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."

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[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.

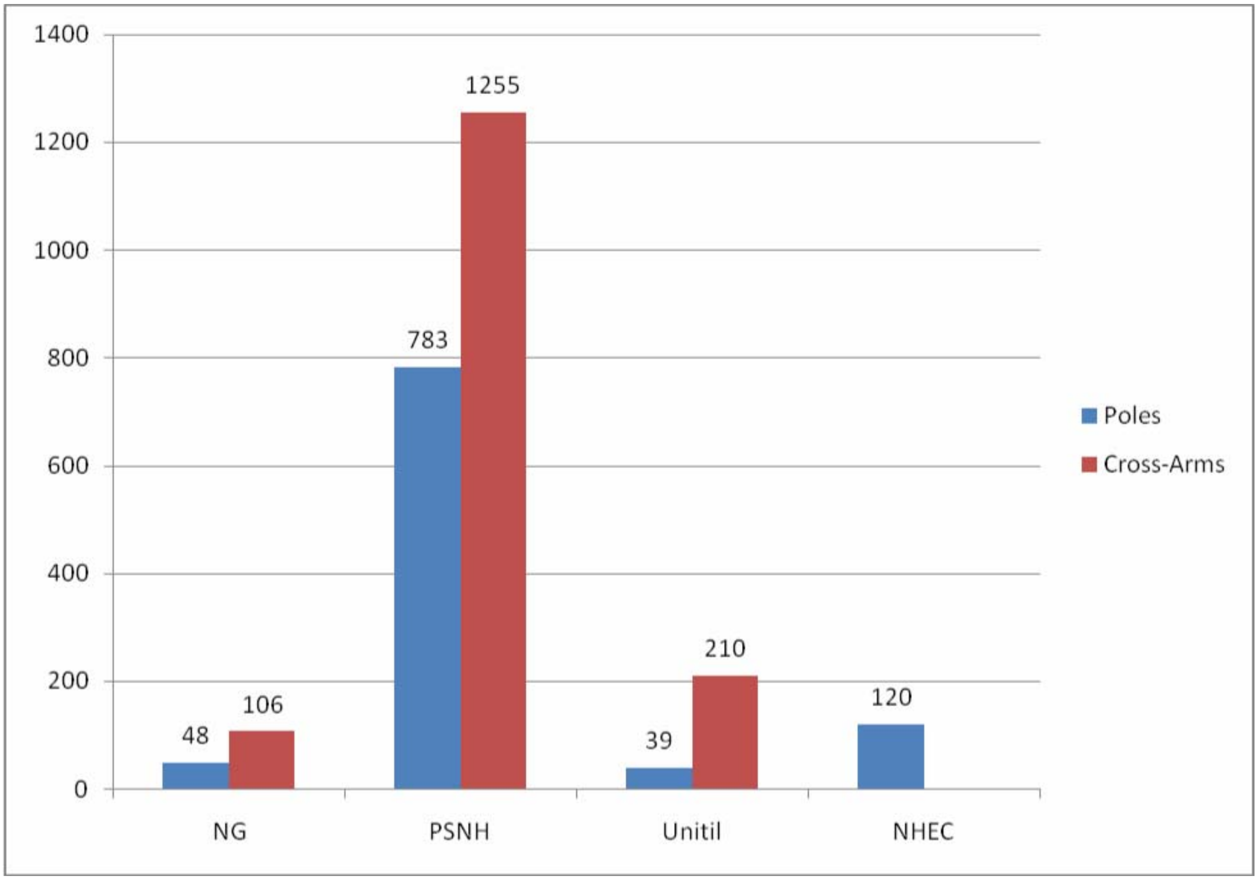

Figure V-3 – Poles and cross arms replaced by each utility following the December 2008 ice storm.[14] [15] [16] [17]

