FORM OF CONTRACT

The terms and conditions set forth in Attachment 1, General Provisions Agreement are part of the proposal and will apply to any contract awarded the bidder.

Any contract resulting from this bid proposal shall not be deemed effective until it is signed by the Commission.

Attachment 1

Print Form

Subject: Test

FORM NUMBER P-37 (version 1/09)

AGREEMENT
The State of New Hampshire and the Contractor hereby mutually agree as follows:

GENERAL PROVISIONS

1. IDENTIFICATION.

1.1 State Agency Name		1.2 State Agency Address	
1.3 Contractor Name		1.4 Contractor Address	
1.5 Contractor Phone Number	1.6 Account Number	1.7 Completion Date	1.8 Price Limitation
1.9 Contracting Officer for State Agency		1.10 State Agency Telephone Number	
1.11 Contractor Signature		1.12 Name and Title of Contractor Signatory	

1.13 Acknowledgement: State of ____, County of ____

On ____, before the undersigned officer, personally appeared the person identified in block 1.12, or satisfactorily proven to be the person whose name is signed in block 1.11, and acknowledged that s/he executed this document in the capacity indicated in block 1.12.

1.13.1 Signature of Notary Public or Justice of the Peace

[Seal]

1.13.2 Name and Title of Notary or Justice of the Peace

1.14 State Agency Signature	1.15 Name and Title of State Agency Signatory

1.16 Approval by the N.H. Department of Administration, Division of Personnel *(if applicable)*

By: Director, On:

1.17 Approval by the Attorney General (Form, Substance and Execution)

By: On:

1.18 Approval by the Governor and Executive Council

By: On:

Page 1 of 4

2. EMPLOYMENT OF CONTRACTOR/SERVICES TO BE PERFORMED. The State of New Hampshire, acting through the agency identified in block 1.1 ("State"), engages contractor identified in block 1.3 ("Contractor") to perform, and the Contractor shall perform, the work or sale of goods, or both, identified and more particularly described in the attached EXHIBIT A which is incorporated herein by reference ("Services").

3. EFFECTIVE DATE/COMPLETION OF SERVICES.
3.1 Notwithstanding any provision of this Agreement to the contrary, and subject to the approval of the Governor and Executive Council of the State of New Hampshire, this Agreement, and all obligations of the parties hereunder, shall not become effective until the date the Governor and Executive Council approve this Agreement ("Effective Date").
3.2 If the Contractor commences the Services prior to the Effective Date, all Services performed by the Contractor prior to the Effective Date shall be performed at the sole risk of the Contractor, and in the event that this Agreement does not become effective, the State shall have no liability to the Contractor, including without limitation, any obligation to pay the Contractor for any costs incurred or Services performed. Contractor must complete all Services by the Completion Date specified in block 1.7.

4. CONDITIONAL NATURE OF AGREEMENT.
Notwithstanding any provision of this Agreement to the contrary, all obligations of the State hereunder, including, without limitation, the continuance of payments hereunder, are contingent upon the availability and continued appropriation of funds, and in no event shall the State be liable for any payments hereunder in excess of such available appropriated funds. In the event of a reduction or termination of appropriated funds, the State shall have the right to withhold payment until such funds become available, if ever, and shall have the right to terminate this Agreement immediately upon giving the Contractor notice of such termination. The State shall not be required to transfer funds from any other account to the Account identified in block 1.6 in the event funds in that Account are reduced or unavailable.

5. CONTRACT PRICE/PRICE LIMITATION/ PAYMENT.
5.1 The contract price, method of payment, and terms of payment are identified and more particularly described in EXHIBIT B which is incorporated herein by reference.
5.2 The payment by the State of the contract price shall be the only and the complete reimbursement to the Contractor for all expenses, of whatever nature incurred by the Contractor in the performance hereof, and shall be the only and the complete compensation to the Contractor for the Services. The State shall have no liability to the Contractor other than the contract price.
5.3 The State reserves the right to offset from any amounts otherwise payable to the Contractor under this Agreement those liquidated amounts required or permitted by N.H. RSA 80:7 through RSA 80:7-c or any other provision of law.
5.4 Notwithstanding any provision in this Agreement to the contrary, and notwithstanding unexpected circumstances, in no event shall the total of all payments authorized, or actually made hereunder, exceed the Price Limitation set forth in block 1.8.

