Manitoba Hydro

CUSTOMER SERVICE AND DISTRIBUTION

Customer Service Operations South Division

Distribution Asset Maintenance Department

REPORT ON

Distribution Asset Condition

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EXECUTIVE SUMMARY

Manitoba Hydro’s distribution system supplies 550,000 customers through 78,000 circuit kilometers of line. The system supplies the electrical customers of the entire province, stretching from Emerson in the south to Churchill in the north. Historically, the reliability performance of Manitoba Hydro’s distribution system has been excellent. However, recently distribution system reliability performance has begun to degrade and asset condition is a contributing factor.

Manitoba Hydro’s electrical distribution system is comprised of eight critical assets: poles, overhead conductors, overhead transformers, streetlights, underground cable, duct lines, manholes, and padmount transformers. The eight assets provide the foundation of the distribution system and consist of over one million separate components.

A significant portion of these critical assets are approaching the end of their designed lifespan and will require substantially higher replacement rates to maintain the distribution system performance over the next 20 years. The asset management strategy to date has served the Corporation well as it is not cost effective to replace assets prior to their anticipated end of life. This strategy has enabled the Corporation to defer hundreds of millions dollars of capital investment.

Two examples of assets reaching their “end of life” are the 250,000 wood poles installed between 1940 and 1960 during rural electrification and Cross Linked Polyethylene (XLPE) cables installed between 1970 and 1986. The replacement value of any single failed component on the system is moderate; however the aggregate replacement value of the eight critical assets in today’s dollars is approximately $7.9 Billion.

This report assesses the factors and risks associated with each asset. The following recommendations are made considering customer value and aligned with the Corporate Strategic Plan.

- Enhance the asset management strategy for the underground distribution system.
- Development of a long term capital investment plan to address the aging distribution infrastructure.

- Enhance inspection and maintenance processes for distribution assets.
- Review alternatives for streetlight below grade corrosion integrity assessment. Continue to implement detailed asset inspections to further optimize asset life cycles.
- Rigorously review contingency plans for the 66 kV and 115 kV cable systems and all unique assets.

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GLOSSARY OF TERMS

Cables

Cables consist of one or three separate conductors insulated with an artificial medium such as paper, plastic, or oil. They are installed under the soil surface and utilized to transmit electricity. On Manitoba Hydro's distribution system cables are most commonly applied on the distribution system (66 kV and below), but are also utilized in several 115 kV applications on the transmission system.

Cross Linked Polyethylene Cable (XLPE)

Cross Linked Polyethylene Cables consist of a single conductor (aluminum or copper), plastic insulation, and a concentric neutral or tape shield. XLPE cables are most commonly found on the 25 kV and below distribution system.

Distribution System

The distribution system is the physical infrastructure outside of substations that transmits electricity to customers. This infrastructure largely consists of eight critical assets: cables, manholes, duct lines, padmount transformers, poles, overhead conductors, overhead transformers, and streetlight standards. Distribution system operating voltages range from 4 kV to 66 kV.

Distribution Maintenance Planning System (DMPS)

The Distribution Maintenance Planning System is Manitoba Hydro's database application used to track assets and prioritize distribution equipment maintenance.

Distribution Supply Center (DSC)

Distribution Supply Centers transform electricity from high voltage distribution (66 kV or 33 kV) or transmission (115 kV) voltage levels to distribution voltage levels (4 – 25 kV). The units are commonly utilized on Manitoba Hydro's distribution system as an alternative to traditional substations.

Duct Lines

Duct lines are physical structures installed below the soil surface to provide conduits for multiple distribution circuits. They are most common in the City of Winnipeg, particularly downtown, and utilized where it is not possible to route the required number of circuits with conventional overhead or direct buried designs. Due to the congested locations duct lines are found, they are often an integral part of major road arteries and sidewalk systems.

Electronic Geographical Information System (eGIS)

Electronic Geographical Information Systems are utilized to store distribution asset data. The computer application enables geospatial view of distribution system assets and facilitates electronic queries of asset data.

High Pressure Pipe Type Cable (HPPT)

High Pressure Pipe Type Cable consists of three conductors (typically copper), wrapped in paper, immersed in oil, and contained in a steel pipe. The oil is maintained at a pressure of 300 pounds per square inch (psi) at the source substation.

Integrated Pole Maintenance (IPM)

The Integrated Pole Maintenance Program is designed to provide an accurate integrity assessment of wood poles on a 15 year cycle.

Kilovolt (kV)

Kilovolt is a unit of measure on the operating voltage level of the distribution system and is equal to 1,000 volts. Common distribution system voltage levels include 4 kV, 8 kV, 12 kV, 24 kV, 25 kV, 33 kV, and 66 kV.

Low Pressure Oil Filled Cable (LPOF)

Low Pressure Oil Filled Cable consists of one conductor (typically copper), wrapped in paper, immersed in oil. The cable utilizes a hollow core phase conductor to permit flow of oil through the circuit. Oil pressure is maintained by hydraulic reservoirs at either end of the circuit. LPOF cables are operated at much lower operating pressures than HPPT cables.

Manholes

Manholes are underground concrete enclosures connecting duct lines in high density areas. They facilitate the repair, splicing, and installation of cables.

Overhead Conductors

Overhead conductors are installed on poles to deliver electricity to customers. Typically aluminum, copper, and steel conductors are utilized on Manitoba Hydro's distribution system.

Overhead Transformers

Overhead transformers are installed at customer facilities to change the voltage to a level suitable for utilization by the customer.

Padmount Transformers

Padmount transformers are installed at customer facilities to change the voltage level to a level suitable for utilization by the customers. These transformers are installed at ground level and mounted on a base (typically concrete or fiberglass).

Paper Insulated Lead Covered Cable (PILC)

Paper Insulated Lead Covered Cable was the first generation of underground cable installed on Manitoba Hydro's distribution system. It typically consists of three conductors (copper), paper insulation impregnated with oil, and a metallic lead sheath.

Poles (Wood)

Poles are utilized to provide adequate ground clearance and mechanical support of conductors and energized equipment.

Poly Vinyl Chloride Jacket Cable (RIPVCJ) and Rubber Insulated Neoprene Jacket Cable (RINJ)

Poly Vinyl Chloride Jacket Cable (RIPVCJ) and Rubber Insulated Neoprene Jacket Cable (RINJ) were the first cables installed on Manitoba Hydro's distribution system that did not use paper and oil as an insulating medium. These cables consist of a single conductor with rubber insulation insulating the conductor from a metallic sheath and a PVC jacket.

Streetlight Standards

Streetlight standards are typically tubular steel or aluminum to support roadway lighting in urban and high traffic locations.

Tree Retardant Cross Linked Polyethylene (TRXLPE)

Tree Retardant Cross Linked Polyethylene Cables consist of a single conductor (aluminum or copper), plastic insulation, and a concentric neutral or tape shield. TRXLPE cables are the next generation of XLPE cable, designed to be more reliable.

1. INTRODUCTION

The distribution system consists of eight critical assets: poles, overhead conductor, overhead transformers, streetlights, underground cable, duct lines, manholes, and padmount transformers. Historically, the reliability performance these assets and the overall performance of Manitoba Hydro's distribution system have been excellent. However, recently Manitoba Hydro's distribution system reliability performance has begun to degrade and asset condition is a contributing factor.

Although, the replacement value of any single component of the system is typically moderate the aggregate replacement value of aging assets approaching their "end of life" is anticipated to be substantial and will require significantly higher replacement rates to maintain the distribution system performance in the next 20 years. Two examples of assets reaching their "end of life" are 250,000 wood poles installed between 1945 and 1960 during rural electrification and Cross Linked Polyethylene (XLPE) cables installed between 1970 and 1986.

This report examines each of the critical assets with respect to demographics, degradation mechanisms, inspection and maintenance practices, asset health, risk, and valuation. The report analyses each of these factors and provides a prioritized list of recommendations to address gaps identified.

2. DISCUSSION

Electrical distribution system components are classified into one of two categories: overhead and underground. Both systems deliver electricity from the bulk transmission system to end use distribution customers and consist of different components each with varying risks and unique challenges. The electrical distribution system is assumed to consist of all of Manitoba Hydro's physical infrastructure operated at 66 kV or lower voltages not associated with generating station and transmission[1] infrastructure.

Underground Distribution Systems

Manitoba Hydro's underground system is predominately concentrated in urban locations, with the vast majority of assets within the City of Winnipeg. Underground cables are installed in duct systems or direct buried to deliver electricity to end use customers. For the purposes of this report four critical assets comprising the underground distribution system will be examined. These assets include: underground cables, manholes, duct lines, and padmount transformers.

Overhead Distribution Systems

Manitoba Hydro's distribution system is predominately an overhead system. Wood poles are utilized to support the conductors, insulators, transformers, and other associated hardware required to deliver electricity to end use customers. For the purposes of this report four critical assets comprising the overhead distribution system will be examined. These assets include: poles, overhead conductors, overhead transformers, and streetlights.

Detailed information on each of the critical assets can be found in Appendices A to H.

[1] The four Pointe du Bois 66 kV circuits P1, P2, P3, and P4 are utilized to transmit electricity from Winnipeg River generation to Rover Terminal in the city of Winnipeg. Although operated at 66 kV these lines are considered transmission infrastructure and outside the scope of this document.

2.1 Demographics

The electrical distribution system supplies Manitoba Hydro's 550,000 customers and consists of millions of separate components. These components are classified into eight critical assets, each of which consists of its own unique set of characteristics. The installed quantities of each asset are summarized in Table 1.

Asset Type		**Quantity**
Underground Distribution Systems	Cables	6,000 km
	Manholes	2,400
	Duct Lines	265 km
	Padmount Transformers	17,000
Overhead Distribution Systems	Poles	1,000,000
	Overhead Conductors	72,000 km
	Overhead Transformers	142,000
	Streetlights	58,000

Table 1 Distribution Critical Asset Quantities

2.2 Economic Evaluation

Equipment installation costs can be influenced by a number of different factors including equipment material, location (urban, rural, isolated, terrain), and characteristics of the distribution system to which it is connected. Table 2 provides a high level estimation of the approximate value of the distribution system critical components assuming 2012 average replacement costs.

Asset	**Quantity**	**Value**
Cables	6,000 Circuit km	$1.5 Billion
Manholes	2,400	$0.3 Billion
Duct Lines	265 km	$0.8 Billion
Padmount Transformers	17,000	$0.3 Billion
Poles	1,000,000	$3.5 Billion
Overhead Conductors	72,000 Circuit km	$0.7 Billion
Overhead Transformers	142,000	$0.5 Billion
Streetlights	58,000	$0.3 Billion
Total		**$7.9 Billion**

Table 2 Distribution Critical Asset Economic Evaluation

2.3 Degradation Mechanism

Distribution asset degradation varies within each of the critical assets and is typically a function of one or more factors which commonly includes environmental conditions, installation type, wildlife, and/or foreign interference. A list of degradation mechanisms for each asset is provided in Tables 3 and 4.

Asset Type	Degradation Modes	Comments
Cables	Corrosion, Foreign Interference, Moisture, Troubleshooting	Degradation of underground cable varies by the asset type and installation method. Corrosion is typically associated with cable designs that utilize a bare concentric neutral or tape shield in contact with the soil. Cables installed in duct line systems are most vulnerable to this form of degradation, however it has also been found to occur in rural areas due to differences in local soil chemistry. Moisture ingress into the cable insulation is one of the most common failure modes. Over time moisture causes the cable insulation to break down and can eventually lead to failure. Moisture ingress is primarily a concern with XLPE and RINJ cable families. Foreign interference such as excavation equipment contact can result in damage for all classes of underground cables. Troubleshooting techniques which rely of excessive reclosing and/or cable testing can also result in damage.
Duct Line	Environmental, Foreign Interference, Vehicular Traffic	Degradation of duct line systems is typically associated with the shifting of a duct section and pinching of underground cables. This movement is typically associated with the underlying soil conditions and the freeze/thaw cycle. Mechanical vibration from traffic above duct lines can also result in degradation of the structure. Asset age and construction type can play a role in duct line failures. The first generation of duct line segments utilized clay tile ducts which are starting to breakdown mechanically and are no longer recommended to be used for new cable installations.
Manholes	Corrosion, Environmental, Foreign Interference, Vehicular Traffic	Degradation of manhole systems is typically associated with corrosion of any reinforcing steel and/or weakening of the underlying concrete or brick structural foundation. Soil movement associated with the freeze/thaw cycle and mechanical vibrations from traffic can also act to degrade manhole condition.
Padmount Transformers	Corrosion, Environmental, Thermal, Wildlife	Padmount transformers are susceptible to damage from corrosive environments (road salt or industrial pollution). Corrosion of the transformer tank resulting in oil leaks or moisture ingress into the tank is a common failure. Other failures include wildlife bridging the transformer insulation (e.g. squirrels), thermal overload due to customer loading exceeding the device capability, and environmental conditions such as flooding.

Table 3 Underground Asset Degradation Modes

Asset Type	Degradation Modes	Comments
Poles	Biological, Environmental, Foreign Interference, Vehicular Accidents, Wildlife	Wood poles are susceptible to damaged caused by biological agents (fungi) rotting the pole structure, wildlife damage (ants and woodpeckers), damage from vehicular accidents or machinery contact. All of these factors reduce the mechanical strength of a pole. Weakened pole strength combined with environmental conditions such as heavy ice and/or wind loading often result in pole failures.
Overhead Conductors	Environmental, Mechanical, Thermal	Overhead conductors are susceptible to damage caused by environmental conditions or previous system faults. Damage can manifest as broken strands, abrasion, stretching, or burning. Damaged conductors have lower current carrying capabilities than undamaged conductors and are susceptible to failure as the result of system loading requirements (thermal failure) or environmental conditions such as heavy ice and/or wind conditions.
Overhead Transformers	Corrosion, Environmental, Thermal, Wildlife	Overhead transformers are susceptible to wildlife bridging the transformer bushings (e.g. birds, squirrels), thermal overload, environmental conditions associated with storms, and damage from corrosive environments (road salt or industrial pollution).
Streetlights	Corrosion, Environmental, Foreign Interference, Vehicular Accidents	Streetlight standards are susceptible to damage from corrosive environments both above and below the soil surface. Dents and/or cuts to the standards as the result of vehicular accidents or contact by construction or snow clearing equipment also act to compromise the mechanical strength of the standard. Weakened standard strength combined with environmental conditions such as heavy wind loading can result in standard failures.

Table 4 Overhead Asset Degradation Modes

2.4 Inspection and Maintenance Practices

Distribution equipment inspection and maintenance practices vary in frequency and detail for the eight critical assets. Table 5 summarizes the existing inspection and maintenance practices for each of the eight critical assets.

Asset Type		Maintenance Practice(s)
Underground Distribution Systems	Cables	No inspection and maintenance practices exist for underground cables. Infrared scans of splice and termination connections are occasionally but not consistently completed.
	Duct Lines	No inspection and maintenance practices exist for duct lines.
	Manholes	Power Line Technician Module 30-1324 outlines the inspection requirements for manholes. Inspections are scheduled for every 3 years, but have not been consistently completed.
	Padmount Transformers	Within the City of Winnipeg, padmount transformers have a yearly security check to confirm there is no evidence of oil leakage, the lock is secure, and there are no obvious problems with the unit. Transformers are opened and inspected on a six year cycle to confirm operation and replaced if required. Within the City of Winnipeg a dedicated Underground Assessment Crew has been tasked with completing this work. Outside the City of Winnipeg this task is organized at the location CSC level and is inconsistent.
Overhead Distribution Systems	Poles	Integrated Pole Maintenance inspections are completed on a 15 year cycle. Poles identified as requiring refurbishment are reinforced through stubbing or replaced through work orders. Poles are also examined visually every six years as part of circuit inspections by operational staff. These inspections have not been consistently completed and data quality is a concern.
	Overhead Conductors	Overhead conductors are examined visually every six years as part of circuit inspections by operational staff. These inspections have not been consistently completed and data quality is a concern.
	Overhead Transformers	Overhead transformers are examined visually every six years as part of circuit inspections by operational staff. Completion of inspections to this requirement has not consistently accomplished by operational staff. Transformer loading is also reviewed by engineering offices. Overloaded transformers are scheduled for replacement.
	Streetlights	Policy P348 outlines streetlight inspection requirements. Within the City of Winnipeg visual inspections are scheduled every four years. Inspections are limited to above grade inspections only. Tools to assess the condition of below grade corrosion for direct buried and power screw installations have not been implemented.

Table 5 Distribution Asset Maintenance and Inspection Practices

Inspection processes are typically more robust and frequent for the overhead system than the underground system as the majority of the underground cable installations are not readily accessible (direct buried or installed in duct lines) and visual inspections would not necessarily provide a complete indication of asset health. Customer Service Operations has also been challenged to complete existing inspection cycle requirements for a number of existing maintenance and inspection requirements, notably overhead circuit inspections.

3. ANALYSIS

3.1 Health

In this section, the health condition of each critical asset will be analysed. Each of the critical assets was assessed against specific criteria to quantify the current asset health and provide a projection of the asset health in 20 years based on current replacement rates. Assets are classified into one of three conditions: acceptable, fair/poor, or critical. The key assumptions for asset condition classification along with the existing asset replacement rates are summarized in Table 6.

	Ranking Criteria		
Asset	**Acceptable**	**Fair/Poor**	**Critical**
Cables	TRXLPE Cable<40 Years, PILC Cable (30% initially rated good)	PILC (70% initially rated fair), XLPE Cable<35 Years, & TRXLPE Cable>40 Years	RINJ, RIPVCJ, and XLPE Cable >35 Years
Manholes	Acceptable Condition Assessment Following Inspection	Fair/Poor Condition Assessment Following Inspection	Critical Condition Assessment Following Inspection
Duct Lines	No Condition or Age Profile Data. Assumed 85% of duct lines are concrete or are in good condition.	No Condition or Age Profile Data. Assumed 10% of duct lines are Transite or are in fair condition.	No Condition or Age Profile Data. Assumed 5% of duct lines are clay tile or are in poor condition.
Padmount Transformers	<30 Years	31 – 49 Years	>50 Years
Poles	<50 Years	51 – 74 Years	>75 Years[2]
Overhead Conductors[3]	Standard Conductors	Non-Standard Conductors	N/A
Overhead Transformers	<50 Years	51 – 74 Years	>75 Years
Streetlights	Concrete Piled Base (80% initially rated good)	Direct Buried, Steel Power Screw Base, Concrete Piled Base (20% initially rated fair)	Identified in DMPS as requiring high priority repairs

Table 6 Asset Health Ranking Criteria

[2] Also includes 18,000 rejected poles based on Integrated Pole Maintenance (IPM) inspections.
[3] Standard conductors include Aluminum ACSR, AASC, and ASC types. Non-Standard conductors include steel, copper, alloy, CCSR, Shrike, Copperweld, and Allomweld.

Customer Service and Distribution (CS&D) currently spends well over $100 million on various programs to increase system capacity, retire aging infrastructure, and prolong asset life cycles. Based on current spending levels the existing and projected health of the distribution system critical assets 20 years in the future health is presented in the following "soccer field" charts. In Figures 1 and 2 the percentage of each asset rated acceptable, fair/poor, and critical is represented by the colors green, yellow, and red respectively.

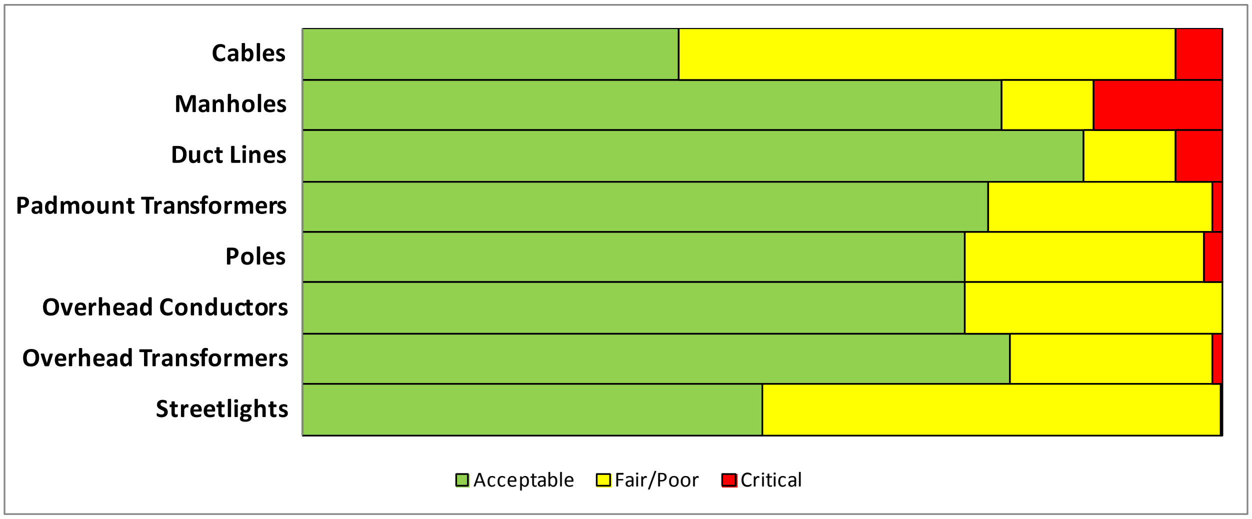


Figure 1 Critical Asset "Soccer Field"

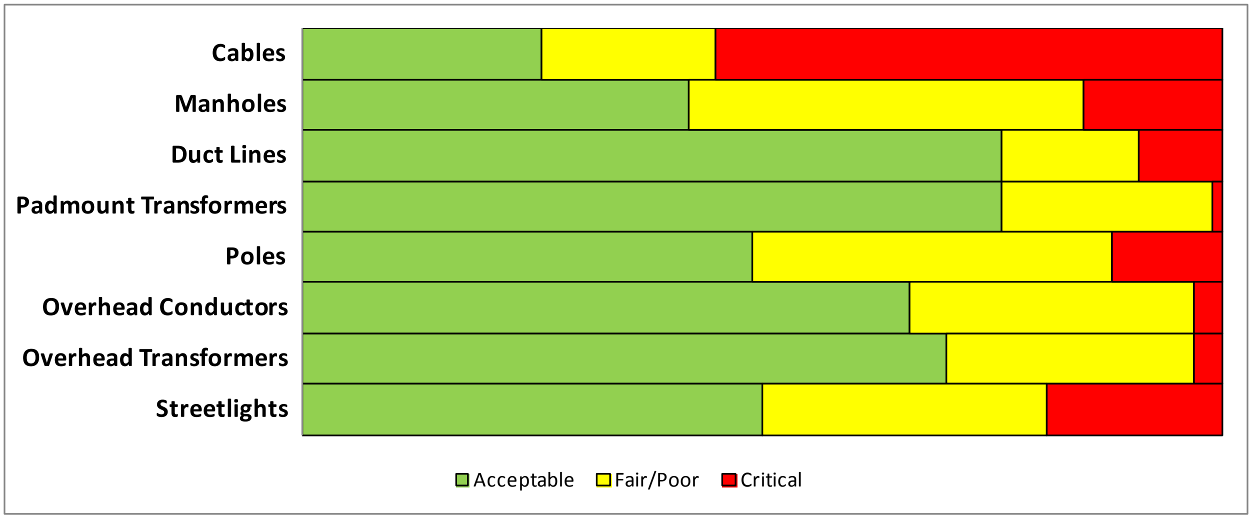


Figure 2 Critical Asset 20 Year Forecast "Soccer Field"

From the preceding charts it is apparent the majority of distribution assets are currently in acceptable condition. This is indicative of effective management of the system, as it would not be cost effective to replace assets prior to their anticipated end of life. However noticeable changes in asset health are anticipated over the next 20 years and the existing replacement rates will not be sufficient to prevent substantial degradation of assets, particularly underground cables, wood poles, and streetlights.

Over the next 20 years significant degradation of underground cables, wood poles, and streetlight standards is predicted to occur. The percentage of those assets in critical condition is projected to increase 5% to 55%, 2% to 11%, and 0.2% to 19% respectively. At that time over 3,300 km of underground cable 110,000 poles, and 10,700 streetlight standards are projected to have met or exceeded their anticipated end of life.

The impact on other assets is also significant, but less severe. Degradation of existing duct line and manhole systems is predicted to increase slightly, however approximately 15% of manholes are already estimated to be in critical condition. Slight degradations are also projected for overhead transformers and conductors. The percentage of those assets in poor condition is projected to increase 1% to 3% and 0% to 3% respectively. Padmount transformers were the only asset class not anticipated to experience a significant increase in critical condition, remaining steady at 1% of the population.

Asset life expectancy along with Manitoba Hydro's asset replacement rate will determine the future asset health of the distribution system. Table 7 presents the asset life expectancy estimation along with the current replacement rate.

Asset	Life Expectancy	Current Replacement Rate
Cables	30 – 70 Years	328 Years[4], N/A
Manholes	80 Years	500 Years
Duct Lines	100 Years	378 Years[5]
Padmount Transformers	50 Years	70 Years
Poles	75 Years	200 Years
Overhead Conductor	100 Years	200 Years
Overhead Transformers	75 Years	70 Years
Streetlights	50 – 70 Years	100 Years

Table 7 Critical Asset Life Expectancy and Replacement Rates

From the preceding table it is apparent the current asset replacement rates are insufficient to replace assets prior to their anticipated end of life for the majority of assets. As those assets age and approach their end of life substantial asset replacement will be required or reliability performance will substantially degrade.

3.2 Investment Gap

In this section the financial implication the projected future asset condition is discussed. The projected amount of infrastructure and the estimated replacement cost of assets in poor condition are presented in Table 8.

[4] The replacement rate for XLPE cable is approximately 328 years. In 2012, the RINJ cable replacement program will be stopped with approximately 30 km of cable remaining in service. There are no plans to refurbish aging distribution PILC cable at this time.

[5] Duct line replacement levels have been very low. Number is calculated based on recent refurbishment projects at Edmonton and Ellice Station areas, but no ongoing programs are scheduled.

Asset	Projected Quantity in Poor Condition		Funding Gap
Cables	3,400 Circuit km	55%	$500 Million+[6]
Manholes	350	9%	$30 Million+[7]
Duct Lines	25 km	15%	$75 Million
Padmount Transformers	170	1%	$3 Million
Poles	117,000	12%	$410 Million
Overhead Conductors	6,300 Circuit km	9%	$63 Million
Overhead Transformers	4,800	3%	$15 Million
Streetlights	11,000	19%	$50 Million+[8]
Total			$1.15 Billion

Table 8 Critical Asset Funding Gap

Assuming the gap was evenly funded over the next 20 years, the anticipated annual incremental funding requirement for each critical asset is presented in Table 9.

Asset	Funding Gap
Cables	$25 Million
Manholes	$1.5 Million
Duct Lines	$3.8 Million
Padmount Transformers	$0.2 Million
Poles	$20.5 Million
Overhead Conductors	$3.2 Million
Overhead Transformers	$0.8 Million
Streetlights	$2.5 Million
Total	$57.5 Million

Table 9 Annual Funding Gap

[6] Estimate based on combination of XLPE cable replacement and injection. Silicone injection costs are approximately 35% of cable replacement and have the potential to reduce cable rehabilitation costs.
[7] Estimate based on combination of manhole roof repair and rebuild costs. Typical rehabilitation costs range from $45,000 to $125,000 per site.
[8] Range based on extent of rehabilitation required for streetlight standards. Replacement of direct buried or concrete piled standards is up to $8,000 per location.

3.3 Risk of Failure

A risk analysis was conducted for each of the eight critical assets considering the probable consequence of a failure against the following five critical factors.

1. Financial
2. System Reliability
3. Safety
4. Environment
5. Customer Value

Tables 10 and 11 detail the likelihood and consequence criteria utilized for this analysis.

Descriptor	**Qualifier**
Almost Certain	The event will occur on an annual basis
Likely	The event has occurred frequently
Possible	The event might occur infrequently
Unlikely	The event does occur somewhere from time to time.
Rare	Have heard of something like this occurring elsewhere.

Table 10 Risk Matrix Likelihood Criteria

Consequence	Measure	Rating
Financial	Net Income / capital investment:	Very Low - $0-$25 Million
		Low - $26- $50 Million
		Medium - $51- $75 Million
		High - $76- $100 Million
		Very High - > $100 Million
System Reliability	Domestic Customers:	Very Low – Annual impact on System Average Interruption Duration Index (SAIDI) < 5 Minutes
		Low – Annual impact on System Average Interruption Duration Index (SAIDI) 6-10 Minutes
		Medium – Annual impact on System Average Interruption Duration Index (SAIDI) 11-20 Minutes
		High – Annual impact on System Average Interruption Duration Index (SAIDI) 21-40 Minutes
		Very High – Annual impact on System Average Interruption Duration Index (SAIDI) >41 Minutes
Safety Employee and Public	High risk accidents, severity rate, frequency rate and public contacts:	Very Low - Minor injuries, in compliance with laws and standards.
		Medium - disabling injuries, in compliance with laws and industry standards.
		Very High - severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in imprisonment for Manitoba Hydro management, significant fines and loss of public trust.
Environment	Environmental Impact - air emissions, water management, spills, land and habitat disturbances, etc:	Very Low - Minor impact to environment in compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing and operating approvals.
		Medium - Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing operating approvals.
		Very High - Severe widespread and uncontained damage to environment and/or non-compliance with stakeholder expectations, laws and regulations resulting in imprisonment for Manitoba Hydro management, significant fines, loss of public trust and long term operating restrictions
Customer Value	Customer perception of service with regard to reputation:	Very Low – No local media coverage with negligible impact on stakeholders
		Low - Limited local media coverage with negligible impact on stakeholders
		Medium - A highly visible event attracting local media coverage; and/or a moderate negative impact on stakeholders.
		High - A highly visible event attracting national media coverage or; and/or a moderate negative impact on stakeholders.
		Very High - A highly visible event attracting international media coverage; and/or a significant negative impact on stakeholders

Table 11 Risk Matrix Consequence Criteria

Details of the rankings of each asset against each of the five criteria are available in the respective appendices. The following chart compares the highest risk score for each of the critical assets can be identified from the following numbers.

