Q. **Asset Management**

The response to PUB-NLH-172 indicates that Hydro bases its Wood Pole Line Management (WPLM) program on a Reliability Centered Maintenance (RCM) principle. Provide a discussion of Hydro's definition of RCM and Hydro's use of RCM principles for its various Transmission and Rural Operations (TRO) asset management operations and maintenance (O&M) and capital programs. Include the formal goals of Hydro's Asset Management activities.

A. Hydro's WPLM program was developed using RCM principles and is described in detail in PUB-NLH-349 Attachment 1. Hydro performed a review of its maintenance program for its TRO assets using Value Based RCM. This work was completed in 2003 prior to the onset of WPLM and the review was guided by Power Systems Solutions International from Calgary. Their definition of "Value Based"™ RCM is a systematic, objective and well documented approach to maintenance optimization. Classical RCM builds on the accepted concepts of risk assessment. As an extension, Value Based RCM allows for a monetary comparison of the cost of maintenance with its benefit. Since this review, Hydro has continually improved the maintenance program for TRO assets based on asset criticality rankings, updated information from OEMs, maintenance practices of other utilities and analysis of asset performance data.

In 2010, Hydro further enhanced its asset management program with the goal of ensuring the comprehensive management of asset requirements, planning, procurement, operations, maintenance and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the provision of safe and reliable service to current and future generations.

Hydro's asset management organizational structure consists of:

a. Long Term Asset Planning;
b. Short Term Work Planning and Scheduling;
c. Critical Spares Management;
d. Project Management;
e. Work Execution; and
f. Operations.

This enables successful execution of Hydro's asset management framework, which consists of:

a. Basis of Design – asset standards, planning criteria and operating parameters;
b. Asset acquisition requirements – new assets, existing assets/sustaining capital and 20-year planning horizon; and
c. Operations, maintenance and asset renewal.

Hydro is committed to continual improvement of its asset management program as demonstrated by its enhanced annual work planning and measurement (S-Curves) process implemented in 2014.

WOOD POLE LINE MANAGEMENT USING RCM PRINCIPLES

Report Prepared By

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St. John's

Dated: April 7, 2004

EXECUTIVE SUMMARY

Hydro has completed a study entitled **"Wood Pole Line Management (WPLM)"** using **Reliability Centered Maintenance (RCM)** principles. This study covers the management of forty-three (43) wood pole lines across Newfoundland and Labrador of various voltage levels ranging from 69 kV - 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages, with the maximum age being **38** years. Almost two-thirds of transmission pole plant assets fall into two age categories; approximately 34% are at or over 30 years, and another 31% are 20 to 30 years old. The remaining asset age is less than 20 years old.

The integrity of a wood pole structure is normally compromised by fungi attack which causes decay. Insects and woodpeckers can also damage the wood poles extensively in certain areas. To prevent against fungi attack, poles are normally factory treated with preservatives at the time of purchase prior to installation. Loss of preservative is one of the primary reasons that a wood pole will be susceptible to fungi attack thus inducing decay (loss of sapwood and heartwood) and, if not detected and treated early, the integrity of the structure could be jeopardized. This would also affect the reliability of the line and introduce a safety issue during climbing inspections.

In the past, Hydro has performed pole inspections based on a 5-year interval using the sounding methodology only. It is also true that Hydro had not replaced any significant amount of transmission size poles until 1998 except for line failures due to ice storms. Hydro spent approximately $600,000 dollars to replace 78 poles on the Avalon Peninsula that were rejected (6.5% of the inspected poles) due to internal decay and rot during the 1998 inspection. Based on the inspection in 2000, Hydro also spent an additional $420,000 dollars in 2001 to replace poles in the Central region that were primarily damaged by ant infestation.

The recent pole inspection program on the Avalon Peninsula in 1998 and 2003 revealed that the preservative retention levels for a large portion of these poles fell well below the minimum threshold, which is required to maintain the "health" of the pole on a long-term

basis. A quick comparison of Hydro's retention level data with those obtained from a major Canadian utility showed that the preservative amount left on these poles is not only well below this utility's data but also below the minimum threshold. **Fig. 1** depicts the comparison of this data where Zones 1 and 2 represent the other utility's data.

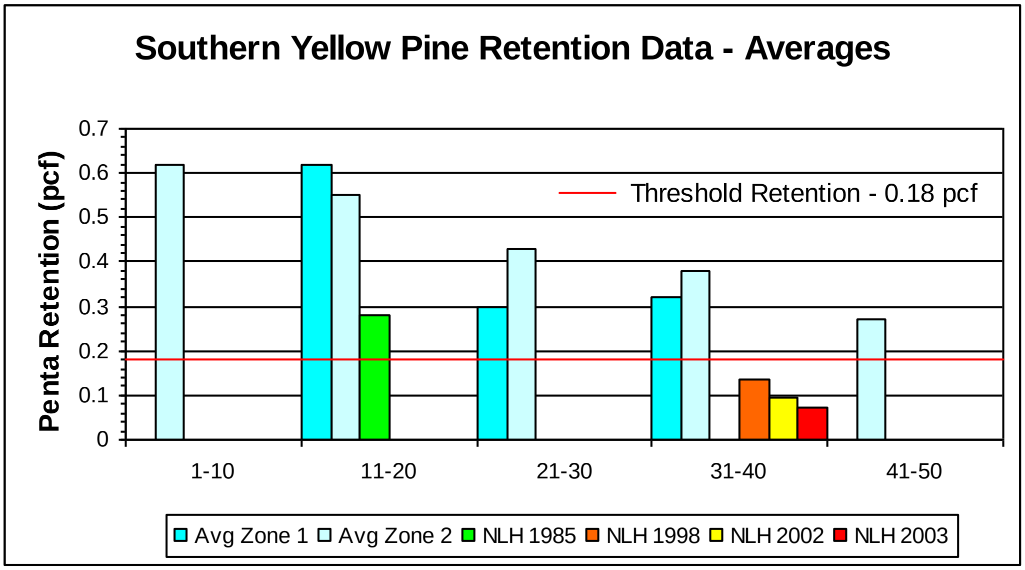

Fig. 1

Even when the inspection does not reveal useful information (i.e. at the early years of operation between 10 and 20 years), the future prediction on pole rejections and/or replacements can still be made using the likelihood of failure by using the pole life expectancy curve known as the IOWA curve, depicted in **Fig. 2**. The curve was validated initially for poles on the Avalon Peninsula using the 1985, 1998 and 2003 pole inspection data. Later, this validation process was extended to cover poles from the Central region based on 2000, 2002 and 2003 data. Although the rejection rate (1 – survival rate) is small in the early part of the 50-year IOWA curve, the rate changes drastically as the poles get closer to their service (economic) life i.e. near 40 years and beyond.

A limited number of full scale tests on in-service poles at the Memorial University also indicated that on average, these poles have lost 25% strength over a 35 year period with regard to their initial mean design strength of 8000 psi. It is not known at this time how fast the strength begins to deteriorate with regard to time once the pole preservative retention level falls below the threshold. It is also recommended that NLH starts implementing NDE as well as periodic full scale tests for all other major line components such as conductors, insulators and hardware particularly for those lines which are 30 years of age or older to develop a historical database on residual strength with regard to aging. This is of considerable importance for developing a sound strategy for asset replacement criteria as well as future life extension work for these wood pole lines. The report also presents a methodology to implement a condition based inspection (CBI) program considering the requirement of a specific line availability and the mean time between failure (MTBF) obtained from historical data.

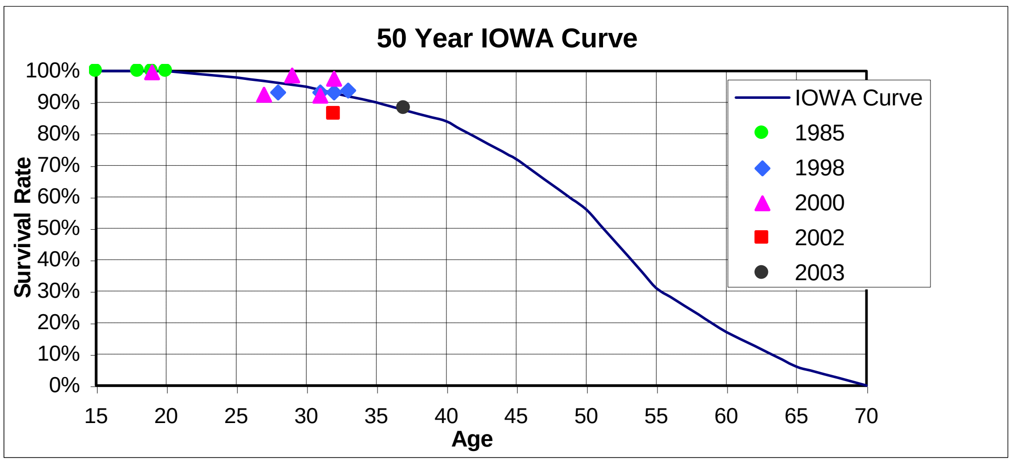

Fig. 2

<u>Deliverables</u>

The proposed annual inspection program will be primarily "visual" in nature**.** Under this program, all wood pole lines will be fully inspected within the next 10 years. Besides routine line inspection work, NLH will also implement a comprehensive pole inspection, test and treatment program, which will continue at least for two "10 year cycles".

The purposes of this Wood Pole Line Management (WPLM) program are:

- to develop a comprehensive RCM program of wood pole lines based on a condition based pole inspection program,
- to establish an inspection program for extending the average service life of all poles in the system by using the conventional sounding and boring techniques supplemented by (1) NDE test of each pole and (2) full scale destructive testing program for a limited number of in-service poles each year,

- to detect the "danger poles" early to avoid safety hazard and premature collapse,
- to implement a full treatment program to ensure an adequate preservative retention level is maintained both internally and externally at specific levels,
- to ensure the decay is arrested at an early stage thus extending the life of the pole plant assets, and
- to develop a comprehensive database to catalogue the inspection and maintenance data

In addition, ten percent (10%) of the poles inspected annually will be tested for preservative retention levels and the data will be analyzed to develop a trend line for future pole rejection and/or replacement criteria.

Since NLH wood pole plant assets are normally assumed to have a 40-year service (economic) life, it is important that these lines are well maintained not only within the service life, but also beyond its economic life. Hydro will be able to extend the asset's life through maintenance with an effective treatment program, thus not only providing increased reliability but also deferring the cost of building new lines for replacement, once the normal service life has expired. Periodic inspection data will also provide early indication when a transmission line needs to be completely replaced based on the residual strength. This will help System Planning to develop long-term replacement criteria for transmission plant assets.

A detailed cost estimate has been prepared based on the assumption that all work will be done using in house resources and expertise with very limited requirement for external resources. All costs associated with this program are capitalized in view of the fact that the inspection and maintenance programs proposed would extend the life of the pole plant assets. Cost benefit analysis indicates a net benefit of $4.5 million dollars, which is due primarily to the rejection, and/or replacement of a fewer number of poles in future years due to application of remedial treatment. The budget estimate indicates that NLH will be required to commit $36 million dollars over a twenty-year period (two "10 year cycles") to implement the RCM program for the wood pole plant assets.

Acknowledgements

I would like to thank the Operation Personnel from Bishop's Falls, particularly Howard Richards, Asset Manager for Central Region, Garland Smith, Transmission Specialist, and Garland Quinlan, RCM Analyst for providing me the necessary support and assistance for developing the cost structure for the Wood Pole Line Management Program. Sincere appreciation is expressed to Kyle Tucker, Transmission Line Design Engineer for providing the technical assistance as well as a constructive critique of the document. I would also like to thank Peter Thomas, Sr. Planning Engineer, for providing the technical input for the cost benefit analysis and for reviewing this document. Finally, my special thanks to Mr. Fred Martin, Vice President, TRO, and Mr. Gordon Holden, Acting Director, TRO Engineering for reviewing the document and providing many helpful comments.

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SECTION 1

Introduction

1.0 Background

During the past 15 years Hydro has consistently used the **Reliability Based Design (RBD)** methodology either in the upgrading of existing lines (TL 228, 230 kV steel lines on the Avalon Peninsula, Haldar, 1990, 1997) and/or building new lines (TL 263, TL 236). The RBD methodology takes into account the capital cost of investment in the upgrading of existing lines, or building of new lines, and balances this cost against any future cost of damage (discounted to the present value) and optimizes the design parameters such as span, reliability, etc. **Fig. 1.1** depicts the saddle point where the total cost is minimized.

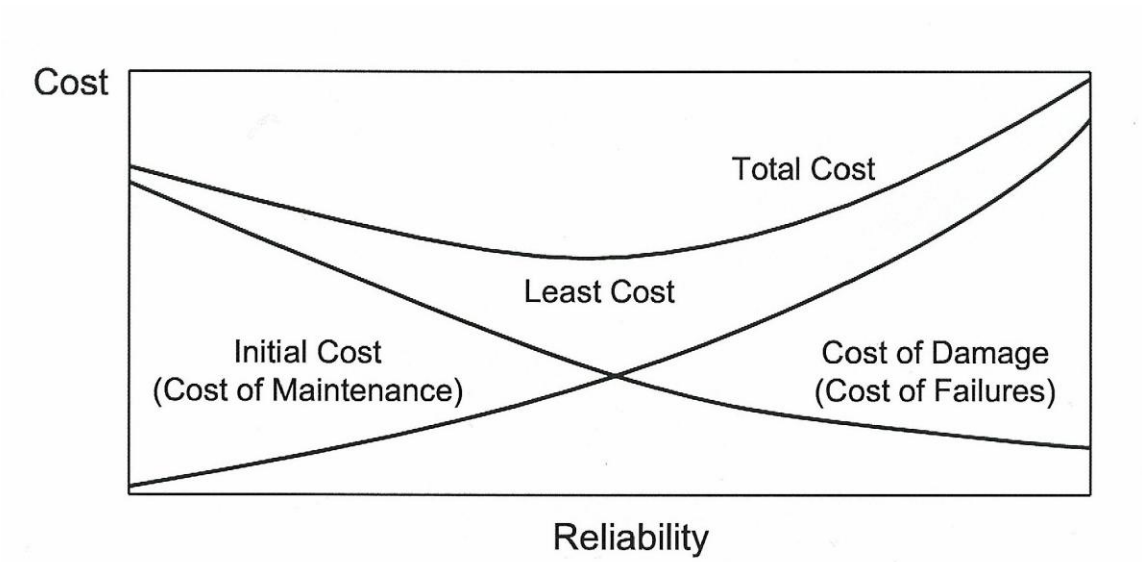


Fig. 1.1 – Optimum Cost Curve

Since 1997, Hydro has been working to implement a Reliability Centered Maintenance (RCM) program in which the cost of preventive and predictive maintenance is balanced against the cost of damage and service interruption. **Fig. 1.1** also captures this idea and shows that in principle, both RBD and RCM methodologies can complement each other to ensure that Hydro gets the best return on its investment during the service life of a transmission line asset.

1.1 Historical Perspective -Wood Pole Inspection Program

Avalon Wood Pole Lines – 1985 Inspection

A pole inspection program on the Avalon Peninsula was launched in 1985 after the sleet storm damage of 1984. This study was conducted by Hydro with the assistance from the Federal Forestry Laboratory at Pleasantville, NL. The inspection program was carried out during the summer of 1985 and the lines inspected were TL 201, TL 203 and TL 218/236. Although no poles were rejected at the time, the study concluded that a few poles had some sort of decay that was in the incipient or early stages. Recommendations were made to treat these poles.

Avalon Wood Pole Study - 1998 Inspection

The Avalon Upgrading study, completed in 1997, recommended the upgrading of the steel transmission line system from Sunnyside Terminal Station to Oxen Pond Terminal Station, and to further study the reliability of wood pole lines on the Avalon Peninsula considering the aging issue. During the study phase, an inspection program of 1500 in service poles (32 years old) on the Avalon Peninsula revealed a 6.5% rejection rate. These rejected poles were replaced in the same year for approximately $600,000 dollars.

A number of full-scale tests of in-service poles at Memorial University revealed they have lost, on average, 25% of their original mean design fibre strength over the past 35 years. However, this data alone was insufficient to predict the residual life of these lines and therefore, a re-conductoring option with an EHSS (Extra High Strength Steel) conductor was not pursued further. Subsequently, this latter study was completed in 2001 with a recommendation not to proceed with the upgrading of these wood pole lines (Haldar, 2001) because of insufficient data with respect to the strength deterioration of these lines.

Development of Current Wood Pole Line Management (WPLM) Program

In an effort to obtain more information on the deterioration of wood poles, Hydro conducted a study in 2002, and from this, a report entitled "Wood Pole Inspection Program-Budget, 2003 & beyond" was issued. This report recommended that Hydro should immediately develop and implement a full wood pole inspection program with Non Destructive Evaluation (NDE) techniques to collect more field data. A comprehensive test and treatment program for both interior and exterior sections of the poles was also proposed to extend their life. Accordingly, a multi-million dollar estimate was proposed based on a program to cover all transmission size poles (26,000 poles) over the next 10 years. The program will include inspection, testing, rehabilitation and, where necessary, replacement.

During the review of this estimate, Hydro decided to undertake the implementation of the program within the RCM framework to ensure that all inspection work associated with these wood pole lines (i.e. not only wood poles but conductors, insulators, hardware, cross braces, guy strands, etc) are completed in a coherent manner and that all wood pole line assets are managed in the most cost effective way. Since 2003, Operations and Engineering have been working closely to provide a "framework" to develop a Wood Pole Line Management (WPLM) program using RCM principles.

Since completion of the 1998 inspection program of poles on the Avalon Peninsula, Hydro has conducted detailed inspection programs: in 2000 lines in the central region; in 2002 TL 220 (Bay D'Espoir Terminal Station to Barachoix Terminal Station); and in 2003 a large number of lines on the Island. Results of these inspection programs are discussed in detail in Section 3 of this report.

1.2 Purpose of the Study

Hydro operates 43 high voltage (69 kV – 230 kV) wood pole transmission lines that total approximately 2400 km. **Fig. 1.2a, b and c** present the age of these lines. Approximately, 42% of Hydro's transmission lines are over 30 years of age and, without a careful assessment of their condition, Hydro's wood pole transmission network could be exposed not only to premature failure under design loading conditions but also to a major pole replacement program in the future.

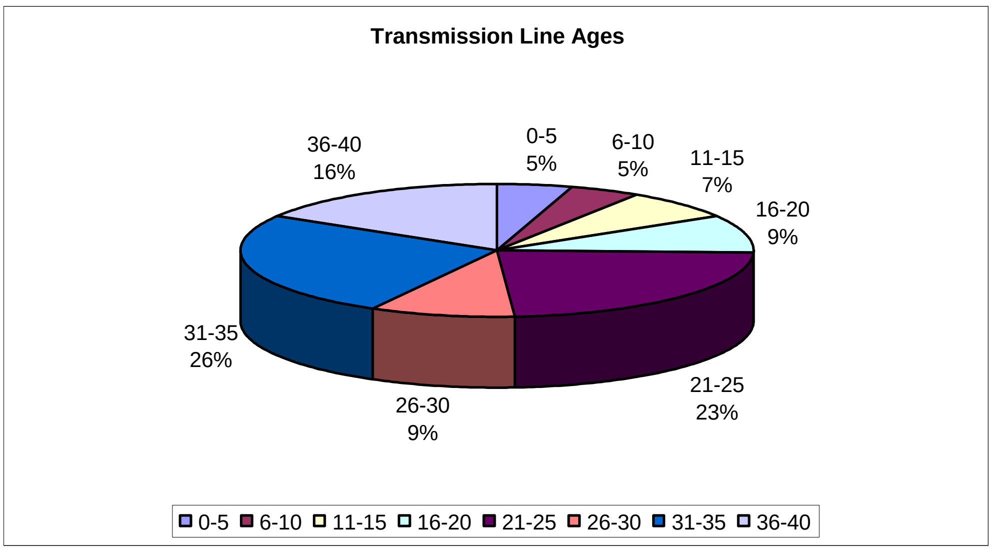


Fig. 1.2a - Transmission Line Ages

Careful planning for possible replacement of these assets is required otherwise Hydro could be exposed to a significant number of forced outages in the future. Therefore, the purpose of this study is to develop a comprehensive "Wood Pole Line Management Program" based on Reliability Centered Maintenance principles that takes into account the cost of inspection and maintenance versus risk scenarios and provides a value-based program which is quite flexible and easy to implement.

