Manitoba Hydro

## Marketing & Customer Service

## Report On

# Natural Gas System Asset Condition Assessment

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| | | |

# Executive Summary

Manitoba Hydro's natural gas pipeline system supplies 270,000 customers through 16,000 km of pipeline and 400 stations. First installed in 1957, the current system supplies all the natural gas in the province from Emerson in the south to as far north as Swan River. The system consists of 3 critical assets: stations and control points, pipelines and lastly services with a total replacement valuation of $1.75 billion. This report examines each of the critical assets with respect to degradation, asset health and risk while taking into account current activities. The report concludes with recommendations that are required for continued delivery of natural gas safely and reliably.

Historically, the safe and reliable performance of natural gas assets has been excellent. Generally, the current replacement rates of assets are not consistent with the life expectancy and the portion of assets reaching end of life in 20 years will increase. Overall, the continued long term safe and reliable performance of some of Manitoba Hydro's natural gas pipeline systems assets will depend on maintenance activities which require assessing asset health condition more directly over the next 20 years.

Degradation of natural gas assets is typically linked to corrosion. The overall asset health of pipelines and services is expected to decline in the next 20 years.

Implementing the recommendations in this report will help meet applicable customer value goals in Manitoba Hydro's Corporate Strategic Plan. Key summarized recommendations are:

A. Stations and Control Points: Maintain current inspection, maintenance and replacement activities.
B. Pipeline: Develop 2 new inspection activities and accelerate an existing activity in order to address critical gaps in asset condition information. Replace pipeline systems where warranted and develop a long term capital investment plan to address aging infrastructure.
C. Services: Develop a service inspection activity, develop a maintenance activity for valves, implement a replacement activity for regulators and accelerate remediation of indentified at risk services in order to address the critical gap of sustainably renewing service assets.

## Contents

# Common Abbreviations & Acronyms

| | |
|---|---|
| ACVG | Alternating Current Voltage Gradient |
| AGA | American Gas Association |
| ASME | American Society of Mechanical Engineers |
| CIS | Close Interval Survey |
| CGA | Canadian Gas Association |
| CSA | Canadian Standards Association |
| CSP | Corporate Strategic Plan |
| DCVG | Direct Current Voltage Gradient |
| DOC | Depth of Cover |
| ECDA | External Corrosion Direct Assessment |
| ERW | Electric Resistance Weld |
| GS | Gate Station |
| ILI | In-Line Inspection |
| MH | Manitoba Hydro |
| MFL | Magnetic Flux Leakage |
| MOP | Maximum Operating Pressure |
| NACE | NACE International - a professional organization for the corrosion control industry |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| SMYS | Specific Minimum Yield Strength |
| TP | Transmission Pipeline |
| GWG | Greater Winnipeg Gas Ltd |
| PWG | Plains-Western Gas (Manitoba) Ltd |
| ICG | Inter-City Gas Utilities Ltd |

# Glossary of Terms

| | |
|---|---|
| 30% SMYS | The accepted Canadian gas industry threshold where a failure incident on a pipeline operated at above 30% SMYS could consist of a rupture. |
| Anodeless Riser | A manufactured piping component that facilitates the transition from plastic to steel piping and from below grade to above grade without the need for cathodic protection. |
| Cathodic Disbondment: | The destruction of adhesion between a coating and the coated surface caused by products of cathodic reaction. |
| Cathodic Protection: | A technique to reduce the rate of corrosion of a metal surface by making that surface the cathode of an electrochemical cell. |
| Corrosion Prevention: | Any method that slows or limits the development of corrosion including primarily pipeline coating and secondarily cathodic protection. |
| Corrosion: | The deterioration of a material, usually metal, because of a reaction with its environment. |
| CSA Z662: | CSA standard for Oil & Gas Pipeline Systems |
| Customer Piping: | Any combination of piping, valves or fittings inside or outside a building used to distribute metered gas; usually all piping downstream of the meter. |
| Customer: | A recipient of natural gas. |
| Distribution System: | The distribution and service lines, and their associated control devices, through which gas is conveyed from transmission lines to the outlet of a customer’s meterset. |
| Emergency: | Any incident that occurs which requires immediate response and continuous action until the situation is brought under control. |
| Fabricated Steel Riser: | A riser or length of steel pipe at a customer meter set that transitions to polyethylene service pipe below grade and brings the gas above grade. |
| Farm Tap: | A small “regulation station” type set up that serves one or very few customers at distribution pressure. Typically located in a rural setting near a transmission pipeline. |

Gate Station (G.S.): A station or facility for pressure reduction of gas supplied from a transmission line and may include metering and/or odourization.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Imperfection, Acceptable: A material discontinuity or irregularity that passes the criteria of CSA Z662 as documented in MH natural gas standards 724.01 to 724.03.

Imperfection, Unacceptable: A material discontinuity or irregularity that fails the conditions of CSA Z662 as documented in MH natural gas standards 724.01 to 724.03, also known as a defect.

Insulating Fitting: A pipe fitting which provides electrical insulation between the inlet and outlet of the fitting.

Integrity, Pipeline System: The condition of pipelines, stations, fittings and other appurtenances as a result of influences during manufacturing, construction, operation or abandonment.

Overpressure Protection: Devices or equipment used for the purpose of preventing the pressure in a pipeline system from exceeding a predetermined value.

Percent (%) SMYS: The actual stress in a pipeline as a percentage of the maximum theoretical stress that a pipeline can sustain.

Pipeline, Transmission: A pipeline to transport gas at pressure above 1900 kPa[1].

Pressure Regulator: A device, either adjustable or nonadjustable, for controlling and maintaining within limits, a uniform outlet pressure.

Pressure, High: Greater than medium pressure, but less than transmission pressure.

Pressure, Maximum Operating (M.O.P.): The maximum working pressure at which a pipeline may be operated as 1) qualified by pressure testing or, 2) limited by the weakest component in the system or 3) the current state of pipeline system integrity.

Pressure, Medium: Generally the same as distribution pressure, but in some contexts can refer to 14 to 420 kPa (MOP)

[1] Manitoba Hydro Natural Gas Standards

| | |
|---|---|
| Primary Station: | Facilities or stations located at gas receipt point and includes check metering, custody transfer, odourization and pressure reduction. |
| Regulator Station: | A facility or station for pressure reduction for gas supplied from a high pressure to medium pressure system. |
| Riser: | The pipe or portion of pipe that transitions from below ground to above ground piping |
| Service (Meter set): | The piping assembly connected to a service riser that controls and meters gas delivered gas to a customer. It includes the meter stop, regulator, meter and interconnecting piping and can include a separate relief valve, vent piping, supports or bypass piping. |
| Service Line: | A pipeline that conveys gas from a transmission line, distribution line or another service line to the customer. |
| Transmission System: | A network of gas transmission lines. |

# 1. Introduction

The Manitoba Hydro natural gas system consists of 3 critical assets: stations and control points, pipelines and services. This report examines each of the critical assets with respect to:

- Demographics
- Degradation mechanisms
- Inspection, maintenance and integrity activities
- Pipeline integrity activities
- Asset health
- Risk
- Valuation

Historically, the safe and reliable performance of these assets has been excellent. Since the current replacement rates of all assets is not consistent with life expectancy, with the exception of stations, as time passes, assets will exhibit increasing age related degradation. Overall, the continued long term safe and reliable performance of some of Manitoba Hydro's natural gas pipeline systems assets will depend on focused, appropriate and in some instances, new integrity activities which will require assessing asset health condition more directly. The report concludes with a prioritized list of recommendations to address identified gaps.

# 2. Discussion

The Manitoba Hydro's pipeline system distributes bulk transmission natural gas received from TransCanada PipeLines (TCPL) and TransGas to approximately 270,000 customers. This is accomplished through the 3 critical asset groups detailed in each of the following appendixes:

- Appendix A – Stations and Control Points: Stations in the natural gas pipeline system are strategically located to serve one or more of the functions of pressure reduction, over pressure protection, metering or odourization. Control points consist of pipeline valves outside of stations. These control points can be operated to direct the flow of natural gas within Manitoba Hydro's natural gas pipeline system. Valves are intended to sectionalize systems to minimize outages and gas releases.

- Appendix B – Pipelines: Underground pipelines are conduits utilized to transport natural gas from stations to services. Manitoba Hydro's natural gas pipelines are most prevalent in urban areas. Transmission pressure pipelines supply high pressure or distribution pressure pipelines with intermittent reductions in pressure by stations. Service lines then supply natural gas to single or multiple services.

- Appendix C – Services: Services are the final component of Manitoba Hydro's natural gas pipeline system before natural gas is consumed by a customer. **S**ervices consist of a service riser, service valve, regulator, meter and associated piping. Manitoba Hydro categories services into residential, commercial and industrials services.

## 2.1 Demographics

The 3 critical assets groups contain 10 critical asset sub-groups referred in the in report appendixes. Table 1 below summarizes the installed quantities of the sub-critical asset groups.

| Critical Asset Groups (Total Quantity) | Critical Asset Sub-Groups | Material Type | | |
|---|---|---|---|---|
| | | **Steel** | **Plastic** | **Total** |
| Stations (397) and Control Points (2,094) | Primary Stations | 27 | N/A | 27 |
| | Gate Stations | 119 | N/A | 119 |
| | Regulation Stations | 54 | N/A | 54 |
| | Farm Taps | 197 | N/A | 197 |
| | Valves | 1,407 | 687 | 2,094 |
| Pipelines (16,479 km) | Transmission Pressure[2] | 1,860 km | N/A | 1,860 km |
| | High Pressure | 198 km | 92 km | 290 km |
| | Medium Pressure | 7,828 km | 6,501 km | 14,329 km |
| Services (267,705) | Residential Services | 247,452 | N/A | 247,452 |
| | Commercial/Industrial Services | 20,253 | N/A | 20,253 |

Table 1 Gas System Critical Asset Quantities[3]

[2] Includes the Gladstone-Austin transmission pressure pipeline which is 32 km of aluminum
[3] As of 2014

## 2.2 Economic Evaluation

The economic evaluation calculated for Manitoba Hydro's natural gas asset consists of the cost of the replacement cost. The valuation takes into account that assets would be replaced are per current practices. For example, the valuation of steel medium pressure pipelines assumes replacement with plastic pipelines. Table 2 provides a $100k level estimation of the approximate value of critical components assuming 2015 average replacement costs.

| Critical Asset Groups (Total Quantity) | Critical Asset Sub-Groups | Value ($Million) |
|---|---|---|
| Stations (397) and Control Points (2,094) | Primary Stations | 53.3 |
| | Gate Stations | 54.0 |
| | Regulation Stations | 23.9 |
| | Farm Taps | 8.8 |
| | Steel Valves | 116.2 |
| | **Sub-Total:** | **256.2** |
| Pipelines (16,479 km) | Transmission Pressure | 508.0 |
| | High Pressure | 99.1 |
| | Medium Pressure | 806.9 |
| | **Sub-Total:** | **1,413.0** |
| Services (267,705) | Residential Services | 58.6 |
| | Commercial/Industrial Services | 20.0 |
| | **Sub-Total:** | **78.6** |
| **Total Valuation of Natural Gas Assets:** | | **1,750** |

Table 2 Gas System Critical Asset Economic Evaluation

## 2.3 Hazards Specific to Degradation Mechanism

A hazard is any influence that increases the likelihood of occurrence of an adverse effect such as asset degradation. Manitoba Hydro recognizes 6 primary types of hazards to its natural gas system. These hazards have been identified with consideration for governing regulations and standards, industry experience, and corporate operating history. The hazards and sub-hazards are based on categories and definitions from the Canadian Gas Association (CGA). This report focuses on only the hazards that are applicable to the degradation of natural gas assets.[4] These include:

- Corrosion and degradation hazards
- Material, manufacturing and construction hazards
- Natural and outside forces hazards
- Equipment malfunction hazards
- Incorrect operation hazards

A list of applicable hazards and degradation mechanisms that are currently require mitigation and are foreseen to impact natural gas assets within the next 20 years is provided in Table 3. A complete discussion of degradation mechanisms is shown in Appendices A, B and C.

Most often, degradation mechanisms of natural gas assets are typically linked to corrosion either by causing corrosion directly or indirectly by removing barriers that protect against corrosion. Once corrosion occurs it either reduces the strength of components until they fail or causes the seizing of valves.

Table 3 below shows the degradation mechanisms to which each of the 3 critical assets is subject and provides some examples of such degradation

[4] External interference is recognized as 1 of the 6 primary hazards, but is not applicable to degradation.

| Critical Asset Groups | Applicable Hazards | Degradation Mechanisms | Comments |
|---|---|---|---|
| Stations and Control Points | Corrosion and Degradation | Metal Loss Corrosion | Insulation that was designed to minimize the noise from regulation equipment or designed to keep heat within the pipe can allow water to penetrate to an unpainted surfaces of the steel pipe gradually causing corrosion. Corrosion pitting can occur at the pipe to ground interface at stations and above grade control points due to cracking or disbonded coating. Water and salt can make their way into sealed components of valves and cause seizing. |
| | Natural and Outside Forces | Soil settlement and heaving | Soil settlement due to compacting backfill, settlement or expansion of soils can put stress on the pipe and cause pipe movement. Settling or shifting pipe can put stress on piping connections such as flanges. |
| | Equipment Malfunction | Obsolescence of equipment | Obsolescence occurs when vendors no longer support equipment that is in use at stations. In the event of vintage equipment malfunctioning, replacement parts may not be available. |
| | Incorrect Operation | Not following procedures | Overturning of valves resulted in the breaking off of stops. Inadequate operation of valves can result in grease not being adequately distributed and the seizing of valves. |
| Pipelines | Corrosion and Degradation | Metal Loss Corrosion | Corrosion metal loss can pose a hazard to steel pipelines by reducing a pipeline's ability to retain pressure. |
| | Material, Manufacturing and Construction | Coating Deterioration | Some coal tar coated pipelines have revealed severely degraded coatings with poor adhesion. The observed severe coating deterioration may be attributed to coating installation practices by the respective companies. Exposed steel has an enhanced the potential for corrosion. Certain coating types are susceptible to moisture penetration and can provide an environment for corrosion and shield the protection from cathodic protection currents (ei. polyethylene tape without primer). |
| Services | Corrosion and Degradation | Metal Loss Corrosion | Wrapping deficiencies are a contributing degradation mechanism related to risers. Unwrapped steel service risers or incorrectly wrapped risers can lead to severe corrosion leaving the strength of the riser compromised. Risers installed in high traffic areas prone to salt spray and snow clearing enhancing the potential for corrosion. |
| | | Degradation of Sealing Surfaces | Regulators can continuously leak slightly (weep) out of built in relief vents when they have reached end of life due to degradation of sealing components. |
| | Material, Manufacturing and Construction | Improper coating | Polyethylene coating on risers is effective for buried pipeline applications, but is subject to degradation from ultraviolet degradation and delaminating due to water ingress causing corrosion. |
| | | Inadequate Swing Angles | Service piping without adequate swing angles can lead to strain on other fittings and eventual failure of a fitting. |
| | Natural and Outside Forces | Soil Settlement | Movement on the joint fittings can lead to minor fitting leaks may need to be repaired. Excessive riser movement beyond the capability of the swing joints can lead to stress on the riser and meter set piping and fittings. |

Table 3 Gas System Asset Degradation Mechanisms Relevant Currently and in the Next 20 Years

## 2.4 Integrity Activities

Pipeline integrity activities include condition monitoring, inspection and maintenances practices that seek to mitigate degradation mechanisms specific of natural gas assets. Table 4 summarizes the activities for each of the critical assets. Greater detail of activities and practices is available in Appendices A, B and C.