1. Underground Cables
2. Manholes
3. Duct Lines
4. Padmount Transformers
5. Poles
6. Overhead Conductors
7. Overhead Transformers
8. Streetlights

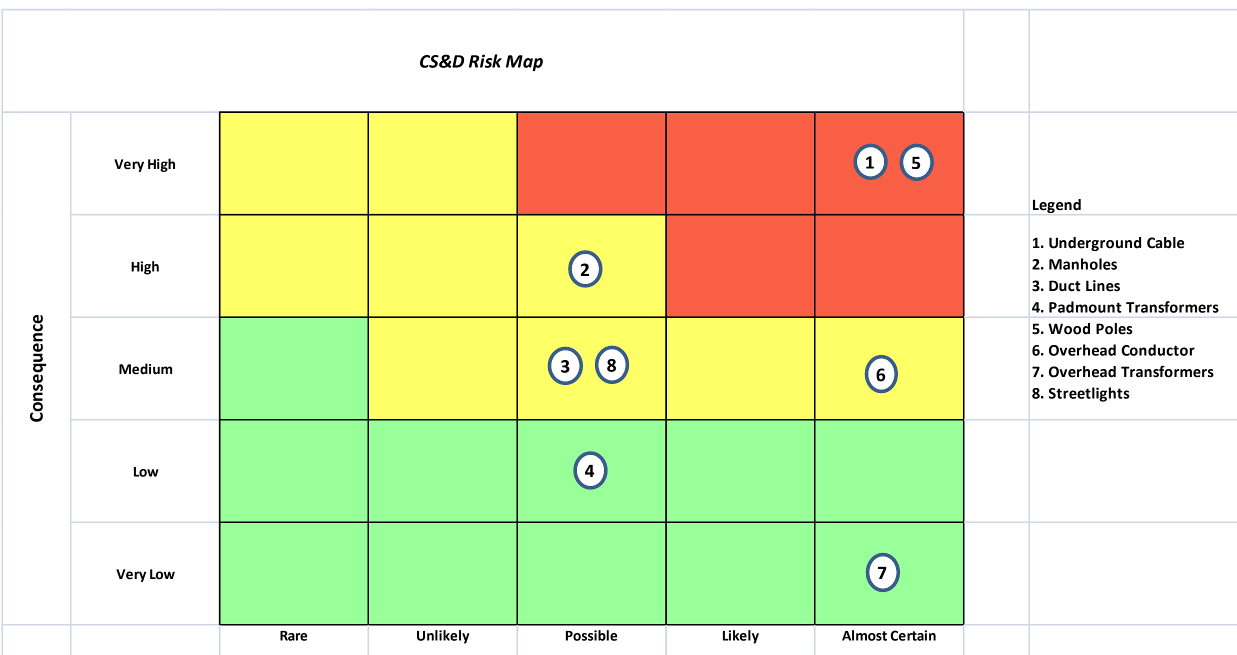


Figure 3 Critical Asset Risk Map

Figure 3 indicates the highest overall risks to the Manitoba Hydro are the pole and underground cable assets. The reason for the high risk ranking is the amount of infrastructure protected to be in poor condition after 20 years and the high cost associated with replacement of those assets. Although rated lower in terms of overall risk the following assets also demonstrated moderately high levels of risk: streetlights, manholes, and duct lines. There are several contributing factors for the moderate ranking of each of these assets.

Streetlights are classified as moderate based on the substantial asset replacement cost for direct buried and power screw anchored installations and the anticipated media coverage if a standard fell and damaged property or injured someone. Lack of an ability to complete below grade assessments of direct buried and power screw streetlight installations is another reason for the moderately high risk score.

Manholes were also rated as a moderate risk due to the relatively high percentage of manholes identified as being in critical condition (14%). The risk associated with manholes is predominately associated with customer value and reliability. Manholes can contain up to 30 circuits within them and a failure could result in major extended customer outages. Although, Manitoba Hydro has been fortunate in avoiding this problem to date, BC Hydro experienced a multiple circuit failure inside a manhole which received national media attention.[9] In that outage, 20% of Downtown Vancouver experienced an outage due to the loss of the fourteen circuits in the structure. It is anticipated a similar failure at Manitoba Hydro would have similar severe impact on reliability and attract national media attention.

Duct lines have similar risks to reliability as manhole systems and were scored similarly. Like manholes duct lines can contain multiple circuits and a failure has the potential to result in major outages. Another potential risk associated with duct line systems is detailed asset condition data is not available. Currently, it is known a number of duct lines utilizing concrete tiles exist on the system and are in critical condition, but the exact amount has not been quantified.

Overhead conductors also have moderate risks due to their anticipated high replacement costs as aging conductors prone to failure from mechanical fatigue require replacement.

The risks associated with, padmount, and pole mount transformers are low due to the limited customer impact, availability of spare parts, and anticipated low levels of assets in critical condition.

[9] http://www.cbc.ca/news/canada/british-columbia/story/2008/07/14/bc-underground-fire-downtown-vancouver.html

4. RECOMMENDATIONS

The following high priority recommendations are made to address the gaps identified in this review. Details of lower priority recommendations for each asset are discussed in the corresponding asset appendix.

1. Enhance the asset management strategy for the underground distribution system.

2. Development of a long term capital investment plan to address the aging distribution infrastructure.

3. Enhance inspection and maintenance processes for distribution assets.

4. Review alternatives for streetlight below grade corrosion integrity assessment.

5. Continue to implement detailed asset inspections to further optimize asset life cycles.

6. Rigorously review contingency plans for the 66 kV and 115 kV cable systems and all unique assets.

5. CONCLUSIONS

Manitoba Hydro's critical assets are aging and an increasing proportion is anticipated to reach the end of its useful life within the next 20 years. Underground cables and wood poles represent the largest financial and reliability risk to Manitoba Hydro. Development of a long term capital plan and asset management strategy for these assets is required to ensure the continued long-term performance of the distribution system.

Implementing the recommendations of this report will help Manitoba Hydro achieve the following goals and strategies set in the Corporate Strategic Plan.

Provide Customers with Exceptional Value

- Enhance the asset management strategy for the distribution system to ensure acceptable reliability and asset performance.

Maintain Financial Strength

- Develop a long term capital plan to address aging assets.

APPENDIX A Underground Cables

Asset Condition

04/27/2012

1. UNDERGROUND CABLES

Underground Cables are insulated conductors that are utilized to distribute electricity from source substations to distribution transformers. Unlike overhead conductors, underground cables typically insulated from ground through a non-gaseous insulating medium. (ie: plastic, rubber, paper, or oil), that can be installed directly in the ground. The main advantage of using insulating material, on underground cables is increased electric strength allowing for the cables to be installed in proximity to one another. Numerous circuits can also be installed in small right of ways through the use of an underground duct line system.

On Manitoba Hydro's province wide distribution system, underground distribution cables are most prevalent in urban centers, particularly the City of Winnipeg. However, there are also significant quantities of underground cables in rural locations, particularly Southern Manitoba. These cables were installed following severe ice storms in the 1970's; Manitoba Hydro undertook an extensive project to install rural underground distribution in areas most sensitive to ice storms in the 1970's and 1980's.

The majority of underground cables are installed on medium voltage level systems (4 kV – 25 kV). However, the distribution system includes modest quantities of 33 kV and 66 kV cable installations. Underground 33 kV cables are utilized exclusively within the City of Brandon as part of the urban sub-transmission system. Buried 66 kV cables are utilized for all 66 kV Distribution Supply Center installations and portions of 66 kV circuits within City of Winnipeg.

This report examines high voltage distribution and medium voltage distribution cables (4 kV – 66 kV) used on Manitoba Hydro's distribution system. Seven different types of cable installed on the distribution system will be discussed, including:

- Paper Insulated Lead Covered (PILC)
- Rubber Insulated Neoprene Jacket (RINJ)
- Rubber Insulated Poly Vinyl Chloride Jacket (RIPVCJ)
- Cross Linked Poly Ethylene (XLPE),
- Tree Retardant Cross Linked Poly Ethylene (TRXLPE)
- Low Pressure Oil Filled (LPOF)

- High Pressure Pipe Type (HPPT)

1.1 Demographics

Paper Insulated Lead Covered (PILC)

PILC cables were the first generation of underground cables to be installed on Manitoba Hydro's distribution system. The majority of the PILC cables were installed prior to the 1970's, however use of these cables continued until the early 2000's in the old Winnipeg Hydro service territory. Although no longer purchased or installed, PILC cables provide excellent system reliability, provided they remain undisturbed.

PILC cables contain all three phases in a common cable and are primarily applied on the 4 kV and 12 kV (City of Winnipeg) distribution systems. Each of the three copper conductors is insulated using a paper insulation soaked in oil. A lead sheath surrounding the paper provides mechanical protection to the cable. Photos of PILC cables are provided Figure 4.

Figure 4 PILC Cables

Historically, PILC cables have been very reliable assets and can be expected to last 70 years or more before reaching end of life.

Rubber Insulated Neoprene Jacket (RINJ or Butyl) and Rubber Insulated Poly Vinyl Chloride Jacket (RIPVCJ)

RINJ and RIPVCJ cables were the first cables installed on Manitoba Hydro's distribution system that did not use paper and oil as an insulating medium. Unlike PILC cables which contain all three phase conductors within a common core, RINJ cables utilize separate cables for each phase conductor, with rubber insulation insulating the phase conductor from a PVC jacket. A protective metallic cable sheath is jacketed with insulation to avoid contact with the surrounding soil. Installation of these cables occurred between the mid 1950's and 1960's and are installed on the 4 kV and 12 kV systems.

RINJ and RIPVCJ cables have a poor performance record. In 1996, a cable replacement project was initiated due to a high failure rate (triple that of the CEA composite). Currently half of the 62.5 km of cable identified in the project was replaced. Cable failures have dropped to low levels and it appears that the majority of problematic cables have been replaced.

Cross Linked Poly Ethylene (XLPE)

A third generation of cables called cross linked polyethylene (XLPE), were installed on the distribution system between 1970 and 1986. XLPE cables are also comprised of a separate cable for each phase conductor. XLPE uses plastic insulation between the phase conductor and a metallic cable sheath which is covered in plastic to protect it from contacting the soil. XLPE cables are broadly applied across the province on all distribution systems (4 – 25 kV) as well as on 33 kV and 66 kV systems.

Initially, XLPE cables were projected to last approximately 50 years before requiring replacement. Currently, XLPE cable failure rates are increasing and many cable sections have required replacement or rehabilitation after only 30 years of age. Manitoba Hydro's experience with XLPE is consistent with that of other utilities.

Tree Retardant Cross Linked Poly Ethylene (TRXLPE)

Tree Retardant Cross Linked Poly Ethylene (TRXLPE) cables are the latest generation of cables to be installed on Manitoba Hydro’s distribution system. These cables have a number of advantages over the previous XLPE design, namely:

- Specification of chemical water tree retardant insulation to prevent water-treating (degradation of Poly Ethylene due to the combined actions of water and electric field stress).

- Specification of moisture inhibiting compounds within the conductor strands. This compound inhibits the ingress of moisture into the cable insulation, reducing the risk of insulation breakdown.

- Specification of a polyethylene jacket over the cable neutral. This coating reduces the probability of neutral corrosion and moisture ingress into the cable.

A figure of TRXLPE cable construction is provided in Figure 5.

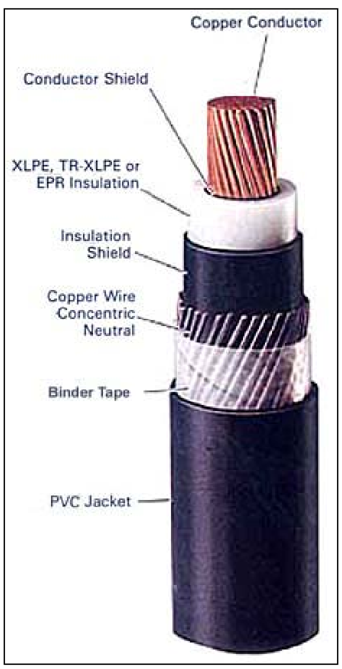


Figure 5 Typical TRXLPE Cable

To date TRXLPE cables have been very reliable and have had few operational problems. Although original TRXLPE cable installations are approaching 26 years of age, it is anticipated they will not reach their anticipated end of life until they are 50 years old.

High Voltage Distribution and Transmission Cables

High voltage distribution and transmission cables (33 kV, 66 kV, and 115 kV) have limited applications on the Manitoba Hydro distribution system. Manitoba Hydro uses four types of HV cables are installed: PILC, XLPE, Low Pressure Oil Filled (LPOF) and High Pressure Pipe Type (HPPT).

Paper Insulated Lead Covered (PILC) 66 kV Cable

In the 1940's approximately 2 km of unique PILC single-phase cables were installed in Winnipeg on the 66 kV W8 circuit. Unlike distribution PILC cables, these cables utilize three separate single-phase conductors. Replacement splices are available for short section cable repair. However, damage to multiple phases would result in an extended outage to the networked circuit and replacement parts would need to be ordered. This cable will be retired as part of the Burrows capital project.

Cross Link Poly ethylene (XLPE) 33 kV, 66 kV, and 115 kV Cable

High voltage distribution XLPE cables are utilized on the Brandon 33 kV system (4 km), Distribution Supply Centers (33 kV, 66 kV, and 115 kV), and several 66 kV circuits. Approximately 15 km of XLPE high voltage cable is currently installed on the system. Between 2012 & 2013, it is anticipated that an additional (15 km of cable) will be installed. Adequate quantities of spare cable, splices, and terminations will be available for emergency situations.

Low Pressure Oil Filled (LPOF) 66 kV and 115 kV Cable

High Voltage Distribution and Transmission LPOF cable installations are limited to the City of Winnipeg. This cable utilizes a hollow core phase conductor inside a single-core oil filled cable. Oil pressure is maintained by hydraulic reservoirs at either end of the circuit. The insulating oil combined with the cable paper insulation maintains the dielectric strength of the cable.

Approximately 12 km of LPOF cable is installed on the 66 kV system and 3 km on 115 kV circuits YX48 and RS51 at St James Station.

Adequacy of spare parts for this system is not anticipated to be an issue; however an inventory of available material is required to be maintained. Most LPOF cable is installed in duct line systems making splicing and localized repairs difficult. If damage occurs on a lengthy run, a new manhole may have to be installed to permit splicing of spare cables. The technical feasibility of this has not been assessed, but it is expected to be very challenging if not impossible. In addition, supply of emergency replacement cables beyond the existing supply is limited to one manufacturer in North America. All other manufacturers have migrated to XLPE technology.

High Pressure Pipe Type (HPPT) 66 kV and 115 kV Cables

HPPT circuits differ in construction from the other cable as all three phase conductors are maintained in a common core. Each phase conductor is insulated with paper and immersed in oil that is contained within a steel pipe and maintained at a pressure of 300 psi. Approximately 5 km if this cable exists on Manitoba Hydro’s Transmission & Distribution systems found on circuits W3 and SB14.

Adequacy of spare parts for this system is not anticipated to be an issue; however an inventory of available material is required to be maintained. Most of the HPPT cable is direct buried. Splicing and localized repairs are possible, however it would require specialized skill sets which do not currently exist at Manitoba Hydro. In addition, supply of emergency replacement cables beyond the existing supply is limited to one manufacturer in North America as the majority of manufacturers have migrated to XLPE technology.

Distribution of Cables on Manitoba Hydro System

Manitoba Hydro has installed approximately 6,000 circuit kilometres of underground cable on the distribution system. The majority of these cables are located within the City of Winnipeg on 4 kV, 12 kV, and 24 kV feeders. The circuit length of cables by voltage and location is detailed in Table 12.

Voltage	Circuit Length
4 kV	680 km
8 kV	135 km
12 kV	3638 km
24 kV	631 km
25 kV	985 km
33 kV	4 km
66 kV	29 km
115 kV	6 km
All circuits	6,108 km

Table 12 Cable Length by Circuit Voltage

PILC, XLPE, and TRXLPE cables were installed in the former Winnipeg Hydro service territory. Prior to the year 2000 PILC cables was the most common installation type for main three-phase runs. XLPE cables were primarily utilized for taps to the customers off the main PILC runs. Winnipeg Hydro switched to TRXLPE cables in the early 1990's.

In the rest of the province a number of different cable types were utilized. Prior to 1955, the majority of cable installations were PILC type. These installations predominately are with Suburban Stations inside the City of Winnipeg and are typically associated with station egresses. Between 1955 and 1965, RINJ and RIPVCJ cables were utilized for residential subdivision supply but limited to suburban areas in Winnipeg. Between 1970 and 1986 XLPE cables were the standard installation at Manitoba Hydro. In 1986 TRXLPE was introduced. TRXLPE cable is the current standard.

Cables are specified in 5 kV, 15 kV, and 25 kV ratings. Table 13 details the installed quantities by type and voltage rating. By far XLPE and TRXLPE cables are the most common cable types on the system. The non-standard cable installations (PILC, RIPVCJ, and RINJ) are largely contained within the City of Winnipeg.

	Cable Design Voltage			
Cable Type	**5 kV**	**15 kV**	**25 kV**	**Total**
PILC	260 km	106 km	3 km	369 km
RIPVCJ	9 km	2 km	0 km	11 km
RINJ	15 km	3 km	0 km	18 km
XLPE	0 km	1209 km	2076 km	3285 km
TRXLPE	0 km	59 km	2327 km	2386 km
Total	284 km	1379 km	4406 km	6069 km

Table 13 Installed Cable Lengths by Type and Design Voltage

Most of the medium voltage (4 – 25 kV) cables specified today are of the 25 kV class regardless of the actual voltage levels. The only exception is when the cable has to fit the size of an existing duct. For example, in Downtown Winnipeg it is common to utilize 15 kV cable circuits to accommodate existing duct lines as25 kV cable cannot be installed.

Specification of standard cable voltage ratings regardless of the feeder operating voltage enables greater operational flexibility and ensures sufficient spares are available. In addition, cables energized at a voltage lower than design voltage operate under less electrical stress and will be less prone to electrical breakdown.

The age profile of underground cable installations is not readily available for the majority of underground cables. However, age data is available for approximately 990 km of XLPE and TRXLPE cable in Suburban Winnipeg and presented in Figure 6.

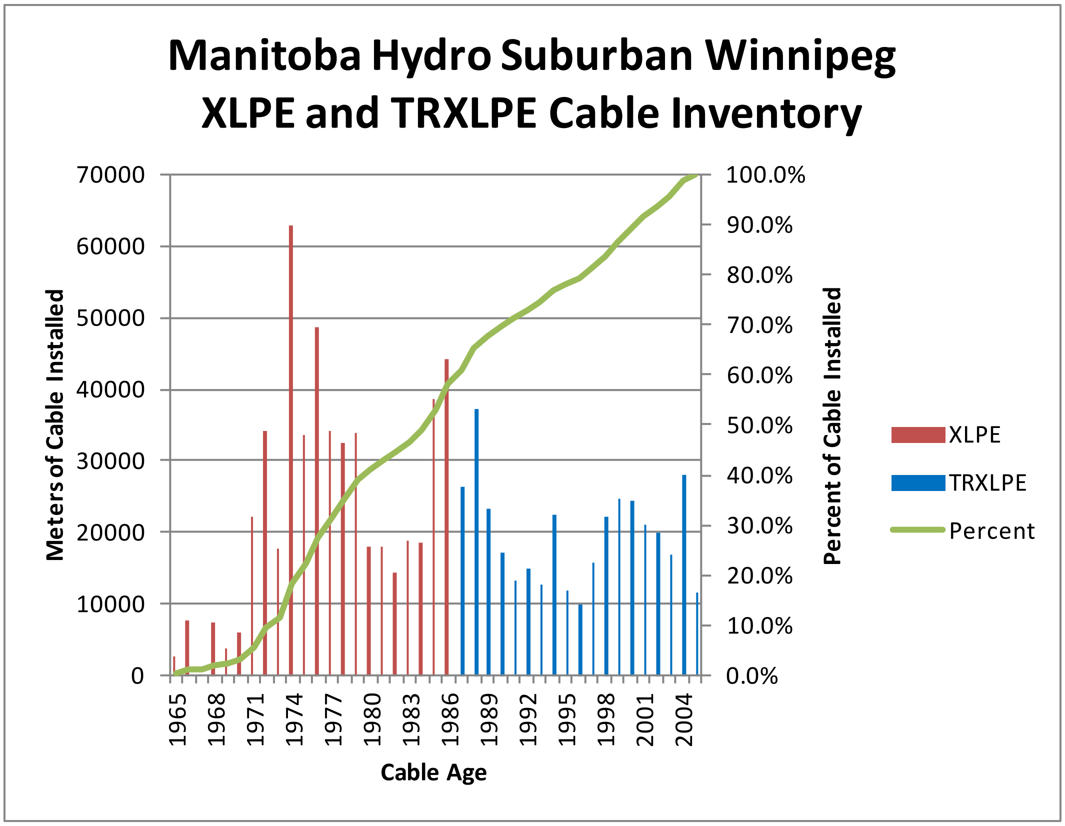


Figure 6 XLPE Cable Installations by Year

It is estimated that there is approximately 700 km of XLPE cable installed in suburban areas of the City of Winnipeg. Installation data is available for approximately 75% of these cables; the majority was installed prior to 1980. The majority of the remaining XLPE cable are split between the former Winnipeg Hydro service territory and rural underground distribution feeder installations. Rural installations were completed in late 1970 and early 1980 and are newer than the majority of XLPE cable installations in suburban Winnipeg.

1.2 Degradation Mechanism

In the course of operation, cables are subjected to voltage stress, heat from loading and environmental elements. The mode of degradation varies with. Underground cable aging is largely dependent on cable type and can be classified as either mechanical damage or operational stress.

Mechanical damage to underground cables is primarily caused from external factors. Examples include excavation or construction equipment contacting energized underground cables or vehicular accidents striking a cable lateral pole. Either incident could result in breaching of the cable insulation, resulting in a cable fault or damage to the cable material. The resultant damage, even if it does not manifest as an immediate fault, could result in a future cable failure due to increased cable electrical stress or moisture ingress into the cable insulation. Photos of cable damage are provided in Figure 7.

Denting of 66 kV Cable Sheath from Construction Equipment

Dig in Damage on 66 kV Cable

25 kV XLPE Splice Failure

Figure 7 Underground Cable Failures

Paper Insulated Lead Covered (PILC) Cables

PILC cables use oil impregnated paper insulation as the primary insulating medium between the phase conductor and the cable sheath. Heating of the insulation from normal operation and overloading conditions will degrade the insulating value of both the paper and oil. These effects are cumulative and cannot be reversed. Over time, the oil in the paper migrates out leaving the paper dry with lower dielectric strength. Dry paper also becomes brittle and is readily damaged if disturbed due to work or vibrations. Cables in vertical configurations are more susceptible to this process because of gravity.

RIPVCJ and RINJ Cables

RIPVCJ and RINJ cables are susceptible to moisture ingress through the rubber cable insulation. Moisture in cables leads to non-uniform electric field stress and electrical faults. Ingress can occur either through deterioration of the rubber material or physical damage to the cable. Most rubber cables installed in moist areas have already failed. The few remaining operational rubber cables are in very dry areas and not currently presenting operational problems.

XLPE Cables

The main cause of degradation of XLPE cables is the formation of water trees. These defects are caused by the presence of microscopic voids in the insulation, that under electric field stress attract water. As water diffuses into the material over time it forms a “water tree”. The cable’s electric field causes the water to oxidize in the polyethylene, creating more electrical stress that causes more water to be attracted to the area. This process continues until localized arcing occurs in the cable insulation and an electrical tree is formed, leading to cable failure. A photo of a water tree which has developed into an electrical tree is provided in Figure 8.

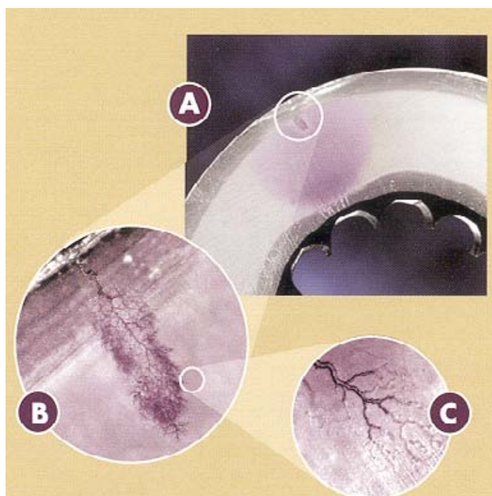


Figure 8 Electrical Tree Formation on XLPE Cable

Manitoba Hydro’s XLPE cables also utilize a bare concentric neutral or tape shield design to ensure the system neutral is in contact with the earth. In some soil conditions with moist duct line environments, extensive corrosion of this neutral has occurred resulting in premature cable failures.

Tree Retardant Cross Linked Poly Ethylene (TRXLPE) Cables

TRXLPE cables utilize a water tree inhibiting compound to limit the growth of water trees in the cable insulation. Moisture blocking material on the stranded conductors also acts to inhibit water ingress into the cable. In addition, these cables cover the exterior concentric neutral or tape shield conductor with a layer of polyethylene insulation. This protective covering protects the neutral from degradation due to corrosion and the cable core from moisture ingress.

Low Pressure Oil Filled (LPOF) Cables

LPOF cables are typically robust. Specific issues with this cable have included:

- lack of maintenance where the cable oil pressure was compromised,
- external damage from excavating equipment
- a breach of the cable jacket resulting in corrosion of the aluminum cable sheath
- Stress cracking of lead type sheaths.

High Pressure Pipe Type (HPPT) Cables

HPPT cables are typically robust and require monthly maintenance. Pressure charts must be reviewed regularly and any issues with pumping equipment rectified. The pipes are also cathodically protected, which is also monitored to prevent corrosion and address pipeline integrity. These circuits are essentially maintained in a similar manner to an energized steel gas pipeline.

1.3 Inspection and Maintenance Practices

Cables are very difficult to inspect. harder to inspect. Not only are they underground, it is difficult to tell the condition just by visual inspection. Manitoba Hydro has not established formal cable condition assessment criteria.

1.4 Health Index and Asset Condition (Useful Life)

1.4.1 Cable Life Evaluation

Underground cables are designed to operate until their reliability performance has reached an unacceptable level. However, the majority of current cable replacements are completed on systems that can no longer be energized through emergency replacement projects.

Decisions to replace or rehabilitate a section of cable outside of emergency replacement projects are typically the result of one of the following triggers:

- Number of faults experienced within a cable section.
    - One Cable Fault: Replace the cable if it is a known defective cable type (e.g. RINJ or RI-PVCJ) unless the circuit is a residential loop; then repair.
    - Two Cable Faults within 18 Months: Replace the cable if it is a known defective cable type. Repair only if it is in a residential loop and not a defective cable type.
    - Three Cable Faults: Replace the Cable.
- A cable section has faulted in a duct line and requires replacement as it cannot be spliced.
- A cable section has irreparably been damaged as the result of a system fault.
- A bare concentric neutral or taped shield XLPE conductor has experienced extensive corrosion and is no longer adequate to carry system inbalance or fault current.
- Distribution Engineering has determined the cable capacity needs to be increased to supply customer load.
- Distribution Engineering has determined the area voltage requires conversion.

In addition to the factors presented above, the age profile of XLPE conductor failures is detailed in Figure 9.

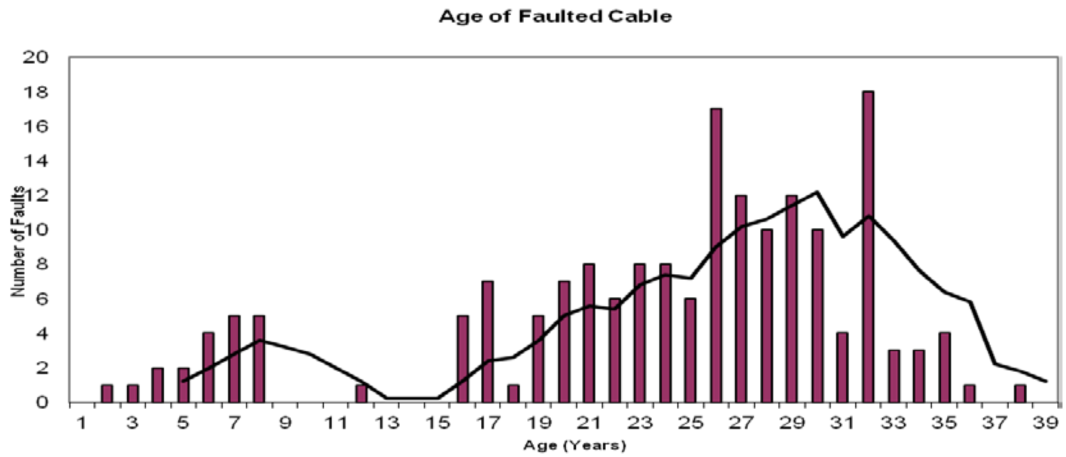


Figure 9 XLPE Faults by Cable Age

Figure 9 demonstrates a substantial rise in XLPE failures occur once the cable age exceeds 25 years. The sharp drop in cable failures greater than 32 years was associated with the limited quantities of cable assets installed at the system in the early 1970's. The report also noted a small initial bump of cable failures between 7 and 10 years of age. These failures were associated with a localized region of defective cable installed on Springfield Feeder SD776 along Tu-Pelo Ave, in Winnipeg. These failures were most likely associated with manufacturing cable defects.