The purposes of this Wood Pole Line Management (WPLM) program are:

- to develop a comprehensive **RCM program** for wood pole lines based on a condition based pole inspection program,

- to establish a inspection program for extending the average service life of all poles in the system by using the conventional sounding and boring techniques supplemented by (1) NDE test of each pole and (2) full scale destructive testing program for a limited number of poles removed from service each year,
- to detect the "danger poles" early to avoid safety hazard,
- to implement a full treatment program to ensure an adequate preservative retention level is maintained both internally and externally, and
- to ensure that the decay is arrested at an early stage thus extending the life of the pole plant assets, and
- to develop a comprehensive database to catalogue the inspection and maintenance data for future record and condition based analysis.

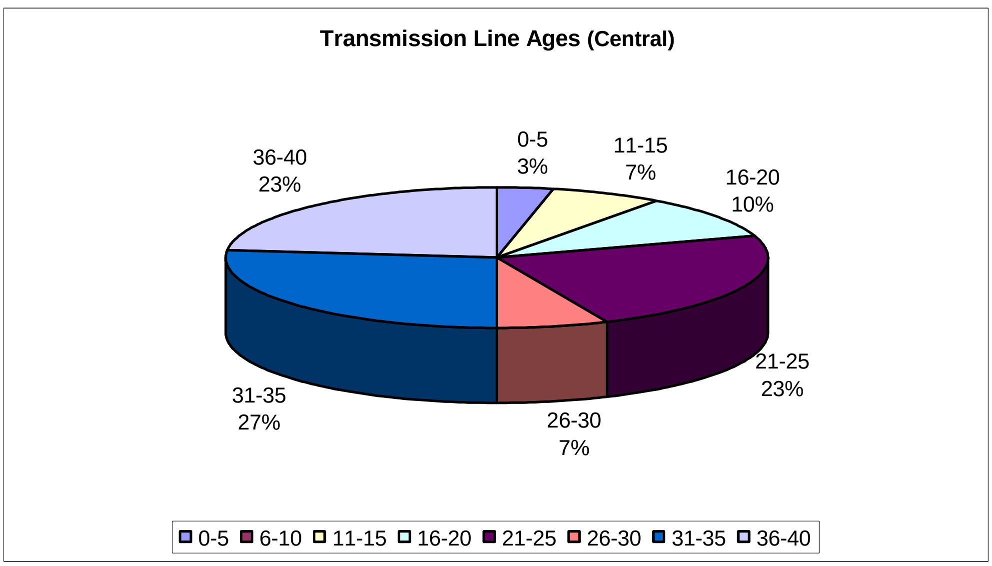


Fig. 1.2b - Transmission Line Ages (Central Region)

The advantages of an effective maintenance program for wood pole lines based on RCM principles are summarized as follows: (1) it provides a mechanism to replace the "danger poles" well in advance before they become problematic or hazardous and (2) Hydro will be able to extend the transmission line asset's life by replacing these poles early enough and maintaining a good treatment program to defer the cost of building new lines for replacement, once the normal service life is expired.

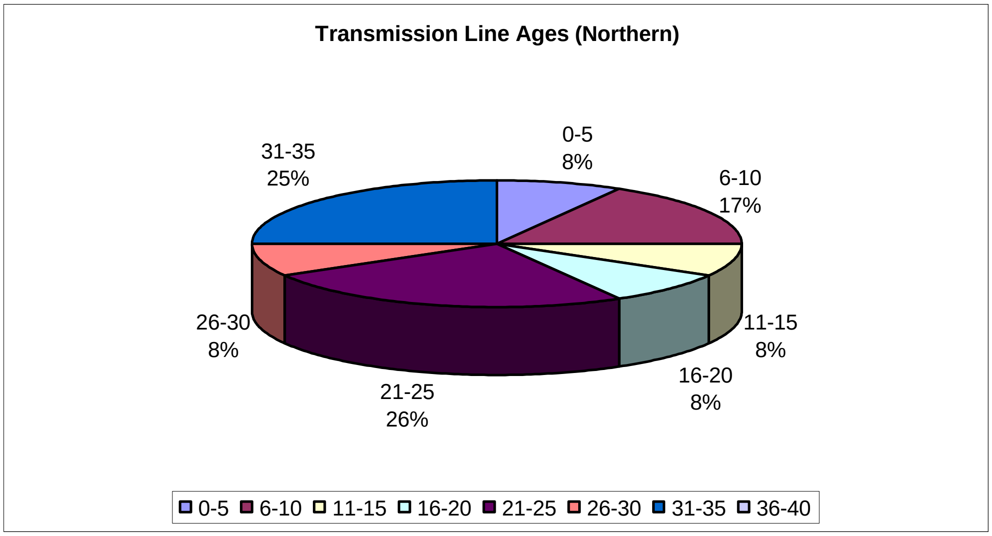


Fig 1.2c – Transmission Line Ages (Northern Region)

1.3 Scope of the Study

To complete this study in a systematic manner various tasks were identified and are listed as follows:

- RCM Methodology;
- Condition Based Inspection Program and Maintenance Strategy;
- Database Development;
- Program Schedule and Cost;
- Summary, Conclusions and Recommendations; and
- References.

SECTION 2

RCM Methodology

2.1 Reliability Centered Maintenance (RCM) of Wood Pole Lines

To understand the RCM principles with particular reference to wood pole lines, one needs to treat the line as a system which can be broken down into various sub-systems as shown in **Fig. 2.1.** The Asset Manager needs to know the condition of the asset (in this case, the condition of the various sub-systems e.g. structures, conductor-hardware etc. or its individual components such as wood poles, conductor, insulators, hardware etc) at present i.e. “year zero” of the future life cycle. The life cycle could be any period of time. A typical period, or life cycle for new wood pole lines is 40 to 50 years.

In order to preserve the system function as well as to optimize the maintenance cost, the manager needs to know the consequence of a failure, identify failure modes that cause the interruption of service and prioritize the function need, and to develop a strategy for specific maintenance tasks that will preserve the system reliability. The primary goal of RCM is to strike an appropriate balance between the cost of maintenance and the customer’s value of reliability (Power System Inc, 1998).

The current maintenance practice of NLH is primarily time based. That is, 20% of each line is inspected and maintained each year to ensure that all lines are fully inspected every 5 years, irrespective of their age. On the other hand, RCM emphasizes **condition based inspection and maintenance (CBIM**) practices where the focus is on preserving system functionality rather than preserving individual components.

Although in principle **RCM** will work for any system, one needs to distinguish one unique characteristic of a transmission line system with regard to other engineering systems, such as aircraft, power plants etc. In these systems, system functionality can be maintained even when a component has failed because of the high redundancy built into the system. Contrary to this, a typical transmission line, in general works as a "series system". That is transmission line failure is normally dictated by the "weak link component" of the system and the prediction of future failure is extremely complicated by the spatial extent of the line and its exposure to widely variable environmental conditions (such as extreme wind and/or ice, vibration, rotting of poles and knee braces, wearing of hardware etc.). Redundancy is only provided through the network system where parallel lines may exist to share the load although during ice storms both lines are exposed equally.

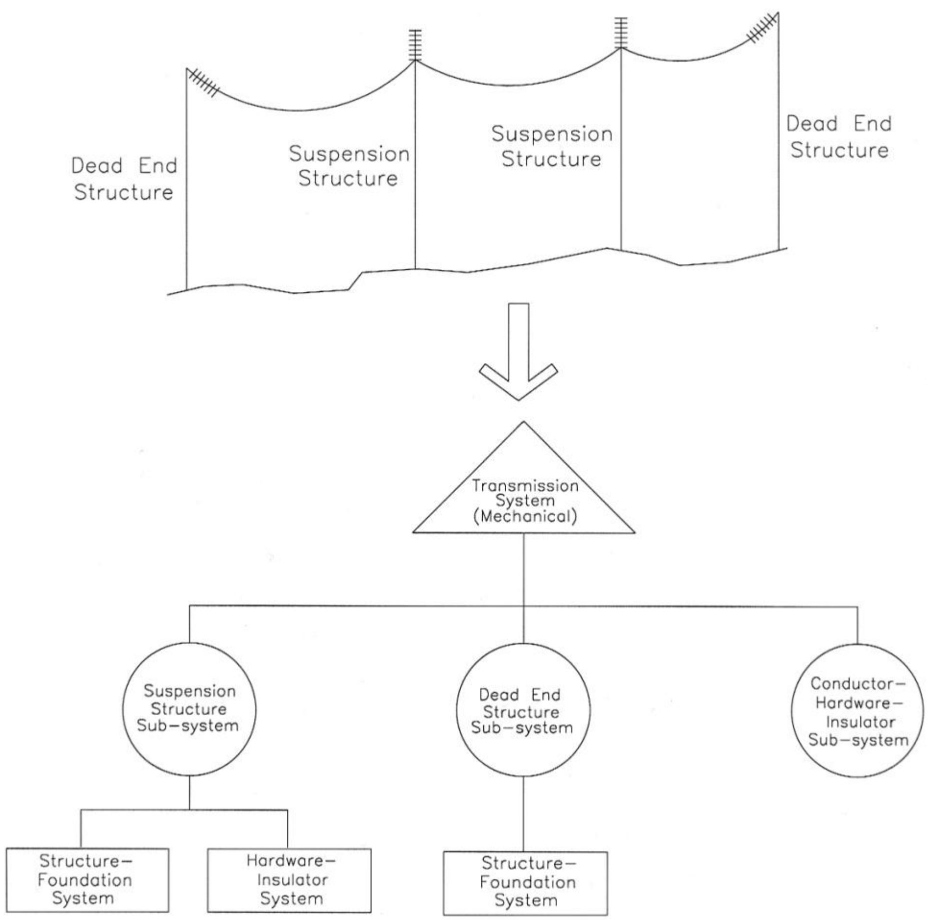


Fig. 2.1 - Transmission Line System

Of course, to implement the **RCM** methodology correctly, one needs to understand the intricate relationships of possible failure modes that could be encountered either due to overloading and/or inadequate strength due to aging. Although **RCM** allows, **"Run to Failure (RTF)"** under certain circumstances, one needs to be extremely careful before this is applied to transmission lines without a proper analysis of the system as a whole and the consequences.

2.2 Model

In **RCM**, it is important that a structured format be developed to evaluate a specific value-based option based on the inspection information provided by the field personnel. This can be accomplished by minimizing the net present value (**NPV)** of the annual expenditures for managing the Wood Pole Line Assets over a predetermined time period, t (e.g. service life). Normally the time period, t, could be identified as part of the estimated service life or the full service life. For a wood pole line, the service life is normally accepted as 40 years.

To ensure that one gets comparable results, future costs must be discounted to the present values.

$$NPV = \sum_{0}^{n} C_i / (1+r)^i \qquad \textbf{(2.1)}$$

where

- **NPV= net present value of the annual expenditures**
- **C_i = the annual expenditures in year i**
- r **= discount rate**
- **n = period undertaken in years**

C_i includes two components: deterministic cost (D_i) which is the planned annual expenditures for inspection and maintenance (historical) in year i, while the probabilistic cost (R_i) is the cost associated with the probability of failure in year, i. This could be failure of a structure (and/or pole), insulator, conductor etc.

$$C_i = D_i + R_i \qquad \textbf{(2.2)}$$

The “ risk” is normally defined as the product of the probability of encountering an event (e.g. likelihood of the failure of a wood pole structure) and the consequence (monetary loss normally in dollars) due to this failure. This consequence needs to be assessed at the local level, at the system level and at the company level.

Cost associated with the local level will include the direct cost of replacing the structure and/or refurbishment to bring it to its original reliability level. At the system level, the risk and cost would be the impact on the system due to the loss of a specific line (loss of power sale, additional cost of generation, any penalty or legal consequences from the regulatory body etc.) The risk at the company level could be a major change or shift in the operational inspection and maintenance strategy (e.g. RCM implementation, change in the frequency of inspection) or a major upgrading scenario that may require a significant monetary investment. All these risk values could be potential for gain or exposure to loss.

Risk = (Probability of an event, p_e) X (Consequence, loss or gain L_i) (2.3)

For example, if the annual probability of an event (loss of a structure) is 1% and the consequence of this loss is $20,000 dollars then the annual risk is $200 dollars. By taking certain actions one can either increase or decrease the risk. Each one of these actions needs to be evaluated to ensure that the NPV of the annual expenditures is minimized. Various options can be weighted by assessing “risk” in an objective manner as well as in a quantitative manner provided one has sound data based on historical record.

2.2.1 Understanding Failure Probability and Consequence

Fig. 2.2 depicts the graphical representation of risk where four specific combinations of probability of occurrence and consequence are shown. This figure divides the coordinate system in four quadrants. The four arrows show the point of direction along which point "A" can move thus creating a change in the risk value. Obviously, Option III is most preferable while Option I is the least preferable.

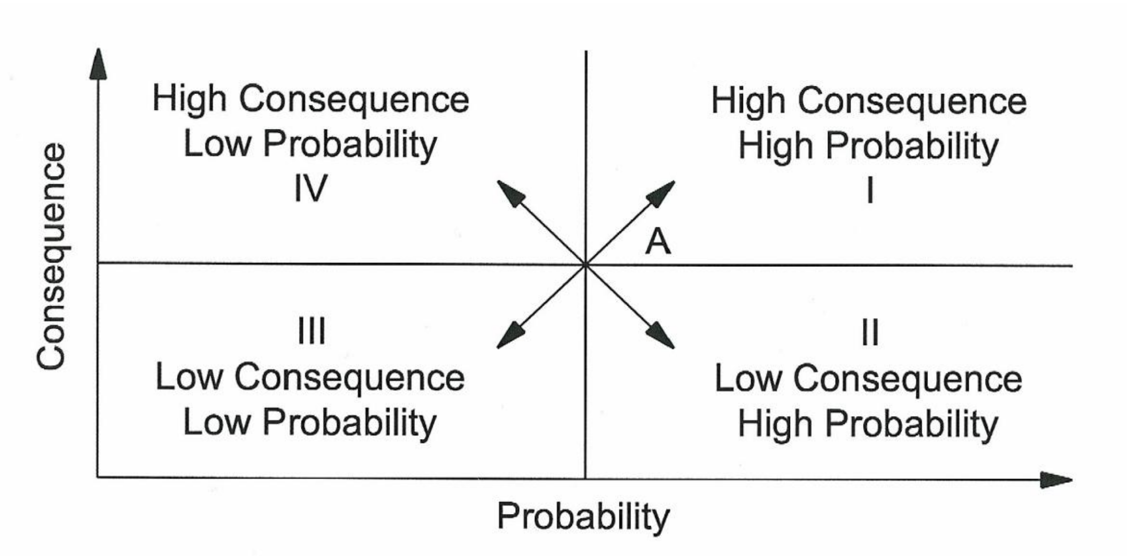


Fig. 2.2 – Risk Evaluation (Jones, 1995)

Through the collection of good quality data, Hydro can control the parameters in Equation 2.3 and thus reduce the uncertainty in the amount of risk exposure. Collection of meteorological data for example can provide for a better understanding of the probability of a severe icing event, and allow for measures to be taken to reduce the consequences, thus reducing the risk. Similarly, monitoring conductor vibration can provide information on the probability of wire fatigue allowing proactive measures to be taken to reduce this probability, and consequentially reduce the risk. Both events can lead to serious consequences through cascade failure; however better understanding through good quality information collection can reduce the risk of exposure.

For an overhead transmission line, risk of failure, R_i, during a time interval, Δt, (which can be part of or full service life) can be assessed in economic terms such as NPV and will be a function of time since both p_e and L_i will also vary with time. The Avalon Wood Pole Study report (2001) showed that p_e is time dependent because of the aging issue of strength deterioration over time. From the above discussion the risk can be controlled by either (CIGRE, 2000):

- Controlling the likelihood of the occurrence, p_e; or
- Controlling the magnitude of the resulting consequences, L_i.

In general, the risk of failure, R_i, is a function of the planned annual expenditures, D_i, which includes routine inspection, maintenance and operating costs. Sometimes the "risk" could be defined also in non-economic terms when strategic issues or policies are involved.

2.2.1.1 Example Problem

Assume a 230 kV line crosses the Trans Canada Highway (**TCH)** and there are two dead end structures on either side of the highway. The original design was based on 25 mm of ice with a 50-year load (annual probability, p_e =0.02) but recent experience has shown that this ice load was underestimated in the region and the new p_e is 0.10 (1 in 10 years). If the consequence of dropping the conductor is L_i = $ 1, 000,000 dollars (legal damage due to an accident which could cause an injury), then the risk of failure under the revised occurrence estimate is $ 100,000 dollars (p_e x L_i = 0.1 x $ 1, 000,000).

However by replacing the conductor for one span with a high strength alloy conductor, the original design probability of failure p_e = 0.02 can be realized. If the cost of replacing the conductor is $20,000, this cost can easily be justified because of the net reduction in the annual risk is $80,000 (i.e. $100,000 - $20,000). In this case it is worth spending the money (planned operating expenditures, D_i) to minimize the potential future risk of failure, R_i.

However, if the consequence of dropping the conductor is L_i = $100,000 dollars (if it can be assessed a-priori) then the reduction in the annual risk is -$10,000 (i.e. $10,000 - $20,000). In this case it may not be beneficial to do the upgrade.

The above example problem shows conceptually the importance of this risk assessment for evaluating various economic options and making decisions with regard to the management of the overhead line assets.

2.3 Predictable Failure Events

Fig. 2.1 depicted a typical line system, which consisted of various subsystems, and each subsystem was further broken down into many components. To determine a predictable failure rate, the line can be modeled as a system and the strength of the weakest link can be equated to the load induced stress (Avalon Study report, 1998). In order to determine the in-service strength of each component, a proper inspection program is necessary to assess the present capability of the line. This is discussed in Section 3.

The probability of failure of a component can be estimated based on the analysis of load and strength distributions. However, whether a line will see a progressive failure or not will depend on the specific failure mode of a component, line characteristics (terrain), extent of the spatial load effect, etc. For example, failure of a "suspension" insulator string will drop the phase and the line will not see progressive damage. However, the failure of an insulator in the dead end structure could initiate a cascade effect and thus induce major line damage.

The most important thing is to know each component's residual strength based on a good condition-based inspection (CBI) program. Since the line components are made of different materials and are subjected to many types of deterioration such as wear, fatigue, vibration, deformation, corrosion etc, they will deteriorate at different rates. **Fig. 2.3a** depicts a typical failure rate curve (known as the "bath tub" curve) showing the expected failure rate of a component or a system. **Fig. 2.3b** shows a typical "bath tub" curve with two different deterioration rates obtained from past historical inspection records. As can be seen, one would expect that poles, having a shorter life, would have a high failure rates from 50 to 60 years, whereas conductor, having a longer life, would have an increased failure rates from 65 to 80 years.