All natural gas assets are periodically surveyed for leaks and leaks are scheduled for repair.

| Critical Asset Groups | Overview of Activities |
|---|---|
| Stations and Control Points | · Valves maintenance: greasing steel valves and operating all valves<br>· Inspection of odorizing equipment<br>· Functional checks of regulators and reliefs<br>· Instrument calibration<br>· Refurbishing regulators<br>· Site security and safety checks<br>· Replacement of obsolete equipment |
| Pipelines | · Maintenance and performance evaluation of cathodic protection of steel pipelines<br>· Surveys of coating integrity on transmission pipelines<br>· Identification of transmission pipeline degradation by selecting excavations based on engineering judgment.<br>· Identification of transmission pipeline degradation through in-line inspection |
| Services | · Raising and straightening<br>· Periodic or batch replacement of meters<br>· Rebuilding services piping or risers formally identified with corrosion pitting or straining<br>· Installed swing joints on service piping<br>· Raising buried services valves |

Table 4 Current Natural Gas Asset Integrity Activities

Condition monitoring is when the state of a pipeline is periodically assessed specifically with regards to degradation mechanisms. Benefits of performing condition monitoring and improving the certainty of asset health, specifically with regards to age dependent degradation include:

A. Continued confidence with regards to operating the transmission pipeline system safely and reliably. Confidence cannot be maintained with the current level of condition uncertainty.
B. Extension of life and deferral of capital investment. Findings from corrosion condition monitoring programs may defer capital for the replacement of transmission pipelines.
C. Continued positive customer perception of service with regards to reputation by prevention of failure incidents.
D. Required Meeting CSA Z662-15 requirements for condition monitoring. ILI meets the requirements for condition monitoring.
E. Contributing to the body of knowledge of where and how Manitoba Hydro's pipelines are deteriorating and thus improving the accuracy of risk assessment.

# 3. Analysis

## 3.1 Asset Health

In this section, the health condition of each critical asset will be analyzed. 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 1 of 3 conditions:

- Acceptable
- Fair/Poor
- Critical

The typical characteristics are indexed and summarized for each critical asset in Table 5 below.

| Critical Asset Groups | | Typical Asset Condition Score Characteristics | | |
|---|---|---|---|---|
| | | **Acceptable** | **Fair/Poor** | **Critical** |
| Stations and Control Points | Stations | · No heaving, no corrosion pitting,<br>· Up to date equipment | · Some heaving occurring, more than superficial corrosion occurring.<br>· Older equipment with replacement parts still available. | · Settling or heaving of pipe is quite noticeable<br>· Corrosion pitting<br>· There are no replacement parts available for equipment |
| | Steel Valves | · No abnormal condition present | · Valve is operating but has an abnormal condition that will lead to failure | · Valve is inoperable and will need to be worked on or replaced |
| Pipelines | Transmission Pressure | · New and some older Pipe<br>· Good cathodic protection history<br>· Good below grade leak history | · Older Pipe<br>· Possibility of cathodic protection time below target<br>· Possibility of below grade leaks due to degradation defects | · Vintage Pipe<br>· History of cathodic protection time below target<br>· Presence of below grade leaks due to degradation defects |
| | High and Medium Pressure | · New and some older pipe<br>· Good cathodic protection history<br>· Good below grade leak history | · Older Pipe<br>· Prevalence of cathodic protection time below target<br>· >1.5 below grade leaks due to degradation defects per kilometer. | · Vintage Pipe<br>· Prevalence of cathodic protection time below target<br>· >4.6 below grade leaks due to degradation defects per kilometer. |
| Services | | · Riser coating has no holidays<br>· Valve turns smoothly, is insulated.<br>· No stress on meter set.<br>· Regulator provides required pressure. | · Riser coating has signs of fading, peeling or cracking.<br>· Valve requires greasing.<br>· Regulator is older than 25 years or may vary slightly in pressure point.<br>· Piping is not at current standard designed to prevent strain. | · Riser is delaminated and exhibits corrosion flaking or strain.<br>· Valve is damaged (ears are broken) or seized.<br>· Regulator is continually leaking or does not provide set pressure.<br>· Piping shows severe signs of strain. |

Table 5: Natural Gas Asset Health Index

Figures 1 and 2 represent the percentage of each asset rated acceptable, fair/poor and critical as per the asset health index categories in Table 5. The majority of natural gas assets are currently in acceptable condition, with the exception of services which are primarily in fair/poor condition as shown in Figure 1 below. The 20 year forecast of asset health shows in Figure 2 that asset health of condition acceptable will decline on average. Note that the due to the below grade nature of pipelines, the asset health of pipelines is the most uncertain relative to other assets.

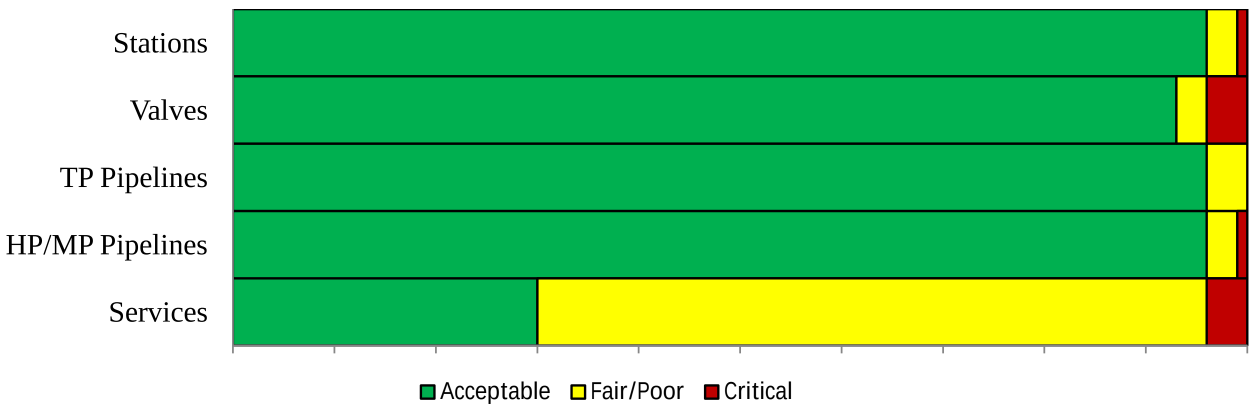



Figure 1: Current Asset Health "Soccer Field" [5]

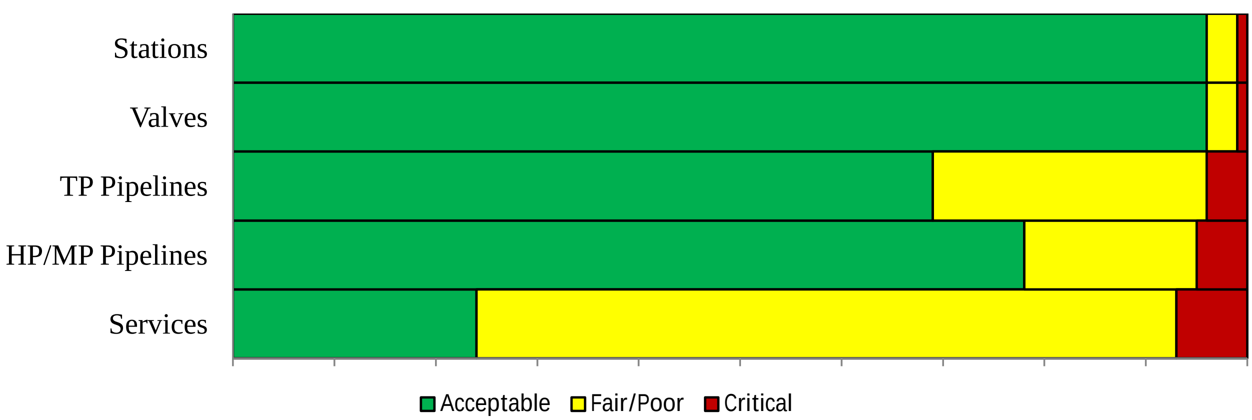



Figure 2: 20 Year Forecast Asset Health "Soccer Field"

[5] Note that the due to the below grade nature of pipelines, the asset health of pipelines is the most uncertain relative to other assets.

Pipeline and services are expected to experience the largest degree on degradation in the next 20 years, with fair/poor asset health portions for pipelines growing by 14 to 23%. Additionally, transmission pressure pipelines which currently are estimated to not have any critical health are expected to be 4% critical in 20 years. A similar increase in critical condition is expected for high and medium pressure pipeline, which includes service lines and service risers. This degradation in asset health is predicted to be entirely applicable to steel pipelines and vintage risers in the form of corrosion despite maintenance of cathodic protection levels.

Other degradation modes which will result in a decline in service health are attributable to aging service regulators and strain on service piping.

Figure 2 indicates that the overall asset health of stations and valves at control points is predicted to largely remain the same with the current rate of asset renewal.

## 3.2 Life Expectancy and Replacement Rates

Specific natural gas assets are currently being replaced at largely varying rates and for the majority of assets, the replacement rate exceeds the life expectancy. Table 6 below presents the asset life expectancy estimation and the current replacement rate.

| Critical Asset Groups | Critical Asset Sub-Groups | Life Expectancy (Years) | Current Replacement Rate (Years) |
|---|---|---|---|
| Stations and Control Points | Primary Stations | 50 - 80 | 75 |
| | Gate Stations | | |
| | Regulation Stations | | |
| | Farm Taps | 70 - 90 | |
| | Steel Valves | 60 - 90 | 90 |
| Pipelines | Transmission Pressure | 80 - 120 | No replacement |
| | Steel High and Medium Pressure | 120 - 150 | No replacement |
| | Steel Service Lines | | 342 |
| | Plastic High and Medium Pressure | >200 | No replacement |
| | Plastic Service Lines | | |
| Services | Residential Services | 25 - 70 | 90 |
| | Commercial/Industrial Services | | |

Table 6 Critical Asset Life Expectancy and Replacement Rates (No replacement refers to a negligible replacement amount)

Table 6 shows that Manitoba Hydro’s pipelines currently have virtually no current replacement rate. To date, with the exception of service lines, replacement of other pipelines has not been required due to degradation mechanisms.

Table 6 also shows that stations are currently being replaced at a rate that is sustainable in the next 20 years, while some valves may fall short based on life expectancy beyond the next 20 years.

## 3.3 Risk of Failure

A risk analysis was conducted for each of the critical assets considering the probable consequence of a failure against the following 5 critical factors given current integrity activities and replacement rates. The risk assessment methodology including the risk rating criteria, likelihood criteria are shown in Appendix D.

- Financial
- System Reliability
- Safety, Employee and Public
- Environment
- Customer Value

Details of the rankings of each asset against each of the 5 criteria are available in Appendix A, B and C. Figure 3 below compares the highest risk score for each of the critical assets can be identified from the following numbers.

1. Stations
2. Control Points
3. Transmission Pressure (TP) Pipelines
4. High and Medium Pressure (HP/MP) Pipelines
5. Services

Figure 3: Critical Natural Gas Asset Risk Map

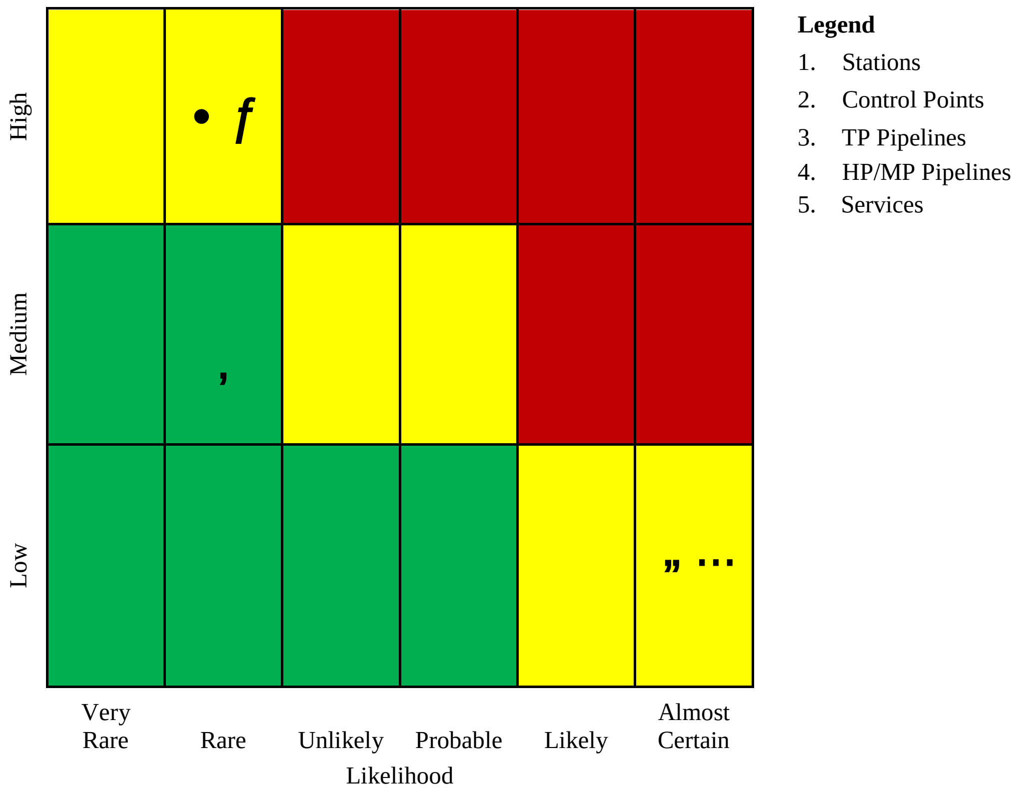



Figure 3 indicates the highest overall risks to the Manitoba Hydro are transmission pipelines and stations. These assets represent the highest risks due to primarily the pressure of gas these assets transport and because they typically represent the single supply major feeder of gas to customers they serve.