[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

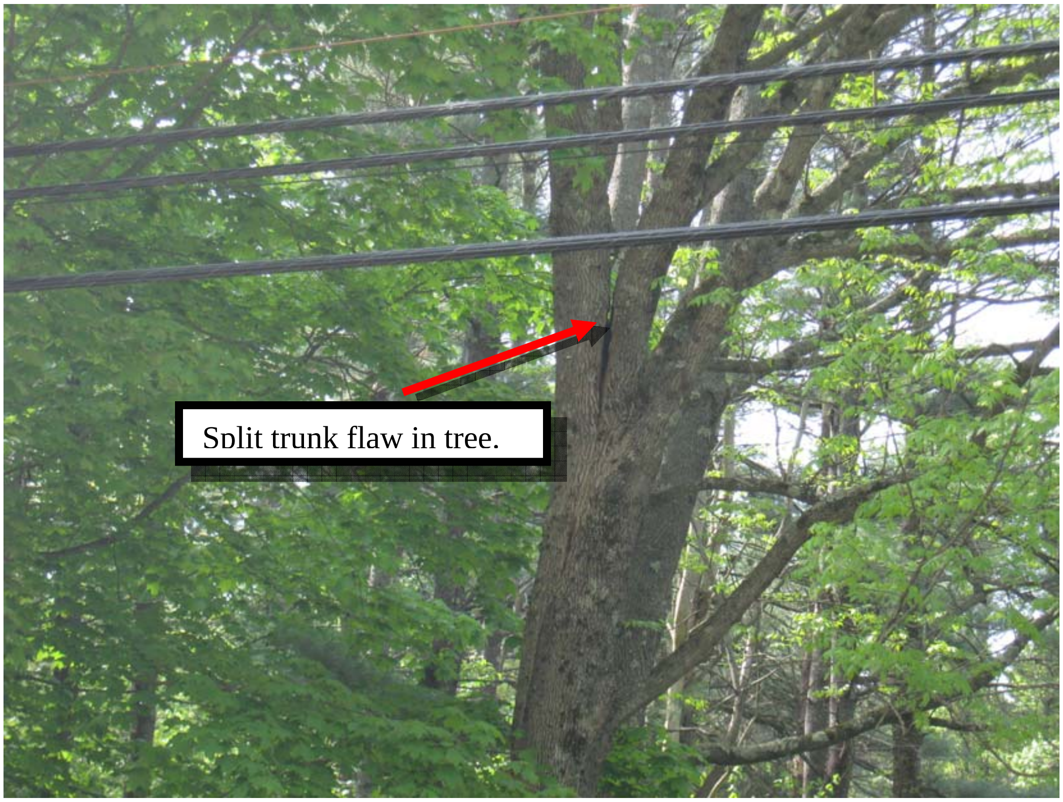

Figure V-4 - Neglected damage and weakness to large limb of tree near Hampton, NH. (Photo by NEI)

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.

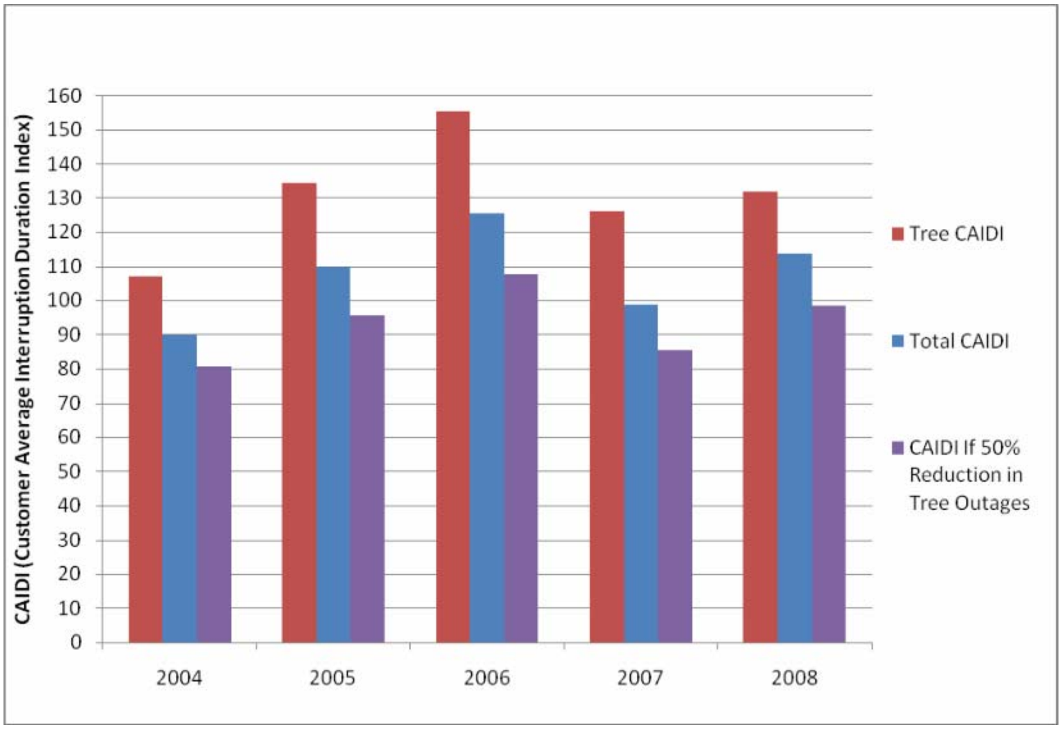

Figure V-6 - PSNH CAIDI statistics.[31]

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.