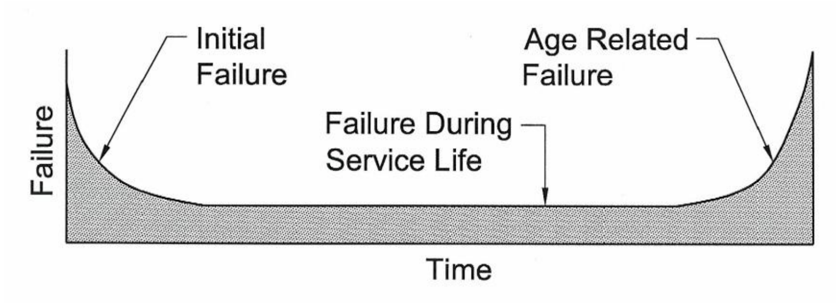


Fig. 2.3a - Typical Failure Rate "Bath Tub" Curve (Jones, 1995)

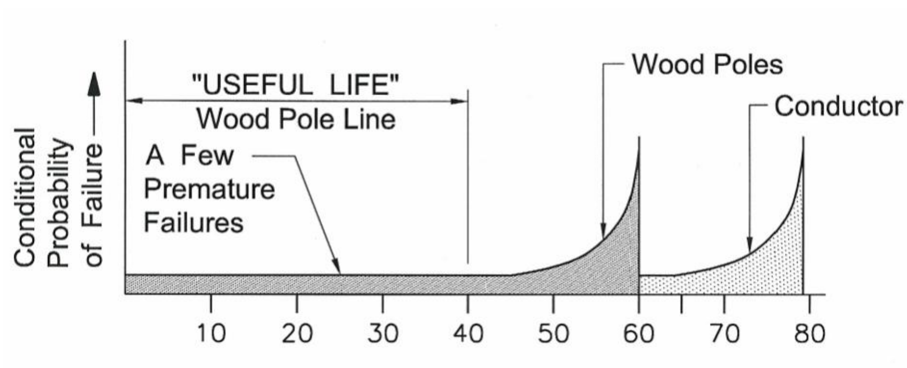


Fig. 2.3b - "Bath Tub" Curves for two components with different deterioration rates

It is important that a good database be developed with past history to ensure that the residual strength and performance of the component can be predicted and the new "weak link" can be established to assess the line reliability.

At any stage, NPV analysis can be carried out following the example shown earlier to justify whether a major component replacement program is necessary. NPV analysis can combine total expected annual expenditures due to ice load failure as well as hardware failure due to excessive wear in a comprehensive manner. The important thing is to analyze each failure's root cause and develop a systematic database to assess various information required to determine the failure rate.

2.4 Unpredictable Failure Events

The term "unpredictable" itself indicates that the failure probability cannot be estimated based on objective analysis. Natural disasters such as major ice storms (e.g. 1998 Quebec storm), typhoons, tornadoes, floods may have a very low probability of occurrence; however, proactive actions cannot be taken to withstand their effects because it may not be economically feasible. Therefore the probable occurrence level needs to be assessed based on judgment, any past experiences and the probability assigned on a subjective basis.

2.5 Consequences

Consequence evaluation depends primarily on the function of an overhead transmission line within the overall system. For example consequence of losing a radial line would be significantly different than to the loss of a line where there is redundancy. Consequences resulting from an extended outage of an overhead line are site and function specific and could be considerable. To develop the current line management program, a ranking of all lines was developed to set up the priority for inspection; details of this will be discussed in Section 6 under "Schedule and Cost". In general the failure effect of a line can be felt at three different levels. These are (a) Company level, (b) System level and (c) Local level. The following provides a list of items that could be considered under each of these levels (CIGRE, 2000).

Company Level

- Injury or death;
- Serious environmental damage;
- Frequent failures (perception problem, political implication); and

- Certain failures that could trigger a major outage in the system.

System Level

- Additional generation to support the system;
- Revenue loss;
- Penalties due to non supply of energy; and
- Regulatory problems; reliability issue if there are too many failures.

Local Level

- Replacement of a structure or any other components or a line that may have failed.

SECTION 3

Condition Based Inspection (CBI) and Maintenance Strategy

3.1 Component Life and Condition Monitoring

A wood pole transmission line consists of many components as shown in **Fig. 2.1**, structures, conductors and insulators are normally considered to be the major components. In this section, some of the issues related to the integrity of these components, how to inspect and monitor the condition of these components and how to develop an appropriate cost effective maintenance strategy are discussed. This section also provides information on various diagnostic, non-destructive tools that are available currently in the market to assist in the condition monitoring process.

3.2 Structural System

The structural system in a wood pole line normally consists of two or three poles, cross braces, knee braces and/or cross arms, connecting bolts and hardware. The primary damage that these poles are subjected to is the loss of mechanical strength. The loss of mechanical strength can be due to loss of fibre strength due to aging and decaying of wood and/or loss of shell thickness due to fungi attack, insects and woodpeckers. **Fig. 3.1** depicts some relative stress distributions for typical structure configurations. The shaded areas show where the stresses are severe.

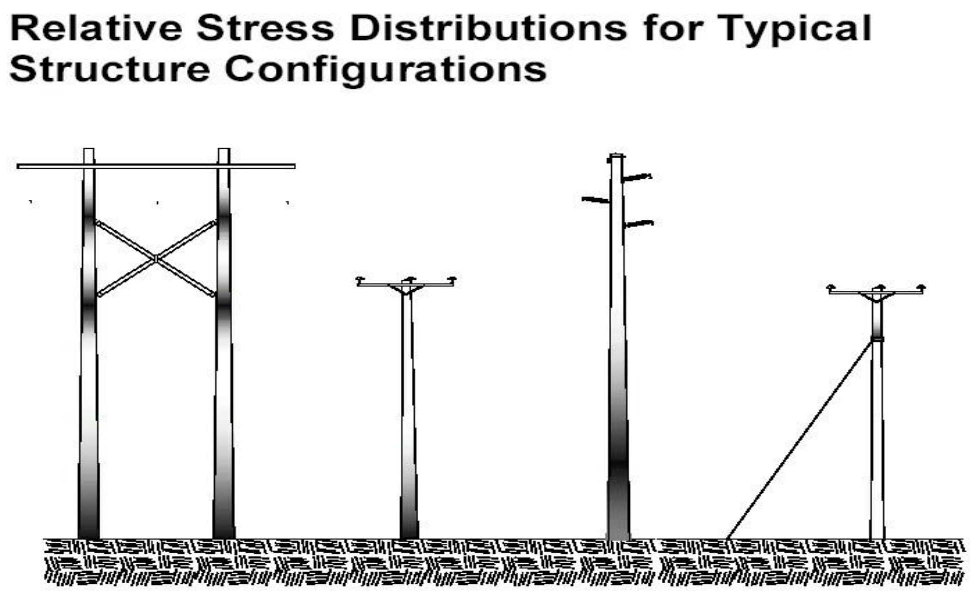


Fig. 3.1 - Relative Stress Distributions (EDM Presentation, 2003)

To guard against fungi attack, poles are normally treated with preservatives at the time of purchase prior to installation. In rare circumstances, untreated cedar poles are used in sensitive areas such as zones designated for community water supply. Treatment of wood poles is specified under the AWPA standard, which sets minimum levels of penetration and retention of preservatives for wood poles and define process limitations for each species. Within Hydro's transmission system, there are three (3) types of pole species, namely Douglas Fir (DF), Southern Yellow Pine (SYP) and Western Red Cedar (WRC). All three species are full-length pressure treated with either pentachlorophenol or creosote while some Western Red Cedar poles are only butt treated with creosote. Southern Yellow Pine poles in environmentally restricted zones are treated with Copper Chromated Arsenic (CCA) and, as stated above, untreated Western Red Cedar poles are now used in highly restrictive zones. **Table 3.1** presents the current minimum retention level for various preservatives based on each species. As shown in the table, creosote is no longer accepted at Hydro as a pole preservative; however the standard prior to removal has been provided.

Table 3.1 - Minimum Retention Levels For New Poles (NLH Standard)

Species	*Treatment (NLH Standard)*	*Retention kg/m3 (pcf)*
Western Red Cedar	Penta	12.8 (0.8)
	CCA	9.6 (0.6)
	Creosote (no longer accepted)	72 (4.5)
Coastal Douglas Fir	Penta	7.2 (0.45)
	Creosote (no longer accepted)	128 (8.0)
Southern Yellow Pine	Penta	4.8 (0.3)
	CCA	9.6 (0.6)
	Creosote (no longer accepted)	128 (8.0)

3.2.1 - Pole Age Distribution

Fig. 3.2a shows the distribution of all 26,000 transmission size poles on NLH system by age. This shows that approximately 34% of the transmission size poles (9000 in-service poles) are over 30 years age. **Figs. 3.2b** and **3.2c** present the age distributions for central and northern regions respectively.

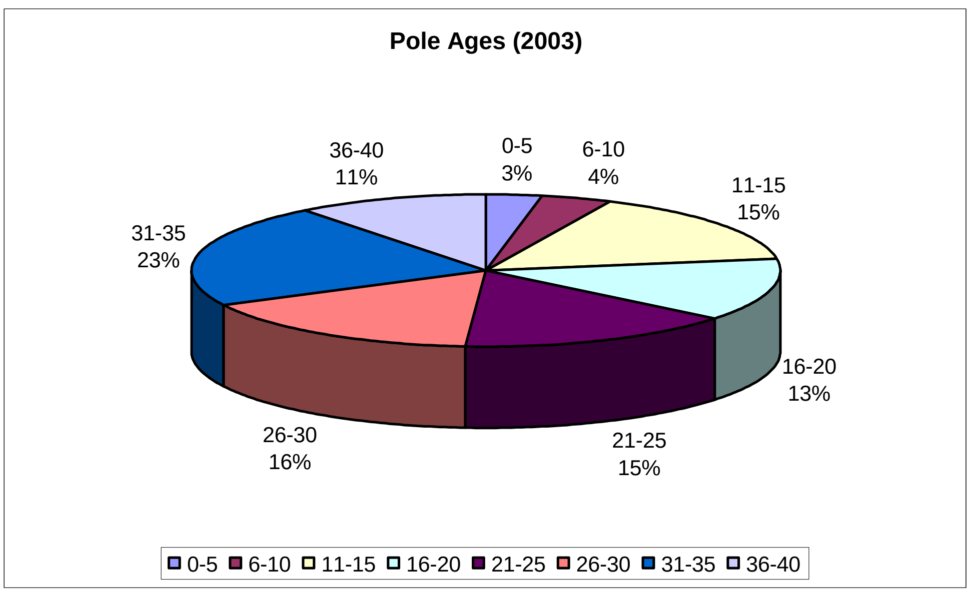


Fig. 3.2a - Pole Age Distribution (2003)

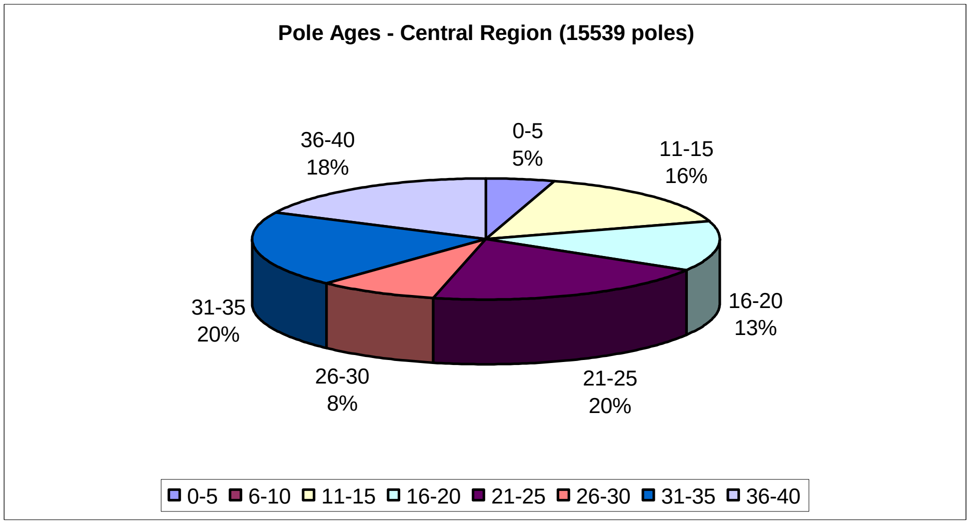


Fig. 3.2b - Pole Age Distribution (Central Region)

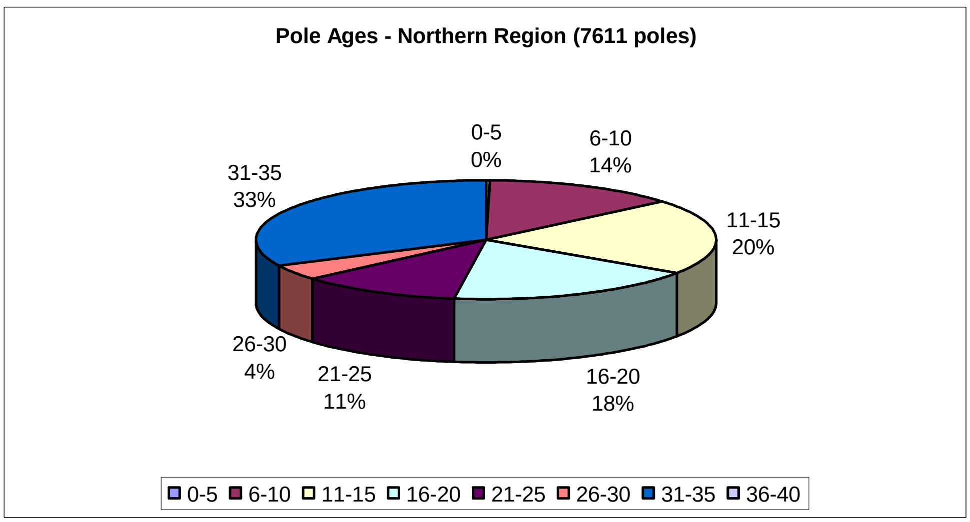


Fig. 3.2c - Pole Age Distribution (Northern Region)

3.2.2 Why Test and Treat Poles?

Fig. 3.3 depicts a typical graph, which shows how the preservatives deplete typically over time ("Yellow" line). The ordinate values in **Fig. 3.3** do not necessarily represent the actual amount of preservative (kg/m^3), but is only used to show the depletion trend. As the level of preservative depletes and falls below the threshold line ("Green" line), poles become more and more susceptible to fungi and insect attacks. For pentachlorophenol (penta) treated poles, the typical threshold value is 0.18 lb/ft^3. If the exposed pole does not have the preservative level restored early enough, particularly at 50% of their expected service life (20 to 25 years), the pole is exposed to decay which leads to degradation of strength (i.e. significant loss of sapwood for Southern Yellow Pine or heartwood for Douglas Fir) and make the pole structurally unsafe.

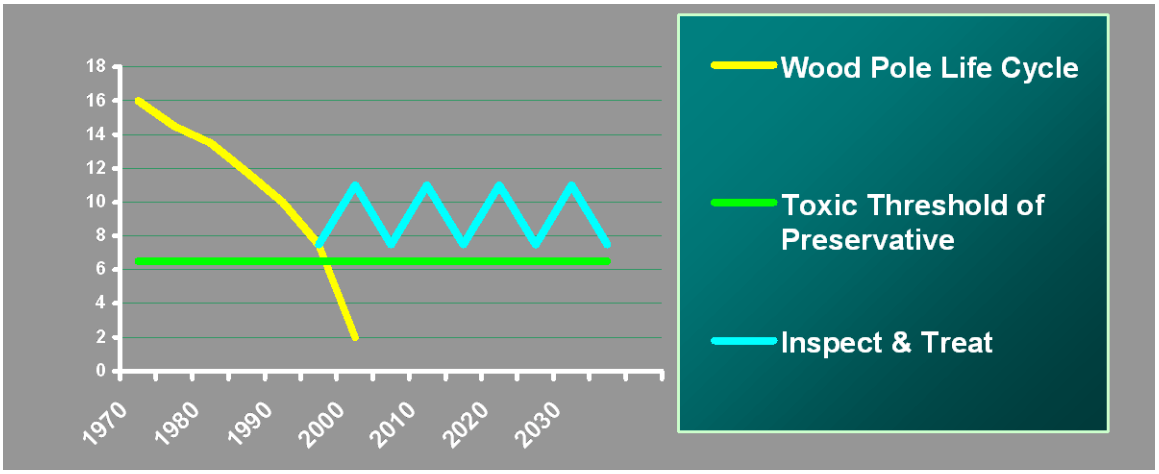


Fig. 3.3 – Typical Depletion Rate of Preservatives (GENICS, 1998)

By inspecting poles at a regular interval and treating the poles at critical zones before they have lost their preservatives to the threshold level **("blue line")**, one can extend the service life significantly. Through an inspection and treatment program, Hydro will be able to extend the transmission line asset's life by replacing and treating poles early enough to ensure not only increased reliability and safety, but also deferral of the cost of building new lines for replacement. Periodic inspection data will also provide early indication when a transmission line asset needs to be replaced completely based on the residual strength. This will assist System Planning to develop a long-term replacement criteria for wood pole transmission line assets. In addition, regular inspections will identify "danger poles" early and by replacing those poles, safety can be improved in the future through the avoidance of accidents.

The benefits of a pole inspection program are:

- to detect the "danger poles" early to avoid safety hazard;

- to detect the poles which are at early stages of decay so that corrective action can be taken to extend the life of these poles (treating with preservatives and/or additional support below ground line); and
- to establish a continuing maintenance program for extending the average service life of all poles in the system.

3.2.3 Inspection Techniques

The pole inspection program includes the following inspection techniques:

- Visual inspection from groundline to the top of the pole including
    - Climbing inspection;
    - Excavation near the ground line;
- Sound and bore (**Fig. 3.4a**);
- NDE measurement (strength) only for poles (**Fig. 3.4b** and **c**);
- Core samples and retention level analysis (samples); and
- Selected sample tests at MUN (destructive - **Fig. 3.4d**).

Fig. 3.4a depicts the tools required to carry out inspection based on sounding and boring. **Fig. 3.4b** depicts the Resistograph, which through the use of a 3mm drilling needle and resistance measurement, profiles the poles core. **Fig. 3.4c** shows the nondestructive PoleTest tool for strength evaluation based on ultrasonic principle. **Fig. 3.4d** depicts the full-scale test bench developed at Memorial University's Engineering laboratory for determining the breaking strength of in-service poles.

Figure 3.4a - Inspection Tools

Figure 3.4b - Resistograph in Use

Figure 3.4c - PoleTest in Use

Figure 3.4d - MUN Test Bed

3.2.4 Past Inspection Programs

The following sections provide a brief summary of various NLH inspection programs conducted since 1985. These inspections are separate from the routine line maintenance inspection carried out by operation and maintenance personnel. The line maintenance inspection program is primarily a time based preventive maintenance program. Under the new RCM program, NLH will inspect every pole by sounding and boring to ensure that data is collected to estimate the internal and external rot conditions as well as residual strength. Preservative levels for a selected sample group will be collected and analyzed for remaining retention level.

Since 1998, NLH has added nondestructive inspection using PoleTest equipment to collect strength data for in-service poles. In addition, core samples are taken from 10% of the pole population for further retention analysis to determine the preservative level remaining. This field inspection program was augmented by carrying out limited destructive tests at MUN to determine the breaking strength of in-service poles. The purpose was to correlate the full-scale strength data with the preservative depletion rate to predict the estimated residual life of the pole plant assets.

The first inspection program was conducted on the Avalon Peninsula in 1985 after the 1984 sleet storm damage. The second program was completed in 1998-2000 and included poles on the Avalon Peninsula as well as selected lines from the Central region. The third program was completed in 2002 with the inspection, testing and treatment of poles on TL 220. In 2003, the inspection program was expanded to include poles from the Northern Peninsula, as well as in the Central region.

1985 Pole Inspection Program

Table 3.2 presents the results of the 1985 pole inspection and **Fig. 3.5** summarizes the primary defects. This program was performed on Avalon Peninsula poles only.