1.4.2 Design Criteria for Cable Health Index Formulation

Table 14 indicates conductor assessment health condition criteria based on conductor type.

Conductor Type/Age	Condition	Probability of Failure	Requirement
RINJ, RIPVCJ, and XLPE Cable Older than 35 Years	Critical	High	Monitor and Schedule Replacement/Refurbishment Projects when Performance Become Unacceptable
70% of PILC Cable and XLPE Cable Younger than 35 Years	Fair/Poor	Medium	Monitor as part of feeder inspections.
30% of PILC Cable and all TRXLPE Cable	Acceptable	Low	Monitor as part of feeder inspections.

Table 14 Cable Health Index

The cable health evaluation table provides a general assessment of asset health. However, only general asset age information for some XLPE and TRXLPE cables is available. Asset projections are based on construction as-built drawings and a more detailed review of project completion dates would be required to develop a specific geospatial age profile. Very limited data is readily available for PILC cable installation dates.

1.4.3 Replacement Rates

The two main mitigation methods for faulty underground cables are replacement and refurbishment:

Replacement

Often replacement of underground cables is not straight forward. For example, original equipment may have been installed in an area prior to the construction of the customer facility and limited space is left for replacement equipment. Once a routing has been selected, the majority of new cable installations that call for the use of 25kV insulated jacketed TRXLPE cable. Synergies can be obtained by completing work with planned system capacity projects in the area (e.g. voltage conversions). In such a case, since the cable has to be upgraded or changed anyways, replacement becomes an incremental cost. However, cable replacements are not necessarily always located in areas where planned system capacity increases are required.

Refurbishment

An alternative to replacement is cable refurbishment by injection of a dielectric fluid into the underground cable. The fluid penetrates the strands of the conductor and flushes the cable of impurities. Cable injection is intended to remove, replace or encapsulate water in the cable, and restore the dielectric strength of the insulation. Cable injections prolongs the cable life by 20 to 40 years depending on which provider is used. Currently there are two technologies that perform injection; CableCURE and Novinium. The cost of cable injection is typically less than half the cost of replacement, but the difference varies with actual conditions such as number of splices, types of terminations, and cable access

Overall cable replacement and injection rates are very low. On average, 2 km of underground cable is replaced through emergency cable replacement and 10 km is due to system improvement projects annually. This corresponds to a 0.2% replacement rate and it would take 500 years to replace the underground cable at the current rate of investment.

The majority of the 400 km (130 circuit km) of cable purchased annually is utilized in customer service work orders. The majority of these projects utilize cables to supply new urban residential sub-developments.

In addition to cable replacement, an alternative for the rehabilitation of XLPE cables is to use silicone treatment. Since 2003, Manitoba Hydro injected 30 km of cables with silicone as part of a pilot project to evaluate this technology. No underground faults have occurred on the treated sections. The project was deemed a success but cable injection has not been utilized since the completion of the Waverley Heights project in 2008.

1.5 Asset Health

Currently, Manitoba Hydro does not have an established health condition rating system in place for underground distribution cables. Figure 10 provides an overview of all underground cable failures on Manitoba Hydro's distribution system (4 – 25 kV) not associated with external factors such as dig-ins. Over the past five years, the number of underground cable faults has increased from 60 per year in 2007 to 72 in 2011 and averaged 72 faults per year over the analysis window. The number of cable failures increased by 12 per year, which translates into a 20% failure rate increase over the same five year timeframe.

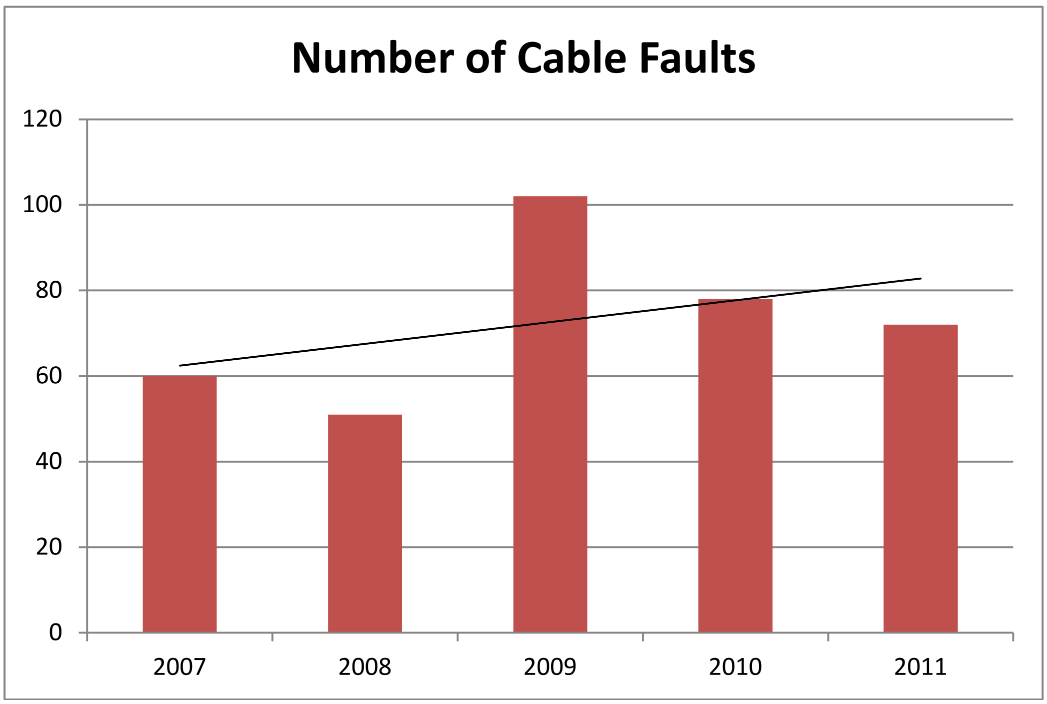


Figure 10 Distribution Cable Annual Failure Rates

Summary of Cable operational experience

Paper Insulated Lead Covered (PILC) Cables

The performance of PILC cables has been excellent, causing approximately 5% of cable failures. Unlike TRXLPE cable, PILC cable requires maintenance. Splices require regular inspections and the exact age profile of these cables is unknown, requiring review of archived paper work-order drawings. Currently, there is no evidence of an accelerated failure rate involving PILC cables adversely impacting system reliability. However, if failure rates increase as cables approach end of life, system reliability may be impacted. Although the lifespan of a PILC cable is estimated at 70 years, the cable age and asset condition profile is currently unknown.

Rubber Insulated Neoprene Jacket (RINJ) and Rubber Insulated Poly Vinyl Chloride Jacket (RIPVCJ) Cables

The performance of RINJ and RIPVCJ cables has been very poor; only a small population remains in service. Historically, these cables have accounted for approximately 5% of cable failures. Although this is a low percentage of overall faults, these failures occurred only on 60km of cable representing an unacceptable failure rate. A program was initiated in 1996 to salvage all of the remaining RIPVCJ cables from the distribution system. At the time of the initiation of the program, the failure rate of the cables was triple the CEA composite for underground cable. In 2012, the program was cut from the Distribution Engineering capital budget due to the low occurrence of cable failures on the remaining 29 km. If cable failure rates increase again to unacceptable levels, mitigation will be addressed through separate capital projects.

Cross Linked Poly Ethylene (XLPE) Cables

The performance of XLPE cables has been gradually worsening over the past several years. A draft study by Distribution Engineering Winnipeg reviewed the reliability performance of the Winnipeg XLPE system in 2008. The study noted that since underground cable fault records have been kept (1988), XLPE failures have accounted for 85% of cable faults and have been increasing at a rate of approximately 7% per year. In addition, the following observations were noted in the report:

- Manitoba Hydro is experiencing approximately 60 underground cable failures per year.
- If the status quo is maintained, cable failure rates could increase to 160 failures per year within 20 years.
- Approximately 75% of the faults involved 15 kV rated cable.

- The original expected life of XLPE cable was 50 years, however a substantial number of faults have occurred on XLPE cables 25-35 years of age.

- The study recommended a 10 year XLPE rehabilitation plan, initially replacing or rehabilitating 25 km of XLPE cable for the first 5 years and increasing the rate to 35 km/yr afterwards.

There was a large swell of XLPE cable installations during most of the 1970's and again in the late 1980's. The cables installed in this period were XLPE (non- tree retardant, unjacketed) and their failure rates are expected to increase as many of these cables approach 50 years of age. Manitoba Hydro distribution has deemed that approximately 700 km of XLPE cable installed in the 1970's and early 1980's are vulnerable and are anticipated to reach end of life within the next 10 years. As the XLPE cables approach their anticipated end of life it is probable their failure rate will increase.

Tree Retardant Cross Linked Poly Ethylene (TRXLPE) Cables

The performance of TRXLPE cables has been excellent since their introduction onto the distribution system and accounts for approximately 5% of cable failures. The anticipated lifespan of TRXLPE cable is 50 years.

In practice, underground cable failure rates are modest, but have been increasing over recent years, with the XLPE cable population being the most vulnerable. The Manitoba Hydro cable overhead transformer assets health profile is presented in the following "soccer field" graphs. In these graphs, the current asset health and 20 year projection are provided. The following assumptions were made:

- Current Status: XLPE cables greater than 35 years of age, RINJ and RIPVCJ cables are rated critical. XLPE cables 34 years or younger and 70% of PILC cables are rated fair/poor. TRXLPE and 30% of PILC cables are rated acceptable.

- Future Status: All XLPE, RINJ, RIPVCJ, and 10% of PILC cables are rated critical. TRXLPE cables greater than 40 years of age and 90% of PILC cables are rated fair/poor. The remainder of TRXLPE cables are rated acceptable. The projection assumes the current 12 km/year XLPE replacement rate is maintained.

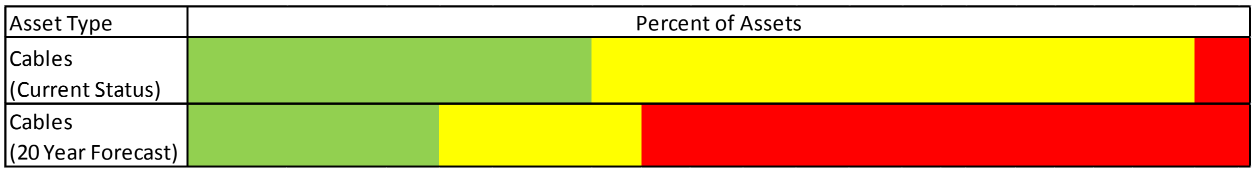


Figure 11 Underground Cable "Soccer Field"

Figure 11 indicates that approximately 5% of Manitoba Hydro's cable assets are estimated to be in poor condition; this percentage will increase to approximately 55% of the population in 20 years as the XLPE population transitions from fair to poor condition as it reaches its anticipated end of life. The estimated cost to rehabilitate the cable at that time will range from $350 - $900 million, depending on the proportion of the cable population that can be refurbished with silicone injection.

1.6 Risk of Failure

1.6.1 Risk Assessment on Cables

Manitoba Hydro has not established a formal risk assessment process for cables. Historically, cables have been repaired as necessary with direct cable replacement projects initiated in the event a faulted cable had been damaged beyond repair. Although cable health relies on a variety of different risk factors the major factor in cable reliability performance is the type of cable installation.

XLPE cables present the highest risk to Manitoba Hydro. Failure rates involving these cables are steadily increasing and expected to continue to do so as the population ages. In addition, underground cables can supply a substantial number of customers and cable failures can result in extended outages to large numbers of customers.

RINJ and RIPVCJ cables are anticipated to be at or past their anticipated lifespan; however the remaining cables have not recently experienced a significant number of faults. Due to the relatively small quantity of these cables (29 km) currently installed, they represent only a modest risk to Manitoba Hydro's system reliability.

PILC cables supply a substantial portion of the old Winnipeg Hydro distribution system and are anticipated to continue to operate reliably for the near future. The long term performance of the PILC cable asset population is unknown, but expected to eventually degrade as the initial cables approach 70 years of age. Due to the uncertain age profile of these cables, they represent a modest risk to Manitoba Hydro's system reliability.

TRXLPE cables are the current design standard for all of Manitoba Hydro's distribution system. These assets are anticipated to last at least 50 years in service and have many years of service remaining based on this assumption. Currently, these cables represent a low risk to Manitoba Hydro's system reliability.

In addition to cable type, the following risk factors must also be considered as part of the cable risk assessment process.

Corrosion: Corrosive environments or soil conditions, particularly underground duct lines can result in extensive corrosion of bare concentric neutral or tape shield XLPE cables.

Foreign Interference: Contact of the cable by excavation equipment could mechanically damage the underground cable.

Moisture: XLPE cables installed in wet conditions could be vulnerable to moisture ingress into the cable. This ingress could result in the formation of water trees inside the cable insulation and lead to eventual cable failure.

Troubleshooting: Excessive reclosing or use of "thumping" equipment to locate faults in XLPE cables could worsen the condition of the asset.

1.6.2 Risk Matrix

Based on the observations made in this report, the following risk matrix has been developed (Figure 12). The matrix considers the anticipated impact cable failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact

2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted in the frisk matrix. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the Number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

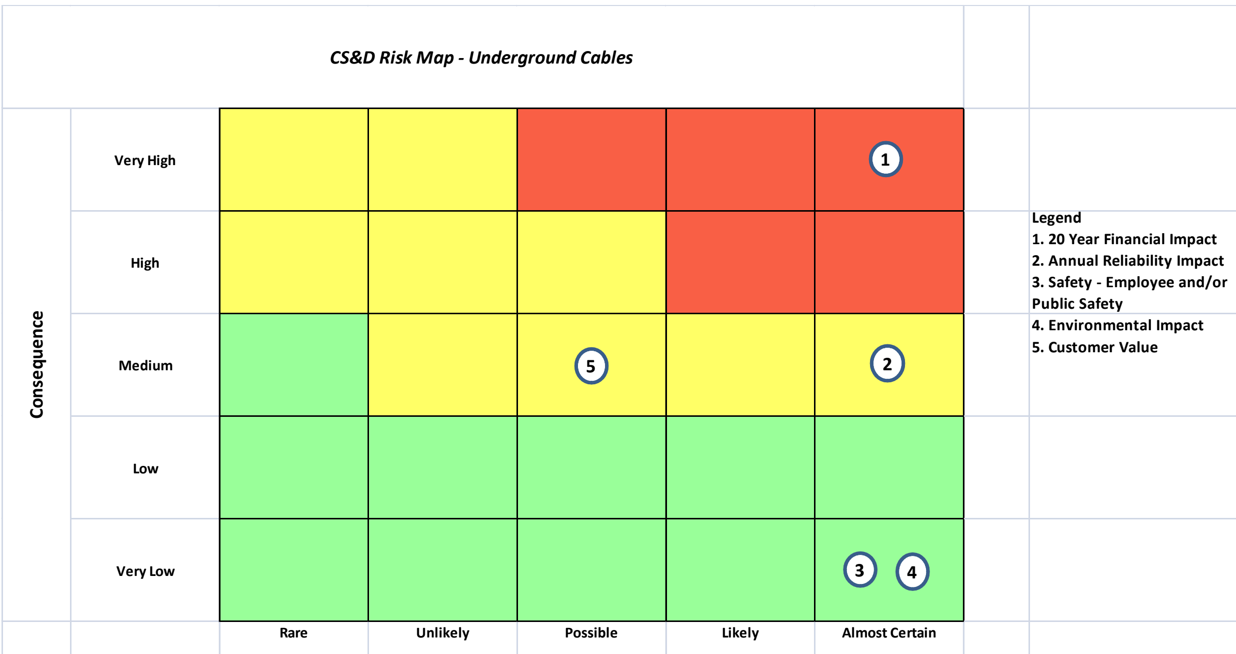


Figure 12 Underground Cable Risk Map

Figure 12 indicates the several of the risks associated with underground cable failures are high. In the worst case scenario an underground cable failures will increase substantially and require extensive rehabilitation or replacement, particularly with the XLPE cable population.

It is anticipated that underground cable failures present only a limited risk to the environment as the majority of cables utilize plastic insulation and there is a very low risk of release of oil to the environment as the result of a PILC, LPOF, or HPPT cable failure.

It is anticipated that underground cable failures present only a limited risk to public safety. The cables are buried underground and not readily accessible by the public.

1.7 Economic Evaluation of Distribution Assets

Underground cable construction costs depend on a variety of different factors including: property availability, cable size, and cable voltage. Table 15 provides an overview of the cable asset value, current replacement rates, and anticipated lifespan.

Asset	Quantity	Life Expectancy	Current Replacement Rate
PILC Cable (4 – 25 kV)	369 km	70 Years	N/A
RINJ and RIPVCJ Cable (4-25 kV)	29 km	30 Years	N/A
XLPE Cable (4 – 25 kV)	3285 km	35 Years	328 Years
TRXLPE Cable (4 – 25 kV)	2386 km	50 Years	N/A
LPOF and HPPT Cables (66 kV)	14 km	50 Years	N/A
XLPE Cables (66 kV)	15 km	50 Years	N/A
Replacement Cost (4 - 25 kV cables)	$250,000 - $350,000/km		
Replacement Cost (66 kV LPOF and HPPT)	$2,100,000/km		
Replacement Cost (66 kV XLPE)	$500,000 - $2,100,000/km		
Replacement Value[10]	$1.5 Billion		

Table 15 Underground Cable Economic Evaluation

1.8 Recommendations

Gaps: During analysis of the asset the following gaps were identified.

High Priority

1. The existing cable replacement rate of 12 km per year is inadequate to deal with the anticipated growth in cable failures.

[10] Cost assumes 1298 km of Three-Phase Cable at $350,000/km and 4726 km of Single-Phase Cable at $200,000/km for 4-25 kV cables.

2. Enhancement of cable inspection and maintenance practices needs to occur.

3. Although spare parts are available in the event of a 66 kV or 115 kV HPPT cable failure, the skill sets to repair the failure has not been evaluated at Manitoba Hydro.

Medium Priority

4. Troubleshooting relying on “thumping” and reclosing in locating XLPE cable faults can result in premature cable failure.

5. Underground cable data is incomplete with respect to historical splice and fault locations.

6. The age profile and condition of the installed PILC cables on the distribution system has not been compiled from available records.

Recommendations: The following recommendations are made to address these gaps.

High Priority

1. Enhance the asset management strategy for the underground cable system.

2. Develop a long term capital investment plan to address aging cable assets.

3. Rigorously review contingency plans for 66 kV and 115 kV cable systems and all unique assets.

Medium Priority

4. Investigate the use of alternative fault locating techniques to “thumping” for XLPE cables.

5. Develop an age and condition profile of the PILC cable system.

6. Enhance underground cable inspection and maintenance criteria. Specific opportunities include inspection of PILC splices, obtaining water tree test results from

failed XLPE cable sections, and obtaining splice location information from Time Domain Reflectometry Testing.

7. Little information on underground cables is captured in the existing eGIS cable object. In particular, collection of splice location and number of faults experienced on a section should be given priority.

APPENDIX B

Manholes

Asset Condition

4/27/2012

1. MANHOLES

Manholes are concrete enclosures built in underground duct lines for installing and splicing underground cables. They provide a connection point in duct lines to facilitate underground cable splicing, facilitate the installation of new circuits in high density areas, and house the underground secondary network transformers in Downtown Winnipeg.

There are approximately 2400 manholes on Manitoba Hydro's distribution system; the majority of these are concentrated around large urban substations, particularly in the former Winnipeg Hydro service territory. The sizes of manholes vary but they are commonly six feet deep, six feet wide, and ten feet long. There are three types of manhole construction: brick, concrete poured in place, and concrete pre-cast.

Manholes are located both on city streets and along the sidewalks and can provide termination points for up to 30 primary and secondary network distribution circuits in heavily congested locations. They are primarily utilized to route medium voltage circuits (4 kV – 25 kV), however 66 kV cable and underground secondary network (216 V) cables can also be found in manholes within the City of Winnipeg.

1.1 Demographics

Manitoba Hydro has approximately 2409 manholes located in the province. The majority, 1850 of these manholes are located in the old Winnipeg Hydro area. The earlier manholes were of brick construction and concrete poured in place or precast are used in today's construction methods. Some of these manholes date back to the early 1900s. As with the duct line segments, the ages and types of manholes installations on Manitoba Hydro's distribution system are not available in the eGIS program. Manual validation of work-order drawings and field inspections would be required to obtain this information.

Photos of an existing brick and pre-cast manhole are presented in Figure 13.

Brick Manhole　　　　　　　　Precast Concrete Manhole

Figure 13 Manhole Installations

1.2 Degradation Mechanism

Manholes are subjected to environmental and vibrational stresses which may cause mechanical failures resulting in unplanned power outages. These factors include soil conditions, ground movement, mechanical vibration (traffic), and tree roots.

Initial degradation of a manhole typically involves corrosion of any reinforcing steel and weakening of the underlying concrete or brick structural foundation. A photo of a manhole with a compromised roof is provided in Figure 14.

Figure 14 Compromised Manhole Roof

1.3 Inspection and Maintenance Practices

Detailed inspection criteria and training is followed according to the Power Line Technician Training Module 30-1324 “Underground Maintenance”. Regularly scheduled maintenance inspections have not occurred with any consistency over many years. Going forward, Manitoba Hydro’s recommended policy (P343) will be to have inspections completed on a three year cycle by operational staff.

An infra-red inspection of all electrical connections as well as a visual check on the structural integrity of the manhole structure will be completed during these inspections. The visual check includes the manhole cover, cover ring, collar, walls, ceiling, and floor. The completed inspections and deficiencies will be documented in the distribution maintenance planning system (DMPS).

1.4 Health Index and Asset Condition (Useful Life)

Manhole asset evaluation consists primarily of visual inspections and infrared scans of electrical connections by operational staff. The infrared scans do not provide indication of manhole health, but rather ensure cables and applicable splices are not operating beyond design temperatures.

1.4.1 Manhole Strength Evaluation

In 2011, Distribution Engineering developed manhole inspection criteria which were used on an inspection blitz of Downtown Winnipeg manholes. Inspections completed prior to 2011, relied on visual inspections made by operational staff and were not consistent. During inspections, manholes are classified into the following four categories:

1. Urgent: An immediate repair to the manhole is required due to one of the following reasons:
    a. There is a staff or public safety concern with the manhole.

b. There are visible signs of buckling of the manhole walls.

c. Holes in the manhole roof to the roadway or sidewalk surface are visible where the public could access manhole interior.

d. The lid has sunk below grade and is starting to cave into the manhole.

e. The manhole has significantly shifted or sunken, pinching the feeder cables to the point where the cable jacket has been cut and a fault is imminent.

2. High: It is strongly recommended that repairs be completed in a prioritized manner due to one of the following reasons:

a. Crews have brought up multiple concerns of manhole structure. Multiple cracks can be seen in the manhole roof, walls or floor.

b. Large sections of the manhole roof have fallen in, exposing large sections of steel beam that show excessive rusting.

c. The manhole lid has begun to slightly shift below roadway grade (i.e. manhole lid shows that it may begin to cave into manhole soon).

d. The manhole has significantly shifted, pinching the incoming feeder cables between the duct line and manhole wall but cable jacket is not compromised

3. Medium: It is recommended repairs be scheduled based on priority due to one of the following reasons:

a. Crews have brought up one or two concerns of manhole structure

b. A single, but large crack can be seen in the manhole roof, wall or floor

c. Sections of the manhole roof have fallen, but no steel beam is exposed

d. Manhole shows sign of shifting, where the duct line and the wall opening do not line up, but the feeder cable is not pinched in any way

4. Low: It is recommended repairs be scheduled based on priority due to one of the following reasons:

   a. Crew has just noticed a defect in manhole structure but no previous concerns have been noted.

   b. A single, but small crack can be seen in the manhole roof, wall or floor.

   c. Drainage issues can be seen (i.e. a backflow valve is broken or sewer drain is plugged).

1.4.2 Design Criteria for Health Index Formulation for Manholes

Table 16 indicates manhole assessment health condition criteria based on considering condition of the unit.

Inspection Priority	**Condition**	**Probability of Failure**	**Requirement**
Urgent or High	Critical	High	Replace/rehabilitate based on structural engineering assessment.
Medium	Fair/Poor	Medium	Continue to monitor as part of inspection requirements.
Low	Acceptable	Low	Continue to monitor as part of inspection requirements.

Table 16 Manhole Health Index

The health evaluation provides a good assessment for manhole condition based on asset condition. However, there is a gap in available manhole age and construction data in the eGIS system. This information is only available on work-order drawings and would require manual review of records and possibly site inspections.

1.4.3 Replacement Rates

Manhole replacement rates are generally very low. On average, Distribution Design Winnipeg replaces five manholes each year, representing a 0.2% replacement rate. At the current replacement rate, it will take approximately 500 years to replace all the manhole installations on the distribution system.

1.5 Health

Customer Service Operations field staff recently completed structural inspections on 850 manholes in City of Winnipeg. The sites were selected in conjunction with Distribution Engineering and selected based on manholes in trafficked roadways. The results are summarized in Table 17 which details the observed inspection category and notes if a primary circuit is contained within the manhole.

Condition	**Number of Manholes With Identified Issues**	**Number of Manholes Containing Primary Circuits**	**Number of Manholes Not Containing Primary Circuits**
Critical	27	20	7
Poor	89	68	21
Fair	87	72	15
Acceptable	128	121	7
Total Problems:	331		
No Observed Problems of Concern	519		
Total Inspected:	850		

Table 17 Manhole Health Index Categories

Based on the survey data, 14% of the surveyed locations (116 manholes) were found to be in poor or critical condition.

It is notable, that prior to this survey Distribution Design also received a list from Customer Service Operations detailing 47 manholes requiring rehabilitation within the City of Winnipeg. Although the remaining unsurveyed locations are not located in trafficked locations, it is probable manholes will have similar issues with their condition and also require rehabilitation.

Assuming, the unsurveyed locations have a similar health profile as the surveyed locations, the health profile of Manitoba Hydro's manhole assets is presented in Figure 15. In these "soccer field" graphs, the current asset health and a 20 year projection are provided. The following assumptions are made:

- Current Status: The survey data for the 850 sites completed within the City of Winnipeg are representative of the remaining unsurveyed population. The manholes found to be in poor or critical condition are rated critical in this chart. The sites found in fair condition are rated fair/poor and the sites found in good condition or with no identified deficiencies are rated acceptable.

- Future status: Since detailed asset age and type data are not available for manholes, a projection based on the anticipated asset condition based on type or age is not possible. Instead a 20 year projection is provided that assumes Manitoba Hydro maintains its existing 5 manhole per year rehabilitation rate, no additional manholes are added to the system, half of the manholes rated fair/poor degrade to critical, and half the manholes rated acceptable degrade to fair/poor.

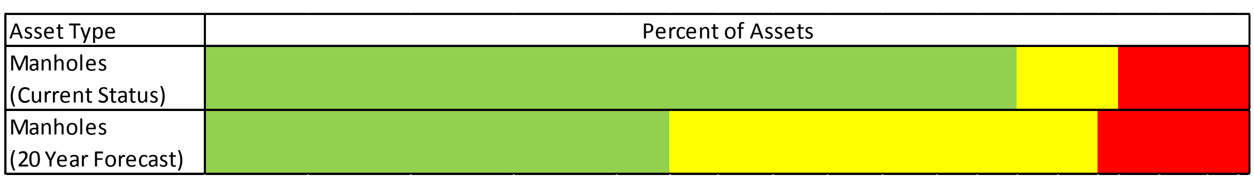


Figure 15 Manhole "Soccer Field"

The preceding figure indicates approximately currently 14% of Manitoba Hydro's manhole assets are estimated to be in critical condition. This percentage is anticipated to remain relatively constant with current replacement rates over the next 20 years. The estimated cost to rehabilitate the estimated 350 manholes (that will be in critical condition within that time) will range from $16 - $44 million, depending on the extent of the required repairs.

1.6 Risk of Failure

1.6.1 Risk Assessment on Manholes

Manitoba Hydro currently has not established a formal risk manhole assessment process. Historically manholes have been repaired as necessary, averaging five units repaired each year. Currently, 116 manholes have been identified as in poor or critical condition and are an indication the existing replacement rate is not sufficient.

Manholes located on public roadways present the highest risk to the public. These structures are subjected to the most severe mechanical loads through weight and vibrations associated with vehicular traffic. In addition, these manholes also present the greatest consequence if they fail, in a worst case scenario a vehicle could fall through a failed manhole.