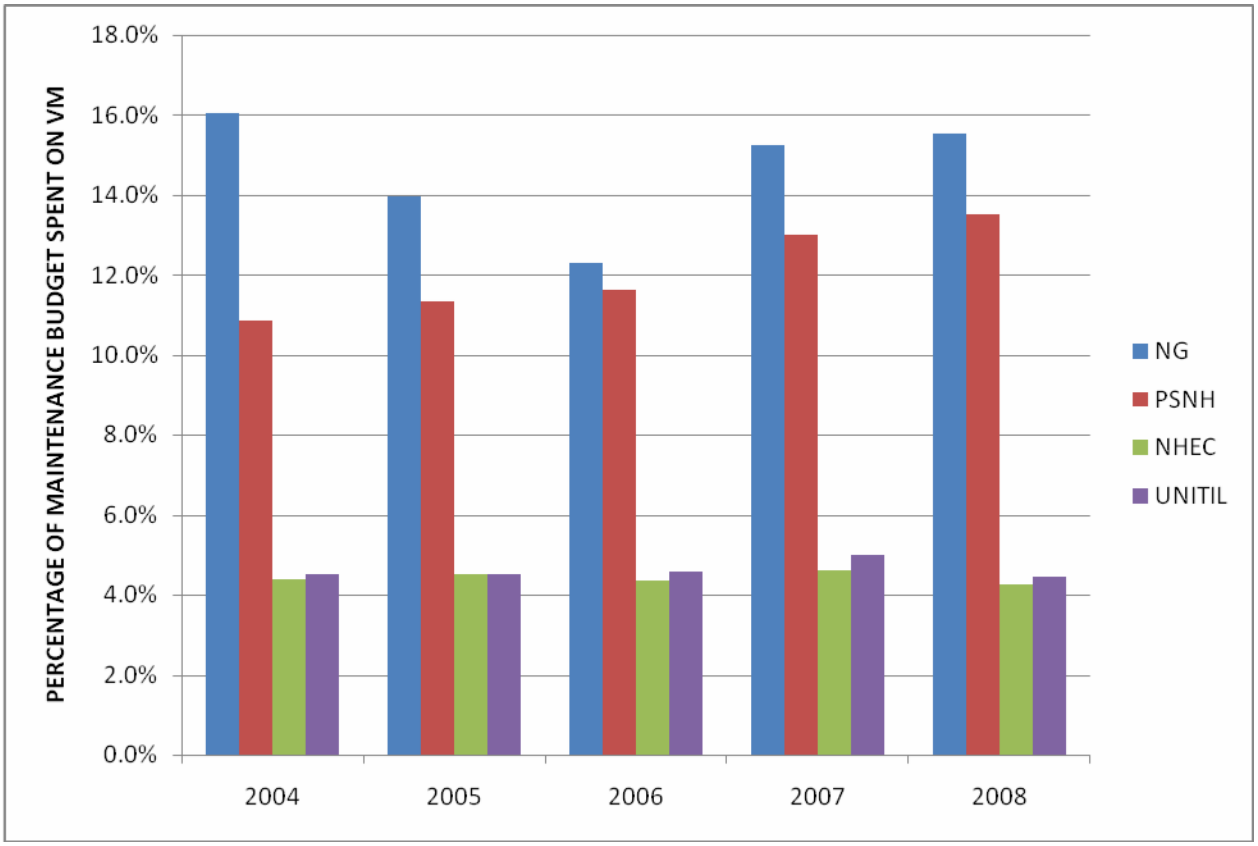

Figure V-8 - Percentage of their distribution maintenance budget each utility spent on vegetation management.

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]

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[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.