Table 3.2 - 1985 Pole Inspection Program – Summary

1985	*TL201*	*TL203*	*TL218*	*TL236*	*Total*
Constructed (Age at inspection)	1966(19)	1965(20)	1970(15)	1966(19)	
Total Poles on each line	754	424	93	125	1394
Poles Inspected	754	424	93	125	1394
Rejected	0	0	0	0	0
Poles to Monitor	22	27	5	6	60
Prominent Defects					
External Decay	1	3	1	8	13
Major Shell Separation	15	28	1	3	47
Internal Decay	0	9	7	13	29
Ant Damage	0	1	N/A	N/A	1
Wood Pecker Holes	48	2	N/A	N/A	50

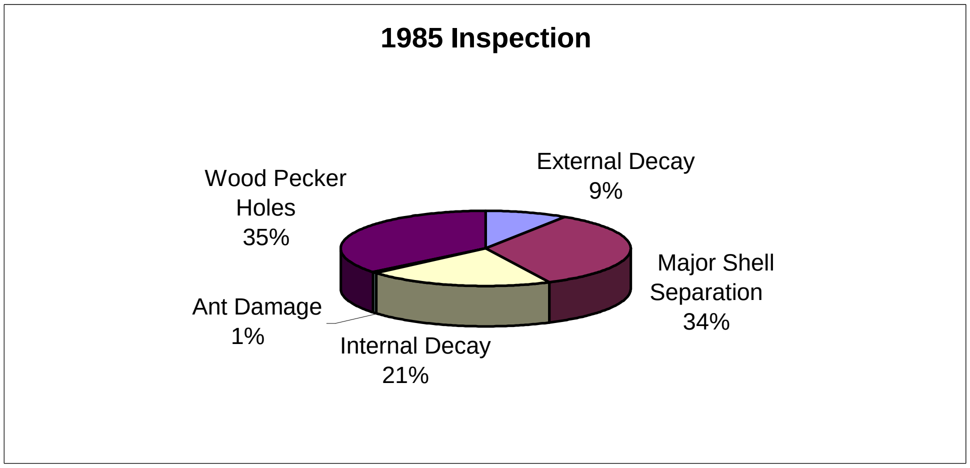


Fig. 3.5 – 1985 Pole Inspection Program – Primary Defects

Fig. 3.6 depicts the results of the retention analysis for pentachlorophenol (penta) treated poles. The analysis indicates that a small portion of this sample size did not meet the minimum preservative retention threshold in the 1985 inspection

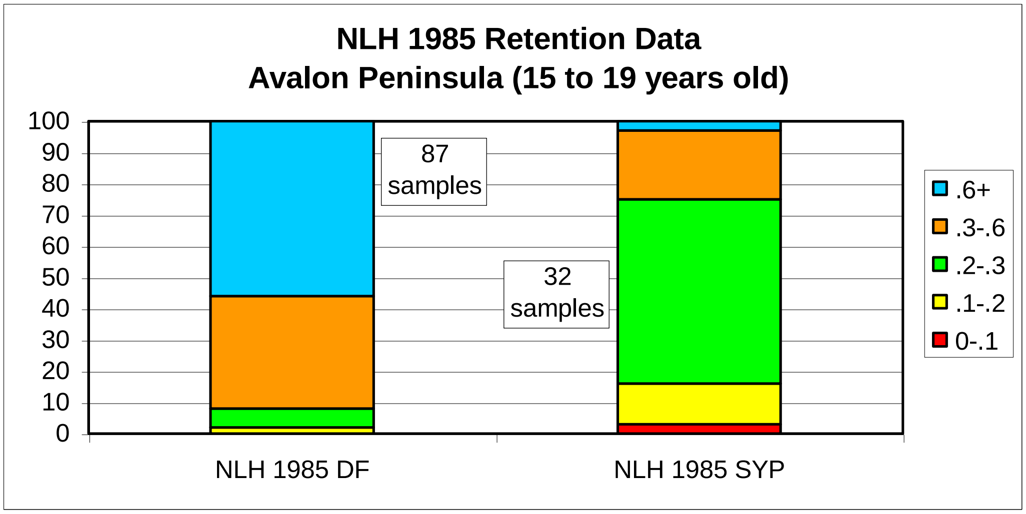


Fig. 3.6 - 1985 Pole Inspection Program - Retention Data

1998 Pole Inspection Program

In 1998, with inspection services provided by Genics Can. Inc., NLH inspected all 1445 in-service poles on the same lines as the 1985 inspection program. This number is higher than the 1985 inspection due to the upgrading of TL 201 at Hawke Hill and Brigus Junction. Of the poles that were inspected, 1201 were of original vintage, reduced from the 1985 inspection primarily by excluding the upgraded sections and the poles replaced during the 1994 failure of TL 201. **Fig. 3.7** depicts the causes of rejections. In this inspection, 6.5% of the poles of original vintage were rejected.

Table 3.3 - 1998 Pole Inspection Program – Summary

1998	*TL201*	*TL203*	*TL218*	*TL236*	*Total*
Constructed (Age at inspection)	1966(32)	1965(33)	1970(28)	1966(32)	
Total Poles on each line	806	422	88	129	1445
Poles Inspected	806	422	88	129	1445
Rejected	45	24	4	5	78
Poles to Monitor	10	2	0	0	12
	Prominent Defects				
External Decay	0	12	1	0	13
Major Shell Separation	28	15	1	0	44
Internal Decay	13	11	3	5	32
Ant Damage	7	4	0	0	11
Wood Pecker Holes	10	2	0	0	12

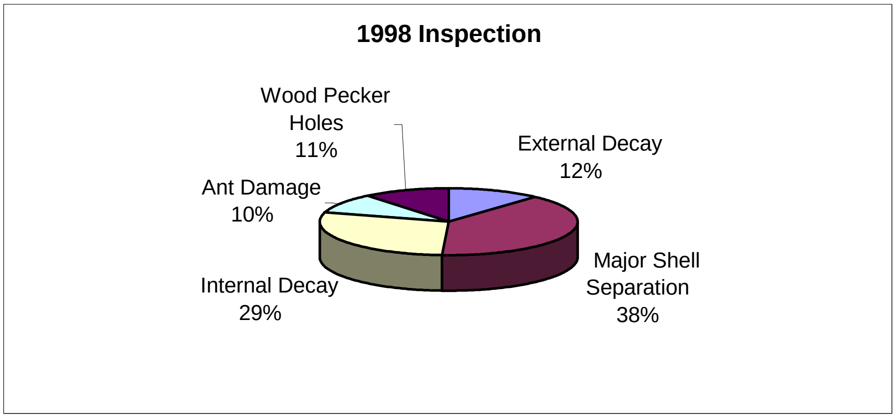


Fig. 3.7 – 1998 Pole Inspection Program - Primary Causes For Rejection

Preservative Depletion

In addition to inspection services, the contractor extracted 121 cores from randomly selected treated poles and the samples were analyzed for preservative retention levels. Sixty poles out of this sample size had full-length penta treatment. Based on the inspection program and core sampling, it was found that 48% of the penta treated poles of 1966 vintage sampled for retention level analysis did not meet the minimum threshold level ("Green Line" in **Fig. 3.3**) for preservative retention and therefore required immediate treatment to arrest the further progression of decay (GENICS, 1998). Only Douglas Fir (DF) and Southern Yellow Pine (SYP) poles are reported in **Fig. 3.8** as the Western Red Cedar poles were butt treated and yielded no results.

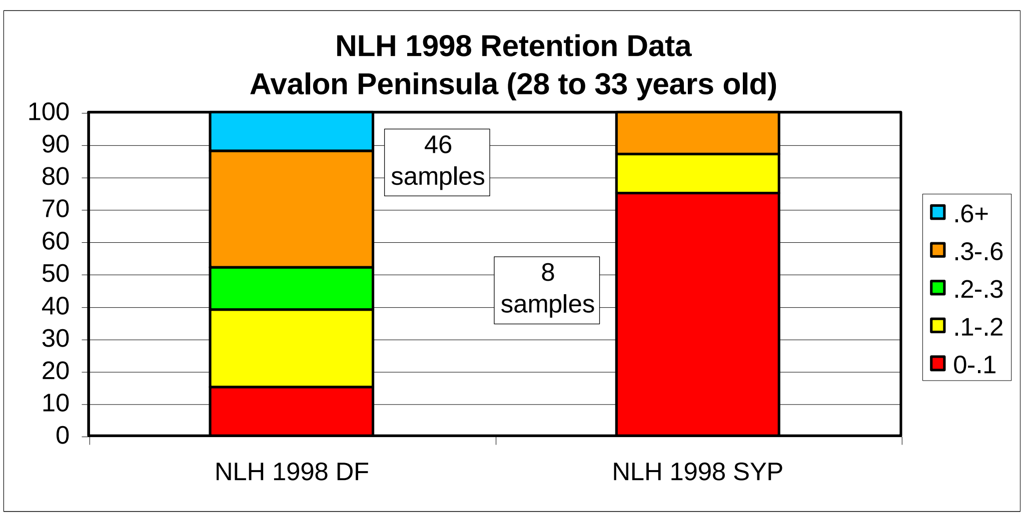


Fig. 3.8 - 1998 Pole Inspection Program – Retention Data

2000 Pole Inspection Program

In August of 2000, NLH contracted TSI to carry out an inspection and treatment program on several wood pole lines located in the central region of the island. **Table 3.4** depicts the results of this inspection and shows that 5.1% of the poles were rejected. **Fig. 3.9** depicts the primary rejection causes. No cores were extracted during this inspection year, so data on preservative retention levels are not available.

Table 3.4 - 2000 Pole Inspection Program – Summary

2000	*TL209*	*TL215*	*TL224*	*TL233*	*TL234*	*Total*
Constructed (Age at inspection)	1971(29)	1969(31)	1968(32)	1973(27)	1981(19)	
Total Poles on each line	185	437	825	1280	489	3216
Poles Inspected	74	257	331	637	243	1541
Rejected	1	20	8	48	1	78
Poles to Monitor	0	0	0	0	0	0
		Prominent Defects				
External Decay	0	0	0	0	0	0
Major Shell Separation	0	0	0	0	0	0
Internal Decay	1	8	7	4	0	20
Ant Damage	0	10	1	44	1	56
Wood Pecker Holes	0	2	0	2	0	4

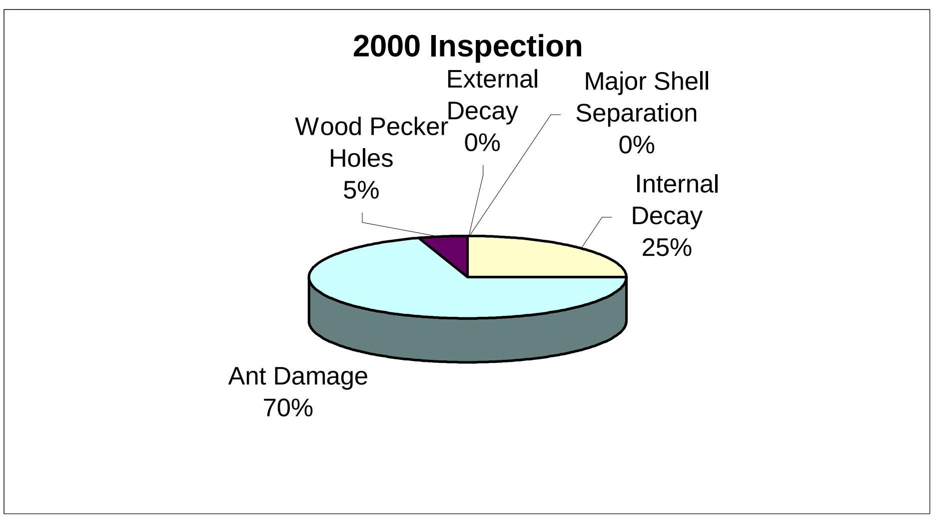


Fig. 3.9 – 2000 Pole Inspection Program – Primary Causes For Rejection

2002 Pole Inspection Program

In 2002, GENICS Can Inc. was contracted to provide inspection and treatment services for the inspection of TL 220. Details of the results of this inspection are tabulated below in **Table 3.5**. **Fig 3.10** provides the primary causes for rejection.

Table 3.5 - 2002 Pole Inspection Program – Summary

2002	*TL220*
Constructed (Age at inspection)	1970(32)
Total Poles on the line	786
Poles Inspected	273
Rejected	37
Poles to Monitor	0
Prominent Defects	
External Decay	1
Major Shell Separation	36
Internal Decay	10
Ant Damage	0
Wood Pecker Holes	0

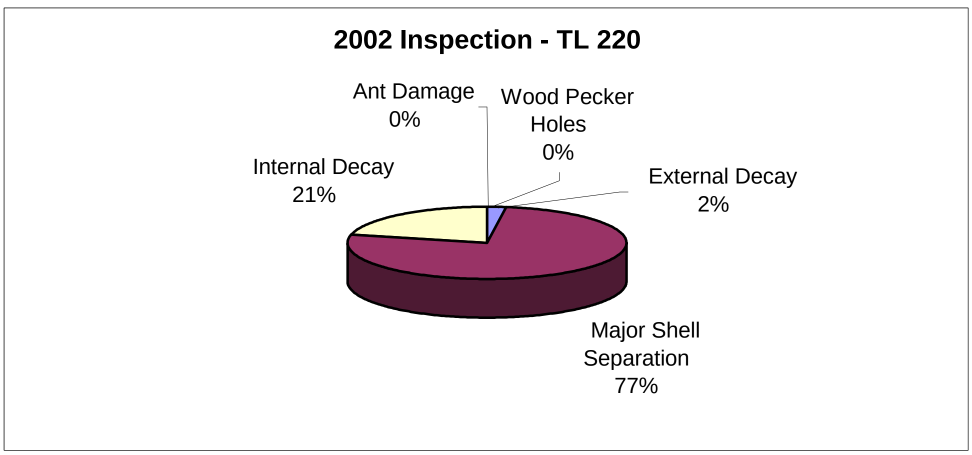


Fig. 3.10 – 2002 Pole Inspection Program – Primary Causes For Rejection

Fig. 3.11 depicts the preservative retention levels for poles on TL 220. It shows that 80% of the sample tested fell at or below the minimum threshold value.

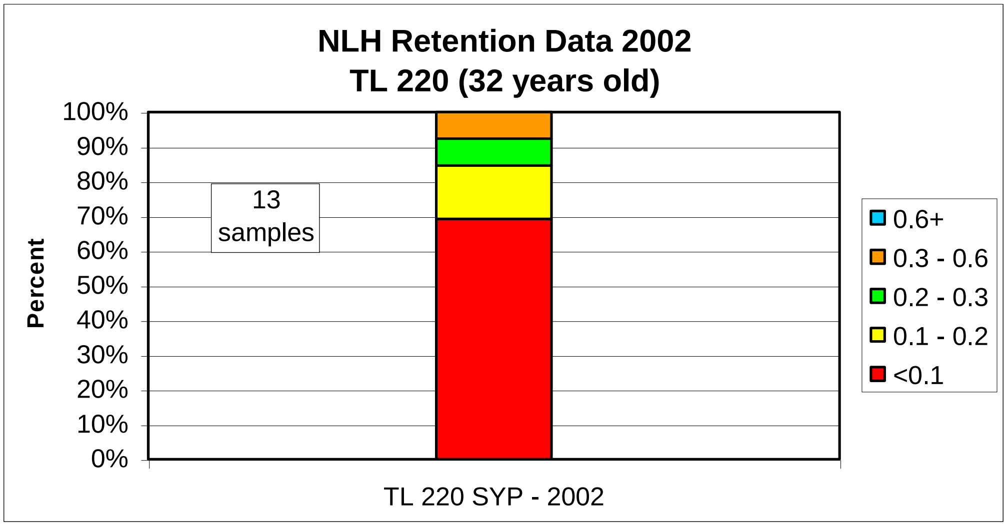


Fig. 3.11 – 2002 Pole Inspection Program – Retention Data

2003 Pole Inspection Program

In 2003, TRO Operations crews performed the inspection program. Although this program was spread across the island, with an estimated 1500 poles inspected, only Southern Yellow Pine and Douglas Fir data from TL 201 was extracted and tabulated in this report from the vast amounts of data collected due to the limited time available to process the paper forms.

Table 3.6 – 2003 Pole Inspection Program – Summary

2003	*TL201*
Constructed (Age at inspection)	1966(37)
Total Poles on the line	806
Poles Inspected	256
Rejected	10
Poles to Monitor	12
Prominent Defects	
External Decay	0
Major Shell Separation	3
Internal Decay	5
Ant Damage	2
Wood Pecker Holes	0

Fig. 3.12 depicts the primary causes of rejection, and **Fig. 3.13** depicts the results of the preservative retention level analysis for penta treated poles. **Fig 3.13** shows that a large

portion of this sample size, did not meet the minimum threshold level indicating that the poles are exposed to further decay. It should be noted that in the 1998 inspection 48% of the samples did not meet the threshold, but by 2003 this had increased to 71%, thus indicating a significant depletion of preservative over a five-year period.

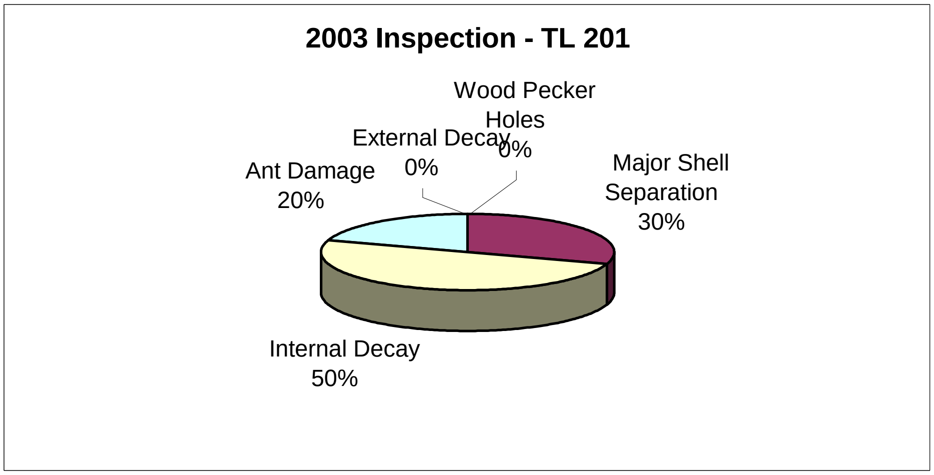


Fig. 3.12 – 2003 Pole Inspection Program - Primary Causes For Rejection

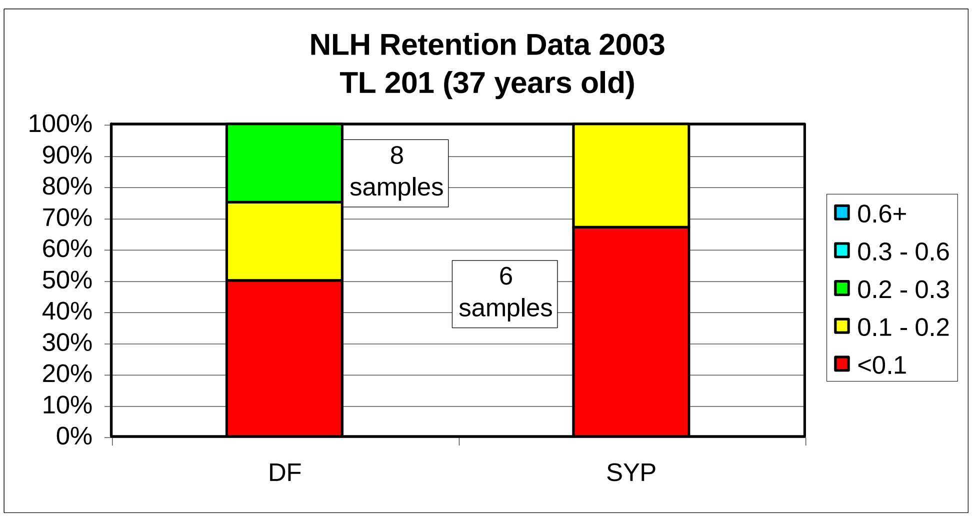


Fig. 3.13 – 2003 Pole Inspection Program – Retention Data

Table 3.7 – Summary of Pole Rejection Percentages by Lines and Inspection Years

	1985	1998	2000	2002	2003
TL 201	0%	6.8%	-	-	5.0%
TL 203	0%	6.2%	-	-	-
TL 209	-	-	1.4%	-	-
TL 215	-	-	7.8%	-	-
TL 218	0%	6.8%	-	-	-
TL 220	-	-	-	13.0%	-
TL 224	-	-	2.4%	-	-
TL 233	-	-	8.2%	-	-
TL 234	-	-	0%	-	-
TL 236	0%	5.4%	-	-	-

Table 3.7 provides a summary of the pole rejection results of all pole inspection programs carried out since 1985. This data will be used later in predicting the rejection rates for future years of pole inspections.

3.2.5 Comparison of Retention Levels For Avalon Poles

Since Hydro has the preservative retention level data for poles on the Avalon for three inspection years (1985, 1998 and 2003), an attempt was made first to understand the trend of the preservative depletion rate. **Fig. 3.14** depicts the average trend for poles on the Avalon Peninsula. The depletion rate trend can be compared with the "yellow line" shown in Figure 3.3.