High/medium pressure pipelines and services also represent a moderate risk due to the releases of natural gas that occur at these assets in conjunction with their close proximity to customers.

# 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.

## 4.1 Conclusion

Manitoba Hydro's critical natural gas assets are aging and in 20 years an increasing number will have reached end of life. This is based on a consideration of various hazard likelihood factors. Steel pipelines and vintage services represent the greatest risk in the next 20 years. Implementing the recommendations in this Section will facilitate meeting the goals applicable to natural gas set forth in Manitoba Hydro's Corporate Strategic Plan:[6]

**Customer value:** "Keep the light on and the gas flowing" with safe and reliable delivery of electricity and natural gas to customers through investment in existing infrastructure and system expansion

## 4.2 Stations and Control Points

**Gaps:** During analysis of stations and control point assets no gaps were identified.

**Recommendations:**

1. Maintain station replacement/upgrade rates to continue to address obsolescence of equipment, stressed piping and corrosion.

2. Continue to repair and replaces valves as deficiencies are identified through inspection and maintenance practices.

[6] Corporate Strategic Plan published in November 2013.

## 4.3 Pipelines

### 4.3.1 Transmission Pressure Pipelines

**Critical gap and deficiencies:** During analysis incomplete asset condition information was identified as a critical gap. Deficiencies as a result of a critical information gap include:

- The current condition monitoring activities do not allow for the detection of the degradation with sufficient time for remediation. This could adversely affect the safety and reliability of Manitoba Hydro's transmission pipelines.
- The current rate of condition monitoring is inadequate to identify the increasing age related degradation to provide for prevention of failures rather than reacting to failures on Manitoba Hydro's transmission pipeline assets.
- Insufficient condition monitoring precludes an accurate determination of the end of useful life and does not allow for the accurate investment planning of capital resources to replace pipelines.

**Recommendations:** The recommendations outlined below will address the critical information gaps outlined above within the next 10 years if implemented. Primarily these recommendations will address the largely unknown extent of corrosion hazards.

1. Develop a plan and provide additional resources for implementation of In-line Inspection (ILI) on a longer term basis. Currently, no budget is allocated for ILI. On a capital project by project basis, $2 to 5 M per year is recommended to modify pipelines for ILI and perform inspections over the next 20 years.
2. Develop a plan for and develop an integrity activity for assessing coating shielding corrosion. The existence of coating shielding corrosion has been recently confirmed and the extent is undetermined. A budget of $250,000 per year for the next 3 years is recommended.
3. Expand the plan and increase funding for External Corrosion Direct Assessment for pipelines. This will complete the detection and assessment of holiday corrosion on Manitoba Hydro's transmission pipelines. An additional budget allocation of $80,000 per year for the next 10 years is recommended in addition to the current budget of $60,000 per annum is allocated to study holiday corrosion through the ECDA program.
4. Replace pipeline systems where warranted and develop a long term capital investment plan to address aging infrastructure.

### 4.3.2 High and Medium Pressure Pipelines

**Gap:** During analysis of the asset the following gaps were identified:

- Pipelines and service lines are anticipated to warrant accelerated replacement rates as failure rates due to degradation are likely to increase at an undetermined time within the next 20 years.
- Based on current pipeline asset health forecasts, an average annual investment gap of $1.4M exists for high/medium pressure pipelines and service lines.

**Recommendations:** Replacement is recommended where:

1. Replacement of distribution and service lines where condition alone warrants.
2. Replacement of distribution and service lines where condition combined with age, damage prevention concerns, encroachment, capacity, or other factors collectively warrant.
3. Develop a long term capital investment plan to address aging infrastructure.

## 4.4 Services

### 4.4.1 High Priority for Services

Gap: A number of identified maintenance requirements and initiatives are not completed or are not undertaken due to available funding and resources being focused on other areas on a priority basis. A gap in funding and resources exists to conduct the recommended maintenance on services to address growing degradation. This maintenance gap includes:

- Below grade entry rehabilitation project lagging behind target activity level.
- There is no regular valve maintenance on service valves. Consequently, valves can be found inoperable or fail during operation.
- Degradation on risers and service piping is occurring more than is being addressed and some degradation issues on risers and service piping is being addressed only upon failure.
- There is no established program to systematically replace regulators. The current replacement rate of 60 years is inadequate to meet the recommended replacement rate of 25 years[7].

Recommendation:

To address the increasing degradation and the gaps identified, it is recommended that additional funding and resources be allocated to maintenance and rehabilitation projects. This would include:

- Establishing a maintenance program to service and lubricate all 2” and larger service valves, particularly the high-traffic areas as they are at greater risk of corrosive seizure due to salt spray.
- Establish a maintenance program to ensure valves meet minimum ground clearances.
- Establish a program to address degradation, particularly above grade corrosion on risers and service piping.

[7] 2013 - Testing and Evaluation of Residential and LGS Service Regulators.

- To address riser strain and fittings prone to leaks, upgrade inside meter services by relocating the meter outside.
- Establish a program for replacing regulators to meet the required replacement rate of 25 years.

### 4.4.2 Medium Priority for Services

Gap: Plant records are not sufficient for asset management and maintenance beyond traditional activities. Examples of this include:

- The records for service risers (size, material etc.) are inadequate and incomplete.
- Records on service valves are largely non-existent.

Recommendation:

Develop improved, more detailed records of components of services enabling improved analysis, planning and program administration. This includes additional data gathering.

## 4.5 The Next Asset Conditions Assessment

The following are recommendations for the next natural gas system asset condition assessment:

- Revise and issue the next asset condition assessment before the end of the 2019 calendar year.
- Enhance emphasis on large industrial/commercial services as a critical asset sub-group
- Enhance emphasis on large diameter urban HP/MP pipelines versus other HP/MP pipelines, particularly with regards to risk mapping.
- Implement a five condition classification system instead of three and insure general congruence in methodology between natural gas and other corporate asset condition assessments.

Natural Gas Asset Condition Assessment

# APPENDIX A – Stations and Control Points

September 28th, 2016

# 1. Stations and Control Points

Stations in the natural gas pipeline system are strategically located to serve one or more of the functions of pressure reduction, over pressure protection, metering or odourization. The major components within a station consist of valves and regulators and sometimes include instrumentation, odorizing equipment and pipeline heaters. Primary receipt stations receive natural gas from TCPL and deliver gas into our transmission or distribution pipeline systems. These stations will meter the volume of gas received, odorize the gas and reduce or regulate the pressure down to the pressure required for the pipeline system into which the gas is delivered. Primary stations are shown in Figure 1 below.

Figure 1: Primary Station: Brandon primary GS-123 (left) and St. Norbert GS-002 (right)

Gate stations receive natural gas from the transmission pressure pipelines and regulate it down to high and/or medium pressure system usually for a distribution system in a town or city. These stations are also referred to as Town Border Stations. Gate stations are shown in Figure 2 below.

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

Figure 2: Gate Stations: Petersfield GS-034 (left) and Elie GS-164 (right)

Within a city with a high pressure system, Regulator Stations receive natural gas from our high pressure pipelines and regulate it down to our medium pressure system. Historically, many urban Regulation Stations were situated below ground in ‘pits’. The pit style stations in urban areas were replaced with ‘box’ style designs beginning in the late 1990s. Inside fence style Regulation Stations are typically prevalent in rural or urban areas where aesthetic requirements are less stringent. Regulation stations are shown in Figure 3 below.

Figure 3 Regulator stations: box style (left) and inside fence style (right)

Farm Taps are very small stations that will reduce the pressure off our Transmission or High pressure system and deliver the gas as medium pressure to a specific customer or small group of customers. These stations are generally located in remote areas, far away from an established medium pressure piping network. A figure of a Farm Tap is provided in Figure 4.

Figure 4: Farm tap

Control points consist of pipeline valves outside of stations. These control points can be operated to direct the flow of natural gas within Manitoba Hydro's natural gas pipeline system. Valves are intended to sectionalize systems to minimize outages and gas releases. They are installed at all pressure levels of our system from the transmission, to the high, and distribution pressure system. Pipeline valves do not include valves that are within a station that block out apparatus within a particular station. These are known as Station valves and are addresses as part of the station piping.

Pipeline valves consist primarily of 2 types: plug or ball valves. Both types require a quarter turn to go from the fully open position to fully close. Some valves, particularly larger ones require such a high torque to turn that a gear assembly is installed to give the operator mechanical advantage allowing the valve to be turned. A valve wheel or valve wrench is turned multiple times to effect the quarter turn of the valve core. Photos of new above grade are provided in Figure 5.

Figure 5: Above grade pipeline valves: Plug valve (left) and ball valve (right)

Pipeline valves can be either above ground or below ground. Below grade valves are installed at the depth of the pipeline and are connected directly to the pipeline. To permit operation of a below grade valve, a stem extension is installed from the valve to the ground surface to which a valve wrench is attached when the valve is to be operated. A valve box is installed to protect the valve stem extension. A valve box is typically a round pipe extending from the valve to the surface and may be sealed to prevent water ingress or may be open at the bottom to allow water to drain out. A cast iron cap, curb box, or roadway box is installed at the ground surface to protect the valve box and to permit access to the valve stem extension. Photos underground of a valve assembly are provided in Figure 6.

Figure 6: Below Grade Valves: Prior to installation (left) and installed with valve box cover visible (right)

Below grade valves that require lubrication also have a length of tubing or small pipe extending to the curb box with an appropriate connection for the lubrication tool. Larger below grade valves that are gear operated will have the gears in a sealed case immediately on the top of the valve or at the top of the valve box.

Valves can either be made of steel or plastic. Plastic valves are used in the medium pressure polyethylene piping system. Steel valves are used in transmission, high and medium pressure systems.

## 1.1 Demographics

The natural gas distribution system contains 397 stations. The proportions of each type of station are shown in Figure 7.

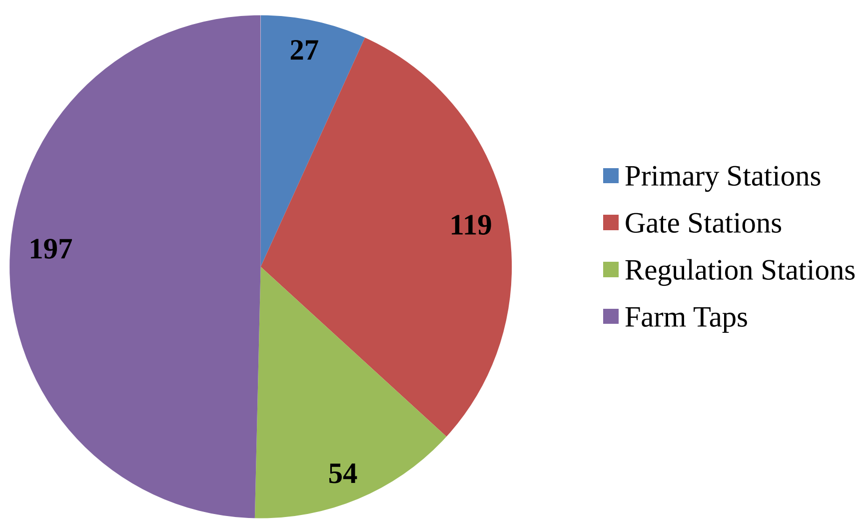



Figure 7: Proportion of station types

The age of stations by decade is shown in Figure 8 below. Age of a station determined by the decade the station was upgraded in or in the absence of an upgrade, the year of installed.

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

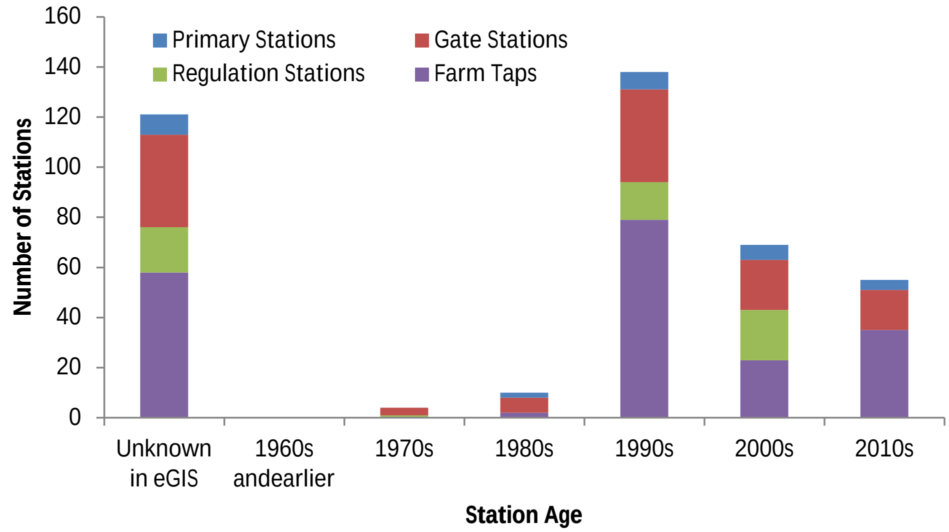



Figure 8: Station of station by age based on upgrading or install date

In 1985, The Inter-City Gas Company (ICG) commissioned ID Engineering to conduct a review and assessment of stations. This report included the stations constructed by Greater Winnipeg Gas (GWG), Inter-City Gas and Plains Western and identified encroachment and any deficiencies present. Following this report, a program was undertaken for station upgrading, rebuilding or relocation addressing approximately 4 to 6 primary, gate or regulation stations per year for more than a decade. This focus on identifying deficiencies and upgrading or rebuilding stations continues to this day. This ongoing practice of station renewal in part explains the low portion of station age in the 1980s and earlier in Figure 8..