Manholes containing a high level of feeders present the greatest risk to reliability. Manholes are an integral component of many circuits, supplying major industrial, commercial, and high density customer areas. If a catastrophic failure of a manhole were to occur, particularly during system peak load, extended outages would occur and extended means very time consuming. These outages could impact numerous high profile customers. The following factors must be considered as part of the manhole risk process.

Environmental: Manholes are subjected to numerous freeze/thaw cycles throughout the year due to changing weather conditions. As they are vented to the environment through the manhole lid, moisture and salt contamination can ingress into the manhole resulting in corrosion of supporting metallic structural materials and damage to the concrete or brick materials within the structure.

Corrosion: Corrosive environments, particularly on roadways, lead to ingress of salty spray into manholes which can accelerate corrosion of metallic elements within the structure and degrade concrete materials.

Vehicular Traffic: Vibrations from nearby traffic or rail lines mechanically stress the manhole.

Foreign Interference: Contact of the manhole by excavation equipment could mechanically damage the manhole.

1.6.2 Risk Matrix

Based on the observations made in this report, the following risk matrix has been developed. The matrix considers the anticipated impact manhole failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted on a risk matrix in Figure 16. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

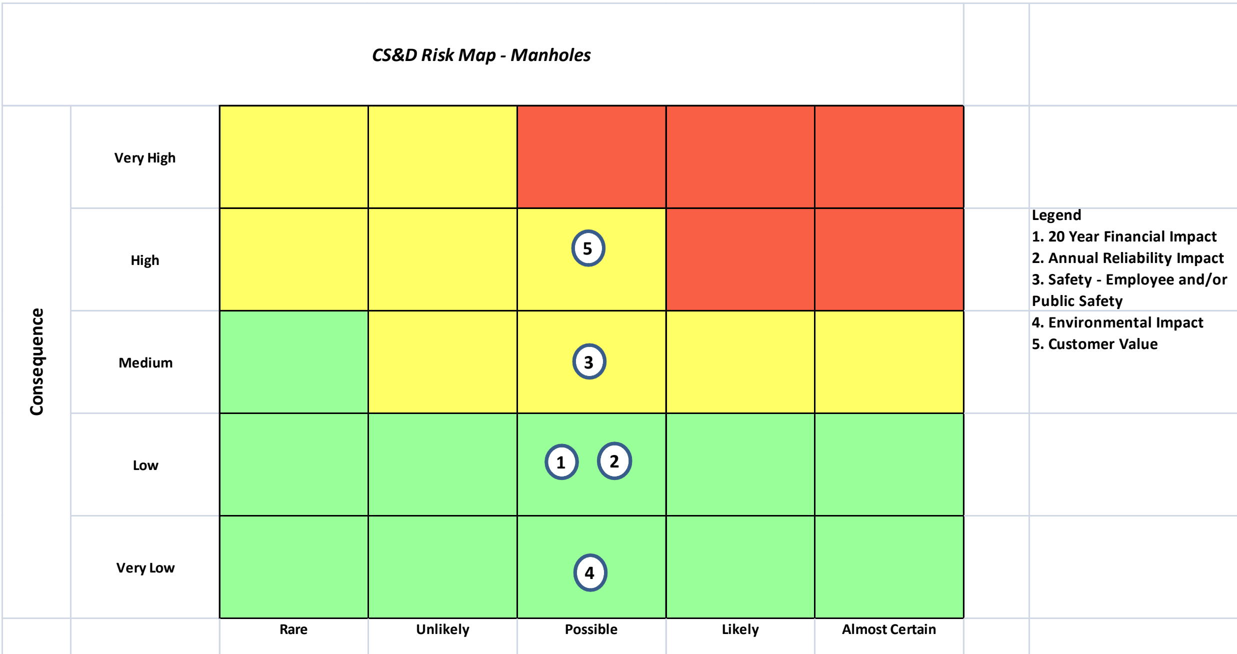


Figure 16 Manhole Risk Map

Figure 16 indicates that the risks associated with manhole failures ranges from low (environmental) to moderate (customer value). In the worst case scenario a manhole failure could result in substantial outages to multiple feeders and result in high profile media attention. It is anticipated that in 20 years the cost required to rehabilitate the manholes projected to be in poor and critical condition will range between $16 million and $44 million, depending on whether complete rebuilds are required, or if lower cost refurbishment is available. It is anticipated that a manhole failure would result in very limited environmental impact.

1.7 Distribution Asset Economic Evaluation

Manhole repair costs depend on a variety of different factors including: property availability, extent of damage, construction material, and number of ducts required. Figure 17 provides an overview of the manhole asset value, current replacement rates, and anticipated lifespan.

Asset	Quantity	Life Expectancy	Current Replacement Rate
Manholes	2,409	80 Years?	500 Years
Replacement Cost	$125,000 each		
Replacement Value	$301 Million		

Figure 17 Manhole Economic Evaluation

The cost and impact of a manhole repair can range from moderate to substantial. Typically manhole failures start with cost degradation with typical repair costs averaging $45,000. Complete manhole rebuild costs average $125,000.

The replacement value of Manitoba Hydro's 2409 manholes is estimated based on the anticipated rebuild cost of $125,000 per location. Based on this assumption, the approximate replacement cost of this system would be $301 million.

1.8 Recommendations

Gaps: The following gaps were identified during the manhole asset analysis.

High Priority

1. The existing manhole replacement rate of five sites per year is inadequate to deal with the anticipated number of manholes in poor or very poor condition.

2. Manitoba Hydro has limited manhole criteria, training, and condition and inspection data.

Medium Priority

3. Data on the manhole construction material, date, and number of circuits contained within the duct lines is currently only available through manual inspection or review of the original construction drawings. It is not stored and available within the eGIS application.

Recommendations: The following recommendations are made to address these gaps.

High Priority

1. Develop a long term capital investment plan to address aging manholes.

2. Enhance inspection and maintenance criteria for manholes.

3. Rigorously review the condition of all manholes. Utilize structural engineering expertise to provide a professional opinion on rehabilitation requirements for manholes found in poor and critical condition.

Medium Priority

4. Creation of the necessary fields in eGIS and DMPS to capture critical data on manhole assets including: specific items to capture include installation date, construction material, and number of circuits contained within a specific duct bank. Much of this data can readily be captured through review of construction drawings and site inspections.

5. High quality images of manholes are starting to be captured by operational staff and stored in eGIS. Collection of photos at all manholes would be beneficial to assist with the design process, monitor manhole degradation between inspections, and respond to outages and plan work.

APPENDIX C

Duct Lines

Asset Condition

04/27/2012

1. DUCT LINES

Duct lines are utilized to provide a path for multiple underground high and low voltage cables in a congested area. They are found throughout the province, but are most commonly used for major station feeder egresses and in congested locations such as Downtown Winnipeg. In locations with limited available space, these structures provide the ability to route many circuits along narrow corridors. Duct lines can be installed under roadways, sidewalks, or street boulevards and are often installed during opportunities such as major road or bridge repairs.

Duct lines typically are constructed utilizing plastic pipes encased in concrete; however older designs were made from numerous other materials. Manitoba Hydro has historically also utilized the following construction materials: clay tile, steel, Poly-Vinyl Chloride (PVC), fibreglass, and transite (cement asbestos).

The primary advantage of duct systems is that existing cables can readily be replaced if a cable has become damaged without the need for extensive excavation. In addition, new circuits can readily be installed in existing duct lines provided there is adequate space.

1.1 Demographics

Manitoba Hydro has approximately 265 km of duct line installed on its distribution system. The majority of this infrastructure is located in the old Winnipeg Hydro service territory (Keewatin & Central Districts) and was installed between the 1960's and 70's. However, older ducts also exist on Manitoba Hydro's system, which were installed during the 1930's and 1940's. Development of a specific age profile of Manitoba Hydro's duct line system is not currently possible as the construction date data is not contained within eGIS. Manual validation of work-order drawings would be required to obtain this information.

Duct lines can contain anywhere between 0 and 30 medium voltage and secondary network circuits. The most heavily congested manhole, MN49, contains nine 12 kV, seven 4 kV, and fourteen secondary network circuits. Table 18 outlines the number of circuits contained by manholes. This data was compiled for the Downtown Winnipeg system and is representative of

1525 of the 2409 manholes on the system. The remaining duct lines are primarily located in suburban Winnipeg and Brandon stations and will typically have ten or fewer medium voltage circuits.

Number of Circuits	Number of Manholes
5 or less	718
6-10	557
11-15	172
16-20	61
21-25	14
26-30	3
Total	1525

Table 18 Duct Line Circuit Profile

Typically duct lines contain ten or fewer or circuits, however it is not uncommon to have over ten circuits in a single duct line. In the Manitoba Hydro system, there are 250 duct line sections containing more than ten distribution circuits. Failure of any one of those sections could result in major system outages.

Photos of a new duct line under construction and existing concrete and clay tile duct lines are provided in Figures 18 and 19.

Figure 18 Duct Line Under Construction

Concrete Duct Line Clay Tile Duct Line

Figure 19 Duct Line Systems

1.2 Degradation Mechanism

Duct lines are subjected to environmental and vibrational stresses which may cause mechanical failures resulting in unplanned power outages. These factors include soil conditions, ground movement, mechanical vibration (traffic), and tree roots. The cost and impact of a duct repair after an incident or failure can be substantial. Depending on the extent of damage, a lengthy outage impacting thousands of customers could be experienced.

Mechanical failure of a duct line is typically associated with shifting of the duct section and pinching existing cables. In addition, failure of individual duct sections between manholes is also possible, but not always detectable until a new cable installation is required. Clay tile duct lines are considered the most likely to fail on Manitoba Hydro’s system due to their age (1920’s installation dates) and are not recommended to be used for new cable installations. A photo of a crumbling clay tile duct line is provided in Figure 20.

Figure 20 Crumbling Clay Tile Duct Line

1.3 Inspection and Maintenance Practices

Typically, duct lines are run until the asset fails or is removed from service due to its assessed condition. Although specific testing is not performed on duct lines, visual inspections do occur as part of regularly scheduled manhole inspections. As part of these inspections, operational staff will note if the duct line is exhibiting any visible signs of shifting or individual duct segments are collapsing or crumbling.

Although, specific detailed inspection criteria has not been developed for duct line systems beyond manhole condition assessments, utilization of in-line camera equipment and other equipment is possible to confirm the integrity of a specific duct section prior to the installation of a new cable.

1.4 Health Index and Asset condition (Useful life)

Health Index criteria have not been developed for duct line systems. Currently, visual inspections are the only tool utilized to assess and inspect duct lines, with inspections occurring at manholes access points. Unless there is visible evidence of damage to a specific duct segment at a manhole, operational staff cannot readily determine if an individual duct section has collapsed and is no longer available to route a new cable. The current practice is to run duct lines to failure with operational staff providing expertise when repairs are required.

1.4.1 Duct line Strength Evaluation

The following factors are crucial for staff to determine the condition of an existing duct line.

- Type of construction (brick or concrete)

- Location (street or sidewalk)
- Traffic density (vibrations)

1.4.2 Design Criteria for Duct lines Health Index Formulation

Table 19 indicates the health condition criteria for duct line assessments considering the health and installation type of the system.

Health/Installation Type	Condition	Probability of Failure	Requirement
Critical or High Priority Condition Issue or Clay Tile System	Critical	High	Immediate risk assessment, secure site, replace based on assessment
Medium Priority Condition Issue	Fair/Poor	Medium	Start planning to replace or reinforce considering risk and impact of failure.
Low Priority Condition Issue	Acceptable	Low	Continue to monitor as part of manhole inspection process.

Table 19 Duct Line Health Index

The duct line health evaluation table provides a general assessment of standard health. However, prior to the implementation of the eGIS system, the installation dates of streetlight standards are unknown and an accurate asset age profile cannot be determined.

1.4.3 Replacement Rates

Underground duct line replacement rates are generally very low. However, the duct line sections are very costly and difficult to repair. Typically, new duct line sections are constructed in parallel with the existing duct line. This is required due to the congested nature of the multiple energized circuits within the structure. Recently completed duct line repair projects have included:

- Edmonton Station: Installation of approximately 300 m of duct line to repair a shifted duct line segment. This project was initiated when one of the two duct lines exiting Edmonton Station shifted and required replacement. The project cost approximately $1.2 million and involved the transition and retermination of all the cables in the failed duct line section to the other and construction of a new duct line.

- Ellice: Installation of approximately 1000 m of duct line to repair a duct line in poor condition. This project was initiated when the existing duct line and manholes were found to be crumbing in very poor condition. The project cost approximately $3 million and involved construction of a new duct line and manhole system and the transition and retermination of the circuits.

In addition to duct line repairs due to condition, duct lines are occasionally replaced (or constructed) in conjunction with provincial, municipal, or city projects. Examples include bridge and road rehabilitation. Recently completed customer service duct line projects include:

- Centerport: Installation of approximately 750 m of duct line under the Perimeter Highway during construction of Centerport Way.

- McPhillips: Installation of approximately 700 m of duct line during a road reconstruction.

- Disrelli: Installation of approximately 750 m of duct line under the newly constructed Disrelli Bridge.

At the current replacement rate of 700m/yr. it would take between 300 and 400 years to replace the duct line systems.

1.5 Health

In practice, duct line failure rates are modest, but recently two substantial capital projects were initiated to repair sections found to be in very poor condition where the duct lines had crumbled or shifted.

Accurate age profile and construction type data is not available for duct line systems and will need to be obtained prior to developing a reinvestment strategy. Consequently, hypothetical current asset health and a 20 year projection for existing assets are provided in "soccer field" graphs shown in Figure 21. The following assumptions are made:

- Current Status: It is assumed that 5% (13 km) of duct lines are in critical condition (to represent the clay tile population), 10% (26 km) in fair/poor condition, and the remainder in acceptable condition.

- Future Status: It is assumed that the existing duct line replacement rate of 0.7 km per year is maintained and the duct lines in fair/poor condition have degraded to critical condition and 15% of the duct lines are in fair/poor condition.

Figure 21 Duct Line "Soccer Field"

Figure 21 indicates an optimistic scenario where 9% of duct lines would be in poor condition in 20 years. If that scenario holds, replacement of the 25 km of duct line would cost $75 million.

1.6 Risk of Failure

1.6.1 Duct Line Risk Assessment

Duct line failures are infrequent in nature and are most commonly associated with duct line shifting due to a mechanical failure. Depending on the severity of the failures, individual cables may or may not be damaged resulting in customer outages.

Manhole KG-2 (King Street) is considered to be one of the most critical on Manitoba Hydro's distribution system. If a catastrophic failure were to occur at that location four of the five secondary network feeders could be lost, resulting in an outage to 70% of the customers supplied by the network along with six 12 kV distribution feeders. The area impacted would be from St Mary's Ave on the south to Henry Ave on the north to Main Street on the east and Vaughan Street on the West. Numerous large commercial buildings, apartment blocks would be impacted including the Richardson Building, Fairmont Hotel, and City Hall.

In addition to KG-2, numerous other duct line segments contain multiple circuits or supplies to critical and high profile customers. Damage or failure to these ducts would result in lengthy power outages and expensive repairs to high profile customers.

Risk factors for underground duct lines include:

Environmental: Duct lines are subjected to numerous freeze/thaw cycles throughout the year due to changing weather conditions. These cycles result in stress on the duct line and could result in mechanical failure of the structure.

Vehicular Traffic: Vibrations from nearby traffic or rail lines could mechanically stress the duct line.

Foreign Interference: Contact of the duct by excavation equipment could mechanically damage the duct line.

1.6.2 *Risk Matrix*

Based on the observations made in this report the anticipated impact duct line failures could have on Manitoba Hydro is assessed with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted in the Figure 22 risk matrix. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

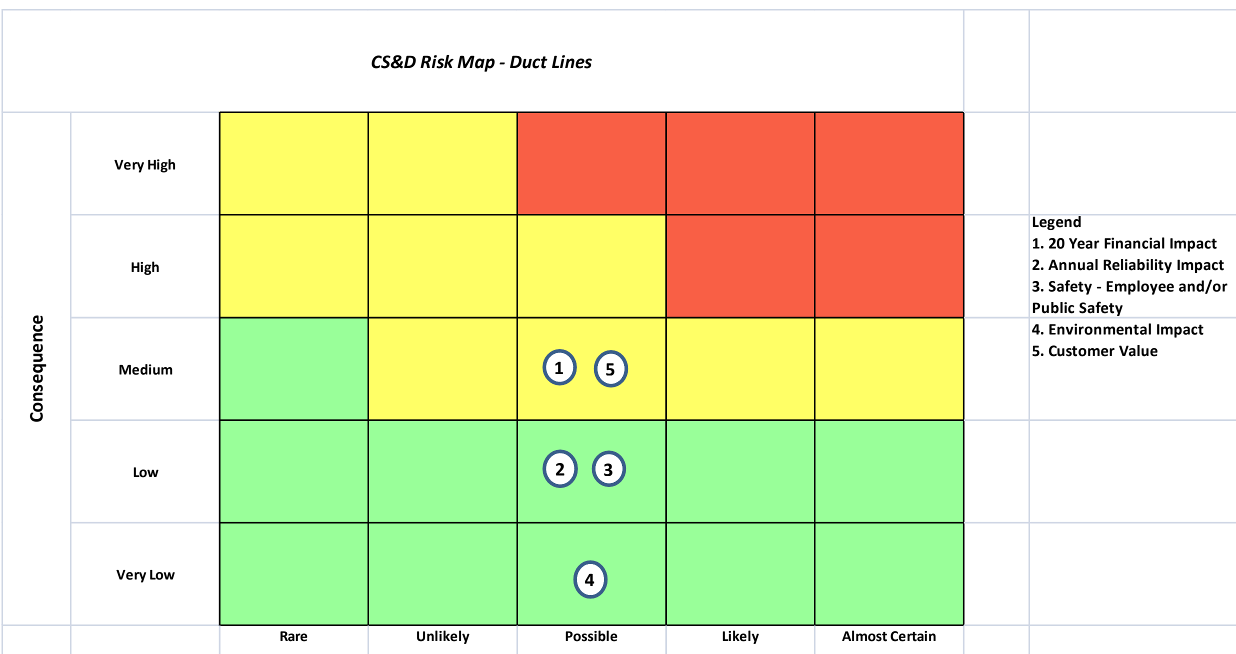


Figure 22 Duct Line Risk Map

Figure 22 indicates that the risks associated with duct line failures range from low (environmental) to moderate financial & customer impact. In the worst case scenario a duct line shift in a location containing multiple distribution circuits could result in substantial outages and result in high profile local media attention. It is anticipated after the next 20 years the finances required to rehabilitate the duct lines projected to be in fair/poor and critical condition could approach $75 million.

1.7 Economic Evaluation of Distribution Assets

Duct line construction costs depend on a variety of different factors including: property availability, duct size, duct material, and number of ducts required. Figure 23 provides an overview of the duct line asset value, current replacement rates, and anticipated lifespan.

Asset	Quantity	Life Expectancy	Current Replacement Rate
Underground Duct Lines	265 km	100 Years ?	378 Years
Replacement Cost	$3 Million/km		
Replacement Value	$795 Million		

Figure 23 Duct Line Economic Evaluation

1.8 Recommendations

Gaps: During the analysis of the asset the following gaps were identified.

Medium Priority

1. Data on the duct line construction material, date, and number of circuits contained within the duct lines is not contained within the eGIS application. In addition, the position of a failed duct segment is not consistently recorded.
2. Detailed inspection criteria have not been developed for the underground duct line system.

Recommendations: The following recommendations are made to address these gaps.

Medium Priority

1. The existing eGIS duct line object does not capture the installation date, construction material, failed individual ducts, or facilitate the querying of the number of circuits contained within a specific duct bank. Capture of this data through review of construction drawings and site inspections would enable more accurate risk analysis of the duct line system.

2. Development of detailed inspection criteria will ensure all duct lines are inspected to the same standards. In addition, the requirement to complete regular duct line inspections will ensure an accurate condition assessment of duct line health can be performed.

APPENDIX D
Padmount Transformers

Asset Condition

04/27/2012

1. PADMOUNT TRANSFORMERS

Transformers are an integral part of Manitoba Hydro's electrical distribution system and are required to change utilization voltage levels. Padmount transformers transform voltage levels from medium voltage to low voltage (120/240 V, 120/208 V, 600/347 V, and legacy delta services). Both single-phase and three-phase padmount transformers are in use at Manitoba Hydro. Typical capacities range from 25 kVA to 2500 kVA. Distribution transformation greater than 2500 kVA is customer-owned and spare replacement units are not available. Generally, suitable spares are available for all padmount transformers; however spare transformers for larger capacity legacy units are no longer purchased. Maintenance of padmount transformers is the responsibility of Customer Service Operations.

Distribution Supply Center (DSC) installations transform voltage levels from transmission (115 kV or 138 kV) or high voltage distribution (66 kV or 33 kV) to medium voltage levels (12 kV and 25 kV). These units are currently specified in 5 MVA and 10 MVA sizes. Due to the relatively modest amounts of these transformers compared to the overall padmount transformer asset base, DSC's are outside the scope of this document.

1.1 Demographics

Manitoba Hydro has approximately 17,000 padmount transformers installed on its electric distribution system. Photos of typical transformer installations are provided in Figure 24. The transformers (left to right) are a single-phase padmount utilized in a residential subdivision and a three-phase padmount utilized to supply a commercial building.

Single-Phase Padmount Transformer Three-Phase Padmount Transformer

Figure 24 Padmount Transformer Installations

Manufactured dates are known for 93% of padmount transformer installations. Using this data as a projection, the anticipated age profile of Manitoba Hydro's total padmount transformer inventory has been projected assuming the remaining 7% of transformers were uniformly installed between 1965 and 2011. The resultant age profile is provided in the Figure 25.

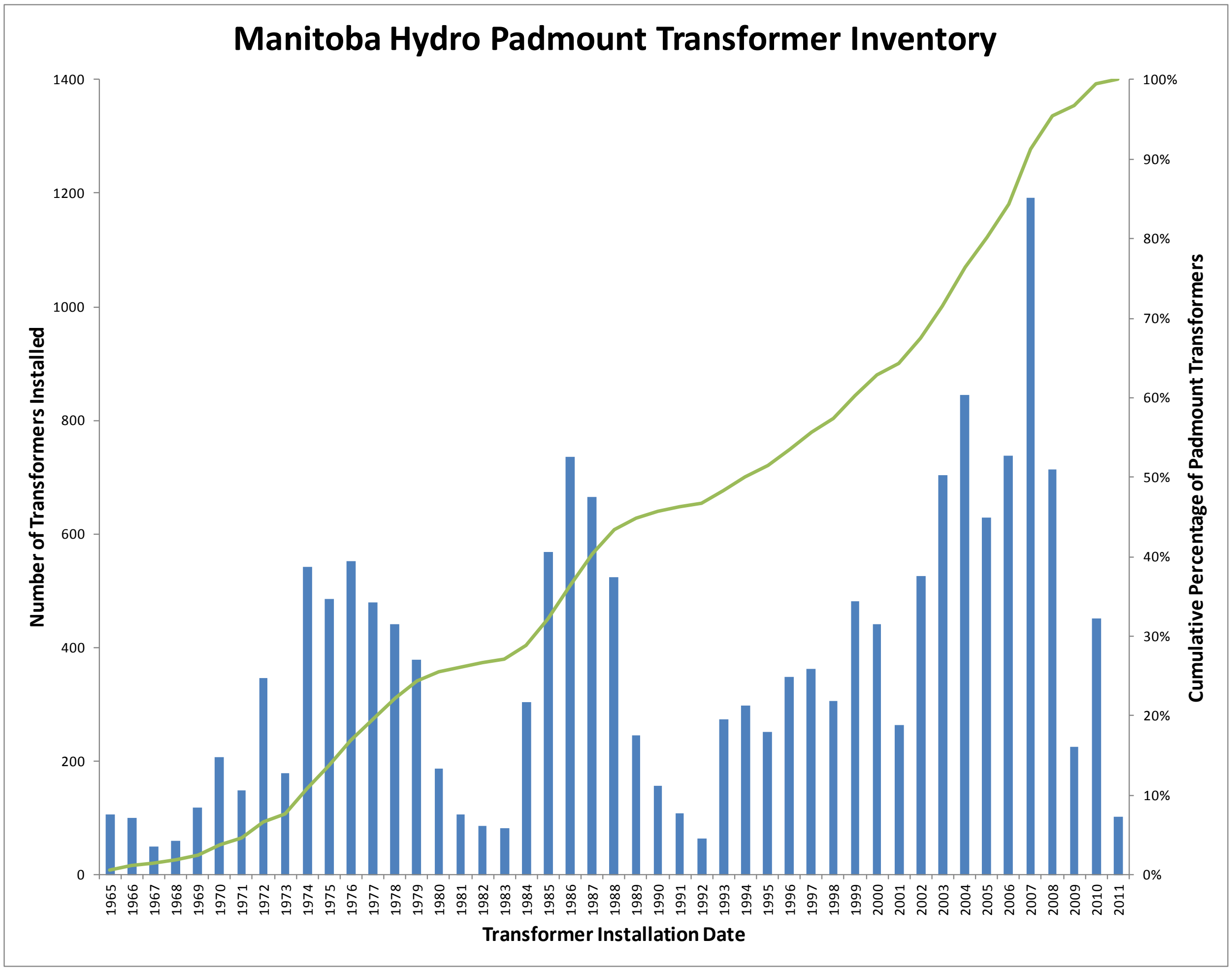


Figure 25 Manitoba Hydro Padmount Transformer Inventory

In Figure 25, it is notable Manitoba Hydro's padmount transformer installations have ranged from less than 100 to approximately 1200 units per year. Of these assets, 25% or 4,200 units were installed prior to 1980. These units will be approaching their anticipated end of life within the next 3 years.

A breakdown of the capacity of the installed distribution padmount transformers by size is provided in Tables 20 and 21.

Single-Phase Padmount Transformer Capacity						
15 kVA	**25 kVA**	**37 kVA**	**50 kVA**	**75 kVA**	**100 kVA**	**167 kVA**
3	386	892	9953	1322	859	276

Table 20 Single-Phase Padmount Transformer Count

Three-Phase Padmount Transformer Capacity							
<150 kVA	**300 kVA**	**500 kVA**	**750 kVA**	**1000 kVA**	**1500 kVA**	**2000 kVA**	**2500 kVA**
795	1066	841	357	228	101	55	10

Table 21 Three-Phase Padmount Transformer Count

It is notable that the majority of the padmount transformers on the system are single-phase transformers with 50 kVA units being the most common size. Availability of suitable spare transformers to replace failed padmount transformers is not anticipated to be an issue for the vast majority of installations.

1.2 Degradation Mechanism

Transformers operate under many extreme conditions that affect their aging and impact their likelihood of failing in service. Over time the insulation utilized in distribution transformers degrades and becomes increasingly prone to failure. The speed of the degradation varies and depends on a variety of factors; however, ambient temperature, wind, and loading history are the most important factors.

In addition, padmount transformers are more susceptible to corrosion due to their close contact with moist soil conditions, limited air flow around the tank, and increased exposure to road salt when installed close to roadways. Underground transformers often fail due to oil leakage from the bushings, welded seams, or areas that have rusted through. Padmount transformers can be expected to last 35 years or more in the field. Typical causes of failures are provided in Figure 26.

Rusted Transformer Oil Leak

Figure 26 Padmount Transformer Degradation

Transformer failures due to overload are relatively infrequent in nature as the majority of units on Manitoba Hydro's distribution system are conservatively sized and potential equipment overloads are regularly monitored throughout the Load Estimation System. Insulation of the padmounted equipment from the elements and potential wildlife contact also acts to make padmount transformers less susceptible to faults from external causes than overhead transformers.

Distribution transformers typically do not fail catastrophically. One of the reasons is the probably the installation of bayonet and under-oil current limiting fuses. Current limiting fuses limit the available fault energy and greatly reduce the risk of catastrophic failures.

1.3 Inspection and Maintenance Practices

Underground transformers have a yearly security check to ensure they are locked, not leaning severely, accessible, and no large oil leaks are visible externally. They also have a maintenance inspection done on a 6 year cycle where they are opened, cleaned, and thoroughly inspected.

In order to assist with inspection of padmount equipment within the City of Winnipeg, Customer Service Operations established an Underground Assessment Crew in 2002. The purpose of the crew was to complete assessment of underground equipment in a timely manner to ensure public safety and identify assets at risk of failure. Specific issues assessed by staff include:

- Adequacy of locks & tamperproof bolts
- Visible signs or corrosion and/or oil leaks on the transformer
- Infrared Scan of Cable Connections
- Pull elbows
- Operate switches

Historically, the Underground Assessment crew replaces between 50 and 220 padmount transformers on the distribution system annually. The majority of the units replaced (80%) are single-phase 50 kVA units with the remaining units a mixture of larger single-phase and three-phase padmount transformers. Details of the number of transformers replaced between 2002 and 2012 are provided in Figure 27.