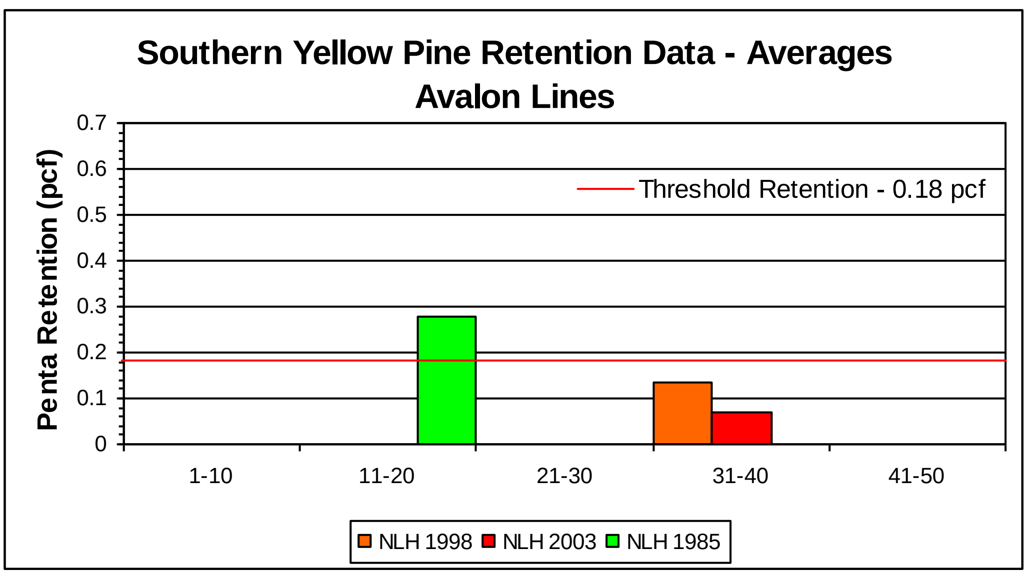


Fig. 3.14 – Multiyear Retention Data For Avalon Lines-Depletion Rate Trend

3.2.6 Comparison with Other Utilities' Practices

A major utility in Canada also carried out a test program to measure preservative retention level for distribution size poles (Southern Yellow Pine) in three different zones of the particular province. **Fig. 3.15** depicts the preservative retention levels at various in-service ages for two different zones. Zone 1 is comparable to the Avalon while Zone 2 could be compared to the Central region. It is shown that around 31-40 years, the average retention levels are 0.33 and 0.38 for Zones 1 and 2, respectively. **Fig. 3.15** also compares the same with the Avalon data (**Fig. 3.14**). The comparison validates NLH data, and shows that the preservative amount left in NLH poles is not only well below this utility's data, but also below the minimum threshold.

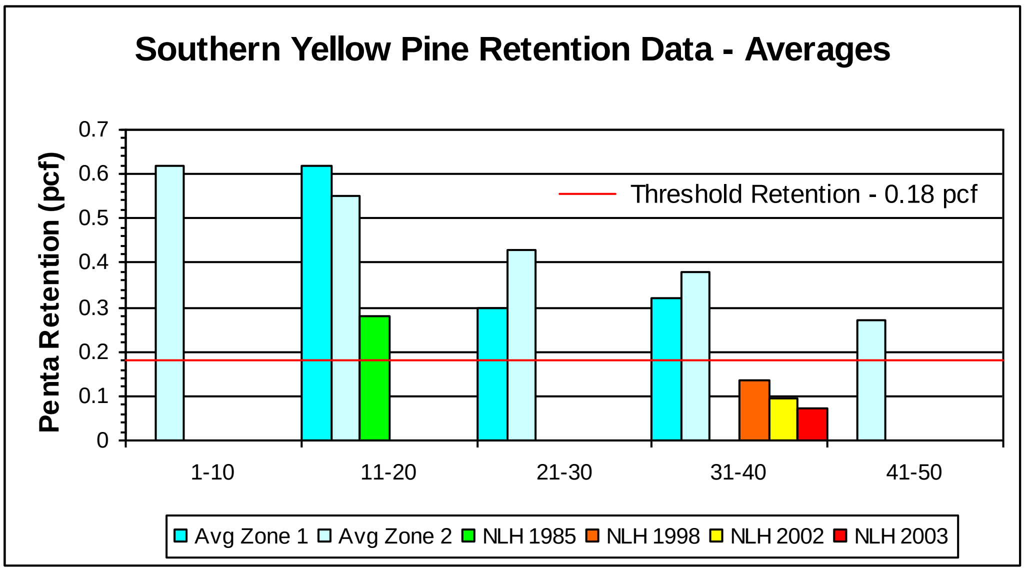


Fig. 3.15 - Preservative Retention Level With Respect To Age - External Utility Data

The comparison is made here merely to show the trend only and to validate the data collected by NLH. One can envisage the possible rate of depletion from these figures in future years if these poles are not treated. This is important information for managing the pole inventory and can be directly linked with the pole decay because these two parameters are highly correlated. **Fig. 3.16** shows such a conceptual curve developed to link these two parameters. The curve can be used in the data analysis when fully developed and validated by Hydro data.

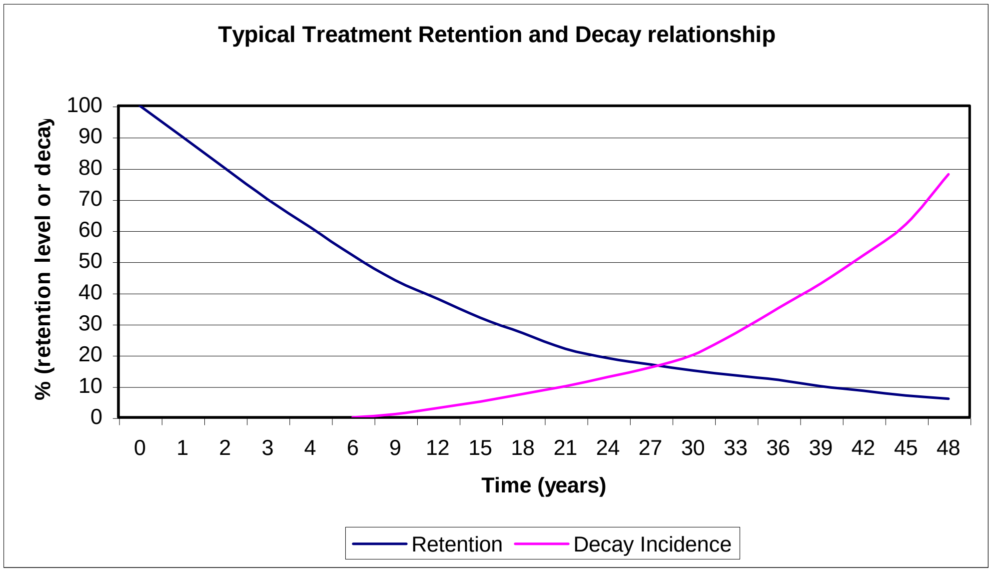


Figure 3.16 – Typical Treatment Retention / Decay Relationship (GENICS, 1998)

3.2.7 Full Scale Test at MUN – In Service Poles (SYP)

NLH undertook a separate study entitled **"Avalon Wood Pole Study"** (Haldar, 2000) where a number of transmission size poles were removed from service (from TL 201 and TL 220) and were tested with the NDE (Non Destructive Evaluation) technique as well as full scale breaking tests at the Memorial University. Since the numbers of poles tested were very limited in terms of population size, data from the other sources (e.g. EDM data) were also reviewed and compared. Results from this study showed that on an average, 25% of strength (**Fig. 3.17** – vertical axis) was lost over a period of 35 years (i.e. rate of degradation 0.7% per year for average strength of 8000 psi originally assumed).

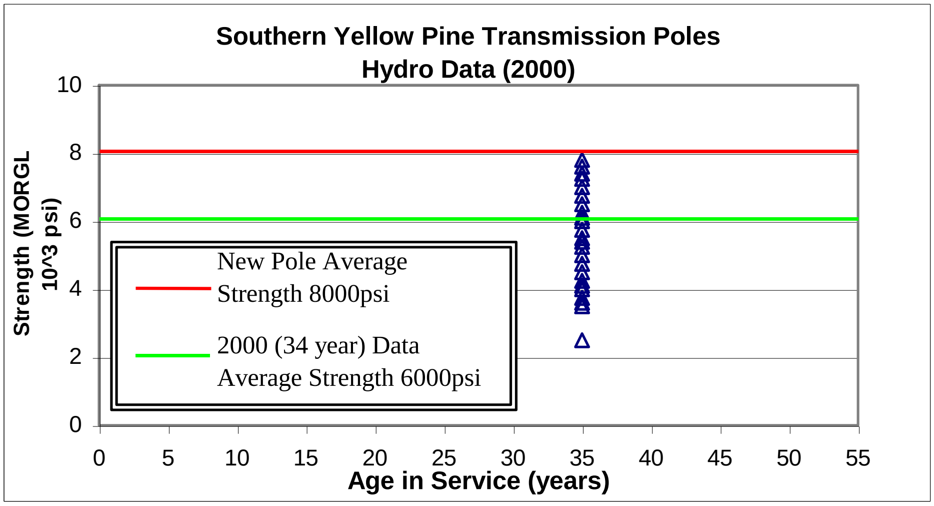


Fig. 3.17 - Strength Data From Full Scale Tests at MUN

3.2.8 NDE Field Tests – In service Poles (SYP) on Avalon Lines

Fig. 3.18 shows the typical NDE data for TL 201 collected during the 2000 and 2003 pole inspections. The results are quite consistent with those obtained from the full-scale test data depicted in **Fig. 3.17**.

During the recent upgrading work near the Hardwoods Terminal Station, a number of poles collapsed when isolated from existing 3-pole suspension structures. These poles were inspected in 1998 and were accepted because of having the adequate sapwood thickness. However inspection after the failures of the poles showed a rapid degradation of strength due to loss of sapwood on the outside shell. This is shown in **Fig. 3.19a.** This indicates that once the preservative is lost, degradation can happen rapidly **(slope of the "yellow" line below the threshold level in Fig. 3.3)** due to fungi attack and/or ant damage.

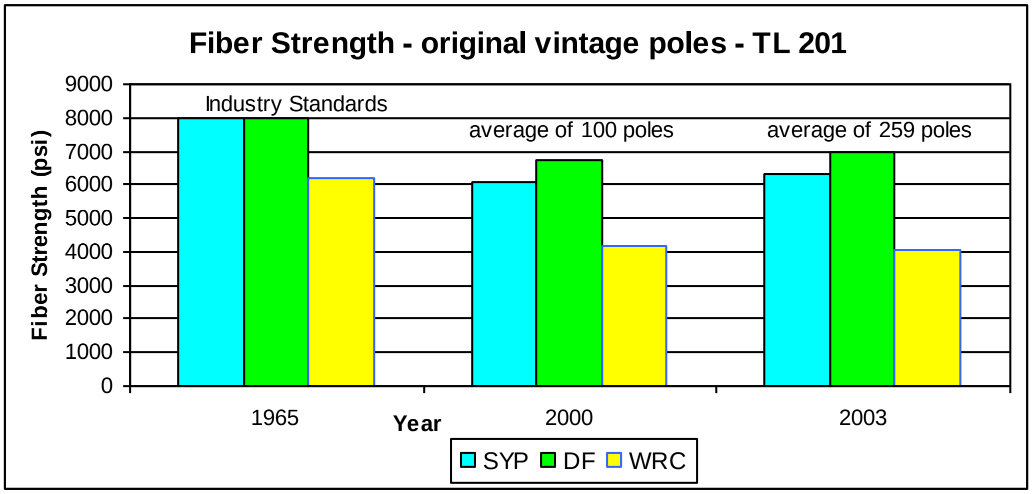


Fig. 3.18 - NDE Strength Data From Field- TL 201 (2000/2003)

Fig. 3.19a – Internal Decay **Fig. 3.19b – Carpenter Ant Damage**

Fig. 3.19a & b show the condition of the collapsed poles due to rot and carpenter ant damage. It also shows the importance of pole treatment and follow-up inspections to ensure that the poles are reliable for transmitting power and safe to climb for future inspections and maintenance work. NLH does not have a structured pole inspection, testing and treatment program at present with particular reference to life-extension of wood pole transmission lines. Therefore it is quite likely that many of the older poles may be exposed to severe decay due to fungi attack. Without a proper inspection and subsequent treatment program, the life of these poles cannot be extended significantly beyond 40 years.

3.3 Conductor

Conductor is the most expensive item in any overhead transmission line. The conductor system typically includes conductor, suspension clamps, spacers, dampers, dead end fittings and any other attachments. Major problems with the conductor deterioration are due to (1) corrosion and (2) vibration. Corrosion problems could be internal and/or external, and are mostly progressive loss of galvanization of the steel core and subsequent loss of steel strength. For ACSR conductor, the steel core is the primary load-carrying member, and any loss of steel strength due to corrosion could lead to catastrophic failure inducing considerable forced outage time. The vibration problem is related to the motion of the conductor and is classified as (1) Aeolian vibration (2) galloping, (3) sway oscillation or (4) unbalanced loading. Four common types of damage that normally occur and the clues to watch for in making line inspections are: (1) abrasion (2) fretting (3) fatigue breaks of strands and (4) tensile breaks. Vibration can also lead to external as well as internal aluminum strand fatigue and, if not detected early, failure can also have severe consequences.

A typical inner strand failure due to fatigue is shown in **Fig. 3.20** where it can be seen that the failures occurred where the inner strand surface had been subjected to fretting caused by contact between individual strands. Metallographic analysis of a large number of failures has shown that all cracks originated in these fretted areas. As fatigue inducing stresses occur near the bottom part of the conductor inside the clamp, they are impossible to measure directly. Thus, for purposes of expressing the severity of exposure to fatigue, it is necessary to represent the conditions at the contact points by means of a related parameter that is accessible to measurement such as the amplitude and the frequency of vibration (**Fig. 3.21b**). Alternatively, conductor samples can be removed from the clamp area at a certain interval and can be inspected further either by NDE or full-scale testing. One Canadian utility removes a conductor sample (typically 20 feet in length) from every 20 km of line inspected for further analysis and testing.

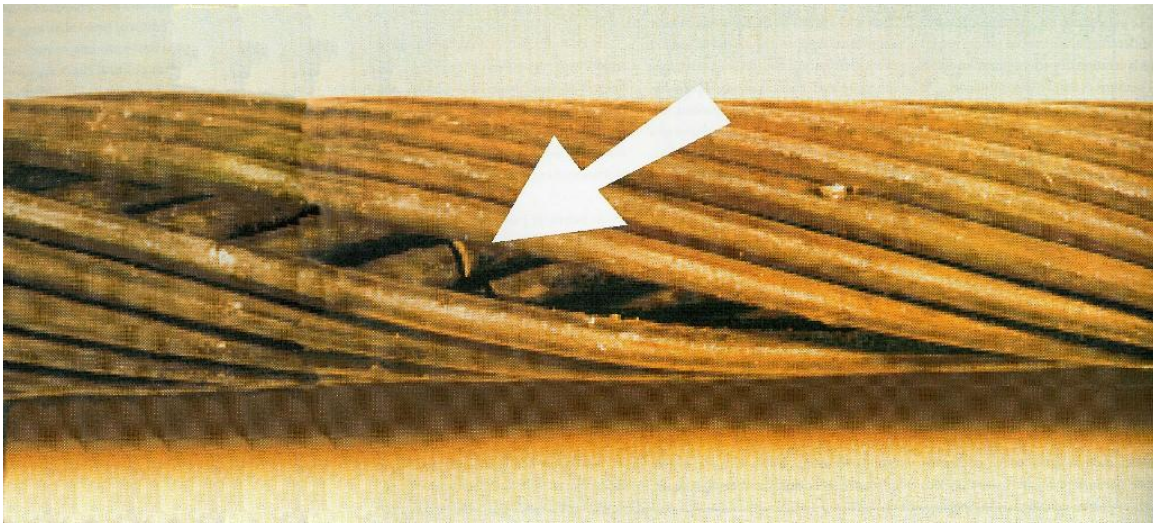


Fig. 3.20 – Broken Strand Due to Fatigue (IEEE, 2003)

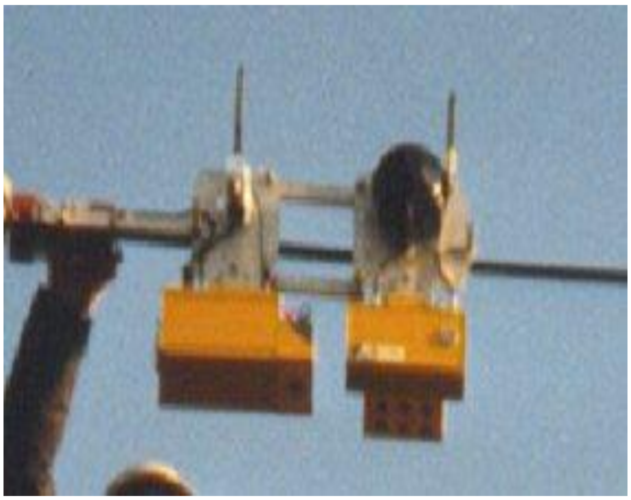
3.3.1 Inspection Techniques

Visual inspection will not detect corrosion at an early stage. As the deterioration becomes pronounced an experienced line inspector will be able to detect this through bulging of the aluminum strands and possibly discoloration of these strands.

A corrosion detector (**Fig. 3.21a**) for steel strands works on the eddy current principle where the loss of galvanization is measured indirectly from a second coil sensitive enough to detect the change in the field patterns. The detector can sample even when it occurs within a few centimeters. Upon detecting the corrosion by NDE, samples can be taken from the line to determine the strand damage by additional testing (bending, twist of wires, etc.)
Potential damage due to Aeolian vibration can be detected by inspecting for the following:

- Dropping/missing/slipped vibration dampers;
- Missing nuts from suspension clamps;
- Cotter pins missing from their normal position;
- Broken outer conductor strands;

- Broken inner conductor strands;
- Loose or broken steel tower members; and
- Severe wear of suspension hardware.



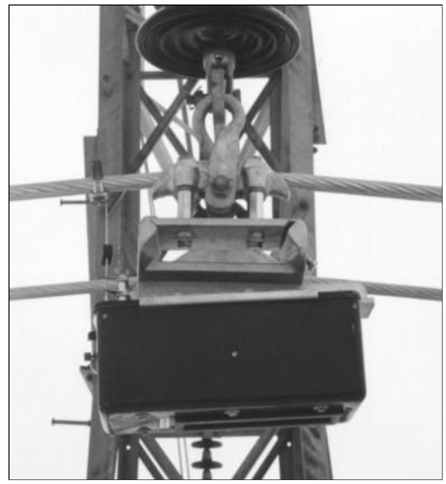


Fig. 3.21a - Corrosion Detector (CEA, 2003) **Fig. 3.21b - Vibration Recorder**

3.4 Insulator

Quite often, the primary cause of the insulator failure is the corrosion of the steel pin in the cap and pin assembly. In the pin area the surface leakage current is concentrated and this causes a dry band formation. Dry band formation leads to partial discharges and eventually causes severe spark erosion. This coupled with the natural corrosion process, reduces the net area of the pin to a point that it is no longer able to support the tensile load. In addition, the corrosion process creates stresses which tend to induce radial cracks in the porcelain insulator.

3.4.1 Inspection Techniques

Inspection techniques for insulators include:

- Visual Inspection;
- Insulator Voltage Drop Measure;
- Electric Field; and
- Infra red Thermography.

Fig. 3.22a – Flashed Insulator

Fig. 3.22b – Cement Crack (CEA , 2003)

3.5 Hardware

Anchor Rod

Anchor rods are normally used in connecting guy wire to the foundation in order to transfer the proper tensile load to the ground. Corrosion is the primary cause of failure.

3.5.1 Inspection Techniques

Inspection techniques for anchor rods include:

- Visual Inspection; and
- Ultrasonic Pulse and Recorder.