There are a total of 2094 located at stations and control points installed in the transmission and distribution system. Table 1 below shows the demographics of the 2094 valves located at stations and control points.

| **Pressure class** | **Total valves by material** | |
|---|---|---|
| | Steel | Plastic |
| Medium pressure | 345 | 687 |
| High pressure | 277 | 0 |
| Transmission pressure | 785 | 0 |
| Total | 1407 | 687 |
| | 2094 | |

Table 1: Total valves at stations and control points based on material and pressure class

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

Figure 9 below shows all valves by size.

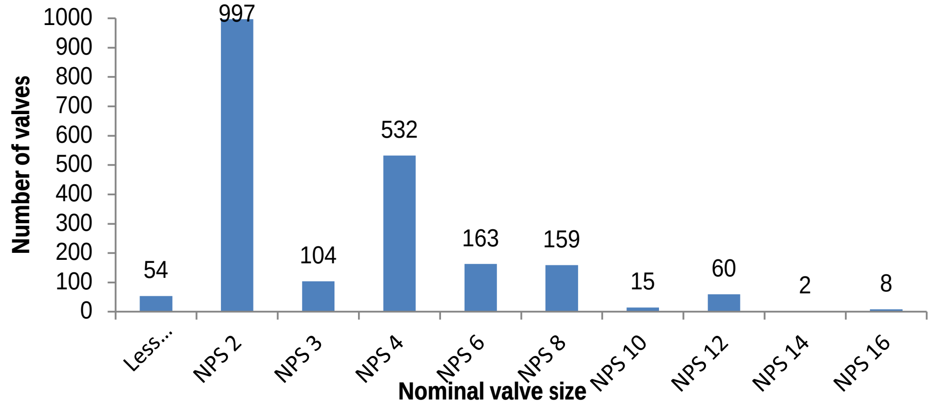



Figure 9: Valves at stations and control points by nominal valve size

Figure 10 below shows the year of installed of valves at stations and control points.

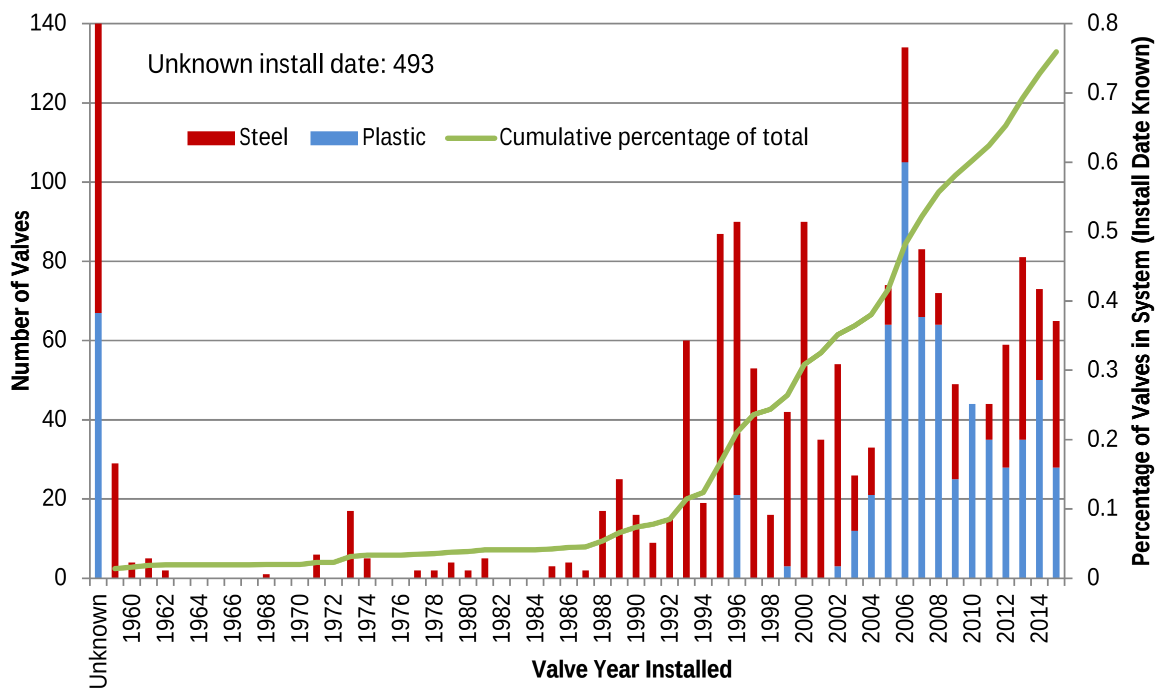



Figure 10: Year of installation for valves at stations and control points by material type

The unknown portion of valves is most likely distributable before the year 1980, based on the era that the majority of Manitoba Hydro's pipelines were constructed.

## 1.2 Hazards Specific to Degradation Mechanisms

A hazard is any influence that increases the likelihood of occurrence of an adverse effect. Manitoba Hydro recognizes 6 primary types of hazards to its natural gas system. These hazards have been identified with consideration for governing regulations and standards, industry experience, and corporate operating history. The hazards and sub-hazards are based on categories and definitions from the Canadian Gas Association (CGA). These hazards are incorporated into Manitoba Hydro's risk assessment initiatives as applicable. This appendix focuses on only the hazards that are applicable to the degradation of stations and control points consisting of:

- Corrosion and degradation hazards (metal loss corrosion)
- Natural and outside forces hazards (heaving and settlement)
- Equipment malfunction (obsolescence of equipment)
- Incorrect operation

### 1.2.1 Corrosion and Degradation Hazards

Metal loss corrosion has the potential to affect all stations, especially the ones with insulation that was designed to minimize the noise from regulation equipment or designed to keep heat within the pipe after a line heater. This insulation which is wrapped around a pipe can allow water to penetrate to an unpainted or poorly painted surface of the steel pipe and gradually cause corrosion. Figure 11 below shows corrosion that has occurred at stations.

Figure 11: Corrosion under insulation at Ste. Agathe (GS-180) and Fort Whyte (GS-020)

As seen with Ste. Agathe station (GS-180) in Figure 11, wide spread corrosion pitting can occur in just over 1 decade below insulation that has trapped moisture against unpainted pipe.[1] Corrosion pitting and flaking can also occur at the pipe to ground interface at stations and above grade control points. This is typically due to cracking of coating or disbonded coating.

Superficial corrosion is typically present at above grade piping where the paint has degraded, been damaged or was poorly applied. However, if moisture is not trapped against the steel surface, superficial corrosion is unlikely develop into a major concern such as corrosion pitting.

Environmental contamination occurs to below grade valves as water, salt and ice make their way into the actuators and either corrode or break the actuators. This occurs mostly because many of our underground valves were not rated for underground service and eventually fail. Even those that are rated for underground use will fail eventually, as steel exposed to excess water, and road salt corrodes the metal quickly. Figure 12 show a vintage valve removed from service due to seizing.

Figure 12: Vintage valve removed from service due to seizing.

Physical damage to an underground pipeline valve can occur when snow clearing equipment damage the stems of the valves or the housing. This will either break the stem or allow water, salt, and ice into the valve housing, causing corrosion. While any steel component below grade is

[1] 2013-04200 Station Piping Insulation Inspection

subject to corrosion, the external coating and pipeline cathodic protection will protect the exterior surfaces of the valve and valve box from corrosion. Corrosion due to the infiltration of water into the valve box or gear operators is not prevented by cathodic protection. Underground valves have a greater frequency of failure than valves above grade. This is not surprising as they have more conditions that may cause damage to the valve. Sometimes the valve itself is not seized, but the actuator itself is damaged, due to ice and/or corrosion. These valves stay inline if the actuator itself can be repaired or replaced. This method is less intrusive and less costly, as no outage or by-pass is needed on the pipeline to conduct the repair.

### 1.2.2 Natural and Outside Forces Hazards

Pipe movement due to heaving or settling is one of several modes of degradation. Gas pipes are typically set at depths that will be subject to freezing in the winter months. Soil settlement due to compacting backfill, settlement or expansion of vertisolic soils can also put stress on the pipe and cause pipe movement. Settling or shifting pipe can put stress on piping connections such as flanges and if left unabated could progress to the point of causing a pipe or weld failure. Figure 13 below shows heaving that has occurred at Transcona gate station due to freezing or water logged soils.

Figure 13: Heaving of piping and pipe supports causing damage to station building and stressing of pipe at Transcona Gate (GS-003)

The heaving due normal soil freezing can be exacerbated by the temperature drop in the natural gas due to pressure reduction. This is due to the Joule-Thompson effect caused by the expansion of natural gas. The effect cools gas by approximately 4$^{o}$C (7$^{o}$F) for every 700 kPa (100 psi) pressure drop. The Joule-Thompson cooling effect may also be observed on above ground piping by external icing as shown in Figure 14.


Figure 14: External icing on station piping due to the Joule-Thompson effect

Ground movement from settling, frost heave, dehydration of clays or geotechnical forces can put stress on the valves or the valve boxes or gear systems which can result in direct failure of a component. Alternatively, failure of a seal allowing the ingress of water and ultimately corrosion causing the seizing of a valve can occur.

### 1.2.3 Equipment Malfunction

Obsolescence of equipment will trigger at least a partial refurbishment of a station. This occurs when vendors no longer support equipment that is in use at stations. In the event of vintage equipment malfunctioning, replacement parts may not be available. This has occurred with odorization, regulation and instrumentation equipment at stations. This results in a replacement program that aims at replacing obsolete equipment within at stations, to reduce the risk of not being able to source replacement parts during an emergency.

Figure 15: 630 Regulator Station in Gimli with Obsolete 630 Fisher Regulator

### 1.2.4 Incorrect Operation

Damage to an underground valve may also occur if personnel force a stiff or frozen actuator. This force may sheer some of the internal gearing of the valve or crack the actuator, rendering the valve inoperable.

Over time, plug valves stiffen or become more difficult to operate due to degradation, contamination or reduction in the lubricating grease between the valve body and the plug. This usually requires lubrication before valve operation. The grease may not distribute completely until the valve is actuated often requiring increased torque to move initially. This increased torque can result in damage to gears or valve stops.

Past poor maintenance practices have caused failures due to improper greasing and operating valves. For example, overturning of valves resulted in the breaking off of stops, thus rendering the valve position ambiguous and inadequate operation of valves resulted in grease being insufficiently distributed causing seizing of valves.

### 1.2.5 Non-Degradation Related Issues at Stations

Various non-degradation related factors may result in the replacement or upgrade of a station. These replacements or upgrades of station assets are beneficial from an asset maintenance perspective, but are not directly condition based or related. These factors include:

- Encroachment: Population centers grow out and eventually may envelop stations or the transmission lines that supply the stations. For safety considerations, stations are moved or upgraded to provide a safer environment for the public. Alternatively, the supply pressure to stations may be decreased to address encroachment concerns.
- Capacity: An increase in load will may call for an upgrade or a replacement of the entire station. Equipment may have been designed for lower loads, but due to population growth or commercial development, stations need to be upgraded to meet in increased demand. This may be exacerbated by decreases in TCPL operating pressures for stations that were designed for minimum tariff supply pressure, but were not upgraded when loads increased because the historically TCPL operating pressures provided more than enough capacity.

- Changes in gas quality: Historically, TCPL has supplied Manitoba customers with moisture levels far below tariff levels. Present day natural gas delivery from TCPL is now receiving natural gas from the USA with higher moisture content as shown by Figure 16 below.

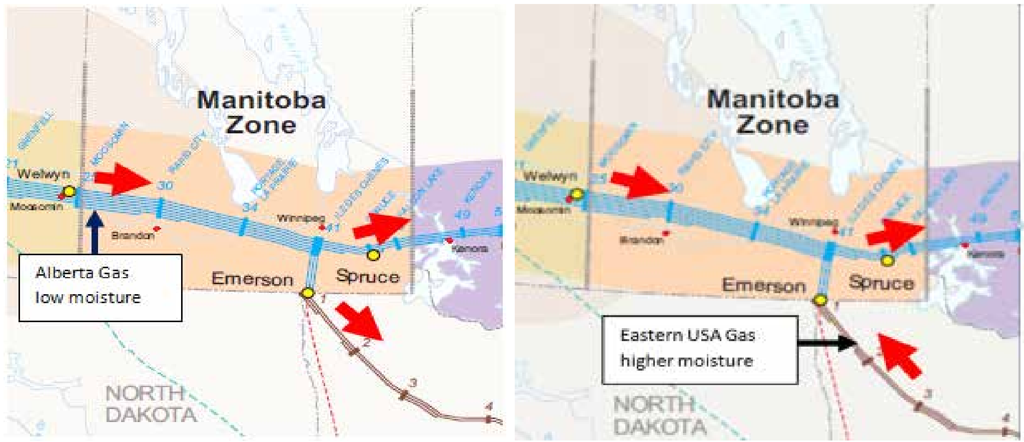



Figure 16: Illustration of changes in natural gas supply: Historically, TCPL supplied Alberta gas to the USA (left). Present day, TCPL supplies USA gas to Canada.

The higher gas moisture content has frozen off regulators, causing disruptions to supply pressure in downstream pipeline systems.

While changes in natural gas quality and reduced supply pressures fall within TCPL tariff conditions, Manitoba Hydro stations and pipeline systems for many decades benefitted from the low moisture levels and the stations were designed accordingly..

## 1.3 Restoration and Maintenance Activities

Pipeline integrity activities that apply corrective actions are restoration and maintenance activities. They generate actions to mitigate hazards as they are found. The activities that are applicable to stations and control point are shown in Table below.

| Activity name | Primary Stations | Gate Stations | Regulation Stations | Farm Taps | Control Points |
|---|---|---|---|---|---|
| Distribution Mains and Service Leak Survey and Repair | | | X | | X |
| Distribution Valve Maintenance | | | | | X |
| Downtown Sectionalization Valve Maintenance | | | | | X |
| Station Inspections | X | X | X | X | |
| Station Leaks Survey and Repair | X | X | | | |
| Transmission Leak Survey and Repair | | | | X | X |
| Transmission Valves Maintenance | | | | | X |

Table 2: Activities applicable to degradation mechanisms for station and control points.