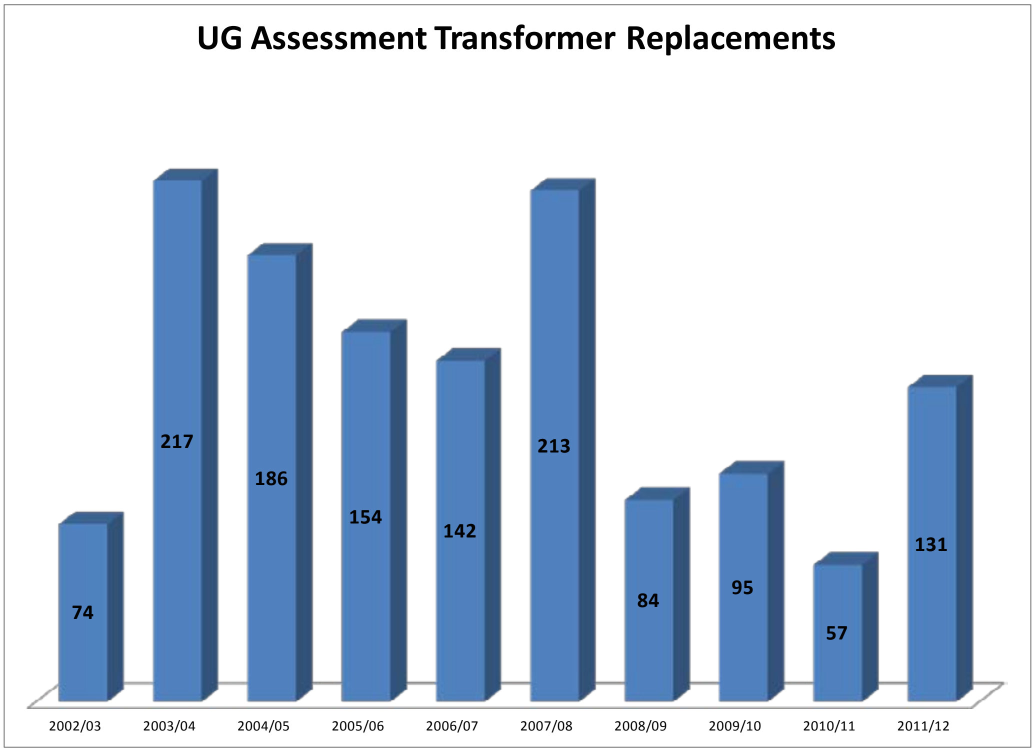


Figure 27 Underground Assessment Crew Padmount Transformer Replacements

Outside the City of Winnipeg, underground equipment assessments is handled at the Customer Service Center (CSC) level and determined by available expertise in the area. If there is a local cable journeyman, inspections can be handed by the local CSC. Otherwise other resources such as neighbouring CSC cablemen or Distribution Construction can be utilized. It is unclear if rural CSC's are conducting the same level of inspections on their padmount transformer assets as the City of Winnipeg.

1.4 Health Index and Asset Condition (Useful Life)

1.4.1 *Transformer Life Evaluation*

Padmount transformers are designed to operate on a run to fail strategy. Individual transformer units are typically only replaced if identified as deficient during an inspection. Padmount replacement decisions are usually the result of one of the following triggers:

- The padmount transformer has extensive indications of rust and is at risk of or leaking oil or the public gaining access to the compartment.
- Distribution Engineering has determined the transformer capacity needs to be increased to supply customer load.
- Distribution Engineering has determined the area voltage requires conversion (e.g. 4 kV to 24 kV).

Transformers that are returned to Central Stores are evaluated against the following criteria to determine if they will be refurbished for future use or scrapped: transformer condition and repair costs, turnover rate, and unit capacity. These factors are entered into a spreadsheet utilized by Materials Management and a decision to retain or scrap the unit is based on the economic analysis calculations.

1.4.2 *Design Criteria for Transformer Health Index Formulation*

Table 22 indicates the health condition criteria for transformer assessments considering the age of the unit.

Age/Health	Condition	Probability of Failure	Requirement
>50 Years	Critical	High	Replace based on condition assessment if necessary.
31 - 49 Years	Fair/Poor	Medium	Continue to monitor as part of feeder inspection and load estimation requirements.
30 Years or Younger	Acceptable	Low	Continue to monitor as part feeder inspection and load estimation requirements.

Table 22 Padmount Transformer Health Index

1.4.3 *Replacement Rates*

Historically, the Winnipeg Underground Assessment Crew replaces between 50 and 200 padmount transformers annually, removing high risk transformers from the system prior to failure. Outside the City of Winnipeg, padmount transformer replacements are determined on a CSC level and at much lower quantity. Padmount transformer replacement ensures Manitoba Hydro's padmount transformer annual failure rate (resulting in customer outages) is very low ranging between 5 and 15 failures or 0.03% to 0.09% of the total padmount transformer population.

Approximately 900 padmount transformers are installed on Manitoba Hydro's electric distribution system annually. Of these units 650 are associated with customer service work orders, 250 are associated with system improvements, and the remaining units are utilized for emergency repairs. Assuming 250 existing transformers are replaced annually with new units, it would take approximately 70 years to replace the total installed population.

1.5 Asset Health

In practice, padmount transformers have a low failure rate and are most often removed from service before they fail due to condition assessment data. The health profile of Manitoba Hydro's padmount transformer assets is presented in the "soccer field" graph on Figure 28. This chart provides the current asset health and a 20 year projection. The following assumptions are made:

- Padmount transformers 50 years of age or greater are rated critical. An additional 1% of transformers are assumed to be in poor condition due to localized corrosion issues.

- Padmount transformers 31 – 49 years or greater are rated fair/poor.

- Padmount transformers 30 years or younger are rated acceptable.

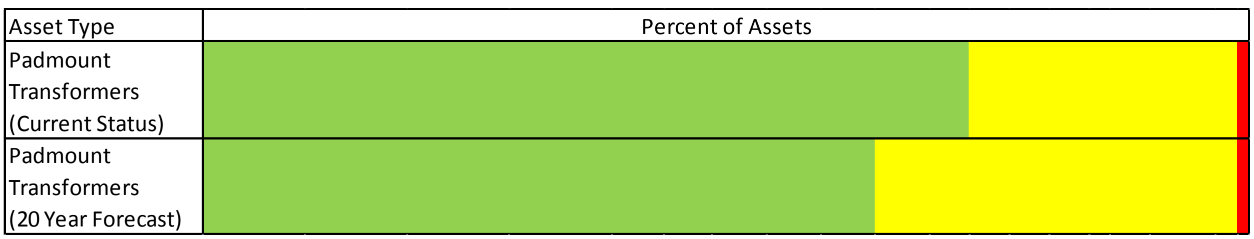


Figure 28 Padmount Transformer "Soccer Field"

Figure 28 indicates that due to current padmount transformer replacement rate, a higher proportion of transformers will transition into fair/poor condition from acceptable condition. However, it is not anticipated that a substantial number of transformers will be in fair/poor condition 20 years in the future if the current replacement rate is maintained. Although it is estimated this projection is somewhat optimistic and some transformers will be found in fair/poor condition requiring replacement, the quantities involved are expected to remain similar to current replacement levels (50 – 200 units per year). If that scenario holds, the replacement of the transformers would cost $3 million.

1.6 Risk of Failure

1.6.1 Distribution Padmount Transformer Risk Assessment

Padmount transformer failures can result in lengthy outages that are isolated to the customers supplied by the transformer. An outage to a small padmount transformer could interrupt between 1 and 12 residential customers; however an outage to a large 3-phase padmount transformer could interrupt service to a Major Account or major apartment building. Repair times can range substantially ranging from a couple of hours for a readily accessible transformer to half a day or more for large padmount transformers or units installed in customer backyards.

Since padmount transformers contain oil there is a risk of fire and release of oil in the event of a catastrophic tank failure. This risk is very low due to the application of bayonet and under oil current limiting fuses in new padmount transformers. Another potential risk during a transformer failure is that of electrocution, however this is also very low, provided the grounding system at the transformer has not been compromised and security inspections have been completed.

Risk factors for padmount distribution transformers include:

Environmental: Severe weather such as lightning and flooding.

Corrosion: Corrosive environments.

Wildlife: Small rodents and animals faulting the transformer bushings or damaging cable insulation.

Thermal: Transformer overloading.

Man Made: Deliberate sabotage.

1.6.2 Risk Matrix

Based on the observations made in this report, the following risk matrix has been developed. The Matrix considers the anticipated impact padmount transformer failures can have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted on the following risk matrix in Figure 29. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

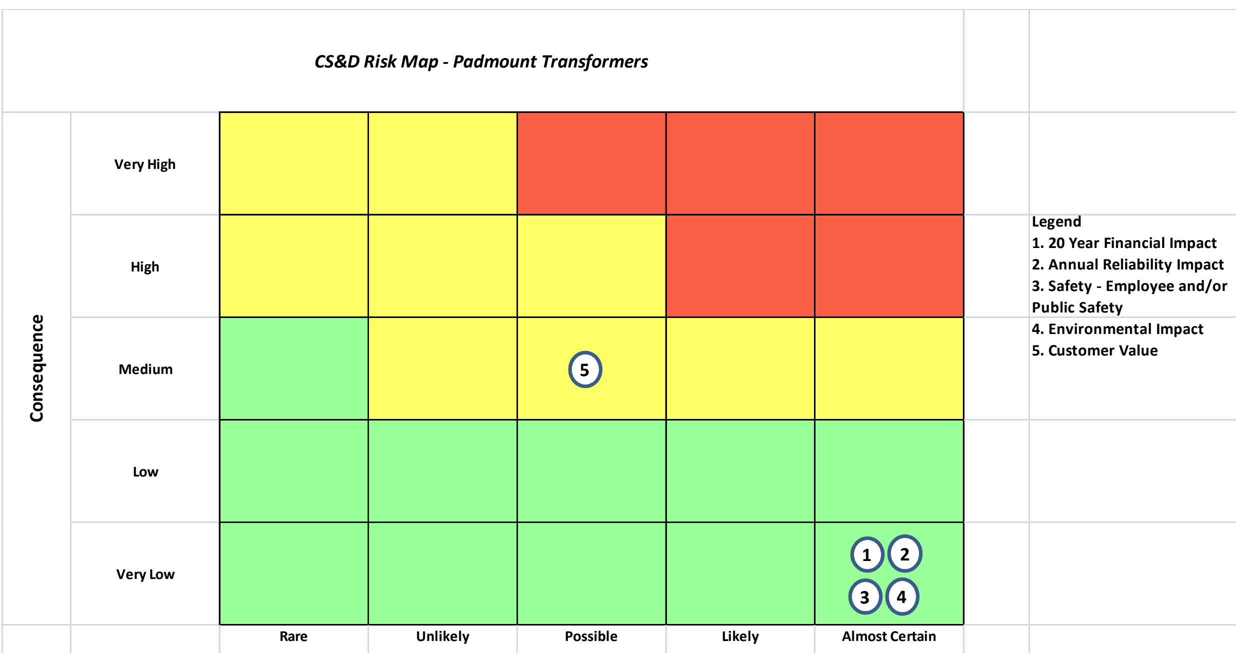


Figure 29 Padmount Transformer Risk Map

Figure 29 indicates that the risks associated with padmount transformer failures are moderate. In the worst case scenario a padmount transformer failure could result in a lengthy outage to a high profile customer which could receive result in high profile local media attention. It is anticipated after the next 20 years the finances required to rehabilitate padmount transformers will not require any substantially changes from existing padmount replacement rates of 50 to 200 per year.

1.7 Distribution Asset Economic Evaluation

The value of Manitoba Hydro's padmount transformers is estimated based on the anticipated replacement cost of the transformer and associated hardware. Replacement of a padmount transformer can range from $12,300 for a 25 kVA transformer to $65,000 for a 2500 kVA transformer. Using these values, the replacement cost of Manitoba Hydro's existing padmount transformer inventory is estimated to be approximately $273 million.

Tables 23 and 24 detail Manitoba Hydro's existing transformer inventory along with the material requirements to replace these assets with standard stock items. The installation costs assume the transformer is replaced with a standard stock material.

Replacement Costs for Manitoba Hydro's Single Phase Padmount Distribution Transformers			
Unit Capacity	**Number**	**Installation Cost**	**Total**
15 kVA	3	$12,300	$36,900
25 kVA	286	$12,300	$3,517,800
37 kVA	892	$12,300	$10,971,600
50 kVA	9,953	$12,300	$122,421,900
75 kVA	1,322	$12,600	$16,657,200
100 kVA	859	$13,500	$11,596,500
167 kVA	276	$14,500	$4,002,000
Total	13,591		$169,203,900

Table 23 Single-Phase Padmount Transformer Replacement Costs

Replacement Costs for Manitoba Hydro's Three Phase Padmount Distribution Transformers			
Unit Capacity	**Number**	**Installation Cost**	**Total**
150 kVA	795	$24,500	$19,477,500
200 - 300 kVA	1,066	$26,000	$27,716,000
333 - 500 kVA	841	$30,000	$25,230,000
667 - 750 kVA	357	$37,700	$13,458,900
1000 kVA	228	$43,500	$9,918,000
1500 kVA	101	$44,000	$4,444,000
2000 kVA	55	$62,000	$3,410,000
2500 kVA	8	$65,000	$520,000
Total	3,451		$104,174,400

Table 24 Three-Phase Padmount Transformer Replacement Costs

Figure 30 provides an overview of Manitoba Hydro padmount transformer asset value, current replacement rates, and anticipated lifespan.

Asset	**Quantity**	**Life Expectancy**	**Current Replacement Rate**
Single-Phase Padmount Transformers	13,591	50 Years	70 Years
Three-Phase Padmount Transformers	3,451	50 Years	70 Years
Replacement Cost	$12,300 - $65,000 per transformer		
Replacement Value	$273 Million		

Figure 30 Padmount Transformer Economic Evaluation

1.8 Recommendations

Gaps: During the analysis of the asset the following gaps were identified.

Medium Priority

1. Larger capacity 4 kV padmount transformers (1000 kVA and greater) are no longer standard stock items.
2. Rural padmount transformers may not receive the same level of inspections as the City of Winnipeg. Standardized inspection padmount transformer criteria and assessment schedules for the province is required.

Recommendations: The following recommendations are made to address these gaps.

Medium Priority

1. Suitable Spare Transformers – Review the availability of spare transformers of adequate capacity for 4 kV padmount transformers 1000 kVA and greater
2. Develop an inventory of these units and contingency plans for customers supplied by those transformers.

Low Priority

3. Develop a long term plan for funding and resources to address the underground assessment function consistently across the province.

APPENDIX E
Poles

Asset Condition

04/27/2012

1. POLES (WOOD)

Wood poles are an integral part of Manitoba Hydro's overhead electrical distribution system and are used to provide adequate ground clearance and mechanical support of conductors and energized equipment installations on the pole. Typical structures support one energized circuit, however it is common for multiple circuits to be installed on a common pole structure, particularly in urban environments or where 66 kV lines and 12 kV or 25 kV feeders share a common right of way. In addition to multiple circuit structures, equipment installations (notably overhead distribution transformers and transition structures between overhead conductors and underground cables) are also common.

Wood pole installations are designed to ensure energized equipment has sufficient clearances and mechanical strength to ensure public safety. These requirements are determined by field and engineering staff that review the requirements and select a pole of appropriate height and strength (e.g. pole class).

Jack Pine, Western Red Cedar, Red Pine Larch, Fir and Southern Yellow Pine wood poles are commonly utilized on the distribution system. They are either full length or butt treated and range in height from 25 feet to 90 feet. Pole circumferences of varying measurements are also utilized and denoted by pole class. Pole classes typically range from Class 1 to 6, with Class 1 poles being the strongest. Typically higher class poles are selected for structures requiring a high pole height or supporting multiple circuits or distribution equipment (e.g. voltage regulators).

1.1 Demographics

Manitoba Hydro's electric distribution system is predominately overhead with 94% of feeder circuit length supported by wood, steel, or concrete structures. With the exception of a few 66 kV lines that utilize steel lattice structures and some concrete structure installation on 12 kV and 24 kV circuits, the vast majority of overhead distribution lines utilize wood poles. These poles are spread over 72,000 km of distribution throughout the province. Photos of typical wood pole structures are provided in Figure 31.

Three-Phase Transformer Pole | Voltage Regulator and Capacitor Poles | Multi-Circuit 4 kV Pole | 66 kV Lateral Pole

Figure 31 Typical Wood Pole Structures

The majority of the distribution system was built in stages over the past 80 years making it difficult to accurately estimate an exact pole inventory. Previous Manitoba Hydro estimates indicate that approximately 700,000 poles exist in the system. A distribution pole inventory project (underway way for several years) has identified 90% of the poles in the province with bar-codes,as such the current pole population is expected to exceed 1 million units.

The Integrated Pole Maintenance Program (IPM) database which contains records of wood pole age, species, class, and pole treatment history, currently contains 525,465 pole records from 2003 to 2010 and is estimated to comprise 53% of the total 1,000,000 pole inventory. Using this data a projection of the anticipated age of Manitoba Hydro’s pole assets is shown in Figure 32. The individual blue bars correspond to the estimated number of poles installed each year. The green line corresponds to the total cumulative percent these poles represent for the total pole inventory.

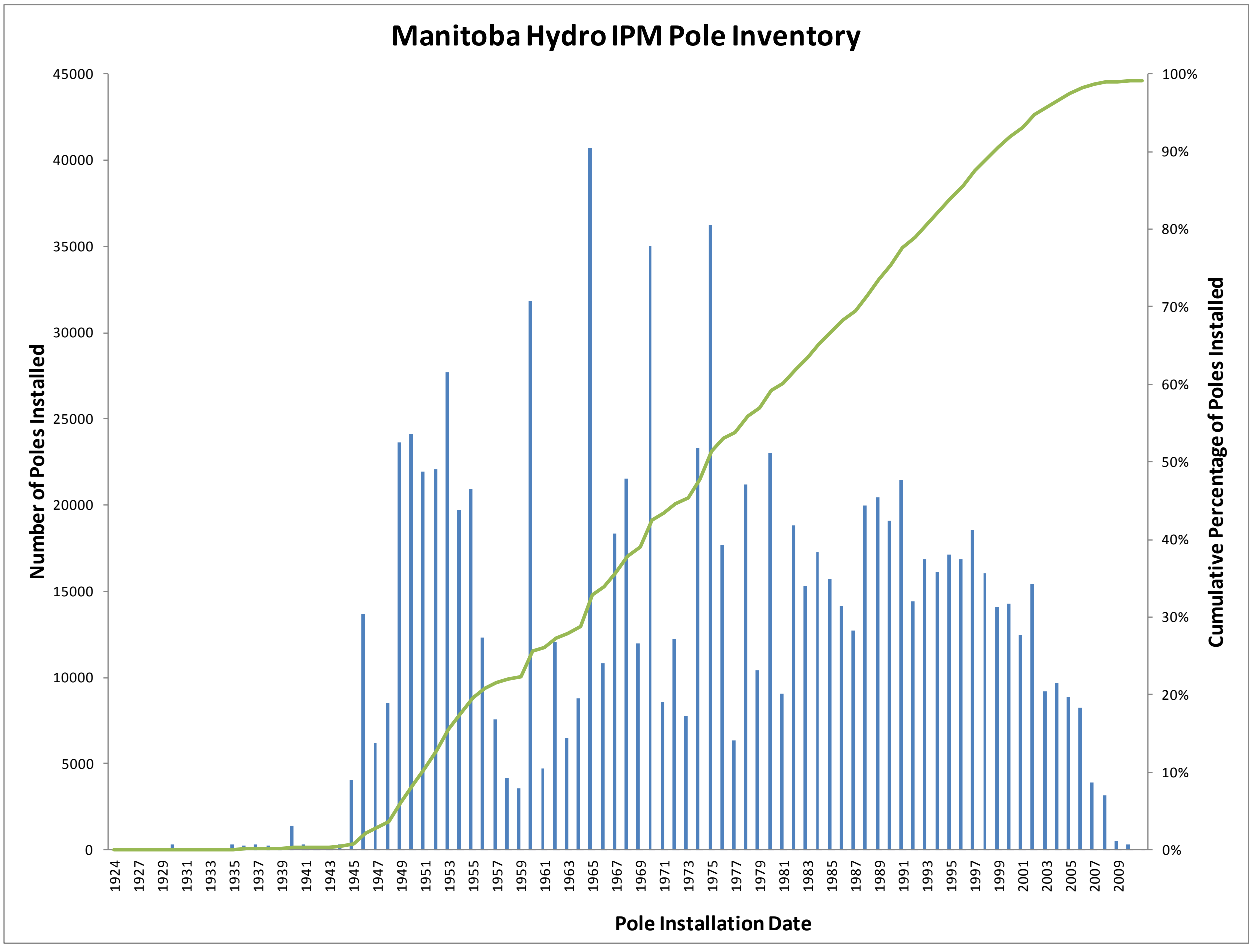


Figure 32 Manitoba Hydro Projected Pole Inventory

In Figure 32, it is notable that Manitoba Hydro's pole assets underwent a major expansion between 1945 and 1960. During that time approximately 250,000 poles were added to the distribution system. These poles are currently between 52 and 67 years of age and represent approximately 25% of the total pole population on the distribution system. Between 2020 and 2035, these poles will reach their anticipated lifespan of 75 years. Manitoba Hydro's current pole replacement rate of approximately 5,000 poles per year is not sufficient to replace this first "hump" of poles when they reach their anticipated lifespan.

It is notable that although the projected pole age profile is the most accurate data available, it is also likely very conservative. Manitoba Hydro archives indicate that substantial expansion of the transmission system (33 kV and 66 kV at the time) had occurred prior to 1939. At the time the system provided electricity to 139 communities. A schematic of the system is provided in Figure 33. Although relatively few farms were supplied off this system, many of the wood poles were used to supply both distribution town customers and the supplying transmission lines. It is probable that many of these poles still remain in service.

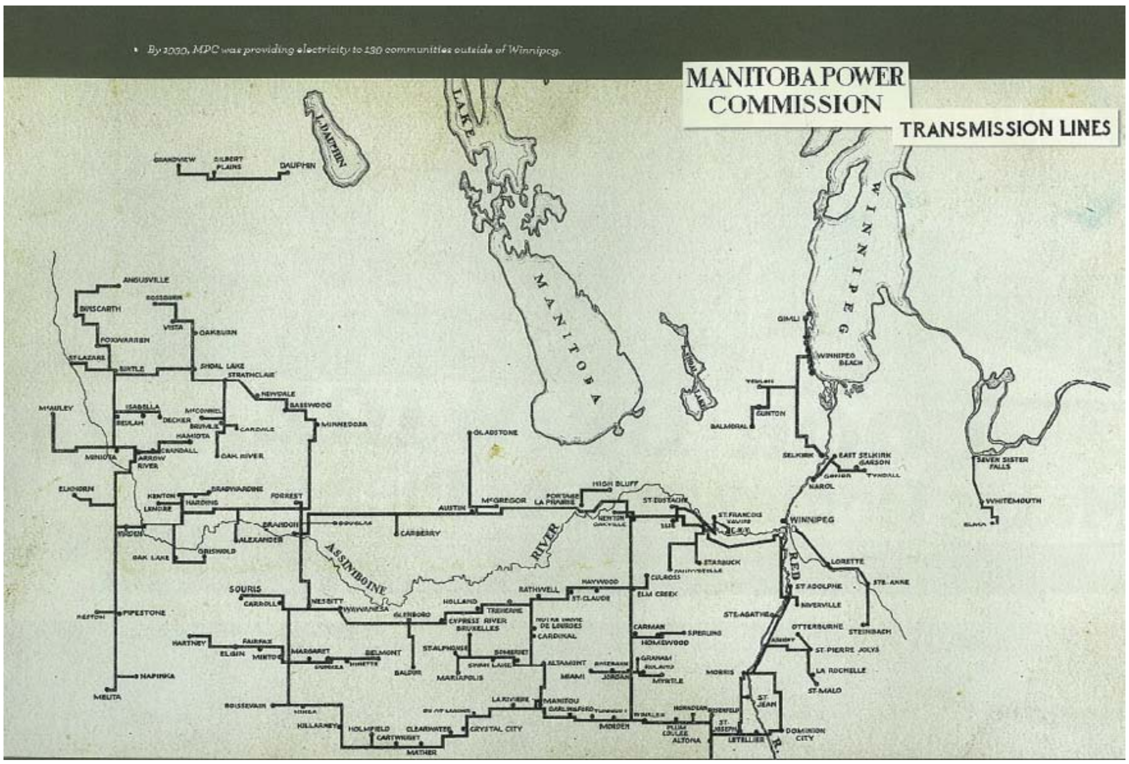


Figure 33 Manitoba Power Commission Transmission Lines in 1939

Tables 25 and 26 detail Manitoba Hydro’s estimated wood pole inventory along with the material requirements to replace these assets with standard stock items.

	Class								
Pole Height	1	2	3	4	5	6	7	8	9
25	2	83	512	752	1258	2075	1312	2	2
30		162	981	3525	16098	44321	6252		
35	79	1538	15427	140500	152496	100883	3521	4	
40	273	15756	116585	134477	9096	2052	87	2	2
45	263	25137	82438	26631	510	94	10		
50	631	11073	14275	1235	42	2			
55	242	9431	18087	15	13	10			
60	1263	5956	3015	558	2	2			
65	2600	1656	1435	133					
70	1637	3287	4152	2			2		
75	2240	4304	362	6					
80	3438	498	190						
85	2858	92	56						
90	6			2					
Total	15533	78971	257513	307834	179515	149438	11183	8	4

Table 25 Estimated Pole Inventory

	Class					
Pole Height	1	2	3	4	5	6
25						
30						53963
35			16919	419035		
40		17538	116585	145715		
45		25137	82438	27244		
50		11073	15554			
55		9431	18125			
60	2754	9533				
65	2600	3223				
70	9079					
75	6912					
80	4127					
85	3006					
90	8					
Total	28486	75935	249621	591995	0	53963

Table 26 Wood Pole Replacement Estimation

1.2 Degradation Mechanism

Poles are subjected to environmental stresses from climatic loads, decay and mechanical damage which may cause mechanical failures resulting in unplanned power outages. Because wood poles are a natural material, the degradation characteristics vary considerably from other steel electrical distribution assets. The nature and severity of the degradation depends on the wood species and its environment. The main contributor to the structural breakdown of our wood pole assets is biological. Wood destroying fungi attacks the wood fibres either on the external surface or through the internal heart wood which results in decay.

Other factors impacting pole strength include wildlife or vehicle damage. Poles are a structural component of the distribution system and the major concern when assessing their condition is the reduction in mechanical strength that is usually caused from decay or by physical damage from equipment or fire. Typical causes of wood pole degradation are provided in Figure 34.

Figure 34 Typical Causes of Wood Pole Degradation

1.3 Inspection and Maintenance Practices

1.3.1 Integrated Pole Maintenance (IPM)

In 1989, Manitoba Hydro implemented the Integrated Pole Maintenance program (IPM). The program is a designed to provide an accurate assessment of our wood poles on a 15 year cycle. Between 1989 and 2002, the program evolved from inspecting 5,000 poles annually to over 70,000 poles. Each pole receives a thorough inspection, strength evaluation, remedial treatments as required and attribute information is collected electronically. These remedial treatments are designed to provide the poles with added protection internally and externally to extend their service life.

1.3.2 Pole Reinforcement Program

The IPM program identifies poles which can be reinforced with engineered steel products. This technology has improved considerably over the last few decades and provides a cost effective option to extend the service life of aging or damaged poles. Manitoba Hydro now stubs (attaches a parallel pole stub to damaged pole) a significantly higher volume of poles yearly through the pole reinforcement program. Typical pole stubbing costs range between $600 and $700. Stubbing is anticipated to extend the life of a pole by approximately 15 years.

1.4 Health Index and Asset Condition (Useful Life)

Pole asset evaluation primarily consists of IPM inspections. These inspections focus on the pole condition between 2 feet below ground line to 6 feet above ground line. Other factors that impact pole life such as shell rot and woodpecker damage are not necessarily detected by the IPM program and would require detailed structure inspections.

1.4.1 Pole Strength Evaluation

Poles are classified into the following four categories:

1. Serviceable poles (S): A pole with an average minimum of 5cm (2 inches) of shell thickness and 70% or greater of their original strength as per remaining strength evaluation charts and tables. Poles that fall in this category require no action.
2. Rejected poles (X): A pole with between 50% and 70% of its original strength and does not qualify as reinforce able. Poles falling into this category are to be replaced within one year of being identified.
3. Reinforce able pole (XR): A pole retaining 50% to 70% of its original strength with a minimum of 5cm (2 inches) of shell and qualifies under pole strength evaluation charts and tables as defined in tender and remaining strength evaluation charts and tables and recommended thicknesses for steel truss manufacture. Poles that fall in this category are reinforced within one year of being identified.
4. Danger pole (XD): A pole with 2.5 cm (1 inch) or less of shell or one that has less than 50% of its original strength. Poles that fall in this category are replaced within one year of being found.

1.4.2 Design Criteria for Pole Health Index Formulation

Table 27 indicates the health condition criteria for pole assessments considering both the age and health of the pole.

Age/Health	Condition	Probability of Failure	Requirement
>75 Years, or Danger Pole (XD), or Reject Pole (X)	Critical	High	Immediate risk assessment, replace based on assessment
51 – 74 Years, or Reinforceable Pole (XR)	Fair/Poor	Medium	Start planning to replace or reinforce considering risk and impact of failure.
50 Years or Younger	Acceptable	Low	Continue to monitor as part of IPM process.