Fig. 3.23 - Inspection Equipment (CEA, 2003)

3.6 Inspection Interval

Quite often, the question is asked as to what interval the inspection should be conducted and the resulting data analyzed to ensure that the line system can be maintained reliably and the asset managed adequately. In other words, to initiate a proactive maintenance program, one needs to know reasonably the expected failure interval of a component based on past inspection and to take actions early enough to prevent complete failure. It is well known that many of the failures are not necessarily related to age only and therefore a fixed "time based" inspection and maintenance program as pursued by **NLH** previously was not adequate and optimum with regard to cost.

For example, fatigue failure of a conductor strand is not related to age but is more prone to terrain exposure, inadequate damping in the system and even a wrong choice of the conductor for a specific location. In this case, a condition monitoring program with a vibration recorder will reveal a trend early enough to prevent a potential failure (P-F) of the conductor in the future. In RCM terminology, this is known as the ***P-F*** curve as shown in **Fig. 3.24**. Point "X", where the failure starts to occur, is not necessarily related to age, while point 'P" shows the potential failure point from the previous inspection, and point "F" is the location where it reaches the failure stage (functional failure).

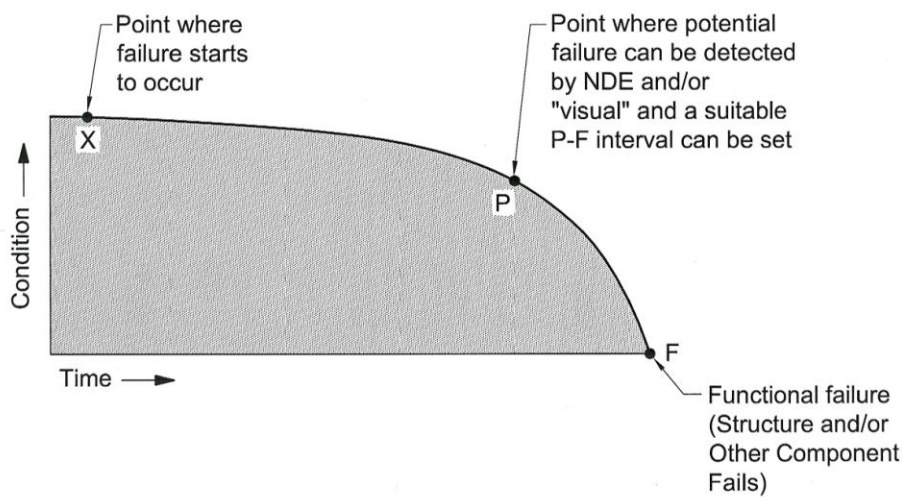


Fig. 3.24 - *P-F* curve (Moubray, 1997)

Fig. 3.25 depicts the P-F interval for two components such as a wood pole (decay) and conductor (fatigue). For a wood pole, service life is normally 40-50 years while for conductor it is normally 50-80 years depending on environmental factors. Since the conductor failure is less likely compared to wood pole failure, a shorter P-F interval for the wood pole will control the frequency of inspection (i.e. shortest interval broken down in various frequencies depending on the inspection and the condition monitored of the component).

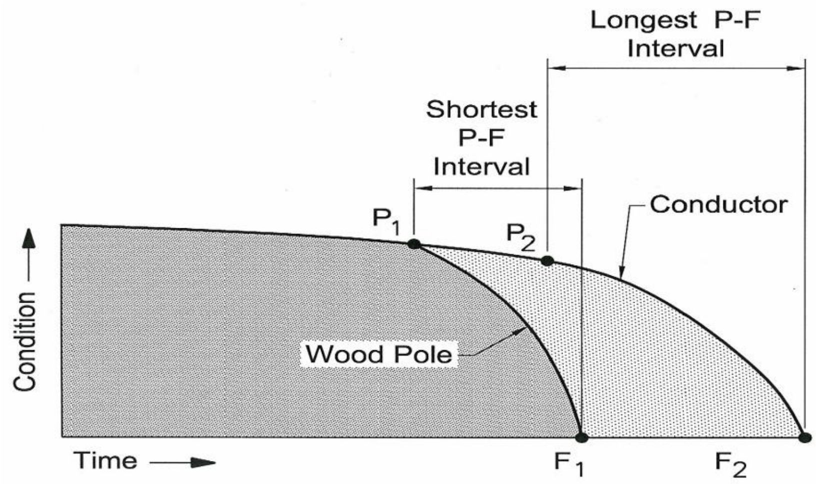


Fig. 3.25 - *P-F* curve – two components

If the objective is to prevent the failure early, then one should plan maintenance tasks based on the **Failure Finding Interval (FFI**) or the interval of inspection (i.e. time between *P-F* interval divided in certain periods). Obviously the frequency of inspection between P-F intervals does not need to be equal. The question becomes what is an appropriate frequency? Of course the answer to this question lies with the line availability and the mean time between failures (MTBF). A line which requires higher availability (radial line) and also has a small MTBF will certainly require a more frequent inspection and condition assessment, compared to a line which is located on a parallel corridor where less availability may be sustained with a similar MTBF. The following formula (Moubray, 1997) provides guidance to the above question:

$$\text{FFI} = 2 \times \text{Unavailability} \times \text{MTBF} \qquad (3.1)$$

For example, a line with a 95% availability (5% unavailability) and a MTBF of 10 years will require a FFI of 1 year. However if one wishes to increase the availability to 99% (1 % unavailability) with same MTBF, the FFI will change to 2.4 months. **Table 3.8** presents the FFI as a percentage of the MTBF provided the availability requirement of a line is known (Moubray, 1997).

Table 3.8 - Failure Finding Interval

Availability Required	99.99%	99.95%	99.9%	99.5%	99%	98%	95%
FFI (as a % of MTBF)	0.02%	0.1%	0.2%	1%	2%	4%	10%

A typical example would be the TL 201 line failure in 1994 due to the breakage of a forged eyebolt on a dead end structure near Western Avalon Terminal Station. The initial failure triggered the cascading of a section of the line, which alone cost NLH $600,000 dollars in subsequent reconstruction. This group of forged eyebolts also failed in 1984 and therefore the MTBF in this case can be assumed as 10 years. If one wanted TL 201 to be available 99% of the time, then the frequency of inspection of these bolts should be 2.4 months (2 x 0.01 x 10 = 0.2 yrs = 2.4 months). On the other hand, if it is acceptable that this line could be out of service for 2 weeks annually (14/365 = 0.0383 unavailability), the frequency of inspection for these bolts should be 9.2 months (2 x 0.0383 x 10 = 0.767 yrs = 9.2 months). Therefore by inspecting these bolts every 5 years (time based), we should expect a very low availability for this line.

The above example assumes the frequency of the line inspection (i.e. inspection of components and its assessment) solely depends on the availability requirement of the line in question and prior information on MTBF. This simple example is also based on a single component assessment and on the assumption that the “weak link” component as identified is always the root cause of expected failure in the future. However, the transmission line system is quite complex and extends spatially in length and therefore FFI needs to be evaluated based on failure rate of various components (sometimes related in a complex manner) and this requires a good understanding of the root cause analysis of the failure event.

It also needs to be understood clearly that failure due to normal wear (such as vibration, fatigue, large displacement, decay, corrosion over a specified time period) will always be accompanied by a loss of strength and a component could fail prematurely even well below the design load if the strength is less than the load effect. On the other hand, if the component were predisposed to degradation, then the line located in a severe environment exposed to significant and/or frequent wind and ice loads would most likely fail when overloaded. Therefore, under RCM one may need to look at different FFI for lines located in harsh environments compared to lines that are not so severely exposed. With a proper condition based inspection procedure (CBI), it is possible to detect this likelihood quite early and a proper group replacement program can be initiated once the risk exposure has been assessed and the maintenance cost can justify the action.

Any data collection and assessment should first focus the actual condition of the line and its importance on local as well as network levels should a failure occur. This will ensure that the fund allocation can well be justified based on a value analysis as presented in **Section 2**. If done properly, the RCM method will provide a more coherent inspection and maintenance program to assess the various options for future maintenance, refurbishment or replacements thus saving money in the long term and avoiding costly outages.

3.7 Recommended Inspection Interval

Since NLH does not have sufficient historical data, **Table 3.9** provides a guideline for inspection interval with respect to line age. However, once the data is collected for one cycle of inspection, the methodology outlined in the previous Section can be used to adjust the frequency of inspection for certain areas. In addition, inspection and test data (both NDE and full scale) for older lines will also provide some insight to adjust the inspection interval as required.

Table 3.9 - Recommended Inspection Interval

Line Components (Service Life)	Lines less than 20 years old	Lines Between 20 and 30 years	Lines above 30 years
Wood Poles (40-50 years)	Typically 10 years	Initially 10 year but can be changed based on inspection data	Initially 10 year and will be revisited in 4 years time to collect sample data on pole preservatives. Adjustment may be necessary based on the condition and analysis
Other Components – Such as Knee braces, Cross arms and Cross braces (40 –50 years)	Same as above	Periodic testing at MUN to ensure adequate integrity-(sample%)	Mostly driven by Pole Inspection Program but requires periodic testing at MUN to ensure adequate integrity; (sample %) - Hydro is currently doing a number of in-service knee brace destructive tests for TL 236 and TL 234 to assess in-service residual capacity.
Conductor (60 – 80 years)	Mostly Visual but Use Vibration recorder as required	Use Vibration recorder to collect sample data in exposed areas supported by sample strand testing	Use Vibration recorder to collect sample data in exposed areas supported by sample strand testing – 5 year interval, Use also Corrosion Detector as a NDE tool to assess the integrity Collect periodic sample data in exposed areas supported by sample strand testing – 5 year interval
Insulators (30-50 years)	Visual	Visual and NDE test	Use Insulator tester to collect sample data in exposed areas supported by sample mechanical tests particularly insulators testing from Dead end Structures – 5 year interval
Hardware (40- 60 years)	Normally "visual" but the problem can be detected through vibration activity	Visual and NDE tests	Selected sample tested for cracks, particularly dead end hardware – 5 year interval
Guy Wire (50 –70 years)	Normally "visual" for corrosion problem;	Periodic checking of "slack" guy and corrosion	Sample test at MUN for pull out to assess the residual strength particularly the lines which are located to coastal areas.

3.8 Maintenance Strategy

Fig. 3.26 depicts a flow diagram to show how a successful maintenance program can be developed using **RCM** principles. It basically follows **Fig. 2.1** where a line is divided into various sub-systems and each sub-system is broken down into line components. A functional failure of a line can eventually be linked to a component by root cause analysis. Therefore condition assessment of a component is important in understanding failure mode evaluation analysis (FMEA). Condition assessment can be done at three different levels: (1) visual, (2) NDE and (3) full scale test. Following assessment, the impact on the sub-system and subsequent impact at the overall system level are evaluated to develop a balanced maintenance strategy, which can cover both preventive and proactive maintenance practices.

However, to develop such a strategy, one must collect condition assessment information for each line component on a historical basis to ensure a systematic evaluation of a line at any given period. Note that the health of the line can be evaluated based on its current condition and a proper future inspection interval can be planned based on the actual condition of the line (or a component which may be a "weak link"). **Section 4** deals with the development of a database based on component inspection. A typical data collection form developed for this project is presented in the Appendix.

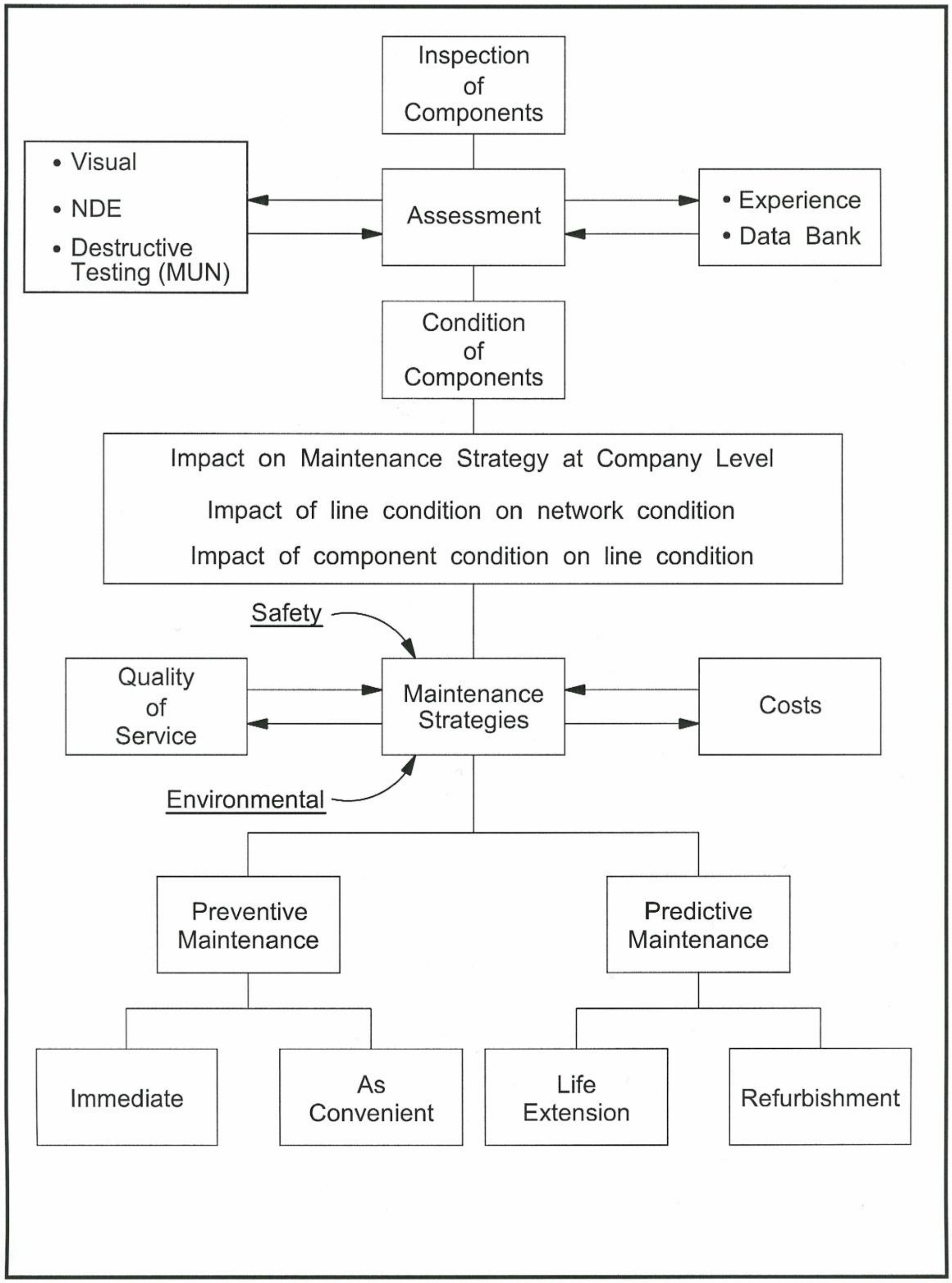


Figure 3.26 – Proposed Maintenance Strategy

SECTION 4

Database Development

4.0 Introduction

The success of the Wood Pole Line Management (**WPLM**) program will primarily depend on how accurately the data is collected in the field and how well it is analyzed. Any decisions made, based on risk assessment, require a proper analysis of data that is of high quality with regard to line performance, component condition, past failure history etc. Therefore, development of a good database is a key component in implementing a WPLM program using RCM principles.

There are three kinds of historical data that are pertinent to line assets. These are: (a) line modifications, (b) failure events and (3) inspections. In addition, all “as built” information defining line circuits, line subsystems and elements (components) and their present conditions should be available.

4.1 Data Collection at Different Levels (CIGRE, 2000)

Inspection can be performed on a typical line and the reporting of the data can be broken down at different levels. For example, data collected on a line at Level 1 can be for planned and forced outages while at Level 2, failure data are collected for sub-systems to assess the reliability. The data at level 2 should be also linked with the data at Level 3 for the element to ascertain the root cause of the failure event (i.e. failure due to strength degradation and/or excessive wear of the component). Suppose a line is hit by lightning and this causes a forced outage. Subsequent inspection reveals that the insulator subsystem is damaged with a burnt pin cap. The root cause of the forced outage is therefore strength degradation in a burnt pin cap due to a lightening strike. Data linkage at different levels is therefore extremely important to do a proper analysis of the system.

4.2 Replacement in Anticipation of Failure

RCM methodology provides a basis for predicting the likelihood of a component failure allowing replacement of a specific component or a group of elements (forged eye bolts, dampers etc.) before failure to ensure that forced outage time and lost revenue are minimized in the long term. Therefore, the question needs to be asked within the framework of *"P-F"* interval **(Section 3.6)**, how frequently, should a component be inspected? Even when the inspection does not reveal useful information (i.e. at the early years of operations between 10 and 20 years), the prediction can still be made using the likelihood of failure by using the pole life expectancy curve as shown in **Fig. 4.1**. A set of curves originally developed for asset replacement known as **IOWA curves** (see **Fig. 4.1**) is used here for wood pole asset replacement.

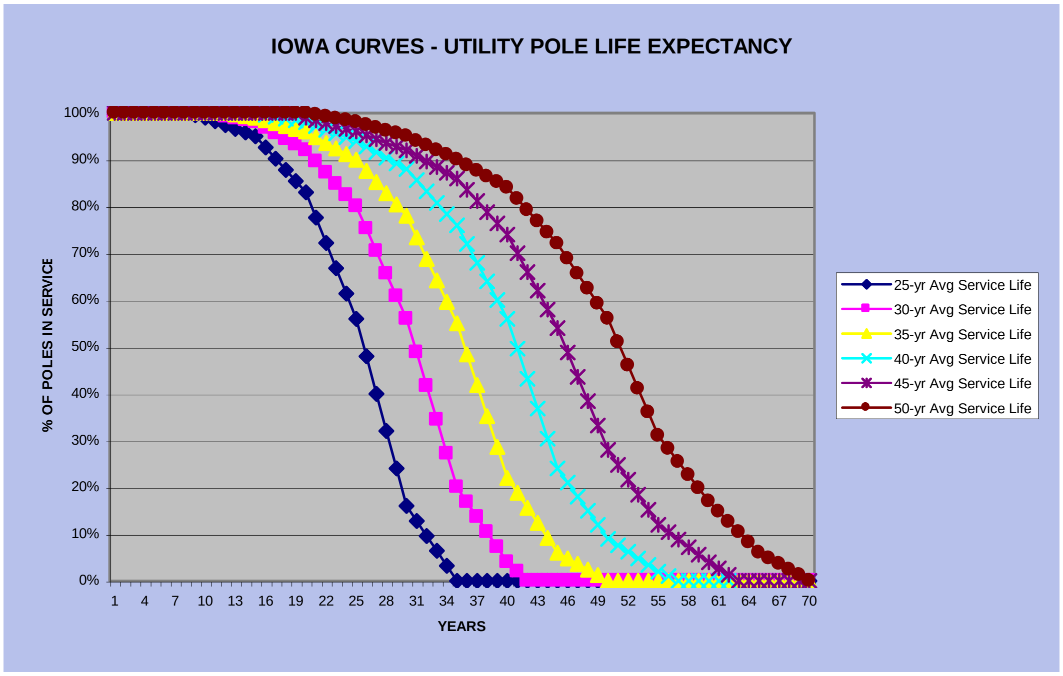


Fig. 4.1 - IOWA Curve

The ordinate of the IOWA curve represents the survival rate in percent while the abscissa represents the age of the pole. Expected service life is also shown on this curve through each average service life line. The 50-year IOWA curve was chosen for validation using the 1998, 2000 and 2003 pole inspection data because it supports the theoretical estimates. **Table 4.1** provides a summary of the rejection rate data described previously.