Restoration and maintenance activities are primarily driven to maintain the pipeline system integrity as required by codes and standards. For example, leak surveys are regularly performed as required by Manitoba Hydro standards, procedures and maintenance standards which are in compliance with the requirements of CSA Z662 and have been developed to establish consistency in maintenance. Additionally, leaks found are remediated in compliance with Manitoba Hydro standards and procedures and in compliance with CSA Z662. Maintenance practices that exceed Z662 are based on experience and some manufacturers' suggestions.

Based on criticality, stations' regulators will be completely rebuilt based on a best practice approach. Functionality of a regulator is tested every year, and a complete rebuild is performed every 1, 3, 5 or 7 years, prioritized by the criticality and throughput of a station. Maintenance and upkeep of the stations is of utmost importance to the service of Natural Gas within our system.

Station inspections include:

- Weekly inspections of all primary (odorant) stations including all odorizing equipment
- Monthly inspections of all gate and regulator stations
- Once per year functional inspection and maintenance of all primary, gate, regulator stations. During these inspections the functionality of the regulators is tested, instrumentation is calibrated , valve and instrument tagging is verified and the accuracy of emergency drawings is confirmed
- Once per year inspection of site security and safety visit of all Primary, Gate, Regulator stations
- Once per year functional inspection and maintenance of all farm taps.

Pipeline valves are required by CSA Z662 to be maintained and partially operated on a yearly basis. All valve maintenance activities include lubrication and operation. Plastic valves have no greasing requirements, and are operated once a year, although this practice for plastic valves is under review.

Poor maintenance practices in the past have lead to underreporting and damage to inoperable valves. Now with the reporting of all damages, and suspect damages, there exists a more accurate picture of what valves require repair. Since improved maintenance and reporting has begun, a small amount of damaged or suspect valves has been found at a rate of 1 or 2 per year.

## 1.4 Risk Assessment of Stations and Control Points

Stations are evaluated by staff after annual inspections based on a set of criteria. Generally, stations will only have replacement of obsolete, damaged, or corroded components along the length of its life.

Gas Facility Assessment forms are filled out once a year for primary, gate and regulation stations. They are then passed along to Gas Planning for prioritization of station refurbishment or replacement based on these criteria. The assessment categories include:

- Health and safety (Access & Egress, Spacing of isolation valves, etc.)
- Compliance (obsolete equipment)
- Security of station (bollards or fence)
- Reliability of supply (relief, worker/monitor, telemetry)
- Encroachment

Valves are evaluated by the technicians who complete maintenance. They report through RMS whether valve is damaged, or inoperable. Description of damage is also recorded and determination of repair based of these observations. Technicians will evaluate condition of the stem, turn counter, ease of turning and positions of stops. If a valve is seized and cannot be moved, the valve will be added to the valve replacement project and will be scheduled to be replaced by priority. According to the assessment criteria, valves are scored and are categorized as critical, fair or acceptable condition.

### 1.4.1 Asset Health

#### 1.4.1.1 Station Asset Health

Previous to the Gas Facility Assessment form, station health would be reported by field staff to management. This assessment information would then get elevated by the Facilities Design Engineers to design a new station or parts of a station.

Gas Facility Assessment forms were first started in 2015. Therefore, many stations have not yet been completed. A full assessment with all stations will be completed in 2016. Prior to Assessment forms, no grading system was used other than the field personnel’s intuition.

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

Farm Taps are not included within this assessment process as the assessment was designed for stations and due to the lower risk they represent.

Figure 17 shows the current and 20 year forecast asset health for stations.

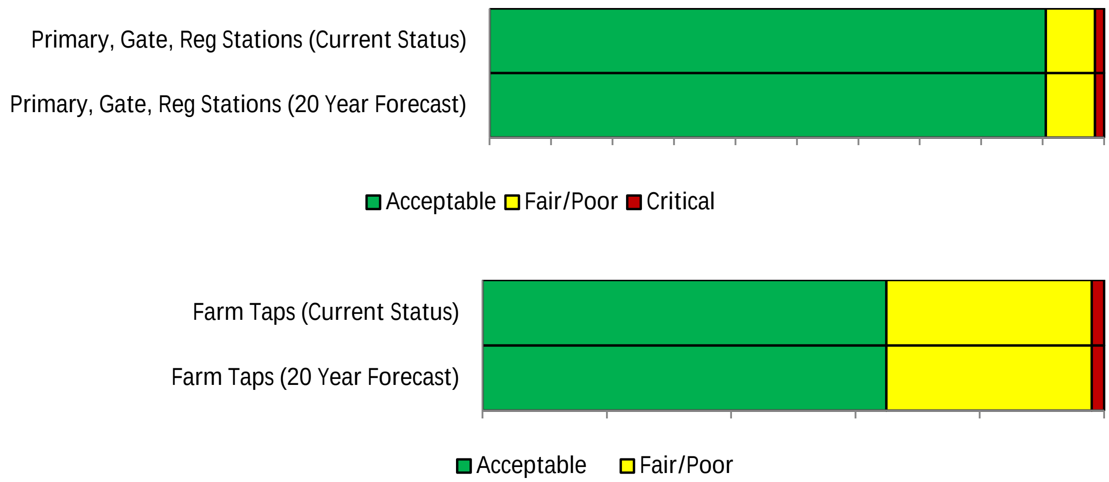



Figure 17: Primary, Gate and Regulation Stations "Soccer Field" (Above), Farm Tap "Soccer Field" (Below)

Table 3 below indicates the Station asset health condition characteristics based on Station Assessment form.

| Health Index Condition | Probability of Failure | Typical Asset Condition Score Characteristics |
|---|---|---|
| Critical | High | · Settling or heaving of pipe is quite noticeable<br>· Corrosion has caused noticeable and measurable wall loss<br>· There are no replacement parts available for equipment |
| Fair/Poor | Medium | · Some heaving occurring, more than superficial corrosion occurring.<br>· Older equipment with replacement parts still available. |
| Acceptable | Low | · No heaving, no corrosion or superficial corrosion only,<br>· Up to date equipment |

Table 3: Stations Asset Health Index

#### 1.4.1.2 Control Point Asset Health

Currently, Manitoba Hydro's health condition rating system in place for our pipeline valves At control points rate valves as either fully operational, have some deficiency but are operational, or are inoperable. Based on this rating system, valves repairs are prioritized based on valve importance and available resources. If the repairs are cannot be implemented immediately, then they are deferred and are put onto the valve repair/replacement project list. Figure 18 shows the current and 20 year forecast asset health for stations.

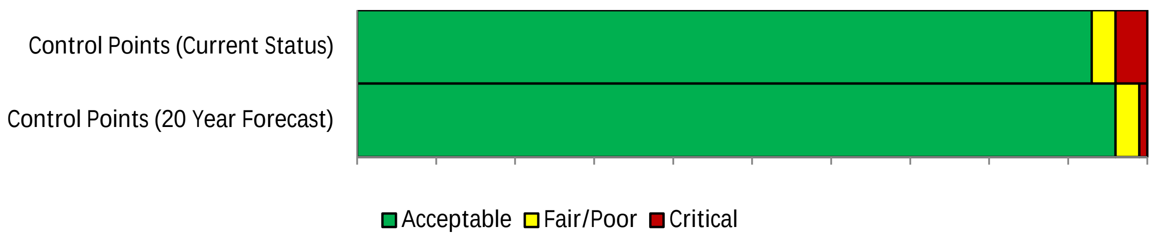



Figure 18: Valves at Control Points "Soccer Field"

Table 4 below shows the general health condition characteristics based on Technician observations collected in RMS.

| Health Index Condition | Probability of Failure | Typical Asset Condition Score Characteristics |
|---|---|---|
| Critical | High | · Valve is inoperable and will need to be worked on or replaced |
| Fair/Poor | Medium | · Valve is operating but has an abnormal condition that will lead to failure |
| Acceptable | Low | · No abnormal condition present |

Table 4: Control Points Asset Health Index

### 1.4.2 Risk Map

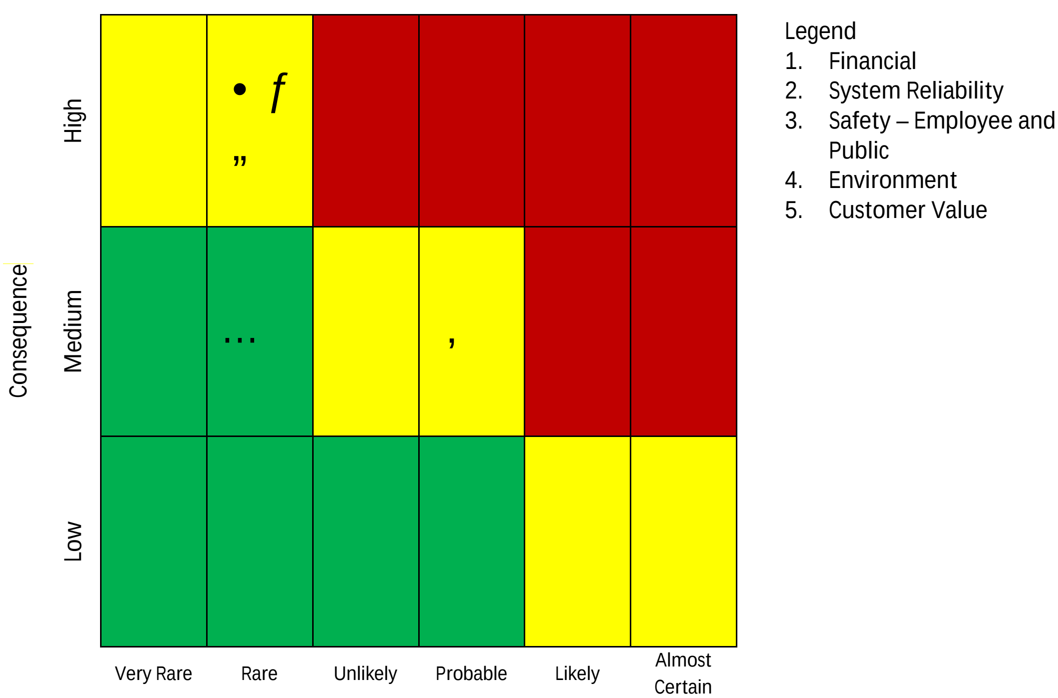
Based on the observations made in this report, the following risk maps were developed. The maps consider the anticipated station failures will have on Manitoba Hydro with respect to the following criteria:

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

The probability and consequence of each factor is plotted in the risk map and reflect current activities. 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.

### 1.4.2.1 *Station Risk Map and Risk Scoring*

A station failure can cause major gas disruptions. The loss of a primary station would cause major outages, loss of odorization and a large safety risk. Loss of Gate, Regulator, and Farm taps will cause outages to several customers.



Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

Likelihood

Figure 19: Primary Stations Risk Map

Figure 19 indicates that Primary Gate Stations have a higher risk. This is due to the fact that they have liquid odorant on site, have expensive odorant pumps that need to be maintained and are the lynch pin in the natural gas system, delivering to all other stations downstream.

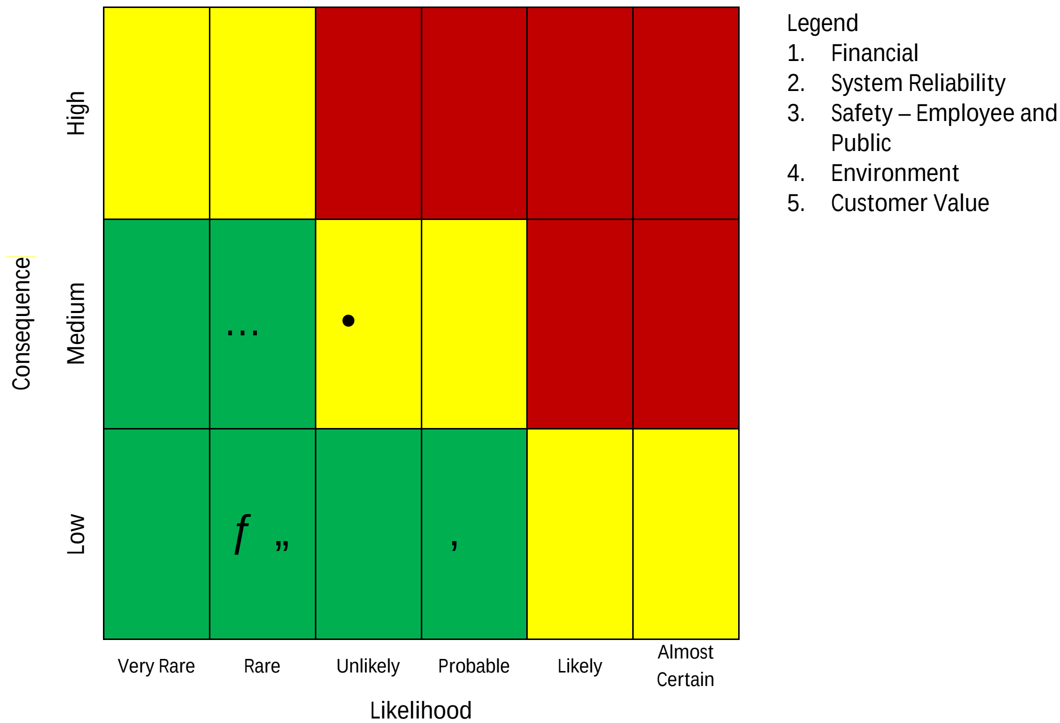



Figure 20: Gate/Regulators Stations Risk Map

Gate and Regulator stations all are downstream of the primary stations and will feed their smaller networks, sometimes being tied in with another stations network to aid in reliability.