Table 27 Wood Pole Health Index

The pole health evaluation table provides a good assessment for the condition of wood poles at and just above ground level. However, there is a gap in pole health data outside of this inspection zone. During the detailed feeder inspection pilot project, inspectors identified a number of poles which failed above grade due to issues not identified through the IPM program. Examples of failures include: woodpecker damage and shell rot.

1.4.3 Replacement Rates

Currently, Manitoba Hydro orders approximately 10,000 poles annually. Of these poles, approximately 5,000 are utilized in system expansion projects and the remainder are utilized to replace assets IPM poles and poles damaged due to external factors (e.g. vehicle hits, pole fires, storm conditions). At Manitoba Hydro's current replacement rate it would take 200 years to replace the total installed pole population.

The IPM program typically identifies a 1.7% failure rate and an assumption could easily be made that 98.3 % of our poles are serviceable or in good condition. Approximately 70,000 poles are surveyed annually, with approximately 1190 poles failing. It is estimated that 18,000 poles will fail to meet the pole health criteria over the next 15 years. If we assume the wood pole life expectancy is 75 years, based on 1 million poles, we would be required to replace 13,000 poles annually or 195,000 poles per 15 year cycle.

There are several programs and projects outside the IPM program in which wood poles have been identified for replacement. The line refurbishment program and capacity/clearance upgrade projects replace poles throughout the province as required. Although these projects retire aging assets, they do not replace them at the volume required to address future aging infrastructure concerns.

1.5 Health

Projections based on IPM inspection data, predict 18,000 poles would be expected to be in non-serviceable condition today. Of these 18,000 poles, approximately 4,000 could be stubbed and the remaining 14,000 require replacement. This projection is the first indication Manitoba Hydro's current pole replacement rate is falling behind requirements.

Although, this is a relatively low value compared to the overall pole population, approximately 260,000 poles were installed between 1945 and 1960 during rural electrification. These poles approach the end of their serviceable lives between 2020 and 2035. At that time it is anticipated pole replacement requirements could average 17,000 per year.

The projected age profile of the pole currently requiring replacement is shown in Figure 35.

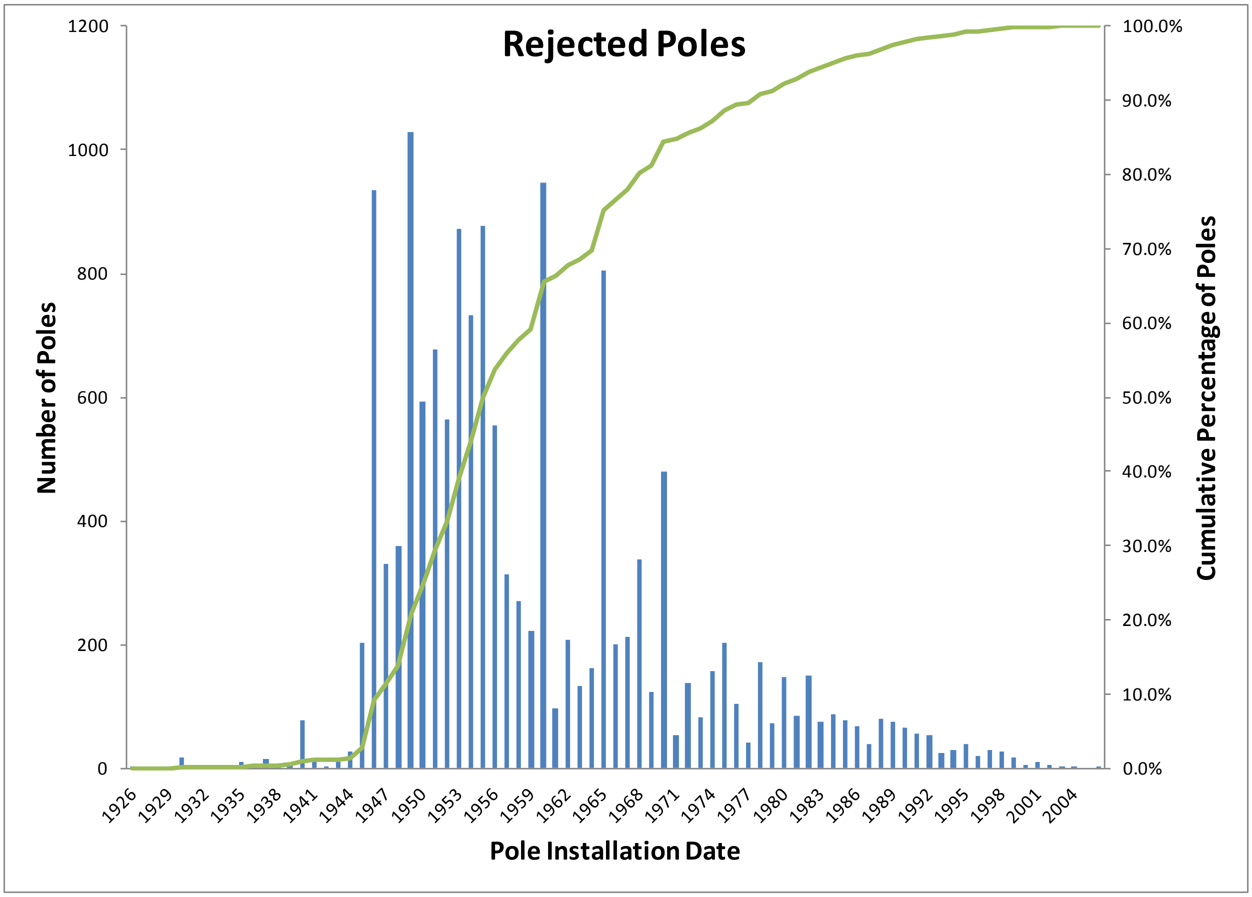


Figure 35 Rejected Pole Age Profile

The preceding chart indicates the majority of poles requiring replacement were installed between 1945 and 1960. Poles installed prior to 1960 account for 66% of rejected pole population. A graph of the rejected pole population as a percentage of total installed assets is provided in Figure 36.

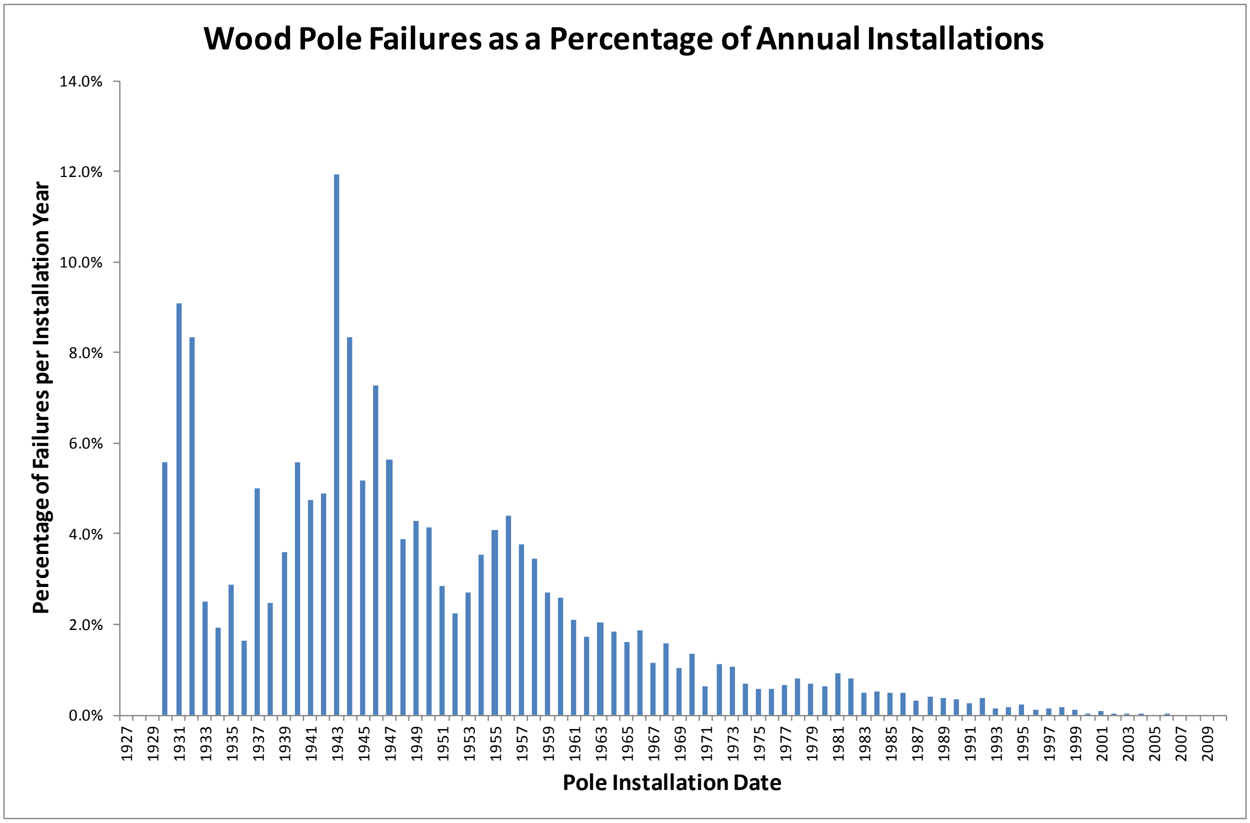


Figure 36 Percent of Poles Requiring Replacement

Figure 36 details the percentage of service pole inspection failures by installation date. Failures range from less than 1% for pole installations since 1971 to 12% for poles installed in 1943. The typical upper range of pole failures ranges from 5% to 12% for poles installed prior to 1960. This data supports the conservative assumption that a 75 year lifespan for a pole is reasonable with typically less than 12% of assets that age failing in service. While relatively little data is available for poles older than 75 years, it is notable that the IPM data for the three 85 year old poles indicated a 66% failure rate. While only three poles that age were available for those data points, it is reasonable to assume in service failures would be more likely to occur with increasing pole age.

The health profile of Manitoba Hydro's wood pole assets is presented in the "soccer field" graphs on Figure 37. In these graphs, poles are classified based on the following conditions.

- Poles 75 years of age or greater or rejected poles are rated critical.
- Poles 51 – 74 years or greater are rated fair/poor.

- Poles 50 years or younger are rated acceptable.

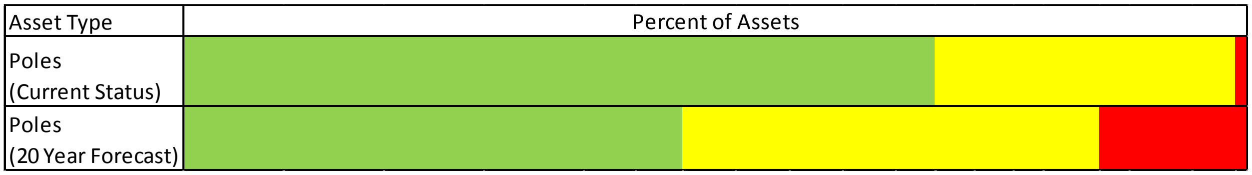


Figure 37 Wood Pole “Soccer Field”

The preceding figure indicates approximately 2% of Manitoba Hydro’s wood pole assets are in critical condition, with a further 26% in fair/poor condition. Within the next 20 years, a significant portion of the wood pole assets installed during rural electrification will approach their anticipated end of life, reaching 12% of the pole population in 2032. The estimated cost of rehabilitating the estimated 117,000 poles at that time will be approximately $410 million.

1.6 Risk of Failure

1.6.1 Distribution Pole Risk Assessment

Wood pole failures can result in substantial customer outages, particularly if they are along a main three-phase section of feeder or on a 66 kV circuit. Typical failures can impact between 1 and 4,000 customers. Repair times can range substantially, ranging from an hour in an urban environment to half a day or more in a remote location.

Risk factors for wood poles include:

Environmental: Wood poles are subjected to wind and ice loads which can result in failures if the structure is not capable of withstanding the mechanical load. In addition, lighting strikes can physically damage the structure and salt spray contamination from vehicular traffic can result in pole fires.

Biological: Wood poles are also subjected to damage as the result of rotting due to fungi.

Foreign Interference: Contact of the pole by construction or snow removal equipment and vehicular traffic can mechanically damage the pole. Grass fires can also result in pole damage.

Wildlife: Poles are susceptible to damage from animals such as ants, woodpeckers, beavers, and bears.

Distribution pole failures typically result in customer outages due to the operation of upstream protection devices. Depending on the circuit involved the number of customers interrupted can range from one or two for a single-phase tap on a rural distribution feeder to thousands for a heavily loaded 66 kV circuit. Repair times can also vary substantially, ranging from a couple of hours in an urban environment to half a day or more in an isolated location.

In addition to customer impacts from the outage (or voltage sag) caused by a pole failure, another risk is potential public exposure to energized circuits. While the risk of circuits remaining energized following a pole failure is low due to the use of protection equipment to detect and isolate faults, conditions can occur where it is possible for the circuit to remain energized (e.g. high impedance fault). In these situations there is a risk of electrocution through either direct contact with the energized conductor (touch potential) or bridging the voltage gradient around a downed conductor with your feet (step potential).

1.6.2 Risk Matrix

Based on the observations made in this report, the following risk matrix has been developed considering the anticipated impact wood pole failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted on the following risk matrix on Figure 38. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

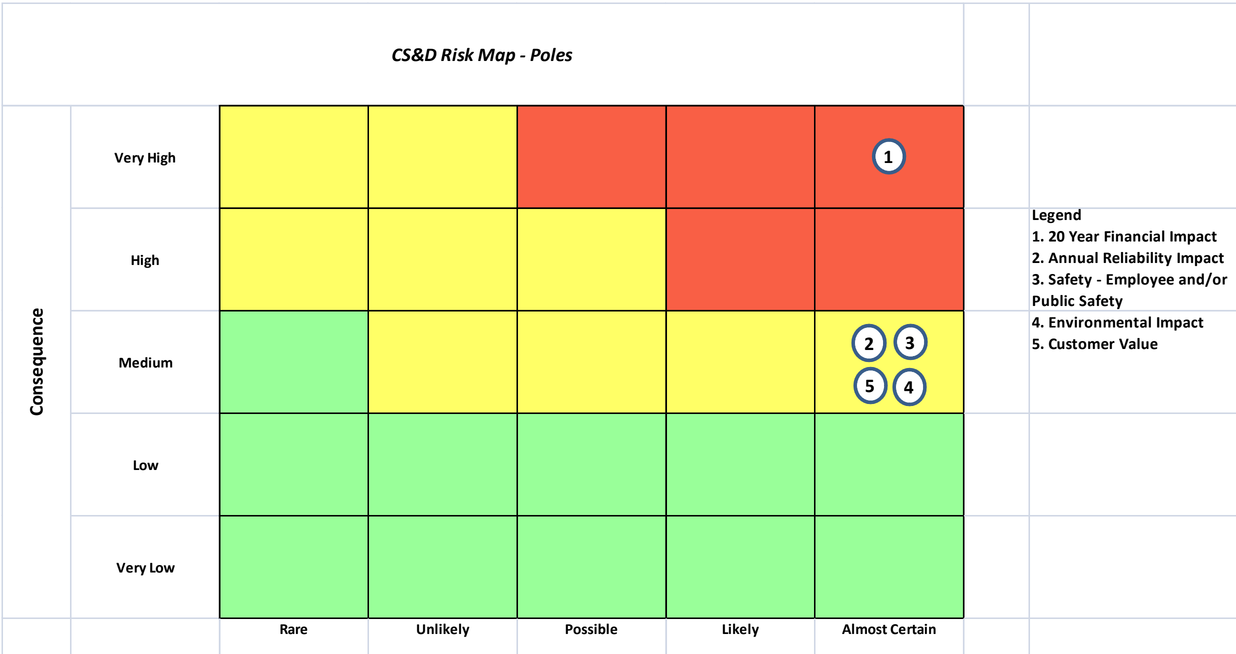


Figure 38 Wood Pole Risk Map

Figure 38 indicates that the largest risk associated with wood poles is financial. With current replacement rates it is anticipated 12% of the wood pole population will be in critical condition within 20 years. At that time, the investment deficit will be approximately $350 million. The remaining risks associated with wood failures are moderate and do not typically result in significant reliability, safety, environmental or customer value concerns.

1.7 Distribution Asset Economic Evaluation

Wood pole construction costs depend on a variety of different factors including: pole height, class, accessibility, and hardware installed on the structure. Figure 39 provides an overview of the cable asset value, current replacement rates, and anticipated lifespan.

Asset	Quantity	Life Expectancy	Current Replacement Rate
Wood Poles	1,000,000	75 Years	200 Years
Replacement Cost	$1,000 - $10,000+/pole ($3,500 Average Cost)		
Replacement Value	$3.5 Billion		

Figure 39 Wood Pole Economic Evaluation

1.8 Recommendations

Gaps: During the analysis of the asset the following the following gaps were identified.

High Priority

1. The current pole replacement rate of 200 years is inadequate.

2. Manitoba Hydro has not implemented a detailed inspection process for poles above grade.

Medium Priority

3. The inspection process currently is a paper-based process and asset condition is not consistently entered into DMPS.

4. The impact of pole replacement decisions on customer reliability is not part of the decision making process.

Recommendations: The following recommendations are made to address these gaps.

High Priority

1. Develop a long term capital investment plan to address aging wood pole assets.

2. Continue to implement detailed asset inspections to further optimize asset life cycles.

Medium Priority

3. Storage of IPM and pole inspection data in the same asset database with capabilities to view asset condition geospatially will expand the ability to leverage the data from both an operations and engineering perspective.

4. Line refurbishment decisions are primarily based on the overall condition of the circuit. In addition to the physical line condition, the risk of pole failure should be considered. Circuits supplying critical infrastructure meeting the basic needs of the communities they

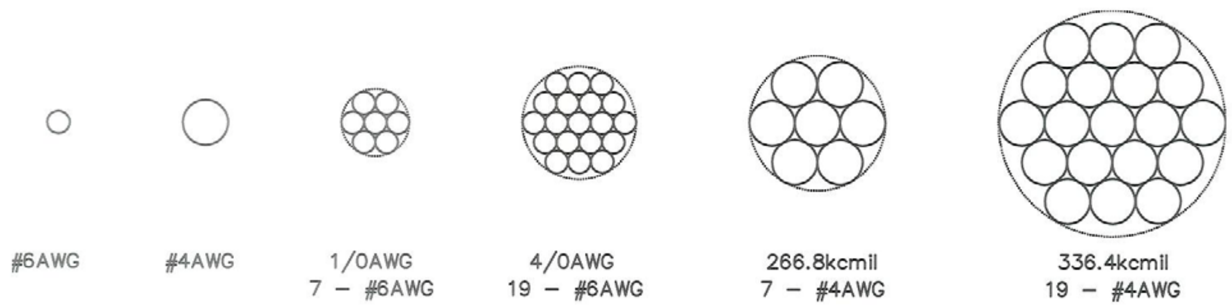
serve (e.g. major hospitals, airport facilities, water treatment facilities) should be given a higher priority than circuits supplying non-critical infrastructure.

APPENDIX F

Overhead Conductors

Asset Condition

04/27/2012



1. OVERHEAD DISTRIBUTION CONDUCTORS

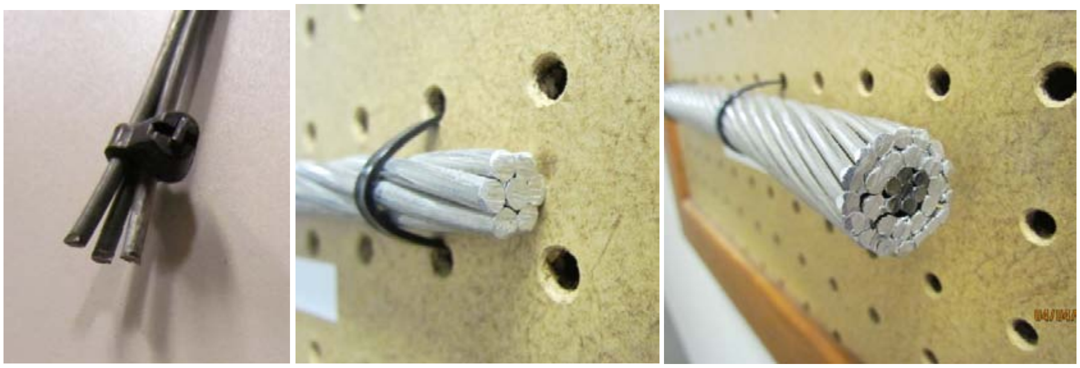
Distribution conductors are utilized to deliver electrical energy from the distribution system to customers supplying customer loads. The majority (94%) of conductors utilized on the distribution system are overhead with the remainder comprised of underground cable. This section focuses on the characteristics of the overhead conductors installed on Manitoba Hydro's distribution system.

Manitoba Hydro has selected aluminum as its standard material for overhead distribution conductors. Aluminum is utilized for all new construction projects due to its high strength, low impedance, and high ampacity ratings. Aluminum comprises approximately 70% of the wire used on the distribution system.

Non-standard conductors such as steel and copper comprise the remaining 30% of wire utilized on Manitoba Hydro's distribution system. While non-standard, these conductors are maintained and operated until there is a need to replace them to increase system capacity, rebuild a line section due to pole condition or road realignment, or replacement due to poor condition.

1.1 Demographics

Manitoba Hydro has installed overhead distribution conductors throughout the province. Manufactured dates are not readily available for specific conductor sections; however it is reasonable to assume the conductors utilized on Manitoba Hydro's distribution system have a similar age profile to the wood poles. Typical conductors found on the distribution system are provided in Figure 40. The conductors (left to right) are 3/13" Steel, 2/0 AASC and 477 kcmil ACSR.



3/13" Steel 2/0 AASC 477 kcmil ACSR

Figure 40 Typical Overhead Conductors

A breakdown of the installed overhead conductors by type and size are provided in Table 28.

Material	KM	Percent	Size	Km	Percent
ACSR	77,747	67.7%	2	52,047	45%
Steel	22,021	19.2%	3/13	22,019	19%
AASC	4,481	3.9%	2/0	19,268	17%
Copper	3,713	3.2%	1	4,469	4%
Alloy	2,730	2.4%	266.8	2,823	2%
CCSR	2,321	2.0%	9	2,730	2%
Shrike	911	0.8%	360	2,127	2%
ASC	562	0.5%	6A	1,289	1%
Copperweld	335	0.3%	4	1,285	1%
Allomweld	56	0.0%	6	1,185	1%
UNKNOWN	4	0.0%	9D	1,057	1%
Grand Total	**114,882**		All Other	4,582	4%

Table 28 Overhead Conductor Size and Type

Manitoba Hydro has standardized on the use of five types of overhead aluminum conductors on its distribution system: 2ACSR, 2/0AASC, 266ACSR, 336.4ASC, and 477ACSR. The selected sizes are selected based on the capacity requirements on the circuit. The smaller conductors (2 ACSR and 2/0 AASC) are commonly applied on single-phase taps and rural distribution feeders. The medium sized conductors (266 ACSR and 336.4 ASC) are commonly applied on urban distribution feeders. The largest conductor (477 ACSR) is commonly applied on the 66 kV distribution system.

3/13" Steel

Steel conductor (3/13") comprises 19% (22,021 km) of Manitoba Hydro's distribution system conductors. It was primarily installed during rural electrification (1945-1960) because of its high strength that allows for long span construction with a minimum of poles. Its impedance is eleven times higher than 2 ACSR, the smallest of Manitoba Hydro's standard conductors. As a consequence the conductor has very limited capacity and often requires replacement to ensure conductors do not become overloaded and customer receive an adequate supply voltage. While it was suitable for rural electrification it is increasingly becoming inadequate to support modern load growth, particularly in former rural areas developing into residential subdivisions.

9 Alloy

Alloy conductor comprises 2.4% (2,730 km) of Manitoba Hydro's distribution system conductors. Like 3/13" steel it is found primarily in rural areas and was utilized during rural electrification. It has impedance three times higher than 2 ACSR and an ampacity of only 50 A. It also is becoming increasingly inadequate to support modern load growth and has also been found to be susceptible to broken conductor strands.

Copper

Copper conductors were primarily installed in urban centers on Manitoba Hydro's distribution system. Unlike 3/13" steel and 9 alloys, the majority of copper conductors have low impedances and comparable ampacities to aluminum conductors.

Both solid and stranded copper conductors have been installed on Manitoba Hydro's distribution system. Generally, there have been few operational issues with copper conductors, however some 2/0 conductors utilized a hemp core. Over time this core has degraded, resulting in loose connections at taps and attachment points. These loose connections occasionally manifest as system faults.

It is unknown how much hemp core copper conductor remains on Manitoba Hydro's distribution system, but the total length of all 2/0 copper conductors (hemp and copper stranded cores) is 713 km.

Other Conductors

CCSR, Copperweld, and Shrike are the other common types of conductor installations on Manitoba Hydro’s distribution system. Like 3/13” steel and 9 Alloy, they are characterized by low ampacities and higher impedances than 2 ACSR. Other than replacement of these conductors for planned system improvement and customer projects, these conductors have presented relatively few operational problems.

1.2 Degradation Mechanism

To function appropriately, conductors must retain both their conductive properties and mechanical strength. Conductors have two primary modes of degradation: mechanical and electrical. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Mechanical degradation includes environmental stresses such as icing and tree contact which may result in failure and lengthy power outages. Electrical degradation includes overloading due to general load growth and high fault levels which may result in premature failure and power outages.

Conductor damage is typically the result of broken strands, strand abrasion, elongation, or burning.

- Broken strands are commonly associated with mechanical forces associated with vibration, icing, and storm condition. Small conductors (particularly 9 Alloy) are the most susceptible to strand breaking. In addition to broken strands, degradation of hemp core copper conductors has also resulted in premature conductor failures.
- Strand abrasion is commonly associated with the movement of the conductor damaging the exterior conductor surface. Often this occurs at a connection to an insulator, but tree contact, wildlife contact, and movement of aerial markers are also potential causes.
- Conductor elongation is associated with the physical stretching of the conductor, increasing conductor sag. This is most commonly associated with the mechanical loading of the conductor due to severe wind and ice loads.

- Burn Damage occurs at locations where arcing between the conductor and another conductor or ground has occur as the result of a system fault.

Typical causes of conductor failure are provided in Figure 41. The causes (left to right) (top row) are: broken strands and burn damage; (bottom row) and conductor elongation due to ice loading.

Broken Strand

Conductor Burn Damage

Conductor Elongation Due to Ice Loading

Figure 41 Typical Causes of Overhead Conductor Damage

1.3 Inspection and Maintenance Practices

Although specific testing is not performed on distribution conductors, visual inspections do occur on a regular basis. Visual inspections are required to be completed once every six years for an overhead circuit. As part of these inspections, operational staff will examine the condition of the overhead conductor against the following criteria:

- Ground Clearance
- Conductor Sag
- Attachment Points
- Condition of Ties

- Stranding Integrity
- Arcing Damage

1.4 Health Index and Asset Condition (Useful Life)

1.4.1 *Conductor Life Evaluation*

Overhead conductors are designed to operate on a run to fail strategy. Individual conductor failures are typically repaired in the field following the identification of a specific problem (e.g. broken strands) or system faults. Beyond detailed circuit inspections, overhead conductors do not have a specific assessment program to determine requirements for replacement. Conductor replacement decisions are usually the result of one of the following triggers:

Planning

- The conductor ampacity has exceeded or is close to exceeding its current carrying capability.
- The conductor impedance causes in a poor voltage profile on the distribution circuit.

Condition

- The distribution pole line requires rebuilding and it is advantageous to replace the conductor rather than transferring it to the new circuit.
- The distribution conductor is in very poor shape (e.g. multiple broken strands) and can no longer be effectively maintained.

1.4.2 *Design Criteria for Overhead Conductor Health Index Formulation*

Table 28 indicates the health condition criteria for conductor assessments considering the type of conductor.

Conductor Type	Condition	Probability of Failure	Requirement
N/A	Critical	High	Monitor and Schedule Replacement/Refurbishment Projects when Performance Become Unacceptable
9 Alloy, 3/13" Steel, CCSR, Copper, Copperweld, & Shrike	Fair/Poor	Medium	Monitor as part of feeder inspections.
Aluminum Conductors: ACSR, AASC, & ASC	Acceptable	Low	Monitor as part of feeder inspections.

Table 29 Overhead Conductor Health Index

The conductor health evaluation table provides a general assessment of conductor health. However, as many conductors are not changed during pole replacement projects, knowing the pole line age is not necessarily indicative of the conductor age. Although conductors are anticipated to last well beyond the lifespan of a typical wood pole line, it is anticipated they will become increasingly prone to failure as they age.

1.4.3 *Replacement Rates*

Currently, Manitoba Hydro orders approximately 2,200 km of overhead distribution conductor. It is unknown how much is utilized for new customer connections versus replacement of existing plant, but an estimated 50 km of 3/13" steel is salvaged annually. Table 30 summarizes the lengths of distribution conductor purchases in 2011.