Table 4.1 – Inspection Results

Inspection Results – TL 201	***Rejected Poles (%)***
1985 Inspection (19 years old)	0 out of 678 (0.0%)
1998 Inspection (32 years old)	45 out of 661 (6.8%)
2003 Inspection (37 years old)	10 out of 199 (5.0%)

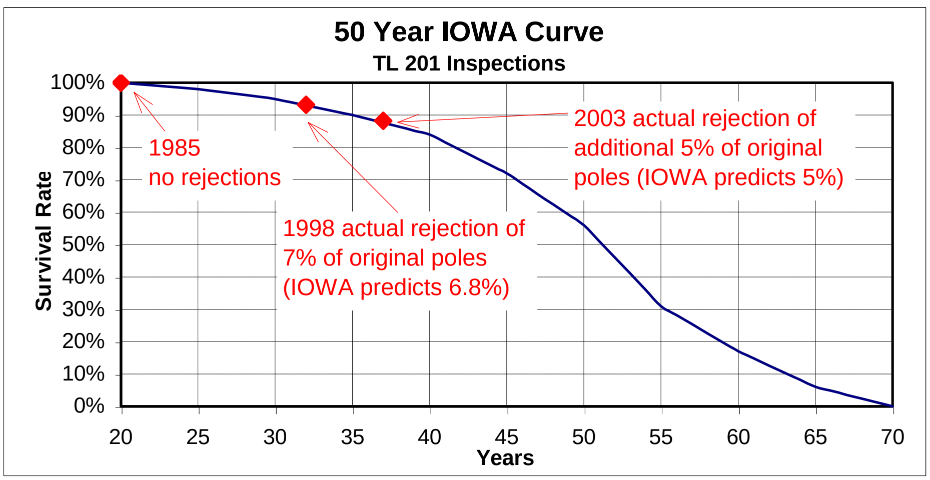


Figure 4.2 – Validation of IOWA Curve

Later, this validation process was also extended to cover poles from the Central region based on 2000, 2002 and 2003 data respectively (**Fig. 4.3**). Although the rejection rate is small in the early part of the 50-year IOWA curve, the rate changes drastically as the poles get closer to their service (economic) life (i.e. 40 years and beyond).

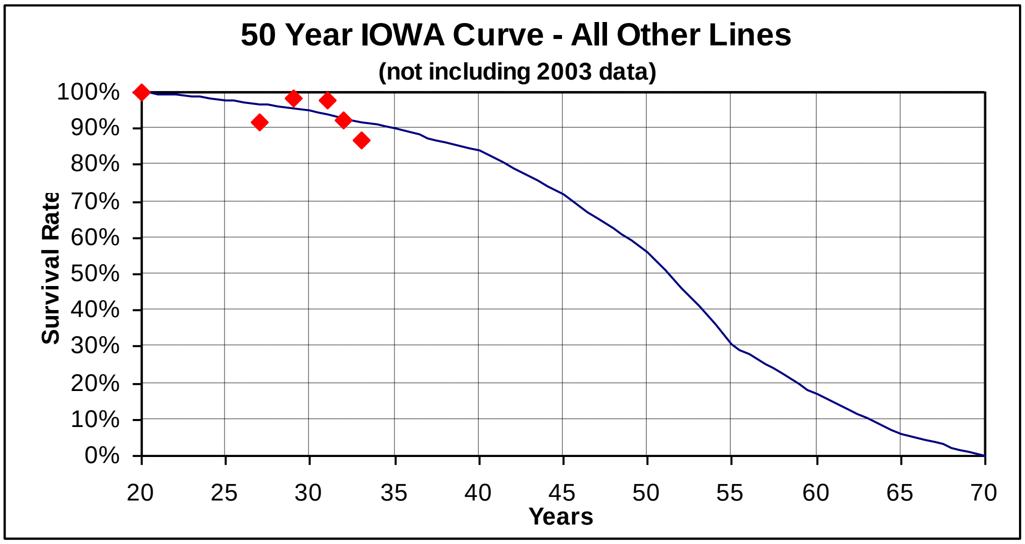


Fig 4.3 - Curve Validation for Non Avalon Poles in 2000 and 2002

4.3 Data Analysis For Wood Pole Inspection Program

The realistic expectation of any wood pole management program is to allow NLH to statistically upgrade the quality of its wood pole plant through a cyclical inspection program coupled with a thorough analysis of the inspection data. This will enable Hydro to predict and identify the risk of unexpected pole failures (i.e. safety issues) as well as reduce the probability of forced outages and loss of revenue (see **Fig. 1.1** - Cost Curve).

The program database can be directly linked to various in-house structural programs (HFRAME, POLE, SCAN, PLSCADD etc.) to assess the line reliability taking into account that the line is part of an overall system **(**Engineering Standard TD-12-001-R0). Any refurbishment, replacement and/or upgrading of a line will be based on the assessment of the quantitative risk associated with in-place strength not meeting the expected load effects (reliability and associated SAIFI and SAIDI exposures) or any associated safety concerns with respect to climbing hazards to operating personnel.

The program will include an annual report which will contain recommendations for refurbishment, replacement and/or upgrading of specific wood pole plant asset for the

Asset Managers. Although initially the program is envisaged for only transmission poles, the future objective is to include distribution size poles as well.

Ultimately, the database will be developed to identify each pole location and prior history. To address this, Engineering has worked with IS&T and the Properties Department to develop a **"Pole Cataloging"** database which will have coordinates of all poles in NLH's system through GPS. **Figs. 4.4a** and **4.4b** depicts typical "flow charts" prepared by IS&T which could be developed further to manage the wood pole line assets. Once this project is approved, IS&T will provide the necessary support to create this database for "Pole Cataloging" in the JD Edwards system with appropriate coordination with Environment & Properties for GIS application. Until the JD Edwards is functional, all data will be recorded on paper forms and manually entered into an Excel spreadsheet for analysis. Eventually, this data will be imported into the database for future record.

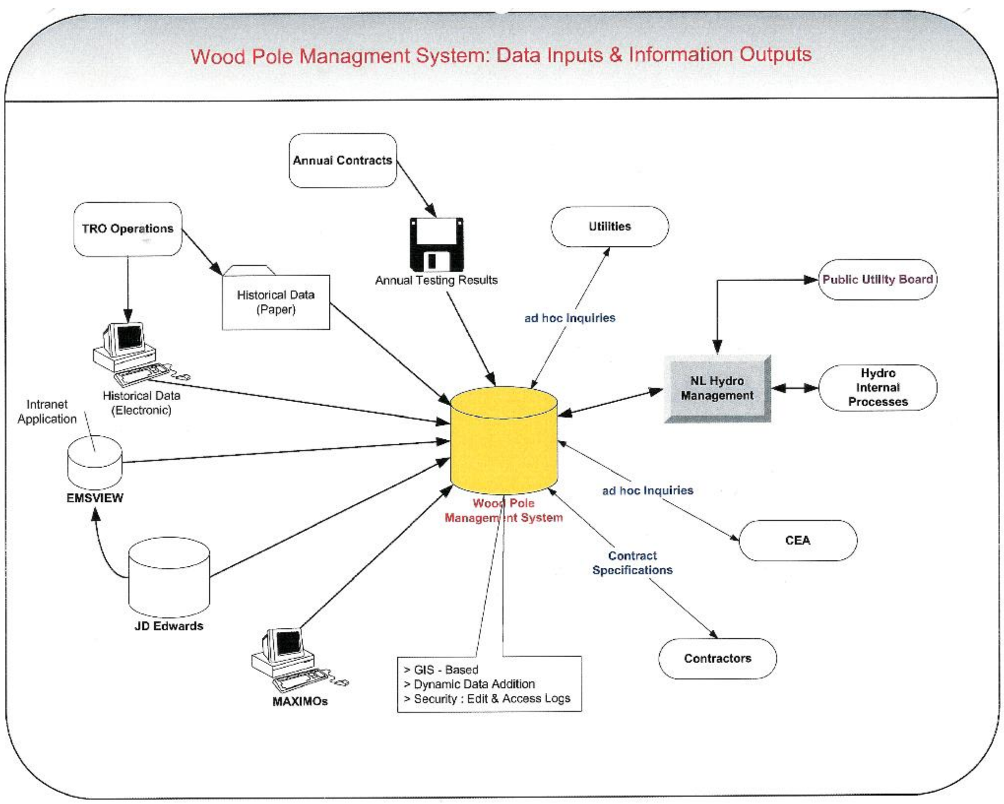


Fig. 4.4a – IS&T Flow Diagram – Data Input/Output

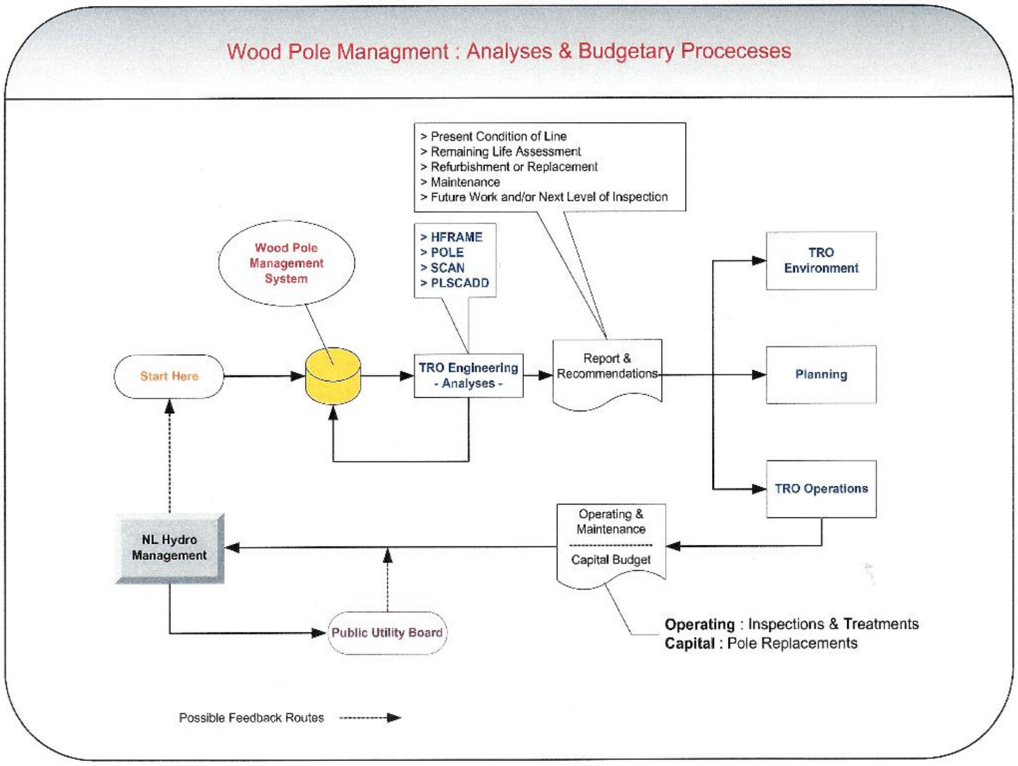


Fig. 4.4b - IS&T Flow Diagram – Analysis and Budget Processes

SECTION 5

Schedule and Cost

5.1 Background

The typical service life of wood pole lines is normally assumed to be 40 years. However, this is based on the criteria that poles are inspected and maintained properly during the service life and a thorough pole by pole inspection, testing and treatment program starts at an age when the poles have passed its 50% service life (i.e. typically 20 years after the installation). NLH's pole inventory data **(Fig. 3.2)** shows that approximately 34% of its transmission size poles (9000 poles) are over 30 years age. Therefore one third of Hydro's poles should have been exposed to a thorough inspection, testing and treatment program 10 years ago.

The pole inspection programs carried out on the Avalon in 1985, 1998 and in 2003 showed a significant loss of preservatives below the threshold value thereby exposing these poles to a greater degree of decay and loss of strength. Since Hydro does not have a formal testing and treatment program at present, it is important that a program be developed and implemented quickly to ensure: (1) the remaining poles in the system are caught early enough to arrest the decay further; and (2) that field data with respect to preservative retention level and decay are collected.

As illustrated in **Fig. 3.3** the depletion of preservative could be quite rapid once the retention has gone below the threshold level. The consequences of this depletion, and associated strength degradation have been shown in **Figs. 3.19a & b**.

In the past, Hydro has performed pole inspection based on a 5-year cycle using the sounding methodology only. It is also true that Hydro had not replaced any significant quantity of transmission size poles until 1998. This observation closely follows the IOWA curve presented in **Fig. 4.2,** as the rejection rate is very small until a pole group has reached 30 years of age for an assumed service life of 50 years. The rejection rate changes drastically as the poles get closer to their service (economic) life i.e. near 40 years and beyond. In 1998, Hydro spent approximately $600,000 dollars to replace 80 poles on the Avalon Peninsula that were rejected during the 1998 inspection. Hydro spent an additional $420,000 dollars in 2000 to replace poles in the Central region that were primarily damaged by ant infestation. All of these poles were detected during the wood pole inspections carried out in each respective year and the results match closely to IOWA curve predictions **(Figs. 4.2 and 4.3)**.

5.2 Inspection Schedule

This section provides a tentative schedule based on the assumption of a 10-year inspection period. It must be noted, as mentioned earlier, that the inspection interval will be a variable quantity depending on the analysis of the data collected, expected availability of the line and the MTBF. As well, the cost estimate for inspection and treatment will be based on a 10-year program and any necessary adjustments will be made in the future as more data is collected.

It is recommended that the inspection, testing and treatment of poles will be focused on those poles that are 30 years of age and older in the first 4 years of the program. A follow up inspection will be done to collect information on preservative retention levels to develop a database to correlate this information with pole decay rate (**Fig. 3.16**). This will enable Hydro to validate the preservative depletion rate ("blue line" shown in **Fig. 3.3**), both the downward and upward slope for predicting the strength degradation rate for future years.

In order to do a cost estimate one needs a tentative schedule for inspection of the lines during the next 10 years. A strategy was developed between Engineering, Operations, System Planning and System Operations to prioritizing the lines for inspection. Two approaches were used to develop the schedule. Operations prioritized the lines based on prior experience particularly with respect to age and on going problems of replacement of poles, insulators, knee braces, hardware etc. Recommendations from System Planning were primarily based on the "Load Flow" analysis and single line out contingency. **Table 5.1** presents the final list that was prepared based on the consensus among the various groups. This table presents the tentative schedule based on the ranking which takes into account both the age related issues as well as service continuity should we lose a line and its impact on the network system.

5.3 Cost of Inspection and Maintenance

Given the decision to carry out the inspection and maintenance program for the entire wood pole line system as per **Table 5.1**, the cost estimate includes the complete inspection of a line, primarily by "visual" inspection supported by field testing of each pole using NDE, limited full scale test at MUN to establish correlation and subsequent full treatment of poles internally. External treatment on poles will be done on an "as required" basis.

The initial cost study was carried out using a computer program that takes into account the entire pole inventory (i.e. 26,000 transmission size poles) and a distribution of these pole assets with respect to various age groups and a tentative schedule following **Table 5.1** in the first inspection cycle. This means that all poles will be inspected in the next 10 years, with the emphasis being placed on the older lines first. In the first 4 years Hydro will be inspecting poles at a rate of 4000 per year followed by 1600 poles per year for the remaining six years of the program (**Fig. 5.1**). This path was chosen to ensure that all old poles are inspected, tested and treated as soon as practical to avoid a large rejection rate in the future years, thereby minimizing the cost of the future year capital program for replacement.

It is assumed that a certain percentage of these poles inspected will also be rejected according to IOWA curve **(Fig. 4.2)** depending on their age and group. Poles rejected in the field will be analyzed with respect to reliability issues, and, if rejected after the structural analysis, a recommendation to refurbish and/or replace will be made. At present it is assumed that 33% of poles rejected can be refurbished, 33% of poles rejected require replacement and the remaining 33% of the rejected poles have sufficient residual strength after analysis such that no further action is required.

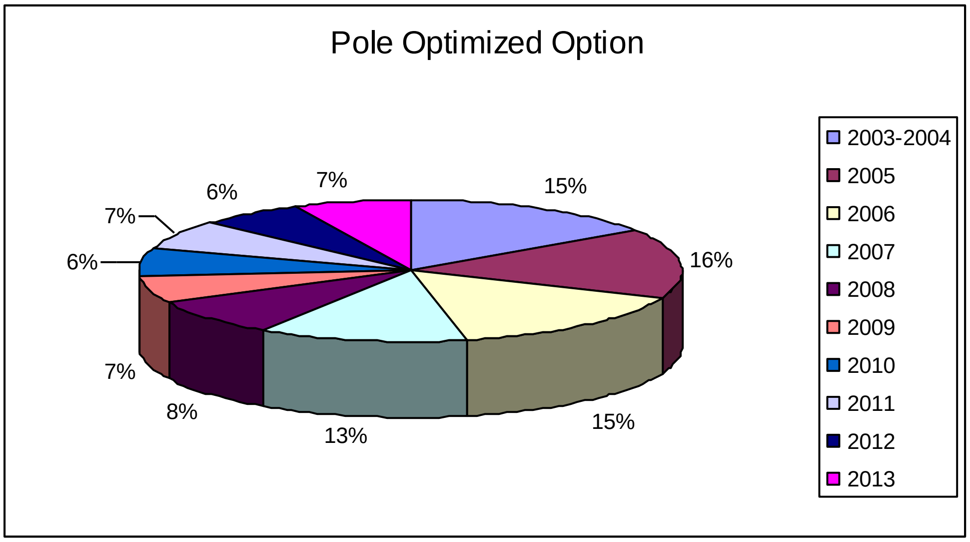


Fig. 5.1 – Annual Inspection

Therefore, the inventory of poles inspected in the first year will have some refurbishment and/or replacement work in the following year with the cost estimate based on the IOWA curve rejection rate and estimated service life. As this program provides for asset life extension, it has been agreed that all costs associated with the inspection, testing and treatment program will be done under a capital budget. It is recommended that NLH carry out some full-scale test program in each year in order to develop a Hydro database on pole strength versus age as per **Fig. 3.17.** This will enable Hydro to use an appropriate degradation rate (on a regional basis) with respect to aging and allow better predictions for future pole replacement, or if necessary a complete line upgrading or replacement

Based on the appropriate analysis, if a decision is made to replace, this will also be done in the following year under a Capital program.