6. COMPLIANCE BY CONTRACTOR WITH LAWS AND REGULATIONS/ EQUAL EMPLOYMENT OPPORTUNITY.
6.1 In connection with the performance of the Services, the Contractor shall comply with all statutes, laws, regulations, and orders of federal, state, county or municipal authorities which impose any obligation or duty upon the Contractor, including, but not limited to, civil rights and equal opportunity laws. In addition, the Contractor shall comply with all applicable copyright laws.
6.2 During the term of this Agreement, the Contractor shall not discriminate against employees or applicants for employment because of race, color, religion, creed, age, sex, handicap, sexual orientation, or national origin and will take affirmative action to prevent such discrimination.
6.3 If this Agreement is funded in any part by monies of the United States, the Contractor shall comply with all the provisions of Executive Order No. 11246 ("Equal Employment Opportunity"), as supplemented by the regulations of the United States Department of Labor (41 C.F.R. Part 60), and with any rules, regulations and guidelines as the State of New Hampshire or the United States issue to implement these regulations. The Contractor further agrees to permit the State or United States access to any of the Contractor's books, records and accounts for the purpose of ascertaining compliance with all rules, regulations and orders, and the covenants, terms and conditions of this Agreement.

7. PERSONNEL.
7.1 The Contractor shall at its own expense provide all personnel necessary to perform the Services. The Contractor warrants that all personnel engaged in the Services shall be qualified to perform the Services, and shall be properly licensed and otherwise authorized to do so under all applicable laws.
7.2 Unless otherwise authorized in writing, during the term of this Agreement, and for a period of six (6) months after the Completion Date in block 1.7, the Contractor shall not hire, and shall not permit any subcontractor or other person, firm or corporation with whom it is engaged in a combined effort to perform the Services to hire, any person who is a State employee or official, who is materially involved in the procurement, administration or performance of this Agreement. This provision shall survive termination of this Agreement.
7.3 The Contracting Officer specified in block 1.9, or his or her successor, shall be the State's representative. In the event of any dispute concerning the interpretation of this Agreement, the Contracting Officer's decision shall be final for the State.

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8. EVENT OF DEFAULT/REMEDIES.
8.1 Any one or more of the following acts or omissions of the Contractor shall constitute an event of default hereunder ("Event of Default"):
8.1.1 failure to perform the Services satisfactorily or on schedule;
8.1.2 failure to submit any report required hereunder; and/or
8.1.3 failure to perform any other covenant, term or condition of this Agreement.
8.2 Upon the occurrence of any Event of Default, the State may take any one, or more, or all, of the following actions:
8.2.1 give the Contractor a written notice specifying the Event of Default and requiring it to be remedied within, in the absence of a greater or lesser specification of time, thirty (30) days from the date of the notice; and if the Event of Default is not timely remedied, terminate this Agreement, effective two (2) days after giving the Contractor notice of termination;
8.2.2 give the Contractor a written notice specifying the Event of Default and suspending all payments to be made under this Agreement and ordering that the portion of the contract price which would otherwise accrue to the Contractor during the period from the date of such notice until such time as the State determines that the Contractor has cured the Event of Default shall never be paid to the Contractor;
8.2.3 set off against any other obligations the State may owe to the Contractor any damages the State suffers by reason of any Event of Default; and/or
8.2.4 treat the Agreement as breached and pursue any of its remedies at law or in equity, or both.

9. DATA/ACCESS/CONFIDENTIALITY/ PRESERVATION.
9.1 As used in this Agreement, the word "data" shall mean all information and things developed or obtained during the performance of, or acquired or developed by reason of, this Agreement, including, but not limited to, all studies, reports, files, formulae, surveys, maps, charts, sound recordings, video recordings, pictorial reproductions, drawings, analyses, graphic representations, computer programs, computer printouts, notes, letters, memoranda, papers, and documents, all whether finished or unfinished.
9.2 All data and any property which has been received from the State or purchased with funds provided for that purpose under this Agreement, shall be the property of the State, and shall be returned to the State upon demand or upon termination of this Agreement for any reason.
9.3 Confidentiality of data shall be governed by N.H. RSA chapter 91-A or other existing law. Disclosure of data requires prior written approval of the State.

10. TERMINATION. In the event of an early termination of this Agreement for any reason other than the completion of the Services, the Contractor shall deliver to the Contracting Officer, not later than fifteen (15) days after the date of termination, a report ("Termination Report") describing in detail all Services performed, and the contract price earned, to and including the date of termination. The form, subject matter, content, and number of copies of the Termination Report shall be identical to those of any Final Report described in the attached EXHIBIT A.

11. CONTRACTOR'S RELATION TO THE STATE. In the performance of this Agreement the Contractor is in all respects an independent contractor, and is neither an agent nor an employee of the State. Neither the Contractor nor any of its officers, employees, agents or members shall have authority to bind the State or receive any benefits, workers' compensation or other emoluments provided by the State to its employees.

12. ASSIGNMENT/DELEGATION/SUBCONTRACTS. The Contractor shall not assign, or otherwise transfer any interest in this Agreement without the prior written consent of the N.H. Department of Administrative Services. None of the Services shall be subcontracted by the Contractor without the prior written consent of the State.