Conductor	Kilometers
2 ACSR	706 km
2/0 AASC	904 km
266 kcmil ACSR	218 km
336 kcmil ASC	260 km
477 kcmil ACSR	117 km
Total	2205 km

Table 30 2011 Distribution Conductor Purchases

1.5 Asset Health

In practice, overhead conductors have a low failure rate and are most often removed from service before they fail due to other planned work (e.g. pole replacement, capacity upgrade, etc). The health profile of Manitoba Hydro's overhead conductor assets is presented in the "soccer field" graphs on Figure 42. In these graphs, the current asset health and a 20 year projection are provided. The following assumptions are made:

- Current Status: Non-standard conductors (9 Alloy, 3/13" steel, Copper, CCSR, Copperweld, and Shrike) are rated fair/poor and standard conductors (AASC, ACSR, and ASC) are rated acceptable.
- Future Status: The majority of non-standard conductors are assumed to remain in fair condition with 10% degrading to critical condition and salvaged at a rate of 50 km/year. The majority of standard conductors are assumed to remain in acceptable condition with 10% degrading to fair/poor condition.

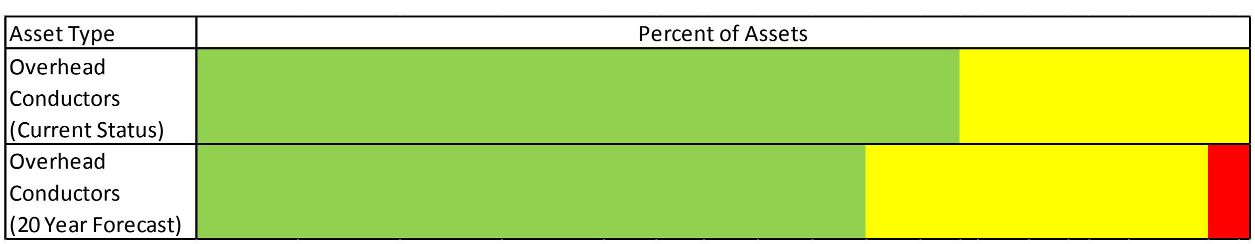


Figure 42 Overhead Conductor "Soccer Field"

Figure 42 indicates approximately 28% of the overhead conductors installed on Manitoba Hydro's distribution system are in fair/poor condition. This number is anticipated to degrade slightly to 31%, assuming the current annual salvage rate of 50 km for 3/13" steel is maintained. Generally speaking, conductors are assumed to outlast the wood poles supporting them, however approximately 3% of conductors are anticipated to transition to critical condition over the next 20 years. If that scenario holds, the replacement of the conductor would cost $63 million.

1.6 Risk of Failure

1.6.1 *Overhead Distribution Conductor Risk Assessment*

Overhead distribution conductor failures can result in substantial customer outages, particularly if they are along a main three-phase section of feeder or on a 66 kV circuit. Typical failures can impact between 1 and 4,000 customers. Repair times can range substantially, ranging from an hour in an urban environment to half a day or more in a remote location.

Environmental: Conductors are subjected to wind and ice loading and can fail mechanically when exposed to loading conditions beyond their design. In addition, lightning strikes can result in localized conductor burning that can result in conductor failure.

Mechanical: Conductors can become brittle and increasingly more susceptible to break with age.

Thermal: Exceeding operating ampacity can anneal conductors, making them prone to failure.

Distribution conductor failures can result in substantial customer outages, impacting an entire distribution feeder or 66 kV circuit. Individual customer outages as the result of a conductor failure can range from 1 and 10,000 customers. Repair times can range from an hour in an urban environment to half a day or more in a difficult to access remote location. Although distribution protection usually detects overhead conductor failures, there is a risk of high impedance faults (e.g. conductor in contact with snow or asphalt) creating a risk of electrocution if the fault has not been detected by the circuit protection.

1.6.2 *Risk Matrix*

Based on the observations made in this report, the following risk matrix has been developed considering the anticipated impact cable failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted on the risk matrix in Figure 43. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

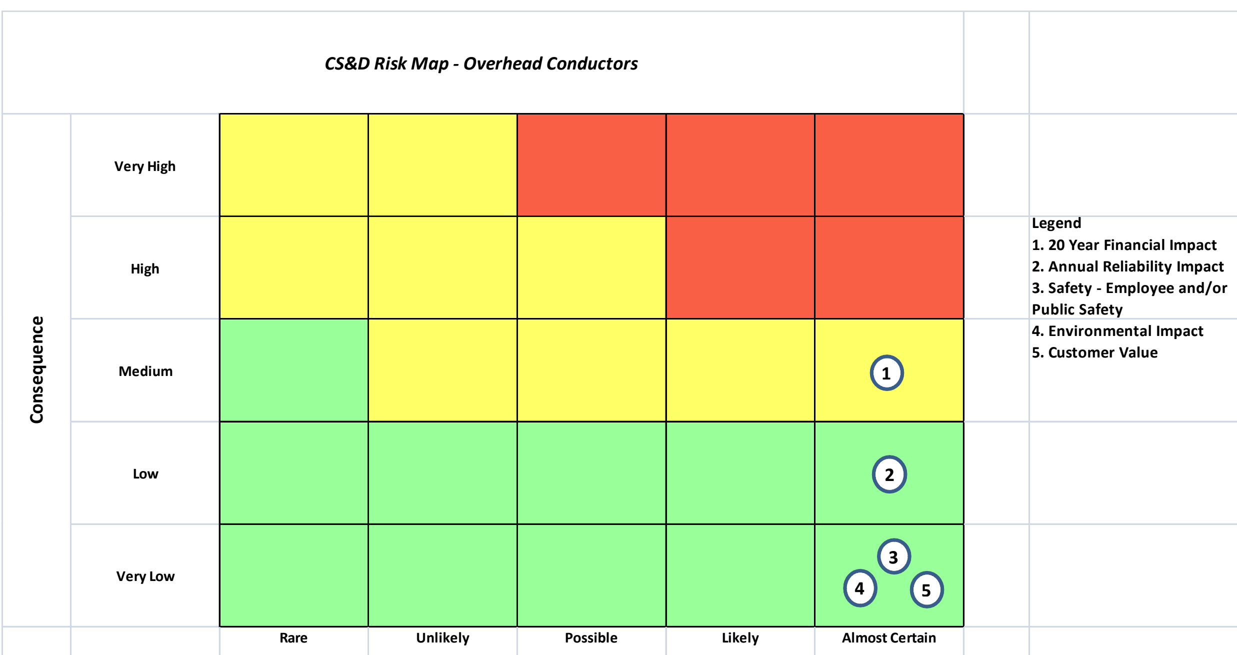


Figure 43 Overhead Conductor Risk Map

Figure 43 indicates that the risks associated with overhead conductor failures are moderate. In the worst case scenario a conductor failure would impact a major 66 kV or 24 kV circuit and result in an outage impacting several thousand customers for several hours. These types of failures are readily repairable by operational staff.

1.7 Distribution Asset Evaluation

Overhead conductor replacement costs are primarily based on the installed conductor size. Figure 44 provides an overview of the conductor asset value, current replacement rates, and anticipated lifespan.

Asset	Quantity	Life Expectancy	Current Replacement Rate[11]
ACSR Conductor	77,747 km	100 Years	200 Years
AASC Conductor	4,481 km	100 Years	200 Years
ASC Conductor	562 km	100 Years	200 Years
3/13” Steel	22,021 km	100 Years	200 Years
9 Alloy	2,730 km	70 Years	200 Years
Other Non-Standard Conductors	7,336 km	100 Years	200 Years
Replacement Cost	$2,000 - $8,000+/km		
Replacement Value	$700 Million		

Figure 44 Overhead Conductor Economic Evaluation

[11] Assumed replacement rate corresponds to wood pole replacement during line rebuilding projects. Existing replacement rate of 3/13” steel is 50 km/year, which will be ramped up during wood pole replacement projects.

1.8 Recommendations

Gap: During the analysis the following gap was identified.

Low Priority

1. The specific location of failed conductors (and all other fault locations) is not consistently captured in the Service Interruption Reporting Program. Without these data the only indication of reliability performance issues involving a specific conductor is anecdotal and verification relies on non-mandatory comment fields in the program.

Recommendation: The following recommendation is made to address the gap

Low Priority

1. Fault location should be captured in the Service Interruption Reporting program so the specific conductor involved in the fault can be identified. These data could most likely be captured in the field following the implementation of the Mobile Workforce Management Program.

APPENDIX G

Overhead Transformers

Asset Condition

04/27/2012

1. OVERHEAD TRANSFORMERS

Transformers are an integral part of Manitoba Hydro's electrical distribution system and are required to change utilization voltage levels. Although transformers are available in numerous sizes and transformation levels, essentially two types are applied on the distribution system: power class and distribution class.

Power class transformers are typically installed within distribution substations and distribution supply center locations. These units typically transform voltage levels from transmission (115 kV or 138 kV) or high voltage distribution (24 kV, 33 kV, 66 kV) levels to medium voltage distribution levels (4-25 kV). Typical capacity of these units ranges from 3 MVA to 100 MVA. Maintenance of these units is the responsibility of Apparatus Maintenance and outside the scope of this document.

Distribution class transformers are typically installed on distribution feeders and transform voltage levels from one medium voltage to another (interchange bank) or to low voltage (distribution transformer). Maintenance of both types of distribution class transformers is typically the responsibility of Customer Service Operations. However as there are only 49 platform mounted overhead interchange transformer installations on the distribution system they are excluded from this document.

Distribution transformers transform voltage levels from medium voltage to low voltage (120/240 V, 120/208 V, 480/277 V, 600/347 V, and legacy delta services). Although some overhead three-phase transformers are installed on the distribution system (most notably in the oil fields of southwest Manitoba), the majority of units are single-phase units. Typical capacity of these units ranges from 15 kVA to 167 kVA and it is common for the transformers to be installed for both single-phase and three-phase applications. Some larger capacity single-phase transformers (e.g. 250 kVA and larger) are installed in customer vaults or on platforms to provide service to the building. These are non-standard stock items and spare parts may not be readily available.

1.1 Demographics

Manitoba Hydro has approximately 142,000 overhead distribution transformers installed on its electrical distribution system. Photos of typical transformer installations are provided in Figure 45.

Single-Phase Overhead Transformer | Three-Phase Overhead Transformer Bank | Three-Phase Vault Transformer (Overhead Banks)

Figure 45 Typical Overhead Transformer Installations

Manufactured dates are known for 70% of the overhead distribution transformer installations. Using this data as a projection, the anticipated age profile of Manitoba Hydro's total overhead distribution transformer has been projected assuming the remaining 30% of the transformers were uniformly installed between 1945 (the start of rural electrification) and 1970 (near the start of the TLMS program which stored transformer manufactured dates). The resultant age profile is provided in Figure 46.

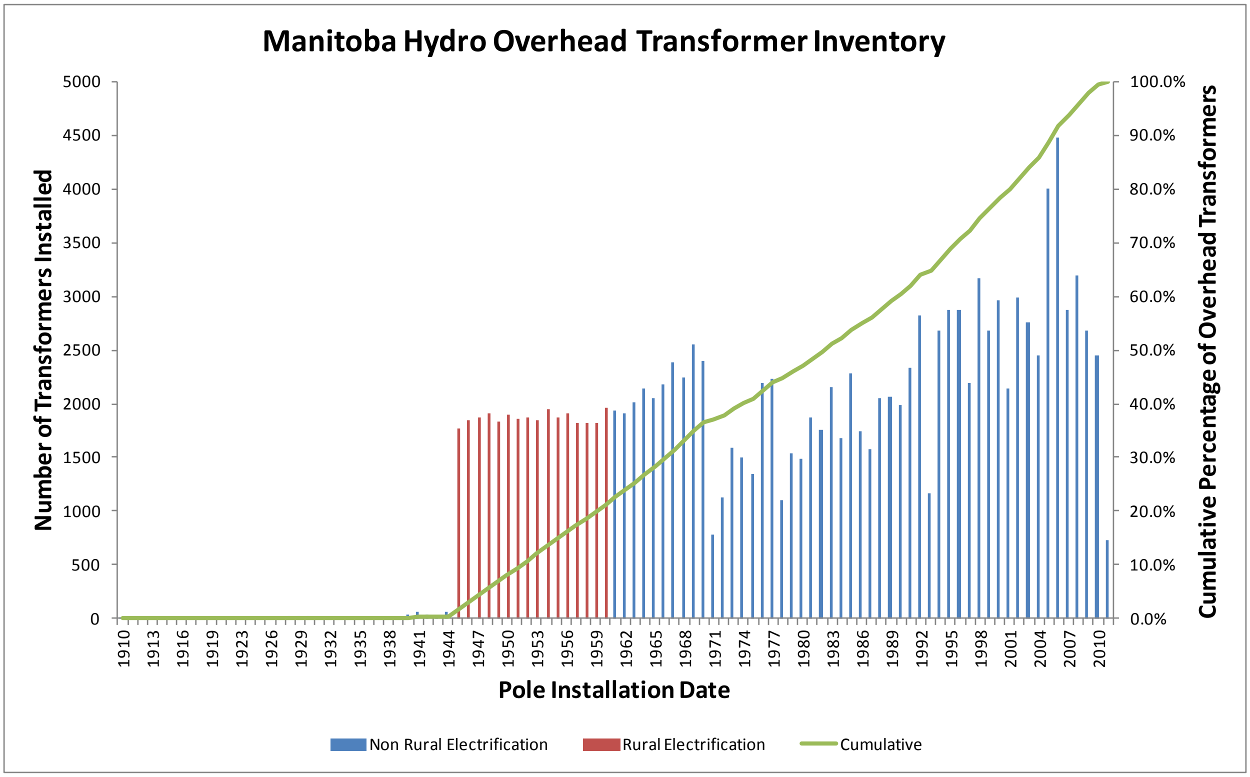


Figure 46 Manitoba Hydro Overhead Transformer Inventory

Figure 46 indicates that Manitoba Hydro's overhead transformer assets have ranged between 1000 and 4500 installations per year. Of these assets 21% or 30,000 units were installed prior to 1960 and will be approaching the end of their serviceable life within the next several years. Although there is uncertainty in the installation dates for transformer installations prior to 1970, Manitoba Hydro's current transformer replacement rate is anticipated to be adequate for the first "hump" of assets when they reach their anticipated lifespan.

A breakdown of the installed pole and platform distribution transformer installations by capacity is provided in Table 31.

	Individual Transformer Capacity									
	<15 kVA	25 kVA	37 kVA	50 kVA	75 kVA	100 kVA	167 kVA	250 kVA	333 kVA	>500 kVA
Single-Phase	49224	34341	4554	19144	3858	1220	170	0	0	0
Two Single-Phase	939	228	29	67	25	6	0	0	0	0
Three-Phase	1560	2211	276	2210	771	523	139	12	3	3

Table 31 Overhead Distribution Transformer Count

The majority of the overhead distribution transformers installed on the system are single-phase distribution transformers, with the majority of units being less than 50 kVA. Eighteen banks of three single-phase transformers have individual transformer capacities of 250 kVA or greater. These units exceed the capacity of the 167 kVA units currently stocked by Central Stores and would require replacement with a padmount transformer if a spare unit is not available.

In addition to overhead pole mounted transformers, Manitoba Hydro also utilizes vault mounted transformers on the distribution system. Details of those installations are provided in Table 32. As detailed phasing information for the vault transformers was not all available, it was assumed that all single-phase units were installed in a three-phase bank configuration.

	Individual Transformer Capacity								
	>100 kVA	167 kVA	250 kVA	333 KVA	500 kVA	667 kVA	750 kVA	833 kVA	>1000 kVA
Three-Phase	110	43	31	31	32	5	5	1	114

Table 32 Overhead Distribution Transformer Count

1.2 Degradation Mechanism

Transformers operate under many extreme conditions that affect their aging potential for failure. Over time the transformers insulation degrades losing its dielectric strength. The speed of the degradation varies and depends on a variety of factors; however ambient temperature, wind, and loading history are the most important considerations. Typically distribution transformers can be expected to last 50 years or more in the field and few units fail in service due to “age.”

The majority of distribution transformer failures (transformers don’t fail out of service) are triggered by an external event such as wildlife, tree contact, or lightning strike at the transformer resulting in internal and/or external damage to the unit. Transformer overloading is another potential failure cause. Transformer failures due to overload are relatively infrequent as the majority of units on Manitoba Hydro’s distribution system are conservatively sized and potential equipment overloads are regularly monitored through the Load Estimation System. Installation of wildlife guards and lightning arresters transformers also reduce the risk of individual transformer failures.

Distribution transformers typically do not fail catastrophically. One potential reason for this is the application of current limiting fuses in areas where the fault level exceeds 4,000 A. Current limiting fuses, although applied primarily to prevent catastrophic failure of fused cutouts, also reduce the amount of fault energy through the transformer.

Typical causes of transformer failures are provided in Figure 47.

Leaking Oil Rusted Tank Overhead Transformer

Cracked Bushing Chipped Bushing Burned Riser

Figure 47 Typical Causes of Overhead Transformer Degradation

1.3 Inspection and Maintenance Practices

1.3.1 Visual Inspections

Typically, overhead distribution transformers are run until the asset fails or is removed from service for another reason (e.g. voltage conversion, transformer capacity upgrade, or line refurbishment). Although specific testing is not performed on distribution transformers, both visual and grounding system inspections do occur on a regular basis.

Visual inspections are required to be completed once every six years for an overhead distribution circuit. As part of these inspections, operational staff will examine the transformer installation and note any signs of potential problems (e.g. oil leakage, overloading, tree contact).

1.3.2 PCB Sampling

Manitoba Hydro has completed PCB sampling of all of its overhead distribution transformers. Units whose PCB levels exceeded 45 parts per million were replaced. This inspection practice enabled operational staff to collect detailed transformer age data which is referenced in this report. Currently, there are no plans to resample PCB levels within distribution transformers.

1.4 Health Index and Asset Condition (Useful Life)

1.4.1 Transformer Life Evaluation

Overhead distribution transformers are designed to operate on a run to fail strategy. Individual transformer units are typically not replaced as the result of a determination the unit has exceeded its end of life. Transformer replacement decisions are usually the result of one of the following triggers:

- The pole supporting the transformer requires replacement and the opportunity to install a new replacement unit is utilized.
- Distribution Engineering has determined the transformer capacity needs to be increased to supply customer load.
- Distribution Engineering has determined the area voltage requires conversion (e.g. 4 kV to 24 kV).
- Customer Service Operations has deemed it necessary to replace the unit due to a unit or supporting pole to a failure. This type of replacement is typically the result of a fault damaging the equipment beyond repair.

Transformers that are returned to Central Stores are evaluated against the following criteria to determine if they will be refurbished for future use or scrapped: transformer condition and repair costs, turnover rate, and unit capacity. These factors are entered into a spreadsheet utilized by Materials Management and a decision to retain or scrap the unit is based on economic analysis calculations.

1.4.2 Design Criteria for Transformer Health Index Formulation

Table 33 indicates the health condition criteria for transformer assessments considering the age of the unit.

Age/Health	Condition	Probability of Failure	Requirement
>75 Years	Critical	High	Replace based on condition assessment if necessary.
51 – 74 Years	Fair/Poor	Medium	Continue to monitor as part of feeder inspection and load estimation requirements.
50 Years or Younger	Acceptable	Low	Continue to monitor as part feeder inspection and load estimation requirements.

Table 33 Overhead Transformer Health Index

The transformer health evaluation provides a good assessment for condition of transformers based on service life. However, there is a gap with respect to other failures which can result in premature transformer failure (e.g. tank corrosion, bushing damage, lightning damage, overloading).

1.4.3 Replacement Rates

Historically, Manitoba Hydro's overhead transformer annual failure rate (resulting in customer outages) has ranged between 200 and 400 failures or 0.1% to 0.3% of the total transformer population.

Between 3500 and 4500 overhead transformers are installed on Manitoba Hydro's electric distribution system annually. Of these units approximately half are associated with customer service work orders, and half are associated with system improvements (voltage conversions), and the remaining units are utilized for emergency repairs. Assuming 2,000 existing transformers are replaced annually with new units, it would take approximately 70 years to replace the total installed population.

1.5 Asset Health

In practice, overhead transformers have a low failure rate and are most often removed from service before they fail due to condition assessment data. The health profile of Manitoba Hydro's overhead transformer assets is presented in the "soccer field" graphs in Figure 48. In these graphs, the current asset health and a 20 year projection are provided. The following assumptions are made:

- Overhead transformers 75 years of age or greater are rated critical.
- Overhead transformers 51 – 74 years or greater are rated fair/poor.
- Overhead transformer 50 years or younger are rated acceptable.

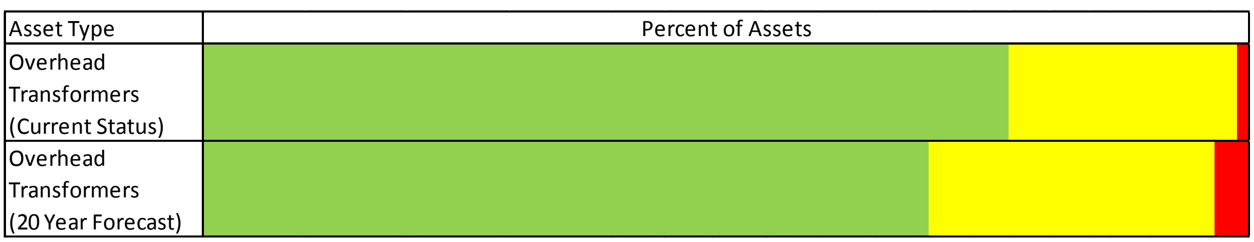


Figure 48 Overhead Transformer "Soccer Field"

Figure 4 indicates that the current existing overhead transformer replacement rate is insufficient to maintain 1% of the transformer population in critical condition. Over the next 20 years, this number is anticipated to increase to 3% of the transformer population or approximately 4,700 transformers. In 20 years the replacement cost of all fair/poor transformers will rise to approximately $15 Million. This increase could be mitigated completely through a modest increase in replacement of aging transformers from 2,000 to 2,250 per year.

1.6 Risk of Failure

1.6.1 Overhead Distribution Transformer Risk Assessment

Distribution transformer failures typically result in small customer outages. Typically, overhead transformer failures impact between 1, and 20 customers, however interchange transformers can supply several hundred customers depending on the application. Repair times range from less than an hour in an urban environment to half a day or more for a difficult to access vault or interchange transformer.

Since overhead distribution transformers contain oil there is a risk of fire and release of oil in the event of a catastrophic tank failure. However, this risk is very low due to the application of current limiting fuses when available fault levels exceed 4000 A. Another potential risk during a transformer failure is that of electrocution, however this is also very low provided the grounding system at the pole has not been compromised. New transformer installations also utilize wildlife guards and lightning arresters installed on the unit to further reduce the probability of a failure from occurring.

Overhead Distribution Transformer Risk factors include:

Environmental: Transformers are most likely to be damaged due to lightning strikes in severe weather conditions. Damage to the supporting pole structure from severe wind and ice loading can also result in transformer damage.

Corrosion: Corrosive environments, particularly on roadways lead to ingress of salty spray onto transformers. This spray can result in localized corrosion on the transformer, oil leakage, and ultimately transformer failure.

Wildlife: Transformers not equipped with wildlife guards can be vulnerable to damage if a bird or small animal bridges the transformer bushing or lightning arrester.

Thermal: Transformers loaded beyond their design capability can fail due to thermal events (insulation breakdown, gassing, etc.)

1.6.2 Risk Matrix

Based on the observations made in this report, the following risk matrix (Figure 5) has been developed. The matrix considers the anticipated impact overhead transformer failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted on the following risk matrix on Figure 49. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

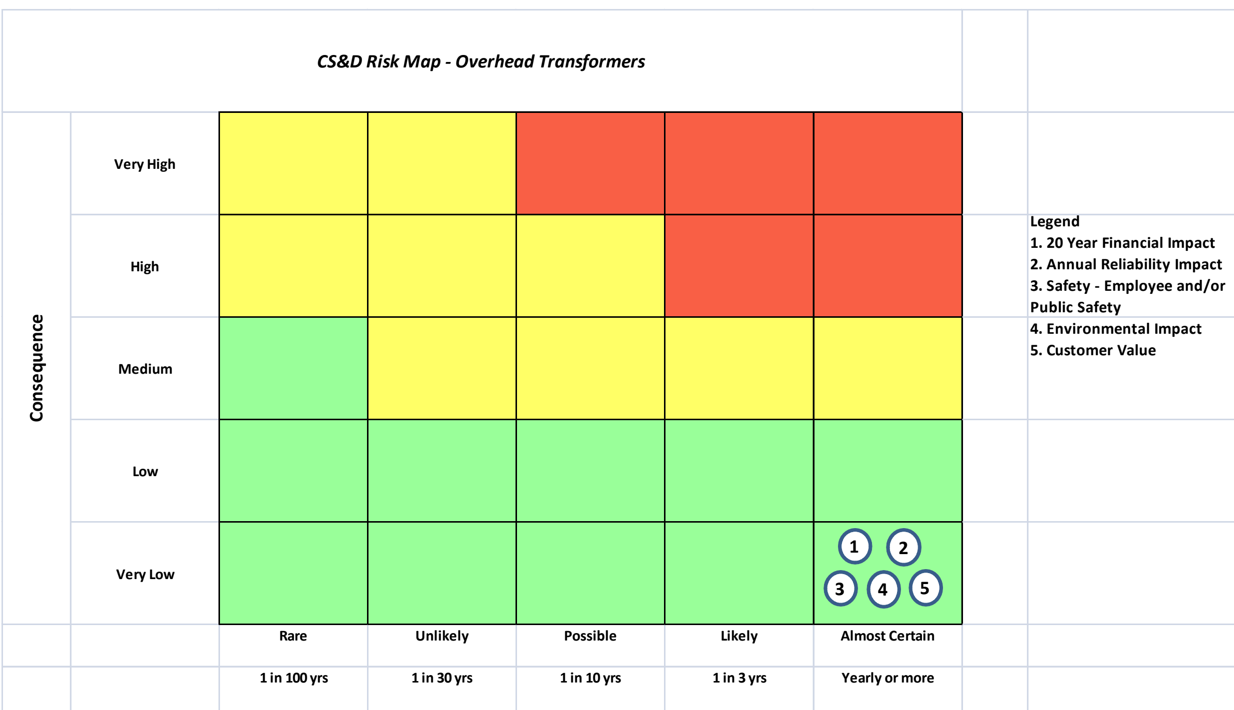


Figure 49 Overhead Transformer Risk Map

Figure 49 indicates that the risks associated with overhead transformer failures are low. In the worst case scenario an overhead transformer failure could result in a lengthy outage to a high profile customer which could receive result in high profile local media attention.

1.7 Distribution Asset Economic Evaluation

The value of Manitoba Hydro’s overhead distribution transformers is estimated based on the anticipated replacement cost of the transformer and associated hardware. Replacement of an overhead transformer can range from $3,100 for a 15 kVA transformer to $22,242 for a 3x167 kVA three-phase bank. Using these values, the replacement cost of Manitoba Hydro’s existing overhead transformer inventory is estimated to be approximately $494 million.

Table 34 details Manitoba Hydro’s existing transformer inventory along with the material requirements to replace these assets with standard stock items. Typically overhead three-phase transformer installations are limited to oilfield 480 V applications; however there are also legacy three-phase transformer installations throughout the province. The installation costs assume the existing pole or platform can be re-used to avoid duplication of pole replacement costs discussed in the wood pole section of the report.

Replacement Costs for Manitoba Hydro's Overhead Distribution Transformer Banks			
Unit Capacity	**Number**	**Installation Cost**	**Total**
15 kVA	50,163	$3,081	$154,552,203
25 kVA	34,571	$3,222	$111,387,762
50 kVA	23,792	$4,129	$98,237,168
75 kVA	3,883	$5,401	$20,972,083
100 KVA	1,226	$6,672	$8,179,872
167 kVA	170	$8,045	$1,367,650
3x15 kVA	1,560	$8,351	$13,027,560
3x25 kVA	2,211	$8,841	$19,547,451
3x50 kVA	2,486	$11,751	$29,212,986
3x75 kVA	771	$15,285	$11,784,735
3x100 kVA	523	$19,125	$10,002,375
3x167 kVA	139	$22,442	$3,119,408
3x250 kVA[12]	12	$25,500	$306,000
3x333 kVA	3	$28,500	$85,500
3x500 kVA	3	$31,500	$94,500
3x100 kVA[13] (Vault)	110	$23,000	$2,530,000
3x167 kVA (Vault)	43	$26,000	$1,118,000
3x250 kVA (Vault)	31	$29,000	$899,000
3x333 kVA (Vault)	31	$32,000	$992,000
3x500 kVA (Vault)	32	$35,000	$1,112,000
3x667 kVA (Vault)	5	$45,000	$225,000
3x750 kVA (Vault)	5	$55,000	$275,000
3x833 kVA (Vault)	1	$65,000	$65,000
3x1000 kVA (Vault)	114	$75,000	$8,550,000
Total			$494,455,373

Table 34 Overhead Transformer Replacement Costs

[12] Overhead transformers greater than 250 kVA in capacity are non-standard stock items and would require special orders if a spare unit was not available. If replacement of the bank with a padmount transformer is required, substantial additional costs could be incurred.

[13] The vault replacement cost assumes that replacement of the existing vault transformers is possible with specially ordered units and the existing primary and secondary infrastructure can be reused. If installation of a padmount transformer and customer secondary wiring changes are required, the cost of an individual vault replacement could range from $125,000 to $200,000 or more.

Figure 50 provides an overview of the overhead transformer asset value, current replacement rates, and anticipated lifespan.