Fig. 5.3 depicts the cost breakdown among inspection, test and treatment and material and engineering, with average dollar values displayed in **Table 5.2.**

Table 5.1 - Operations, System Planning and Merged Line Ranking

Operations Line Ranking	Planning Line Ranking	Merged List broken down by geographical region	
TL 215	TL 234	Central	TL 220
TL 220	TL 241		TL 234
TL 234	TL 243		TL 246
TL 209	TL 244		TL 243
TL 201	TL 250		TL 251
TL 246	TL 255		TL 252
TL 221	TL 256		TL 260
TL 243	TL 260		TL 210
TL 203	TL 215		TL 233 (½)
TL 251	TL 220		TL 222
TL 252	TL 221		TL 254
TL 229	TL 229		TL 223
TL 241	TL 246		TL 224
TL 218	TL 251		TL 253
TL 260	TL 252		TL 232
TL 210	TL 253		TL 263
TL 240	TL 254		TL 235
TL 244	TL 257	Eastern	TL 201
TL 225	TL 261		TL 203
TL 233	TL 209		TL 218
TL 250	TL 239		TL 212
TL 222	TL 245		TL 219
TL 254	TL 259	Western	TL 215
TL 212	TL 225		TL 209
TL 255	TL 201		TL 225
TL 239	TL 203		TL 233 (½)
TL 223	TL 218		TL 250
TL 224	TL 232		TL 255
TL 253	TL 233		TL 245
TL 226	TL 210		TL 238
TL 227	TL 212	Labrador	TL 240
TL 245	TL 219	Northern	TL 221
TL 232	TL 222		TL 229
TL 257	TL 223		TL 241
TL 219	TL 224		TL 244
TL 256	TL 226		TL 239
TL 259	TL 227		TL 226
TL 261	TL 262		TL 227
TL 262	TL 240 not ranked		TL 257
TL 263	TL 263 not ranked		TL 256
TL 238	TL 238 not ranked		TL 259
TL 235	TL 235 not ranked		TL 261
			TL 262

Table 5.2 - Distribution of Program Cost

Cost per pole (total $300)	*Cost*
Preventive Maintenance	$160 (54%)
Test and Treat	$40 (13%)
Treatment Materials	$30 (10%)
Engineering (including NDE)	$70 (23%)

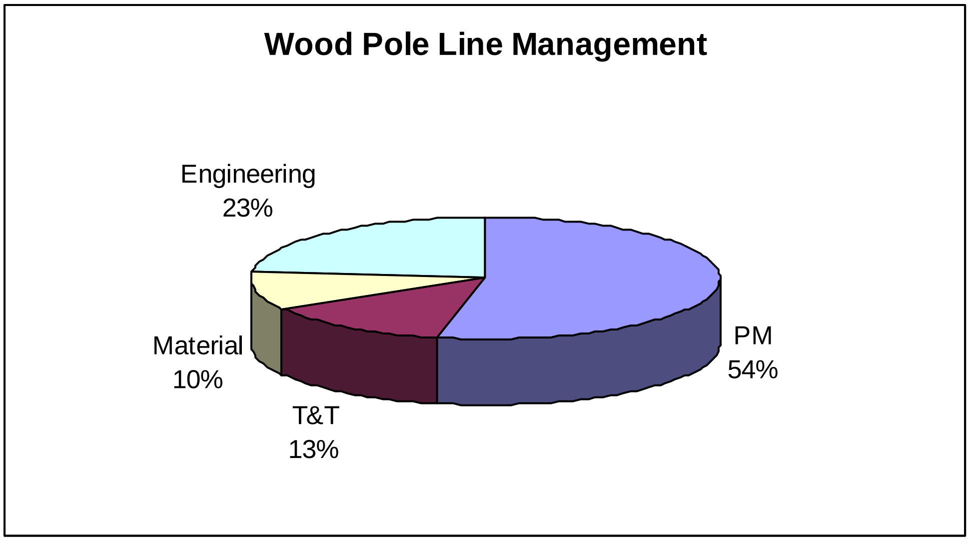


Fig. 5.2 - Average Cost Breakdown per pole

The application of remedial treatment to poles will provide a reduction in the rejection rate. This reduction is referred to as the "improvement rate" over the rejected poles without any treatment. A typical value of 60% has been recommended (GENICS, 2002) for the "second 10-year cycle". Note that during the "second 10 year cycle", poles are also 10 years older and therefore, one would expect a much higher rejection rate as per the IOWA curve (**Fig. 5.3**) than if the poles were not treated after the first inspection cycle. **Fig. 5.3** depicts a typical pole replacement curve developed with and without the treatment program and based on 10 year inspection cycle and 50 year service life.

It should be noted that the rejection of a pole does not necessarily mean that Hydro needs to replace the pole. Based on the structural reliability analysis, a decision will be made whether to replace the pole or not when the risk has been assessed with respect to reliability, security and safety.

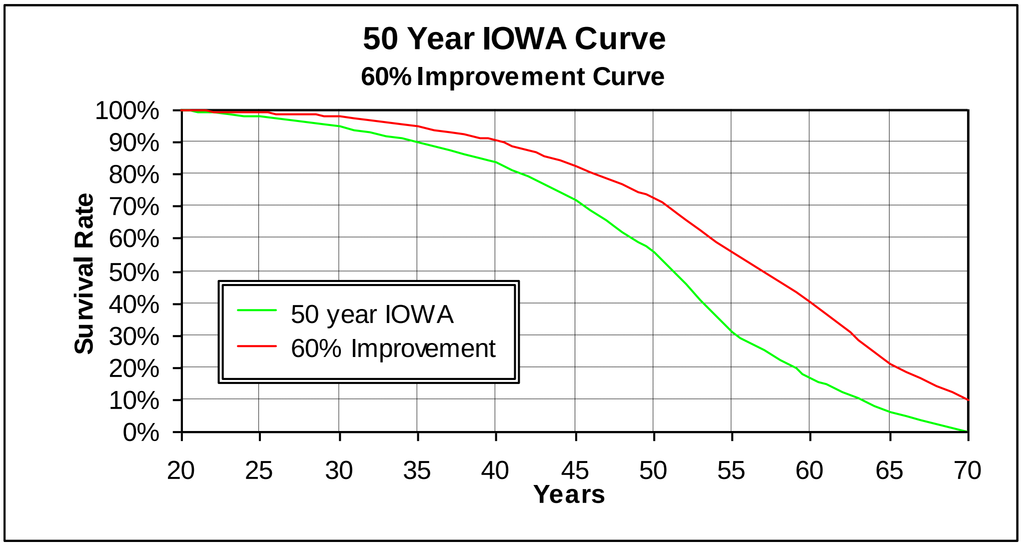


Fig. 5.3 - IOWA Curves with Improvement Rate

5.4 Cost Benefit Analysis – Typical Line Segment

Almost two-thirds of transmission pole plant assets fall into two age categories. Approximately 34% of the poles are at or over 30 years, and another 31% are 20 to 30 years old. The remaining asset age is less than 20 years old. Through the inspection and remedial treatment of these poles, it is predicted that a reduction in the future rejection rate of inspected poles will be realized. Based on the IOWA curves, and an assumed improvement in the expected failure rate of poles due to the application of remedial treatment, the cumulative present worth benefit of a remedial treatment program can be estimated. In order to estimate the cost and benefit, a number of assumptions were made:

- Cost model based on 100 poles;
- Cost to inspect, test and treat: $230 per pole based on 2003 productivity rates;
- Cost to inspect only, $160 per pole. (No Non-destructive Evaluation (NDE) or remedial treatment applied);
- Pole replacement cost: $7,000 based on 1998 and 2000 replacement of rejected poles;
- All costs are escalated using the November 2002 Electric Utilities Project Escalation Indices, prepared by Hydro’s Economic Analysis Section;
- The discount rate is set at 8.5%;

- The base year is taken as 2003;
- Engineering time is not included in this estimate. Engineering input has an associated cost, but yields benefits in reduction of rejection through structural analysis and alternate refurbishment methods;
- It is assumed that the realization of a rejection rate improvement is based on poles treated in the first cycle being again treated in subsequent cycles;
- Rejection improvement is based on an industry suggested 60% improvement rate due to application of treatment. Sensitivity to the improvement rate is also reviewed;
- For ease of analysis, rejected poles are replaced in the same inspection year; and
- Future year rejection rates are estimated based on the IOWA curve.

5.4.1 Scope of the Cost Benefit Analysis

This analysis will consider the two age dependant treatment cycles: 1) starting at 25 years, and continuing every 10 years until 55 years, and 2) starting at 37 years, and continuing every 10 years until 57 years. This will cover the benefits of starting the program at the industry recommended start age of 25 years, and also starting later in the life of the pole (37 years plus). Combined, the two cycles will cover approximately 65% of Newfoundland and Labrador Hydro’s pole plant assets (17,000 poles). Inspections will be performed on 10-year cycles, and the cost of performing the inspection, as well as the cost of replacing the poles will be tabulated.

For each of the cycles, two options will be reviewed and compared. Option one will be to provide inspection services only, and all poles rejected will be replaced. Option two will be to provide for inspection and remedial treatment, with the assumption of an improvement in the rate of pole rejection due to the treatment application. Both age group cycles will provide the cumulative present worth of the treatment versus no treatment options.

5.4.1.1 Age Dependent Treatment Cycle 1: Inspection commencing at 25 years

Thirty-one percent of Hydro's transmission pole inventory is approximately 25 years old. Ideally, a full inspection and remedial treatment program for these poles should commence at this age. In this way, a maximum improvement in the rate of rejection should be realized over the life of the poles. Inspections will be performed at the initial year (age 25) and every 10 years following (age 35, 45 and 55).

For option 1 (inspection only), application of the standard 50-year IOWA curve indicates that 69 of the original 100-pole sample would be replaced by the time the poles reach 55 years of age. The cumulative present worth cost of inspection and replacement is calculated at $164,500. For option 2 (inspection and remedial treatment), with an improvement rate of 60% due to treatment application, it is estimated that 45 of the original 100-pole sample would be replaced by the time the poles reach 55 years. The cumulative present worth cost of inspection, remedial treatment and replacement is calculated at $134,000. This provides for a net benefit of $30,500 for every 100 poles that enter the inspection and remedial treatment program at 25 years of age. Given an estimated 8000 poles in this age group, the total net benefit of providing an inspection and remedial treatment program for these poles is $2.4M.

5.4.1.2 Age Dependent Treatment Cycle 2: Inspection commencing at 37 years

Thirty-four percent of Hydro's transmission poles are over 37 years old. Using the IOWA curve, it is estimated that 74 poles will be replaced by the time the poles reach 57 years of age by option 1 (inspection only). The cumulative present worth cost for inspection and replacement is calculated at $284,000. For option 2 (inspection and treatment) it is estimated that 55 poles will be replaced over the life of the program. The cumulative present worth cost for inspection, remedial treatment and replacement is calculated at $243,000. This provides a net benefit of $41,000 for every 100 poles that enter the program at 37 years of age. Given a pole inventory of 8800 poles in this group, a net benefit of $3.6M will be realized over the life of the poles. Therefore, for the inspection of poles over 20 years of age, a total net benefit of $6.0M can be shown.

5.4.2 Sensitivity of Improvement Rate

As the rate of improvement due to the application of remedial treatment is subject to factors such as local climate, treatment effectiveness on older poles, etc., and without the benefit of detailed long-term data on improvement, sensitivity in varying this rate was addressed. As can be seen from **Fig. 5.4**, if the improvement rate is greater than 20%, a net benefit for the treatment program will be realized. Thus, if it is assumed that poles entering the program at 25 years have a 60% improvement, and poles 37 years or older have a 40% improvement, somewhat less than the example, a total net benefit of $4.46M will still be realized for the approximately 17,000 poles that fall into these two categories. The improvement rates can only be determined through the application of treatment, and the future analysis of the benefits based on actual costs.

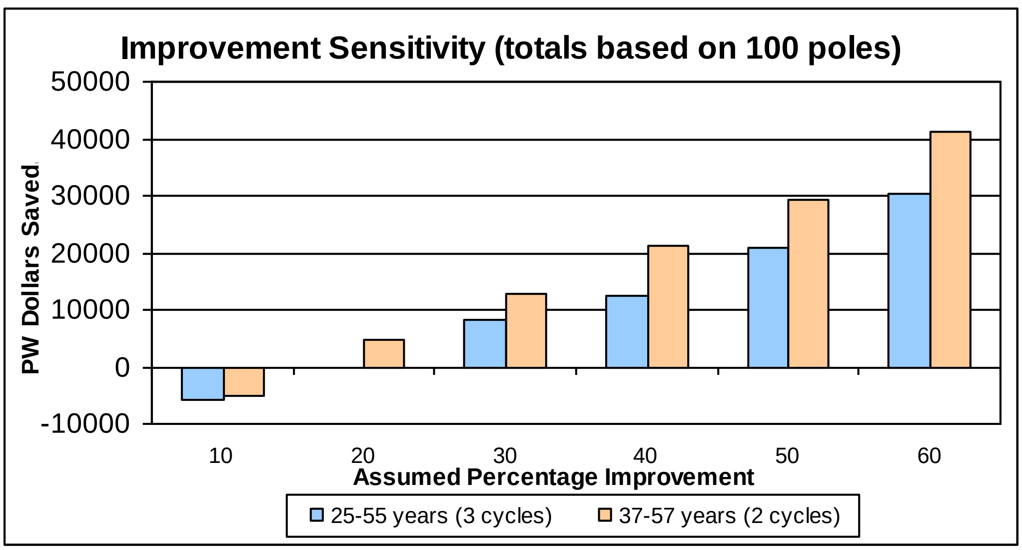


Figure 5.4 – Improvement Rate Sensitivity

The inspection program will also provide valuable information with respect to the present health of the wood pole lines. Based on the annual report of this inspection, testing and treatment program, a more "pro-active" maintenance and replacement plan can be established which, in the long run, will save Hydro a considerable amount of money due to proper planning and execution.

Based on the limited data collected in 1998, NLH has a large number of poles falling below the required preservative retention threshold level (retention level, refer to Avalon inspection report and Table 3.2 and Fig. 3.7 and Fig. 3.8). The current program will require a full pole-by-pole inspection, testing and treatment. The schedule & cost of this phase is also shown separately under "Cost and Budget" for 2005 to 2009 & beyond in **Table 5.3** with a cash flow in the Appendix.

5.5 Budget Cost Breakdown and Assumptions

The following information was used to prepare the budget estimate:

- Total cost of inspection, testing, treatment, data collection, material and providing engineering support is $300 per pole;
- All poles will be inspected in the next 10 years and the program is a 2 - "10 year" cycle program;
- Operations personnel have been involved to ensure the budget cost reflects the current cost of line inspection plus the additional expenditures needed to carry out a full pole inspection, test and treatment program;
- It has been agreed that Operations personnel will be responsible to carry out the regular line inspection work and in addition, they will also be responsible to carry out this inspection, test and treatment program. A specification and a terms of reference has also been agreed between Operations and Engineering;
- All work will be done each year, beginning early May and be completed by late October. This will give Operational personnel time to do any other preventive maintenance work in the reminder of the year;
- It has been assumed that each crew in the region will be able to do 10 poles per day based on Operations input and agreement;
- All five crews will be engaged each year particularly in the first few years when NLH will be covering a large number of poles per year **(Fig. 5.1)**;

- Referring to **Fig 5.1**, 60% of poles (16000 poles) will be inspected in next 4 years to ensure that all old poles are inspected first to avoid excessive rejection in subsequent years. This will minimize the capital program cost in the future years;
- Poles over 30 years age will be inspected again within 4 years of the treatment to collect data on depletion rate (**Fig. 3.3**) However this will be done on a selected sample to obtain the trend;
- Engineering will analyze the data and prepare an annual report. To do so Engineering should allocate adequate resources and this cost has been budgeted;
- The budget includes some replacement costs of other components such as conductors, insulators etc; However if the analysis of the field inspection data indicates that a major replacement is warranted for other major line components then this should be followed up through a separate study for capital replacement;
- Poles inspected in one year will encounter a certain percentage of rejection and upon engineering analysis, final recommendation to do nothing, refurbish and/or replace will be made to the respective Asset Manager. Budget estimate for the capital program has been included here; and
- It is assumed 33% poles rejected in the field will require no actions, 33% will be refurbished and the remaining will be replaced. However these numbers could change up or down depending on what is found in the field and the severity of deterioration of pole assets. Therefore this budget proposal needs to be flexible for future adjustment.

As indicated earlier, the original estimate is based on poles being optimized for inspection and treatment. It is estimated that in the initial phase of the program (i.e. at least the first 3 year period) many activities need to be completed to ensure that the program runs smoothly and the database is developed properly for full analysis.

Table 5.3 2005 to 2009 (and beyond) Capital Budget Proposal (2003 projection)

Costs (x $1,000)	2005	2006	2007	2008	2009	Beyond
External Engineering	$50	$50	$50	$50	$50	$700
Material Supply	$382	$470	$336	$154	$90	$2906
Labor	$1,492	$1,700	$1,265	$675	$465	$11,670
Engineering	$228	$228	$172	$114	$114	$1,602
Escal, Contingency & O/H	$436	$558	$462	$277	$221	$9,264
Total	$2,588	$3,006	$2,285	$1,270	$940	$26,142
Total Program Cost (20 year)						$36,231

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SECTION 6

Summary, Conclusions and Recommendations

6.1 Summary and Conclusions

The report describes the principles and plans for the wood pole line management (WPLM) program for Newfoundland and Labrador Hydro's **26,000** transmission size poles. This program is based on RCM principles and, by using internal resources, will replace the old time based inspection program. It is also emphasized here that the actual inspection interval for the program is determined on the basis of field data (condition of the line) and the proper analysis of this data, rather than a fixed time interval. Since NLH does not have long-term data at this time, it is recommended that the inspection interval proposed in **Table 3.8** be used to initiate the "new" program. Further, the inspection interval should be reviewed on an annual basis for subsequent adjustment once specific line inspection data is obtained.

The report also describes the methodology to be used to evaluate various options for line maintenance strategy systematically using a "risk" based criteria for the management of the wood pole lines. Based on the current year inspection data, the following year's capital program will be developed. This will "stream line" the budgeting process for managing the wood pole lines once the program is in place.

Although the current inspection technique is primarily "visual" in nature**,** it is identified that in some areas (for some components, e.g. conductor, insulators) Hydro should start using NDE to collect strength data on a more objective basis. The wood pole test program using NDE is a first step to achieve this objective. Hydro should be doing similar NDE for conductors, insulators, conductor joints, etc. Early detection of the potential failure initiation point (e.g. strand break near or below the clamp for conductor, deterioration of pin cap of insulator, knee brace crack etc.) could guide Hydro to predict the functional failure before it happens, thereby avoiding a costly forced outage. Also this information is of considerable importance with respect to the residual life of a line when one considers refurbishing and/or upgrading an existing line.

Finally, a schedule and a cost breakdown will be provided for each year of the inspection program and the capital program that will follow in the subsequent year. A cost benefit analysis of the inspection, testing and treatment program demonstrates that this cost can well be justified against the savings one would obtain by not only containing the line/structural failure in the future years, but also by extending the life of the older lines by a reasonable number of years thereby deferring the cost of building new lines in the future.

6.2 Recommendations

A number of recommendations are made to ensure that the wood pole line management program implemented based on RCM principles produces data in a structured format to ensure that a proper analysis can be completed annually to determine the program's trend and effectiveness.

- Implement the inspection, test and treatment program in 2005 and complete the entire inspection, test and treatment program for 26,000 poles by 2013.

- Repeat the program for the next 10 years i.e. between 2014-2023 to investigate the benefit in the second year cycle (improved rate of rejection in the second cycle) as per estimated data (**Figs. 4.1** and **5.3**) and future validation.

- Operations to carry out inspections of these poles on an annual basis and to send this data to Engineering for further analysis in a timely fashion. Engineering will carry out the analysis and make the appropriate recommendations to Operations for future refurbishment and/or pole replacement program under a capital budget proposal.

- If the analysis identifies that a large number of poles need to be replaced then a separate study should be undertaken considering full refurbishment and/or upgrading or even building a new line before a capital program is launched.

- The program should be expanded to investigate other component inspection data closely e.g. knee braces, conductor, insulators, hardware to confirm that other components have a considerable residual life left before any major pole replacement program is undertaken.

- Data to be analyzed to develop a “Replacement Criteria” for Wood Pole Lines based on a minimization of cost model as shown in **Fig. 1.1**. Some initial work has been completed as part of this study and this should be followed up further for validation of this model with additional field data.

- It is noted that any cost model developed should include the cost of deferral of building new lines in the future. To accomplish this, data must be collected to ensure that the rate of decay and the preservative depletion rate can be correlated (**Fig. 3.9**). It is important to know when treatment is no longer effective in life extension.

- In each year of this inspection program, a separate fund is allocated to do routine testing of components including the in-service wood poles of various ages to develop a long-term database. Hydro, in collaboration with MUN, has developed special benches to do this type of testing and this should be funded annually.

- Once the program is in place, all routine data analysis for the current inspection year should be completed by the year-end with appropriate recommendations made to justify replacement and/or upgrading for the subsequent year. This will provide documentation of the line inspected in a year and the various actions that have been taken to provide remedial measures. To do this in a systematic manner, proper resource allocation is needed and has been reflected in the CBP.

- A working group be formed within Hydro's **TRO** division, which should include one representative from each of Engineering, Operations, and System Planning. The primary role will be to review the annual Engineering report on the inspection results and its recommendation to ensure that if any major line replacement is required in the future based on the data trend, Hydro will be able to plan this program in advance to avoid a large capital expenditure in any given year and distribute the resources in an even and timely manner.

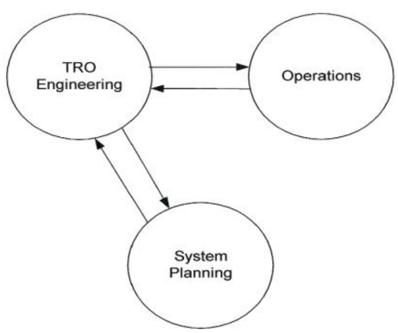

Fig. 6.1 Working Group For Line Management

SECTION 7

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