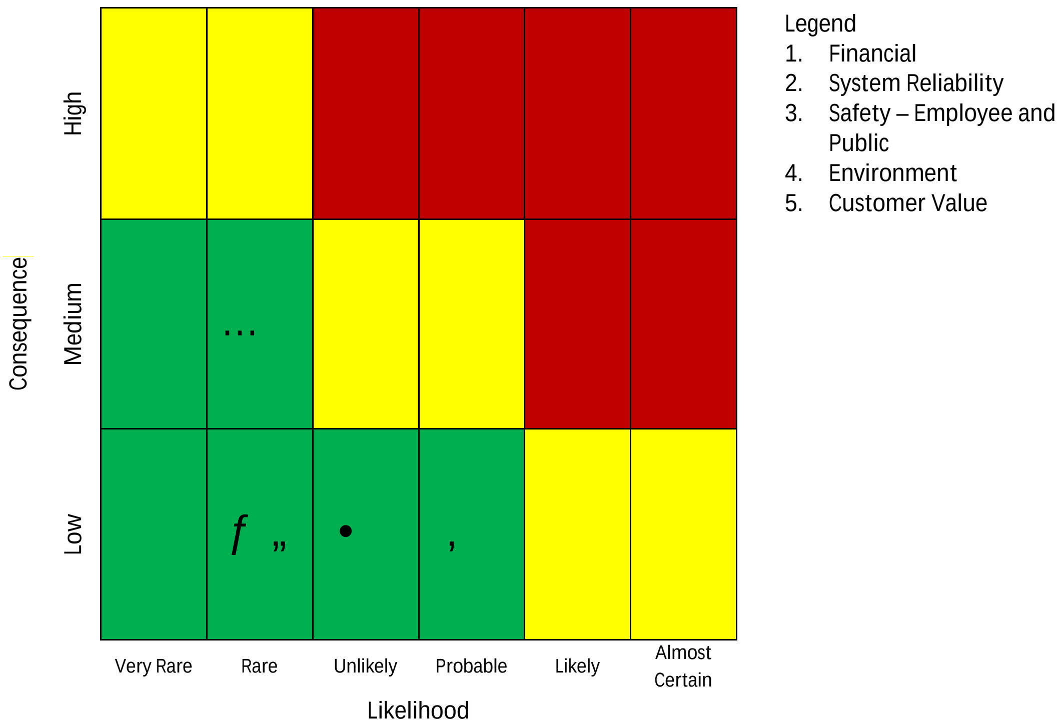



Figure 21: Farm Taps Risk Map

Farm Taps have the least amount of risk as they supply gas only to either individual customers or to small groups of customers.

### 1.4.2.2 *Valves Risk Map and Risk Scoring*

Pipeline valve failures result in the inability to isolate pipeline systems. In an emergency, where a pipeline has ruptured, if a pipeline valve cannot be closed, another valve, further from the rupture must be closed causing greater delays in an emergency situation. If no suitable valve can found smaller diameter pipe can be squeezed, which damages the pipe and required further maintenance to remove that damage. Squeezing also takes more time as the pipeline must be exposed and cannot be done safely on a transmission pipeline. The inability to operate a pipeline valve can carry additional consequences during a failure incident. These consequences can include a greater release of natural gas and a larger outage area. For transmission pipeline, a pipe may need to be stopped if no suitable valve can be operated or station shut down resulting in further delays.

During normal operations, if a pipeline valve is inoperable, a larger outage than necessary must be planned to accommodate the larger volume of pipe that needs to be isolated, or hot tap fittings will need to be installed in the pipe to stop the flow. This increases the difficulty of the operation as the pipe needs to be exposed.

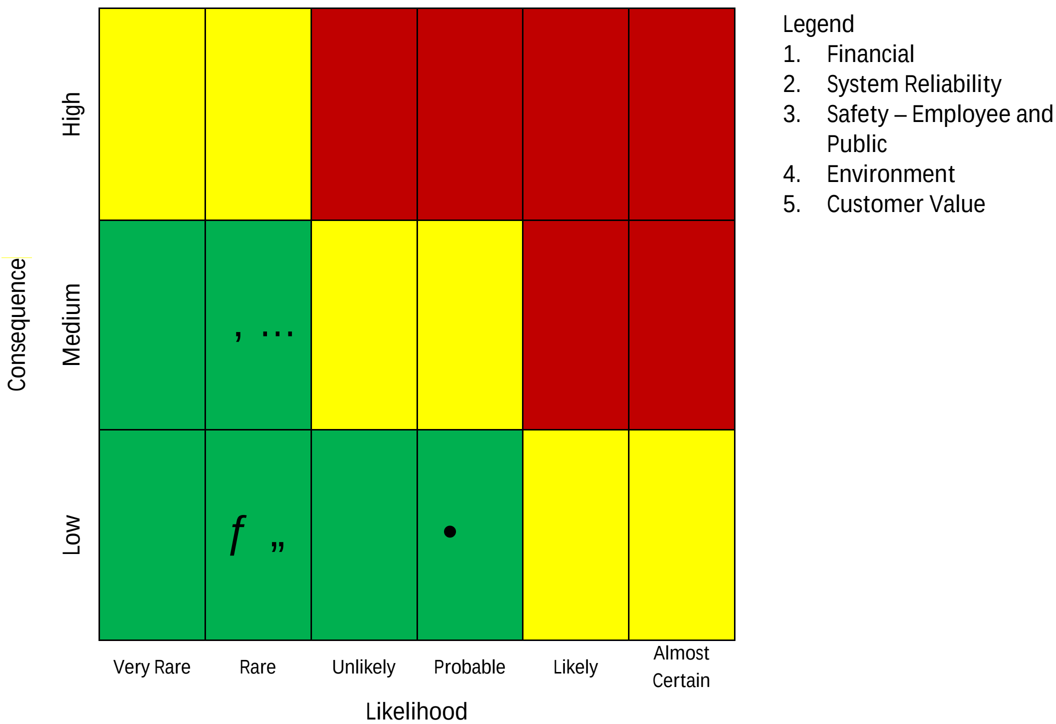



Figure 22: Valves Risk Map

Figure 22 indicates that several of the risks associated with pipeline valves are rare occurrences. Pipeline valves are rarely damaged to the point of inoperability.

## 1.5 Station and Control Point Replacement

### 1.5.1 Station Replacement Rates

Complete primary, gate and regulation station replacements currently occur at a rate of 2 to 3 per year. Farm Taps are replaced at an average rate of 3 per year, on an as needed basis due on inadequacy of load, obsolescence and damage. Partial refurbishment including the replacement of obsolescent equipment of primary, gate and regulation stations occurs at a rate of approximately 8 to 10 per year. For farm taps the partial replacement rate is approximately 6 per year.

Rarely will a whole station be replaced, and this is done mostly on the necessity of increased load demands or a change in a station standard. Changes in station standards usually occur when Manitoba Hydro purchases a new natural gas station asset from another gas distribution company, such as the stations that belonged to the Gladstone- Austin Natural Gas (GANG) Coop or Swan Valley Natural Gas (SWNG).

Most common station upgrades occur due to obsolescence of a particular part. The second largest contributor to a station being replaced is due to environmental conditions (freeze/thaw) shifting and heaving due to a station being under stress. The other likely condition of a station being replaced is due when a changes in station standards which cause Manitoba Hydro to replace a station to improve the safety of station operations. A past example of this included upgrading underground to above ground stations.

Manitoba Hydro has never had a formal risk assessment process for the replacement of stations. Previous to last year, stations would be replaced based on communication between operations and design or based on a change of loading on the station.

### 1.5.2 Valve Replacement Rates

Valves are being replaced at a rate of roughly 1% per year. The replacement of valves is selected by priority of importance to supply. Higher pipeline pressures and larger diameters generally reflect the increased relative importance of a valve. Valve replacement is an option when a valve is found to be seized and refurbishing of the actuator would not move the valve.

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

This year Manitoba Hydro is accelerating the replacement of valves, (up to 20) in order to address a back log of inoperable valves. This backlog of critical valves is due to the following:

- poor reporting,
- a lack of action to remediate damaged valves and,
- a lack of resources necessary to repair all the valves

This surge has temporarily doubled the valve replacement rate from 1% to 2%.

## 1.6 Economic Evaluation of Station and Control Point Assets

Construction costs vary greatly between stations. This has to do with station capacity, whether the station is a Primary and has an odorant pump, , the need for a pipeline heater and whether the station is being monitored remotely.

Table 5 provides an overview of the station and control point asset value, current replacement rates, and anticipated lifespan.

Table 5: Stations Economic Evaluation

| Asset Class | Quantity | Life Expectancy (Years) | Replacement Rate (Years) | Replacement Cost ($k) | Total Replacement Cost ($M) |
|---|---|---|---|---|---|
| Primary gate station | 27 | 50 - 80 | 75 | 1500 - 6000 | 53.3 |
| Gate station | 119 | 50 - 80 | | 450 | 54.0 |
| Regulator station | 54 | 50 - 80 | | 450 | 23.9 |
| Farm tap | 197 | 70 - 90 | | 35 - 55 | 8.8 |
| | | | | | |
| **Total** | **397** | | | **Avg. 354.4** | **140.0** |

Valve replacement costs depend on the size, pressure class, location (above ground or below.) and whether the assistance of contractors is required.

Life expectancy for the majority of valves is a “best guess” scenario. Some of our valves that are 50+ years still operate fine, yet others with much less service time fail. There are no records of valves wearing out, since there is no data to support a life expectancy. In practical terms of life expectancy, underground pipeline valves are expected to last 60 years. During those 60 years, most likely one of the degradation methods will have taken effect and rendered the valve inoperable. This is not always the case, as some valves have a greater life span.

Above ground valves are faced with less degradation methods, will have an expectation of a life span of 90 years. Plastic valves have been excluded from Table 6 as the total replacement cost would not amount to a significant amount in comparison to other assets.

Appendix A – Stations and Control Points of Natural Gas Asset Condition Assessment

Table 6: Steel Control Points Economic Evaluation

| Asset | Quantity | Life Expectancy (Years) | Replacement Rate (Years) | Replacement Cost ($k) | Total Replacement Cost ($M) |
|---|---|---|---|---|---|
| Transmission pressure valves | 785 | 60 - 90 | 90 | 32 - 290 | 75.7 |
| High pressure valves | 277 | | | 31 - 275 | 25.5 |
| Medium pressure valves | 345 | | | 31 - 81 | 15.0 |
| | | | | | |
| | **1407** | | | **Avg. 82.9** | **116.2** |

## 1.7 Recommendations

**Gaps:** During analysis of stations and control point assets no gaps were identified.

**Recommendations:**

1. Maintain station replacement/upgrade rates to continue to address obsolescence of equipment, strained piping and corrosion.
2. Continue to repair and replaces valves as deficiencies are identified through inspection and maintenance practices.

Natural Gas Asset Condition Assessment

# APPENDIX B - Pipelines

September 28th, 2016

# 1. Pipelines

Underground pipelines are conduits utilized to distribute natural gas from natural gas sources to services. Manitoba Hydro’s pipelines receive natural gas from TransCanada PipeLines (TCPL) and TransGas through stations, and supply all industrial, commercial and residential natural gas customers in Manitoba.

Manitoba Hydro uses two distinct systems for classifying pipelines. The first is defined in Natural Gas Standard 510.01 *System Pressure Classifications*, and classifies pipelines based on maximum operating pressure (MOP) and pipeline function. This system is used primarily for internal corporate purposes and is denoted by:

- Medium Pressure (MP) class exists when MOP ≤ 700 kPa
- High Pressure (HP) class exists when 700 kPa < MOP ≤ 1900 kPa
- Transmission Pressure (TP) class when MOP > 1900 kPa

Service pipelines are distribution pressure pipelines and are functionally defined, and denote pipelines which tee from distribution lines with the express purpose of providing natural gas service to a single or several customers.

The second system is an industry standard system used to apply codes and requirements by classifying pipelines using percent specified minimum yield strength (%SMYS), where:

- %SMYS < 30% denotes distribution pressure applications (see CSA Z662 Oil and Gas Pipeline System Standard, Clause 12).
- %SMYS > 30% denotes transmission pressure applications.

The system defined in Standard 510.01 based on pressure has historic roots but conforms to the CSA Z662 %SMYS system of classification.

Manitoba Hydro’s natural gas pipelines are most prevalent in urban areas. Transmission pressure pipelines (orange outline in red) that supply high pressure or distribution pressure pipelines (orange) are shown in Figure 1 below. Service lines that are supplied by high pressure or distribution pipelines are not shown.