Asset	**Quantity**	**Life Expectancy**	**Current Replacement Rate**
Single-Phase Overhead Transformers	113,805	75 Years	70 Years
Three-Phase Overhead Transformer Banks	7,708	75 Years	70 Years
Three-Phase Vault Transformers	372	75 Years	NA
Replacement Cost	$3,000 - $75,000 per transformer		
Replacement Value	$494 Million		

Figure 50 Overhead Transformer Economic Evaluation

1.8 Recommendations

Gap: During the analysis of the asset the following gap was identified.

Medium Priority

1. Vault transformers can be difficult and time consuming to repair and spare transformers of suitable size (e.g. 250 kVA single-phase) are not standard stock items.

Recommendations: The following recommendations are made to address this gap.

Medium Priority

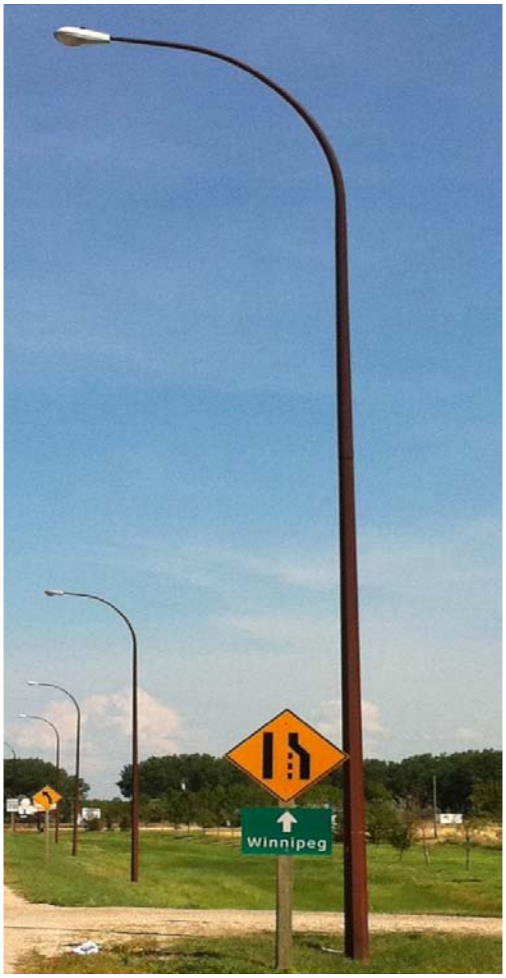
1. Vault transformers – Vault transformers can be difficult to replace in emergency situations and spare transformers of adequate capacity are not necessarily available. An inventory of these units and contingency plans for high profile customers supplied by vault transformers should be developed.

Low Priority

2. Transformer Hardware – The installation of bird guards and lightning arresters can reduce the risk of transformer failures. The benefit of retrofitting vulnerable transformers should be evaluated during the development of maintenance plans for worst performing circuits.

APPENDIX H
Streetlights
Asset Condition

04/27/2012



1. STREETLIGHTS

Streetlight standards typically consist of tubular steel or aluminum that support lights and are used to provide roadway lighting in urban and high traffic locations. The majority of Manitoba Hydro street lights are concentrated within the City of Winnipeg and to a lesser extent in other large urban centers in the province.

Streetlights standards come in a variety of different heights and designs. The structures are typically painted, galvanized, or self weathering steel. In addition, aluminum standards are also used in specialized applications such as bridges due to their lower structure weight. Although lighting also exists on overhead pole structures, the condition of those assets are covered in the pole section of this report and considered outside the scope of this document.

1.1 Demographics

Manitoba Hydro has approximately 58,000 streetlight standards installed in the province. The majority, 49,600 of these standards are located within the City of Winnipeg. There are three primary methods of streetlight installations: concrete pile bases, direct burial, and steel power screw. The types of standard installations are detailed in Table 35.

Installation Type	**Quantity**
Concrete Pile & Bases	24,842
Direct Burial	11,484
Steel Power Screw	2,981
Unidentified	18,908
Total	58,225

Table 35 Types of Streetlight Standard Installations

Concrete pile and bases are the most prevalent installation of streetlight standards and are the current design standard. Direct burial and power screw streetlight installations are also common and were installed based on previous design standards. Both direct burial and power screw standard installations can be susceptible to below grade corrosion. Typical streetlight installations are provided in Figure 51. The installations are (left to right): galvanized standard, decorative standard, and painted standard.

Galvanized Standard Decorative Standard Painted Standard

Figure 51 Typical Streetlight Installations

Photos of streetlight bases are provided in the Figure 52. The bases are (left to right): concrete pile, power screw, and direct buried.

Concrete Pile Power Screw Direct Buried

Figure 52 Typical Streetlight Base Installations

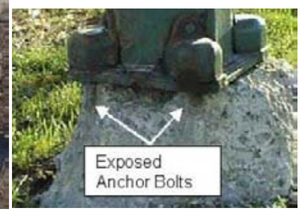
1.2 Degradation Mechanism

Streetlights are subjected to environmental conditions and mechanical damage. The nature and severity of the damage depends on the pole location and its environment. The main contributor to the structural breakdown of streetlight standards is corrosion, both above and below the soil surface. Corrosive environments are typically associated with the proximity of the streetlight to salt spray from vehicular traffic, but differences in soil chemistry also contribute to below grade corrosion. Streetlight standards with metal in contact with the soil (power screw anchored or direct buried) are the most susceptible to this type of degradation.

Another factor impacting streetlight strength is damage caused by contact from snow clearing or construction equipment and vehicular accidents. Dents, cuts, or severe damage from this type of contact can also result in the failure of a standard. Typical causes of streetlight degradation are provided in Figure 53. The causes (left to right) are (top row): above grade corrosion and damage from vehicular or construction equipment contact; (bottom row) below grade corrosion and concrete pile degradation.

Above Ground Corrosion

Dented Standard



Concrete Degradation

Below Ground Corrosion

Figure 53 Typical Causes of Streetlight Standard Degradation

1.3 Inspection and Maintenance Practices

Scheduled inspections are conducted according to the requirements of Policy P348, but have been inconsistent over many years. These inspections are completed using specific criteria, but are limited to assessing above grade condition only. The condition of direct buried and steel power screw anchored standards below the soil surface has not been assessed.

City of Winnipeg streetlights are scheduled for inspection once every four years. Standards are inspected by the Streetlight Maintenance and Underground Inspection Section. Outside the City of Winnipeg inspections are organized by the local CSC. Inspections have been recently completed for all districts. However, lower priority maintenance items such as sandblasting and painting standards exhibiting signs of corrosion have stopped. That may have slowed the rate of corrosion on the impacted standards.

In the fall of 2011, a group of six District Service Workers inspected over 5,000 standards at high risk locations along main thoroughfares within the City of Winnipeg. These inspections were initiated following 16 standard failures due to high winds. These failures caused Manitoba Hydro to revisit streetlight inspection criteria, frequency, and data management. Details of the failures which triggered this review are provided in Table 36.

	STREET LIGHT STANDARD BLOW DOWNS				
Date of Incident	Location	Standard Size	Injuries	Property Damage	Comments
May 31, 2011	Highway 12 and Park Rd (Steinbach)	55'	None	Vehicle	Standard fell onto car waiting for light to change.
July 25, 2011	Portage and Broadway (Winnipeg)	45'	None	None	
August 18, 2011	Portage and St. Charles (Winnipeg)	35'	None	None	
August 28, 2011	119 Olive St. (Winnipeg)	25'	None	None	
September 13, 2011	Century and Saskatchewan (Winnipeg)	35'	None	None	
September 13, 2011	50 Mirabelle (Winnipeg)	25'	None	None	
September 13, 2011	2829 McGregor Farm Rd (Winnipeg)	35'	None	None	
September 23, 2011	Grant and Ash (Winnipeg)	35'	None	None	Breakaways broke, std not rusted
October 7, 2011	750 Pembina (Winnipeg)	45'	None	None	
October 7, 2011	750 Pembina (Winnipeg)	45'	None	None	
October 7, 2011	15 Barker (Winnipeg)	30'	None	None	
October 7, 2011	15 Tumbleweed (Winnipeg)	25'	None	None	
October 7, 2011	680 Moray (Winnipeg)	30'	None	None	
October 31, 2011	1030 Empress (Winnipeg)	45'	None	None	Street Signs
October 31, 2011	Wellington Cres and Lindsay (Winnipeg)	25'	None	None	Street Signs
November 10, 2011	225 Aldine (Winnipeg)	25'	None	None	notification 10175532

Table 36 Streetlight Standard Failures

1.4 Health Index and Asset Condition (Useful Life)

Streetlight health has not been formally assessed beyond regularly scheduled inspections. Standard installation dates are not currently entered into the eGIS program prior to 2005, so an accurate age profile of the asset cannot be determined. Maintenance issues involving streetlights are documented in the Distribution Maintenance & Planning System (DMPS); however streetlight data has only been recently maintained on the system.

Although a specific streetlight age profile is not known, it is known that direct buried and power screw anchored streetlights are susceptible to corrosion below the soil surface. Field staff has indicated below grade corrosion involving these two types of standards can be extensive and failures of this nature usually involve the visible leaning of the standard. Such failures have been gradual and have not resulted in rapid collapse of the streetlight.

Rapid collapse failures are most typically associated with extensive above grade corrosion and wind conditions. The force exerted by the wind on the base of the standard can result in the collapse of the unit if substantial damage from corrosion or other factors had compromised the strength of the structure.

1.4.1 Streetlight Strength Evaluation

In 2010, Distribution Asset Maintenance expanded existing inspection criteria which were used on an inspection blitz of Winnipeg streetlights. These requirements are outlined in Policy P348 which requires standards to be inspected on a four year cycle. Standards are replaced when:

- The standard has a dent exceeding 50 mm, or
- The standard has a puncture exceeding 50 mm, or
- There is any evidence of rust penetration.

During inspections, streetlights are classified into the following four categories:

Critical: Critical issues typically associated with severely damaged standards at risk of falling are addressed immediately. If a standard is found to be in this condition, the site is secured and the failed light is replaced on a priority basis.

High: High priority issues evidence of rust penetration, cracked welds/bottom plates, and major dents.

Medium: Medium priority issues include minor dents and localized corrosion.

Low: Low priority issues include peeling paint and graffiti.

1.4.2 Design Criteria for Streetlight Health Index Formulation

Table 37 indicates the health condition criteria for streetlight assessments considering the health and installation type of the standard.

Health/Installation Type	Condition	Probability of Failure	Requirement
Compromised Structural Integrity, Severely Corroded, or Major Dent	Critical	High	Immediate risk assessment, secure site, replace based on assessment
Power Screw Anchor, Direct Buried Installation, or Signs of Corrosion	Fair/Poor	Medium	Start planning to replace or reinforce considering risk and impact of failure.
Low Priority Condition Issue	Acceptable	Low	Continue to monitor as part of streetlight inspection process.

Table 37 Streetlight Standard Health Index

The streetlight health evaluation table provides a general assessment of standard health. However, the installation dates of streetlight standards prior to the implementation of the eGIS system, are unknown and an accurate asset age profile cannot be determined.

1.4.3 Replacement Rates

Streetlight replacement rates are relatively low, with approximately 1300 – 1500 standards installed annually. Installations are split amongst new customer service requests and replacement of failed plant. Recently, Customer Service Operations replaces approximately 560 standards annually: 120 of these are due to billable hits (e.g. accident or equipment contact) and 440 are due to corrosion. At the current replacement rate, it will take approximately 100 years to replace all the streetlight installations on the distribution system.

It is notable the vast majority of these replacements (99%) involve concrete piled installations. Unless an above grade condition issue or visible evidence of leaning (indicating below ground corrosion) is identified on a power screw anchored or direct buried standards they are not replaced.

1.5 Health

Customer Service Operations field staff survey the City of Winnipeg streetlights each summer on a four year inspection cycle. Table 38 indicates the number of streetlights with identified maintenance issues in the DMPS program.

Priority	**Number of Streetlights With Identified Issues**
High	109
Medium	2,393
Low	15,743
Total Problems:	18,245

Table 38 Streetlight Health Index Categories

Of the identified issues, high priority repairs are required on 0.6% of the population. Medium priority issues comprise 13.1% of the total and the remaining 86.3% of the issues are low priority. The majority of the low priority items involve painting requirements (approximately 12,000 items).

In practice, streetlight standards have a low failure rate and are most often removed from service before they fail due to planned replacement work however as discussed in Section 1.3, in 2011, Manitoba Hydro experienced 16 standard blow downs. The health profile of Manitoba Hydro's streetlight standard assets is presented in the following "soccer field" graphs. In these graphs, the current asset health and a 20 year projection are provided. The following assumptions are made:

Current status: Standards listed as requiring high priority repairs are listed in critical condition. Direct buried or power screw standard installations are classified as fair/poor condition along with 20% of concrete piled installations. The remaining concrete piled installations are classified in good condition.

Future status: Half of direct buried and power screw installations transition along with the 20% of concrete piled standards in fair/poor condition to critical condition. Half of direct buried and power screw installations remain in fair condition with 20% of concrete piled standards transitioning from acceptable condition to fair/poor condition. All remaining concrete piled installations remain in acceptable condition. The projection assumes the current streetlight replacement rate of 560/year is maintained but only concrete piled standards are replaced.

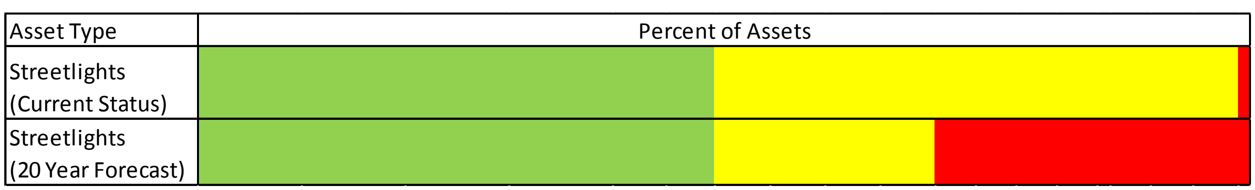


Figure 54 Streetlight Standard "Soccer Field"

The preceding figure indicates relatively few streetlights are in critical condition however very little replacement of direct buried and power screw standards is occurring. It is anticipated those standards will fail in increasing quantities over the next 20 years. If half of those standards require replacement substantial asset replacement or rehabilitation will be required. If it is viable to cathodically protect those standards then rehabilitation would be approximately $11 million. If, cathodic protection or another lower cost rehabilitation strategy is not feasible and the standards have to be replaced with concrete piled installations, the replacement cost would escalate to $88 million.

1.6 Risk of Failure

1.6.1 Streetlight Risk Assessment

Manitoba Hydro currently has not established a formal risk assessment process for streetlights. Historically streetlights have been repaired as necessary with most repairs scheduled based on priority.

The following factors must be considered as part of the streetlight risk process.

Corrosion: Corrosive environments, particularly on roadways lead to ingress of salty spray into streetlights which can accelerate corrosion of streetlights above the ground line. Proximity to high traffic volumes and snow height against the standard all impact streetlight corrosion. Corrosion failures could involve deterioration of the steel or aluminum pole and supporting anchor bolts. In addition, direct buried and power screw anchored standards can be susceptible to below grade corrosion due to local soil chemistry conditions.

Environmental: Streetlights are subjected to similar wind loads as wood poles and can fail mechanically if exposed to loading conditions beyond the structural integrity of the standard.

Vehicular Traffic: Vehicular accidents can result in streetlight damage requiring replacement of the standard.

Foreign Interference: Contact of the streetlight by construction or snow removal equipment can also mechanically damage the streetlight.

A recent streetlight replacement project along Kenaston Boulevard, involved the installation of the new standards back from the road edge towards the properly line. This location will reduce the salt exposure (i.e. corrosion) and chance of the standard being struck by vehicle traffic or snow clearing equipment.

1.6.2 Risk Matrix

Based on the observations made in this report, a risk matrix has been developed. The matrix considers the anticipated impact streetlight failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted in the following risk matrix on Figure 55. Each factor is assigned a unique number and corresponds to the list above. For example, the Environment factor is assigned the number 4 on the following chart. For further discussion of the risk chart along with the corresponding classification of each probability and consequence please refer to Appendix I of this report.

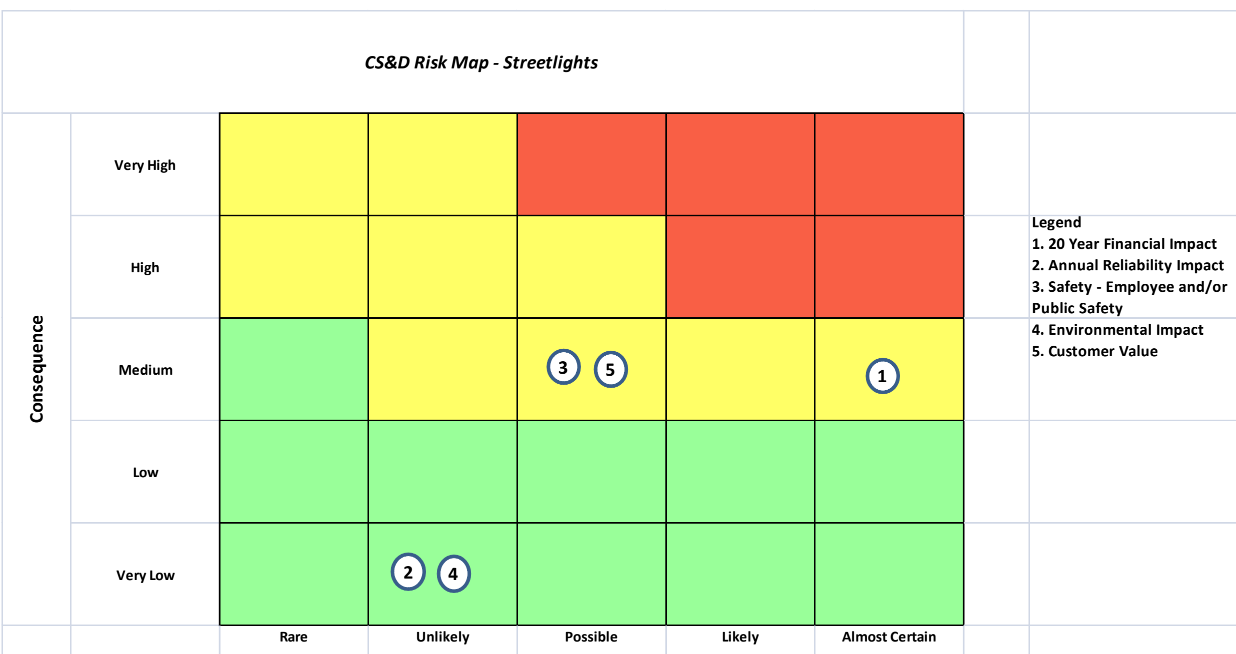


Figure 55 Streetlight Risk Map

Figure 55 indicates that the risks associated with streetlight standard failures are moderate. The existing replacement rates appear to be adequate if diagnostic tools can be utilized to identify below grade corrosion issues on direct buried and power screw anchored standards prior to failure and if 50% of existing installations of these types degrade to unacceptable levels over the next 20 years. The worst case scenario of a streetlight blow down coming into contact with the public is a concern. In addition to the risk of property damage or public injury there is also a potential for highly visible local media coverage.

1.7 Distribution Asset Economic Evaluation

Underground cable construction costs depend on a variety of different factors including: property availability, cable size, and cable voltage. Figure 56 provides an overview of the cable asset value, current replacement rates, and anticipated lifespan.

Asset	**Quantity**	**Life Expectancy**	**Current Replacement Rate**
Direct Buried Streetlights	16,885	50 Years?	100 Years
Steel Power Screw Streetlights	4,658	50 Years?	100 Years
Concrete Piled Streetlights	36,682	70 Years?	100 Years
Replacement Cost (4 - 25 kV cables)	$3,000 (Concrete Pile) to $8,000 (Direct Buried or Steel Power Screw)		
Replacement Value	$282 Million		

Figure 56 Streetlight Economic Evaluation

1.8 Recommendations

Gaps: During the analysis of the asset the following gaps were identified.

High Priority

1. Manitoba Hydro does not have a process to evaluate the condition of streetlight standards below the soil surface.

2. There is inconsistent standard inspection frequency and training across the province.

Medium Priority

3. Streetlight painting and sandblasting is no longer completed on an annual basis. This preventative step could extend the lifespan of the standards.

4. DMPS inspection data are not consistently being leveraged resulting in standards that were identified for replacement to be missed.

Recommendations: The following recommendations are made to address these gaps.

High Priority

1. Development of a below grade inspection strategy and tool procurement for direct-buried and power screw streetlight installation is required.

2. Development of improved inspection criteria and training material to ensure a standardized approach across the province.

Medium Priority

3. Development of a painting strategy to extend the lifespan of steel standards.

4. Consistent application of DMPS/data management for streetlights.

5. Constantly review industry best practices for inspection methods and implement changes as required.

APPENDIX I
Risk

Asset Condition

04/27/2012

Risk Rating Criteria

Consequence	Measure	Rating
Financial -	Net Income / capital investment:	Very Low - $0-$25 Million
		Low - $26- $50 Million
		Medium - $51- $75 Million
		High - $76- $100 Million
		Very High - > $100 Million
System Reliability -	Domestic Customers:	Very Low – Annual impact on System Average Interruption Duration Index (SAIDI) < 5 Minutes
		Low – Annual impact on System Average Interruption Duration Index (SAIDI) 6-10 Minutes
		Medium – Annual impact on System Average Interruption Duration Index (SAIDI) 11-20 Minutes
		High – Annual impact on System Average Interruption Duration Index (SAIDI) 21-40 Minutes
		Very High – Annual impact on System Average Interruption Duration Index (SAIDI) >41 Minutes
Safety- Employee and Public -	High risk accidents, severity rate, frequency rate and public contacts:	Very Low - Minor injuries, in compliance with laws and standards.
		Medium - disabling injuries, in compliance with laws and industry standards.
		Very High - severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in imprisonment for Manitoba Hydro management, significant fines and loss of public trust.
Environment -	Environmental Impact - air emissions, water management, spills, land and habitat disturbances, etc:	Very Low - Minor impact to environment in compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing and operating approvals.
		Medium - Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing operating approvals.
		Very High - Severe widespread and uncontained damage to environment and/or non-compliance with stakeholder expectations, laws and regulations resulting in imprisonment for Manitoba Hydro management, significant fines, loss of public trust and long term operating restrictions
Customer Value	Customer perception of service with regard to	Very Low – No local media coverage with negligible impact on stakeholders
		Low - Limited local media coverage with negligible impact on stakeholders

	reputation:	Medium - A highly visible event attracting local media coverage; and/or a moderate negative impact on stakeholders.
		High - A highly visible event attracting national media coverage or; and/or a moderate negative impact on stakeholders.
		Very High - A highly visible event attracting international media coverage; and/or a significant negative impact on stakeholders

Likelihood

Descriptor	Qualifier
Almost Certain	The event will occur on an annual basis
Likely	The event has occurred frequently
Possible	The event might occur infrequently
Unlikely	The event does occur somewhere from time to time.
Rare	Have heard of something like this occurring elsewhere.

Asset Risk Scoring

Underground Cables

1. Financial: In 20 years the investment gap to address underground cable condition will range between $350 and $900 Million. The lower range refers to the cost if silicone cable injection is widely applied to rehabilitate XLPE cables. The upper range refers to the cost if mass replacement of the XLPE cables is required.
2. System Reliability: Increasing XLPE cable failure rates are predicted to have a substantial impact on distribution system reliability in 20 years. In 2010/11, cable failures contributed 4.5 SAIDI minutes to corporate reliability performance. Over the past 5 years, the number of cable failures has increased by approximately 20%. Assuming a similar trend over the next 20 years, cable failures are anticipated to contribute between 11 and 20 SAIDI minutes if the current replacement rates are maintained.
3. Safety – Employee and Public: Cable failures are not predicted to have any significant impact on employee or public safety.
4. Environment: A very low impact to the environment is anticipated as the result of a cable failure. Oil filled cables have a slight risk of a minor oil leak as the result of a catastrophic failure but represent only 6% of the installed cable population. The remaining population utilizes solid dielectric insulation (e.g. XLPE or TRXLPE insulation) and does not contain oil.
5. Customer Value: A medium impact is anticipated as the result of a high profile cable failure resulting in an extended customer outage attracting local media coverage.

Manholes

1. Financial: In 20 years the investment gap to address manhole condition will range between $16 and $44 Million. The lower range refers to the cost if only minor roof repairs are required for the majority of installations. The upper range refers to the cost if extensive reconstruction or refurbishment of the manholes is required.
2. System Reliability: Manhole failures are predicted to have a low impact on overall reliability performance. In the worst case scenario portions of the manhole structure collapse into the energized circuits contained in the structure, resulting in a fire causing extended outages to multiple distribution feeders. It is anticipated an event of this nature could contribute between 6 and 10 SAIDI minutes to corporate reliability performance, but would be infrequent.
3. Safety – Employee and Public: It is possible for a manhole failure to result in disabling injuries. In the most likely scenario, portions of the structure roof cave in resulting in a fire inside the structure.
4. Environment: A manhole failure is anticipated to have a low impact on the environment.
5. Customer Value: A catastrophic manhole failure is anticipated to be highly visible and attract national media attention.

Duct Lines

1. Financial: In 20 years the investment gap to address duct line condition is estimated to be approximately $75 Million.
2. System Reliability: Duct line failures are predicted to have a low impact on overall reliability performance. In the worst case scenario portions of the duct line structure collapse into the energized circuits contained in the structure, resulting extended outages to multiple distribution feeders. It is anticipated an event of this nature could contribute between 6 and 10 SAIDI minutes to corporate reliability performance, but would be infrequent.
3. Safety – Employee and Public: A duct line failure is anticipated to have a low impact on safety.
4. Environment: A duct line failure is anticipated to have a low impact on the environment.
5. Customer Value: A duct line failure is anticipated to be highly visible if it results in extended customer outages and attract local media attention.

Padmount Transformers

1. Financial: In 20 years the investment gap to address padmount transformer condition is estimated to be approximately $3 Million.
2. System Reliability: Padmount transformer failures typically impact only a handful of residential customers, but could impact a major account if supplied off a dedicated unit.
3. Safety – Employee and Public: A padmount transformer failure is not anticipated to pose a substantial risk to safety.
4. Environment: A padmount transformer failure is anticipated to have a low impact on the environment. In the worst case scenario a minor oil spill could occur.
5. Customer Value: A padmount transformer failure has the potential to attract local media coverage if a major customer was impacted by the failure.

Poles

1. Financial: In 20 years the investment gap to address pole condition will be approximately $410 Million.
2. System Reliability: Increasing pole failure rates are predicted to have a medium impact on distribution system reliability in 20 years. Pole failures are anticipated to contribute between 11 and 20 SAIDI minutes if the current replacement rates are maintained.
3. Safety – Employee and Public: Pole failures are anticipated to have a medium risk. There is the potential for disabling injuries as the result of a pole failure
4. Environment: A moderate impact on the environment is anticipated as the result of increasing pole failures. As failing poles are replaced additional logging and pole treatment will be required to provide replacement poles. In addition, pole replacement

requires significant construction equipment consuming fuel and contributing greenhouse gas emissions.
5. Customer Value: A medium impact is anticipated as the result of a pole failures resulting in an extended customer outage attracting local media coverage.

Overhead Conductors

1. Financial: In 20 years the investment gap to overhead conductor condition will be approximately $66 Million.
2. System Reliability: Increasing conductor failure rates are predicted to have a low impact on distribution system reliability in 20 years. Conductor failures are anticipated to contribute between 6 and 10 SAIDI minutes if the current replacement rates are maintained.
3. Safety – Employee and Public: Conductor failures are anticipated to have a low risk to safety.
4. Environment: Conductor failures are anticipated to have a low risk to the environment.
5. Customer Value: Conductor failures are anticipated to have a low impact and attract little to no media coverage.

Overhead Transformers

1. Financial: In 20 years the investment gap to address overhead transformer condition is estimated to be approximately $15 Million.
2. System Reliability: Overhead transformer failures typically impact only a handful of residential customers, small commercial or industrial customers.
3. Safety – Employee and Public: An overhead transformer failure is not anticipated to pose a substantial risk to safety.
4. Environment: An overhead transformer failure is anticipated to have a low impact on the environment. In the worst case scenario a minor oil spill could occur.
5. Customer Value: An overhead transformer failure is unlikely to attract media coverage.

Streetlights

1. Financial: In 20 years the investment gap to address streetlight standard condition is estimated to range from $11 to $88 Million. The lower range refers to the cost if cathodic protection or alternative forms of rehabilitation can be utilized on direct buried and power screw anchored standards. The upper range refers to the cost if these standards have to be replaced with new concrete piled installations in significant quantities.

2. System Reliability: Streetlight standard failures are not anticipated to result in customer outages. In the worst case scenario a standard could fall into an energized distribution line resulting in an outage. This scenario, while possible, is expected to be a very infrequent occurrence.
3. Safety – Employee and Public: A streetlight standard failure has the potential for disabling injuries.
4. Environment: A streetlight standard failure is anticipated to have a low impact on the environment.
5. Customer Value: A streetlight standard failure in a highly visible location or one resulting in an injury is likely to attract national media coverage.