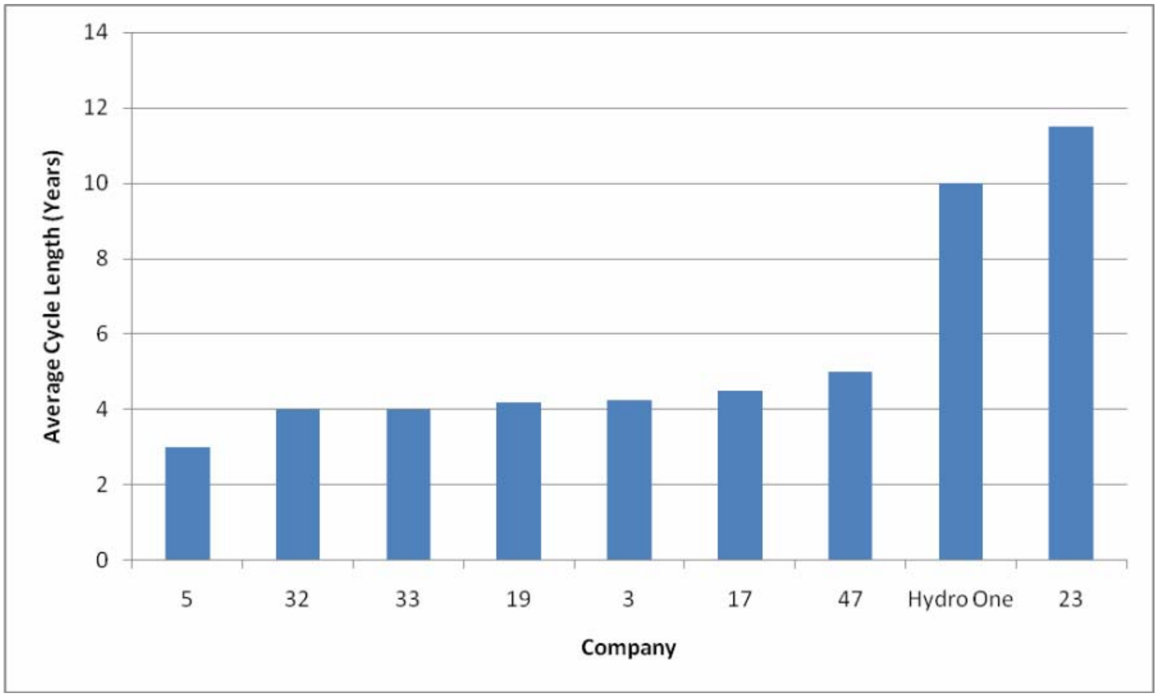

Figure V-16 -Vegetation management cycle lengths for nine utilities.

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.

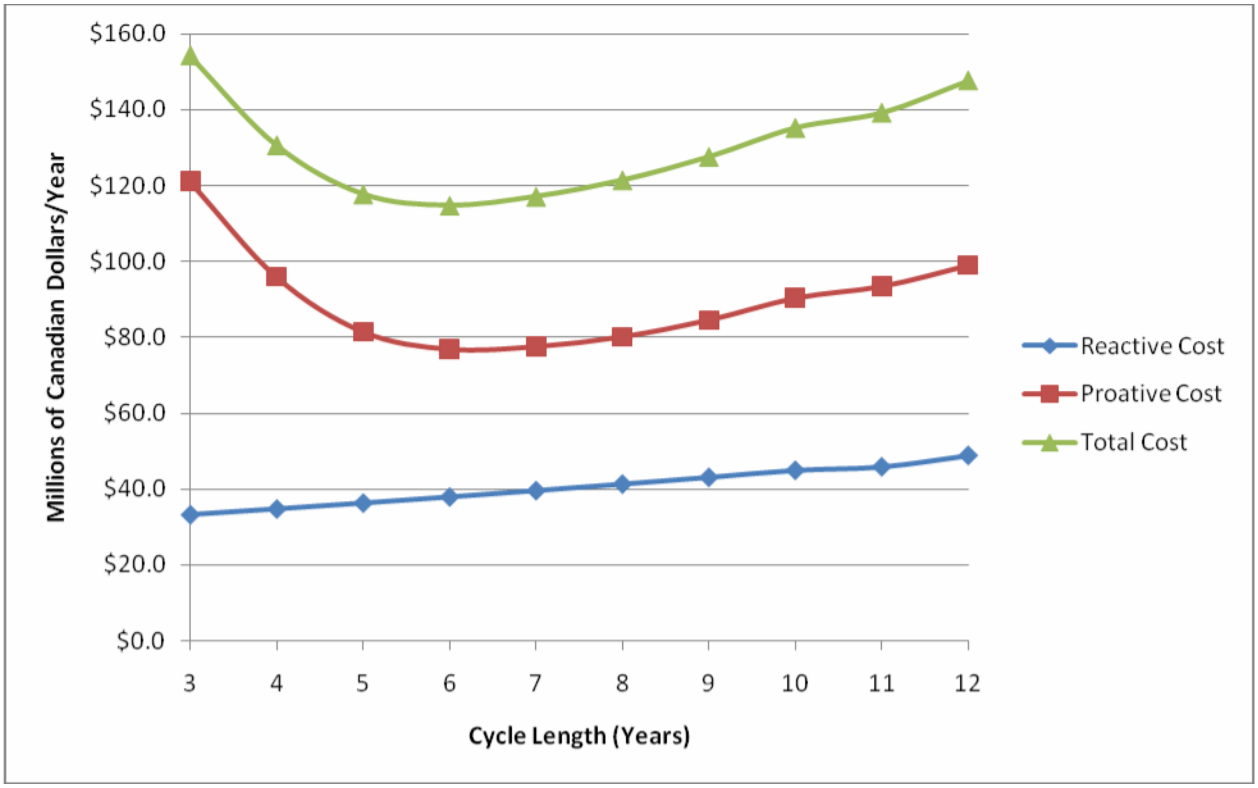

Figure V-17 – Hydro One's total costs of for vegetation management compared to cycle length.

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.