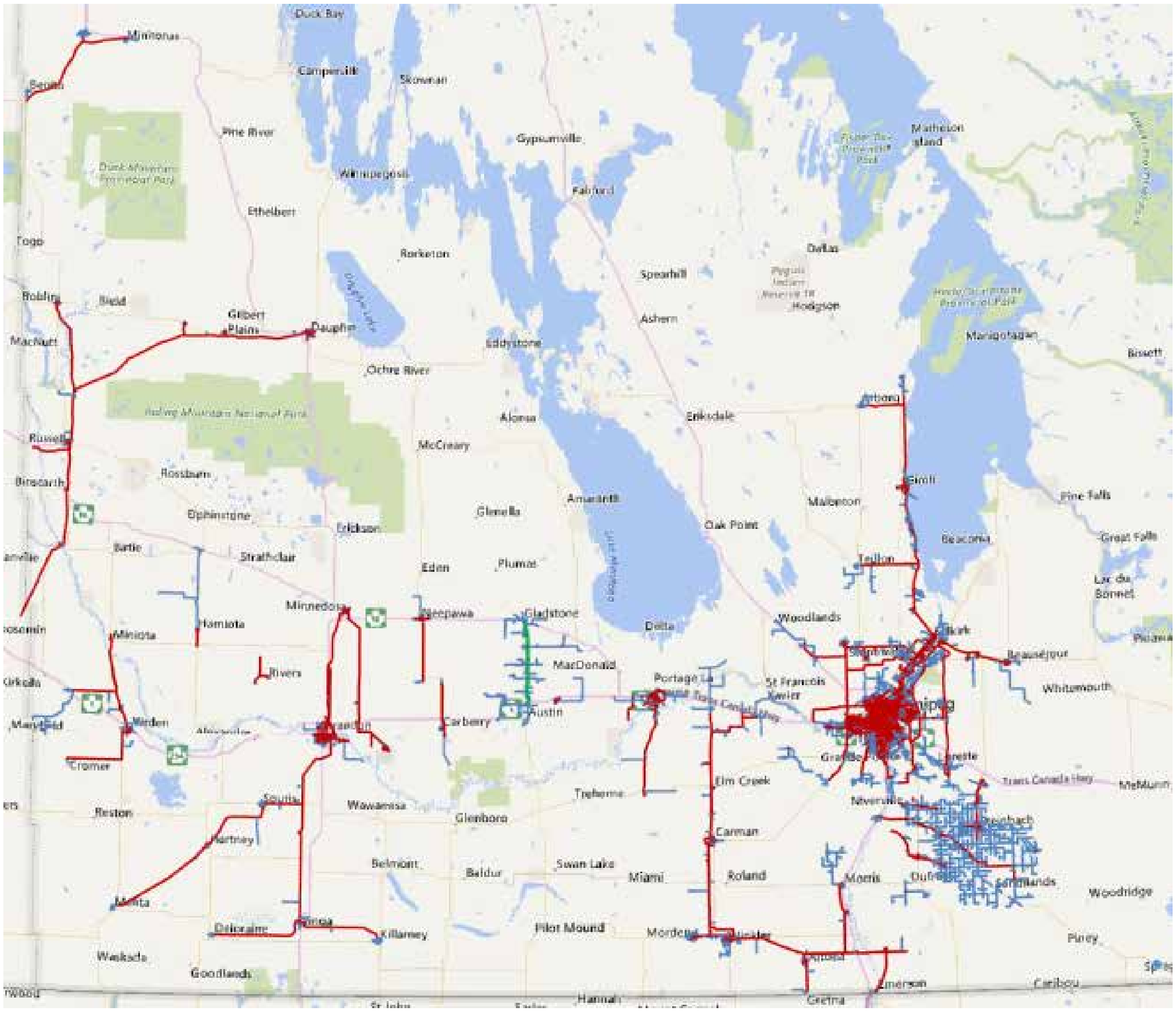



Figure 1: Manitoba Hydro Natural Gas Pipelines (Red – Steel, Blue – Plastic, Green – Aluminum)

## 1.1 Demographics

Steel services lines were first installed as part of the low pressure manufactured gas distribution system installed prior to 1957. With the arrival of TCPL in Manitoba in 1957, externally coated steel pipelines were the first generation of new pipelines distributing natural gas installed in Manitoba. The low pressure gas distribution system which utilized cast iron mains in Winnipeg was replaced with steel mains between 1965 and 1974 in the old Greater Winnipeg Gas service territory and continued to utilize some original steel services. Figure 2 below shows the various coating types for steel pipelines in Manitoba Hydro's system.

Figure 2: Various types of coatings on steel pipelines: fusion bonded epoxy (top left), paraffin wax (top right), polyethylene, informally yellow jacket (bottom left) and coal tar enamel (bottom right).

The Gladstone-Austin transmission pipeline is the only aluminum pipeline in Manitoba Hydro's system and is coated with polyethylene.

Figure 3 below illustrates the percentage of pipeline coating types by length on Manitoba Hydro transmission pipelines. The total length of transmission pipelines is 1860 km.

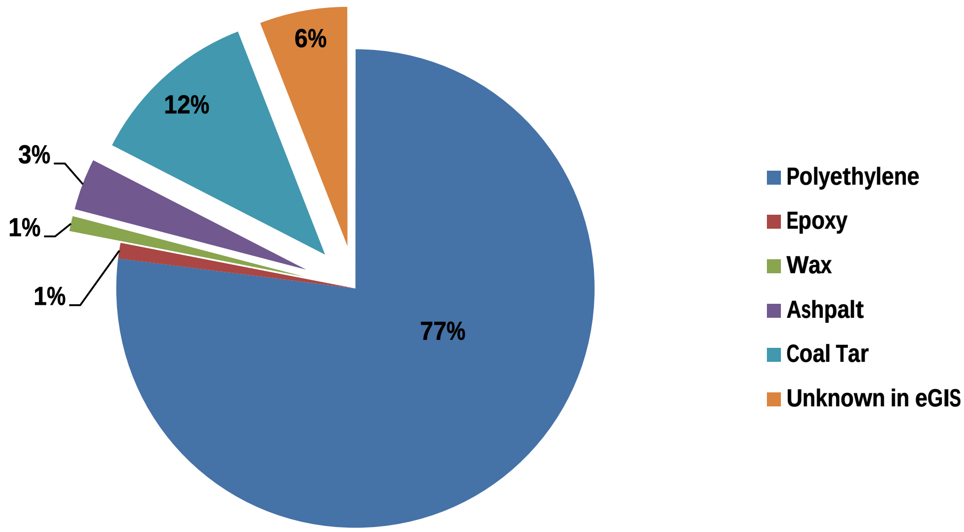



Figure 3: Percentage of coating types by length on Manitoba Hydro transmission pipelines[1]

The first transmission pipeline systems installed in Manitoba were coated with coal tar, asphalt or wax. Polyethylene, a superior coating material, has been used on all new transmission pipeline construction for sizes NPS 4 and smaller as of 1964. As of 1969, polyethylene coating was used on all sizes of pipeline in the Manitoba Hydro pipeline system. Epoxy coatings have been limited in use to select pipelines in the last 10 years.

A similar proportion of polyethylene coating is estimated to exist for steel distribution mains and services lines, with the remaining portion of coating consisting of coal tar/asphalt.

Plastic pipelines were first installed in the early 1970's and have primarily been used in medium pressure distribution applications using medium density polyethylene (MDPE). The earliest generations of plastic pipe used in Manitoba consisted of Aldyl-A pipe. In the last 10 years, plastic pipelines have been used in high pressure applications up to 1000 kPa (145 psi) using

[1] eGIS Gas Database – Note: The unknown coating type in eGIS refers to intermittent pipeline segments. Overall on a transmission pipeline system basis, the type of pipeline coating is known.

high density polyethylene (HDPE). Figure 4 below shows the various types of plastic pipelines installed in Manitoba Hydro's system.

Figure 4: Various types plastic pipelines: PE 2306 Aldyl-A (top left), Aldyl-A pipe with grey pigment due to reaction with soil (top right), PE 2406, commonly PE (bottom left) and PE-100 a.k.a. PE 4710, commonly HDPE, (bottom right).

Table 1 below illustrates the total length of each of the pressure classes and distinguishes by type of material.

| **Pressure class** | | **Total Length (km) by Pipeline Material** | | |
|---|---|---|---|---|
| | | Steel | Plastic | Aluminum |
| Medium pressure | Service lines | 4529 | 2349 | 0 |
| | Gas Mains | 3299 | 4152 | 0 |
| High pressure | | 198 | 92 | 0 |
| Transmission pressure | <30% SMYS | 674 | 0 | 0 |
| | >30% SMYS | 1154 | 0 | 32 |
| Total | | 9854 | 6593 | 32 |
| | | 16,479 | | |

Table 1 Pipeline Length by material and pressure class

The length of pipelines by size is detailed in Figure 5.

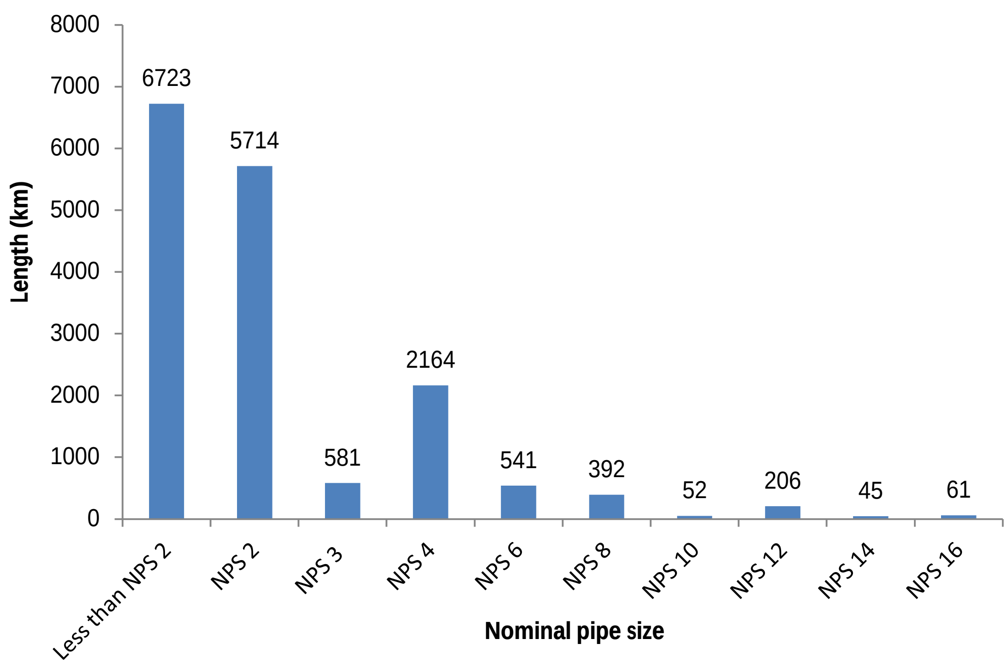



Figure 5 Pipeline Length by pipe diameter in nominal pipe size (NPS)

The age of Manitoba Hydro's pipeline assets including service lines, distribution pipelines, high pressure pipelines and transmission pipelines is illustrated in Figure 6 below.

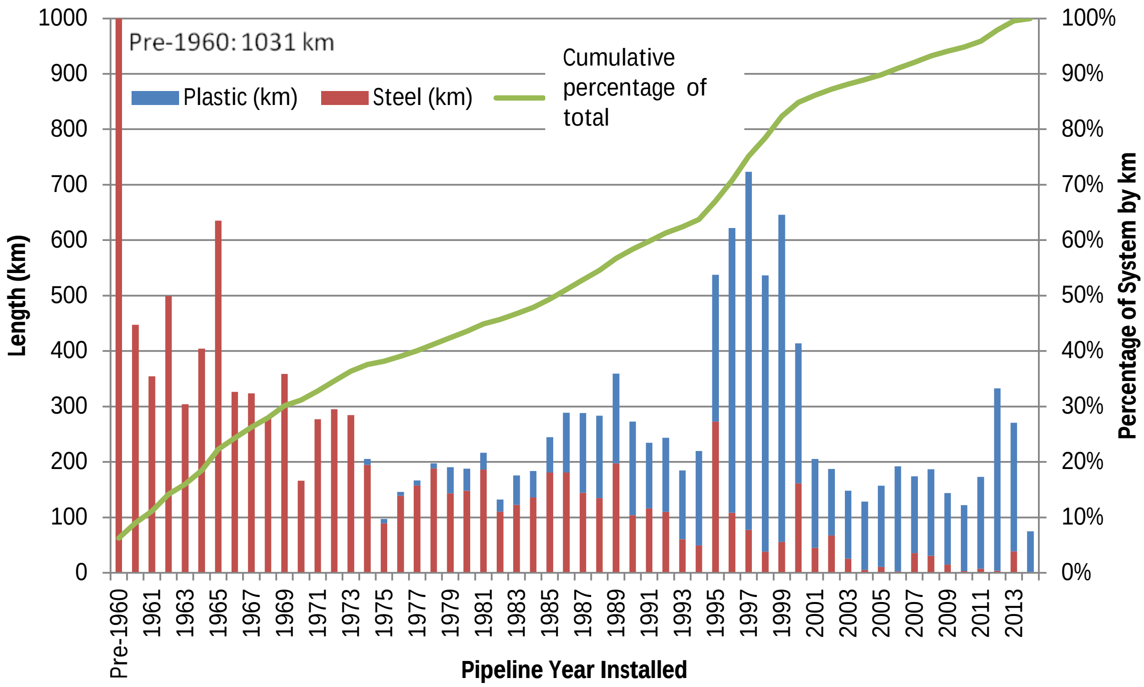



Figure 6 Pipeline Installations by Year

Overall, 50% of Manitoba Hydro's pipeline assets are older than 30 years, whereas 50% of the steel pipe assets are older than 46 years. Figure 5 illustrates that in the late 1980s plastic primarily the pipeline material of choice over steel for distribution pressure pipelines. This was especially demonstrated during the rural gas expansion from 1995 to 2000; where over 80% of newly installed pipelines consisted of medium density polyethylene (MDPE).

## 1.2 Hazards Specific to Degradation Mechanisms

A hazard is any influence that increases the likelihood of occurrence of an adverse effect. Manitoba Hydro recognizes 6 primary types of hazards to its natural gas system. These hazards have been identified with consideration for governing regulations and standards, industry experience, and corporate operating history. The hazards and sub-hazards are based on categories and definitions from the Canadian Gas Association (CGA). These hazards are incorporated into Manitoba Hydro's risk assessment initiatives as applicable. This appendix focuses on only the hazards that are applicable to the degradation of pipelines consisting of:

- Corrosion and degradation hazards
- Material, manufacturing and construction hazards (typically enhancing corrosion)

### 1.2.1 Corrosion and Degradation Hazards

#### 1.2.1.1 Metal Loss Corrosion

Corrosion metal loss can pose a hazard to steel and aluminum pipelines. The first line of defense against corrosion is the passive protection provided by pipeline coatings such as polyethylene, various tapes, shrink sleeves and epoxy coatings. However, in the event of coating holidays, the second line of defense for buried plant is cathodic protection, which makes use of anodes and impressed electrical currents to prevent corrosion. Formally, the failure of anodes or impressed current systems is considered an equipment malfunction hazard.

Corrosion metal loss occurs where the integrity of a pipeline's coating has been compromised and where cathodic protection currents are insufficient to protect the pipe. Failures due to corrosion metal loss have occurred at an average rate of 29 leaks per year over the last 10 years, with higher than proportional failures on distribution mains and services as opposed to transmission pipelines.

#### 1.2.1.2 Metal Cracking Corrosion

Stress corrosion cracking (SCC) is a form of metal cracking that has occurred on some pipeline including TCPL transmission pipelines. SCC was investigated on Manitoba Hydro Natural Gas Pipelines from 1999 to 2002 as a consideration from TCPL's experience of SCC related pipeline failures. A total of 44 examinations for SCC were performed. The SCC investigations ceased due to the absence of SCC evidence found. Manitoba Hydro Natural Gas transmission pipelines are not considered susceptible to SCC.