13. INDEMNIFICATION. The Contractor shall defend, indemnify and hold harmless the State, its officers and employees, from and against any and all losses suffered by the State, its officers and employees, and any and all claims, liabilities or penalties asserted against the State, its officers and employees, by or on behalf of any person, on account of, based or resulting from, arising out of (or which may be claimed to arise out of) the acts or omissions of the Contractor. Notwithstanding the foregoing, nothing herein contained shall be deemed to constitute a waiver of the sovereign immunity of the State, which immunity is hereby reserved to the State. This covenant in paragraph 13 shall survive the termination of this Agreement.

14. INSURANCE.
14.1 The Contractor shall, at its sole expense, obtain and maintain in force, and shall require any subcontractor or assignee to obtain and maintain in force, the following insurance:
14.1.1 comprehensive general liability insurance against all claims of bodily injury, death or property damage, in amounts of not less than $250,000 per claim and $2,000,000 per occurrence; and
14.1.2 fire and extended coverage insurance covering all property subject to subparagraph 9.2 herein, in an amount not less than 80% of the whole replacement value of the property.
14.2 The policies described in subparagraph 14.1 herein shall be on policy forms and endorsements approved for use in the State of New Hampshire by the N.H. Department of Insurance, and issued by insurers licensed in the State of New Hampshire.
14.3 The Contractor shall furnish to the Contracting Officer identified in block 1.9, or his or her successor, a certificate(s) of insurance for all insurance required under this Agreement. Contractor shall also furnish to the Contracting Officer identified in block 1.9, or his or her successor, certificate(s) of insurance for all renewal(s) of insurance required under this Agreement no later than fifteen (15) days prior to the expiration date of each of the insurance policies. The certificate(s) of insurance and any renewals thereof shall be

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attached and are incorporated herein by reference. Each certificate(s) of insurance shall contain a clause requiring the insurer to endeavor to provide the Contracting Officer identified in block 1.9, or his or her successor, no less than ten (10) days prior written notice of cancellation or modification of the policy.

15. WORKERS' COMPENSATION.
15.1 By signing this agreement, the Contractor agrees, certifies and warrants that the Contractor is in compliance with or exempt from, the requirements of N.H. RSA chapter 281-A *("Workers' Compensation").*
15.2 To the extent the Contractor is subject to the requirements of N.H. RSA chapter 281-A, Contractor shall maintain, and require any subcontractor or assignee to secure and maintain, payment of Workers' Compensation in connection with activities which the person proposes to undertake pursuant to this Agreement. Contractor shall furnish the Contracting Officer identified in block 1.9, or his or her successor, proof of Workers' Compensation in the manner described in N.H. RSA chapter 281-A and any applicable renewal(s) thereof, which shall be attached and are incorporated herein by reference. The State shall not be responsible for payment of any Workers' Compensation premiums or for any other claim or benefit for Contractor, or any subcontractor or employee of Contractor, which might arise under applicable State of New Hampshire Workers' Compensation laws in connection with the performance of the Services under this Agreement.

16. WAIVER OF BREACH. No failure by the State to enforce any provisions hereof after any Event of Default shall be deemed a waiver of its rights with regard to that Event of Default, or any subsequent Event of Default. No express failure to enforce any Event of Default shall be deemed a waiver of the right of the State to enforce each and all of the provisions hereof upon any further or other Event of Default on the part of the Contractor.

17. NOTICE. Any notice by a party hereto to the other party shall be deemed to have been duly delivered or given at the time of mailing by certified mail, postage prepaid, in a United States Post Office addressed to the parties at the addresses given in blocks 1.2 and 1.4, herein.

18. AMENDMENT. This Agreement may be amended, waived or discharged only by an instrument in writing signed by the parties hereto and only after approval of such amendment, waiver or discharge by the Governor and Executive Council of the State of New Hampshire.

19. CONSTRUCTION OF AGREEMENT AND TERMS. This Agreement shall be construed in accordance with the laws of the State of New Hampshire, and is binding upon and inures to the benefit of the parties and their respective successors and assigns. The wording used in this Agreement is the wording chosen by the parties to express their mutual intent, and no rule of construction shall be applied against or in favor of any party.

20. THIRD PARTIES. The parties hereto do not intend to benefit any third parties and this Agreement shall not be construed to confer any such benefit.

21. HEADINGS. The headings throughout the Agreement are for reference purposes only, and the words contained therein shall in no way be held to explain, modify, amplify or aid in the interpretation, construction or meaning of the provisions of this Agreement.

22. SPECIAL PROVISIONS. Additional provisions set forth in the attached EXHIBIT C are incorporated herein by reference.

23. SEVERABILITY. In the event any of the provisions of this Agreement are held by a court of competent jurisdiction to be contrary to any state or federal law, the remaining provisions of this Agreement will remain in full force and effect.

24. ENTIRE AGREEMENT. This Agreement, which may be executed in a number of counterparts, each of which shall be deemed an original, constitutes the entire Agreement and understanding between the parties, and supersedes all prior Agreements and understandings relating hereto.

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