#### 1.2.1.3 Plastic Degradation

The North American natural gas distribution industry is aware of performance issues with early generation plastic piping, particularly Aldyl-A plastic piping. Although, no failures due to plastic degradation have been encountered on Manitoba Hydro plastic pipelines, Jana Laboratories conducted performance property tests on the Manitoba Hydro gas distribution system.

The performance of the samples far exceeded the performance that other utilities have experienced with earlier generations of Aldyl material and especially the Low Ductile Inner Wall (LDIW) Aldyl that has been notorious with low resistance to slow crack growth. The evaluation by Jana Laboratories concluded that Manitoba Hydro's early generation Aldyl piping is highly reliable, with low predicted failure rates due to slow crack growth in the near future on properly installed mains and services.

Although there currently is no established industry experience regarding degradation of modern plastic pipelines, there may be potential realizations in the future. Additionally, with increased concentrations of heavier than normal hydrocarbons in natural gas due to the advent of eastern shale gas production, the there is a potential for an impact on the integrity of plastic pipeline polymers. With an increase in heavier than normal hydrocarbons the impacts on plastic piping should be studied.

### 1.2.2 Material, Manufacturing and Construction Hazards

Material, manufacturing and construction imperfections are those that are created during construction or due to material defects and defective manufacturing. These types of imperfections are generally more frequent in older steel pipelines and can contribute to an exacerbating element such as corrosion metal loss.

#### 1.2.2.1 General Coating Deterioration

The gradual absorption of moisture is the primary factor in coal tar/asphalt coating deterioration. While this process will occur naturally through prolonged exposures to soil moisture, permeation of water through intact coal tar/asphalt coating is accelerated through electro-osmosis.[2] The process of electro-osmosis is driven by the electric field created by the cathodic protection system which can result in the formation of coating holidays. Coal tar/asphalt coating is considerably more susceptible to electro-osmosis than polyethylene coating.

Once a holiday exists in pipeline coating, moisture may creep between the pipe wall/coating interfaces resulting in a loss of coating adhesion. This process is known as cathodic disbondment and is caused by the products of a cathodic reaction.[3] Soil immediately next to coating holidays on Manitoba hydro pipelines has been discovered to contain the products of cathodic reactions. Although, alkaline moisture created by the cathodic protection generates a protective film on the steel surface, the alkaline moisture around the pipeline serves to further deteriorate coating.[4] As a pipeline's coating deteriorates further, higher cathodic protection currents are required, thus resulting in the acceleration of coal tar/asphalt coating deterioration.

Overall the severe deterioration detected during coating integrity surveys is attributable to:

- the moisture susceptibility of the coating
- electro-osmosis and cathodic disbondment
- cathodic reaction products
- coating application practices

While the above described cathodic process may not deteriorate polyethylene, wax coating or visco-elastic coatings, once a holiday exists in the coating, cathodic disbondment may still occur. This involves disrupting the adhesion of the coating to the pipeline and traps water between the coating and steel surface, thus creating a potentially corrosive environment.

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[2] CEOCOR Subcommittee – Cathodic Disbonding of Steel Pipe Coatings, 1987.
[3] NACE Standard Practice: Pipeline External Corrosion Direct Assessment Methodology
[4] Pipeline & Gas Journal – Coating Properties and Test Procedures, 2010.

#### 1.2.2.2 Pipe Body Coating Deterioration

Coal tar coated transmission pipelines that were installed by Greater Winnipeg Gas Ltd (GWG) have been identified to possess significantly fewer coating holidays per kilometer than coal tar coated transmission pipelines installed by Inter-City Gas Utilities Ltd (IGC) and Plains-Western Gas Ltd (PWG). Furthermore, no significant coating deterioration has been observed on GWG coal tar coated transmission pipelines.

Direct examinations conducted on GWG coal tar coated transmission pipelines have revealed coating with strong adhesion, very good structural integrity and typically small holiday sizes. However, most direct examinations on IGC and PWG coal tar coated pipelines have revealed severely degraded coatings with poor adhesion and lacking structural integrity. These observed differences cannot be explained by age or geographics as soil resistivity and the pH of cathodic reaction products are similar. Figure 7 below shows deteriorating coating on transmission pipelines installed by ICG and PWG.


Figure 7: Deteriorated coal tar enamel coating on Shilo (left) and Dominion City (right) transmission pipelines.

The observed severe coating deterioration on IGC and PWG coal tar coated pipelines may be attributed to coating installation practices by the respective companies. PWG pipe was delivered to the field bare and coated by the installing contractor in sections after girth welds were completed.[5] GWG pipeline lengths were factory coated by Bredero Shaw, a coating manufacturer, leaving only joints to be coated in field.[6] The application of large quantities of coating in the field is likely to be less reliable than the application of coatings in a factory environment where conditions are controlled. Additionally, rectifier cathodic protection systems that were primarily used IGC and PWG provide larger amounts of current which results in a faster rate of coating deterioration than anode cathodic protection used by GWG.

### 1.2.2.3 Pipe Joint Coating Deterioration

Pipe joint coating deterioration has been observed in conjunction with polyethylene tapes and petrolatum wrap (Denso). Polyethylene tape has been applied where 2 sections of pipe are welded together, whereas petrolatum wrap has been applied to coat fittings. Moisture penetration below the polyethylene tape joint coating can provide a suitable environment for corrosion and shield the protection from cathodic protection currents. This has usually been exacerbated by coating installation practices during construction. Since the mid-1980s, primer has been used in conjunction with polyethylene tape to provide improved adhesion and moisture resistance. In the absence of primer, moisture propagates below the coating more readily specifically into the void next of a girth weld as a result of tenting between the pipe surface and the raised weld cap. It is estimated by CSO that 50 to 80% of corrosion leaks are within the polyethylene tape area. Figure 8 below shows steel services lines where corrosion leaks occurred in the polyethylene joint tape region.

[5] Plains-Western Gas & Electric Co. Ltd. Specifications for the Construction of the Natural Gas Transmission and Distribution System for the Towns of Altona, Winkler, Morden and Plum Coulee, May 1962.
[6] Discussions with W. Tibelius, retired Chief Engineer Centra Gas.

Figure 8: Corrosion leaks on service lines below polyethylene tape joint coating

Additionally, corrosion in the region of polyethylene tape has been observed on transmission and distribution pipelines. The exhumed cylinders in Figure 9 below are an example of this corrosion.

Figure 9: Cylinder of severely corroded pipe from below polyethylene tape joint coating

The corrosion in Figure 9 above is considered uncontrolled corrosion as it cannot be prevented with cathodic protection. In-line inspection performed in 2015 of the La Salle NPS 12 transmission pipeline showed that external metal loss indications are 30 to 40 times more frequent in the vicinity of joint coating than the remainder of the pipe body. It is assumed the majority of these indications are corrosion underneath the polyethylene joint coating.

Moisture penetration below the polyethylene tape joint coating provided a suitable environment for corrosion and prevented protection from cathodic protection currents. It has been observed that the degree of ground moisture plays a significant role in the rate of corrosion that will occur. Approximately, 80% of Manitoba Hydro's steel pipelines have polyethylene taped joint coating that is not resistance to moisture penetration. Overall, corrosion due to pipe joint coating deterioration is considered a greater hazard than pipe body coating deterioration.

Since the late 1980's transmission lines have lines have been coated with polyethylene shrink sleeves. The sleeves are shrunk into place with the application of heat and provide a superior field applied coating in comparison to polyethylene tape.

### 1.2.3 Other Material, Manufacturing and Construction Hazards

Other types of material, manufacturing and construction imperfections are generally more frequent in older than newer steel pipelines. Although, these imperfections alone are stable, in conjunction with hazards that promote corrosion metal loss, the likelihood of a failure incident can be exacerbated. Therefore, some material, manufacturing and construction hazards are considered as they may bring about an earlier end of life. These include:

- Defective Joining Method: Leaks caused by improper welds, fusion and mechanical fittings (improper installation)
- Defective Pipe Body: Leaks caused by manufacturing or delivery of the pipe (such as lamination or seam weld defects)
- Other Improper Construction: Leaks caused by pre-commission construction issues (such not following construction procedures, inadequate competency or training, cross bores, loose tee cap, cracked tee cap due to over tightening).

## 1.3 Pipeline Integrity Activities

A hazard is any influence that increases the likelihood of occurrence of an adverse effect. The primary influences are those that could result in a release of gas from the piping system or those that could impact the detection, flow rate, duration or migration of such a release. In this consideration of risk, unless the consequence posed is sufficiently low, the hazard is considered as requiring control. Hazards are controlled operationally by addressing the constituent influences of frequency. Pipeline integrity activities either increase influences that maintain a desired attribute when necessary and/or decrease influences that disturb a desired attribute.

For example, adequate cover is an influence that promotes the integrity of buried pipelines, a general desired attribute. The restoration of adequate cover following the identification of a loss of cover increases the positive influence on a buried pipeline. Additionally, the application of safe excavation procedures decreases the probability of disturbance to a buried pipeline. This methodology, employed for the purposes of avoiding a line hit, reduces risk by decreasing the degree of likelihood of damage to a pipeline due to contact.

Pipeline integrity activities are carried out by numerous groups throughout the corporation, with pipeline integrity intrinsic to many corporate activities. The activities cover a broad range of work including inspection and maintenance. Pipeline integrity activities at Manitoba Hydro consist of the following categories defined by the nature of the work:

- **Restoration and Maintenance Activities:** Pipeline integrity activities that apply corrective actions are restoration and maintenance activities. They generate action to mitigate hazards as they are found. Restoration and maintenance activities are primarily driven to maintain the pipeline system integrity as required by codes and standards. For example, leak surveys are regularly performed as required by Manitoba Hydro standards and procedures which are in compliance with the requirements of CSA Z662. Additionally, leaks found are remediated in compliance with Manitoba Hydro standards and procedures and in compliance with CSA Z662

- **Hazard Assessment Activities:** Hazard assessment activities generally involve inspection. These activities consider attributes to evaluate and prioritize specific sites within activities based on risk. Based on the findings in hazard assessment activities, corrective actions through restoration and maintenance activities may be initiated. These relative assessments are completed as formal risk assessments or developed as a set of criteria unique to the administration of the activity.

- **Hazard Research and Identification Activities:** Hazard research and identification activities are used to monitor the long-term results of restoration and maintenance activities. Hazard research and identification activities apply a system wide risk consideration to Manitoba Hydro's natural gas pipeline system to focus the identification of specific hazards. Hazard research and identification based activities represent the core of integrity activities owned by the Pipeline Integrity Group. The Pipeline System Risk Assessment Model is one research and identification activity that acts as a driver for other activities. For example, if a pipeline asset has a high risk ranking that is found to be driven primarily by a corrosion hazard, already established activities, such as the External Corrosion Direct Assessment (ECDA) Program or In-Line Inspection, are focused on that asset.

The Pipeline Integrity Activities applicable to the Gas Asset Condition Assessment are shown in the Table 3 below. Table 2 acts as a key for determining the type of pipe a pipeline integrity activity applies to. Further details can be found in the Pipeline System Integrity Management Plan.

| Type of Pipe | Character |
|---|---|
| Metallic (e.g. Steel) | S |
| Plastic | P |
| Metallic and plastic | SP |
| Not applicable | NA |
| Selective | + |

Table 2: Type of material key for Table 3.

Appendix B – Pipelines of Natural Gas Asset Condition Assessment

| Activity Category | Activity Name | Transmission Piping | Distribution Piping | Service Lines |
|---|---|---|---|---|
| **Hazard Assessment Activities** | | | | |
| | Cathodic Protection System Monitoring and Performance Evaluation | S | S | S |
| | Close Interval Potential Survey | S | NA | NA |
| | External Corrosion Direct Assessment (ECDA) Program | S+ | NA | NA |
| | In-Line Inspection (ILI) Program | S+ | NA | NA |
| | Coating Shield Corrosion Preliminary Assessment | S+ | NA | NA |
| **Restoration and Maintenance Activities** | | | | |
| | Business District Leak Survey and Repair | NA | NA | SP |
| | Distribution Mains and Service Leak Survey and Repair | NA | SP | SP |
| | Defect Assessment Program | S | S | NA |
| | Public Building Leak Survey and Repair | NA | SP | SP |
| | Special Leak Survey and Repair | S | SP | SP |
| | Transmission Leak Survey and Repair | S | NA | NA |

Table 3: The pipeline integrity activities applicable to degradation mechanisms for pipelines.

Hazard research and identification activities provide a platform for the discovery and consideration of new hazards. The discovery of new hazards can be based on reported findings by experienced staff and the media. Additionally, Manitoba Hydro maintains an awareness of hazards present elsewhere by participating in industry groups and committees. If the potential consequence of a new hazard is considered noteworthy and applicable to Manitoba Hydro following primary consideration and information gathering, the new hazard will be assessed by a hazard assessment activity.

These activities are not shown in Table 3 since they are not currently active and not closely applicable to degradation mechanisms.

## 1.4 Pipeline Failure and Replacement

### *1.4.1 Pipeline Failure Mechanisms*

The failure mechanisms of a pipeline depend on the stress level or %SMYS under which the pipeline is operated. It is accepted in the Canadian gas industry that a failure incident on a pipeline operated at below 30% SMYS will most likely consist of a leak, while a failure incident on a pipeline operated at or greater than 30% SMYS could consist of a rupture. A pipeline leak would be expected to have significantly lesser consequences than a rupture with regards to public safety, customer impact, financial impact and corporate image impacts. CSA Z662-15 has selective provisions for gas distribution pipelines intended to be operated at below 30% SMYS.

Of Manitoba Hydro's pipelines, 93% have a leak as the expected failure mechanism based on the 30% SMYS criteria. The remaining 7% of pipelines while most likely fail as a leak; however they do have the potential to experience rupture as they exceed the 30% SMYS threshold.

### *1.4.2 Pipeline Leaks and Age*

Pipelines that experience leaks are usually repaired and in most cases replaced. Regardless of the failure cause or pipe material these repairs consist of welds repairs or a cylindrical pipe replacement typically less than 2 m in length in each case.

The age profile of pipeline leaks per kilometer is detailed in Figure 10. The leak per kilometer profile was chosen to normalize the leak statistics based on the length of pipe that was installed in a given year.

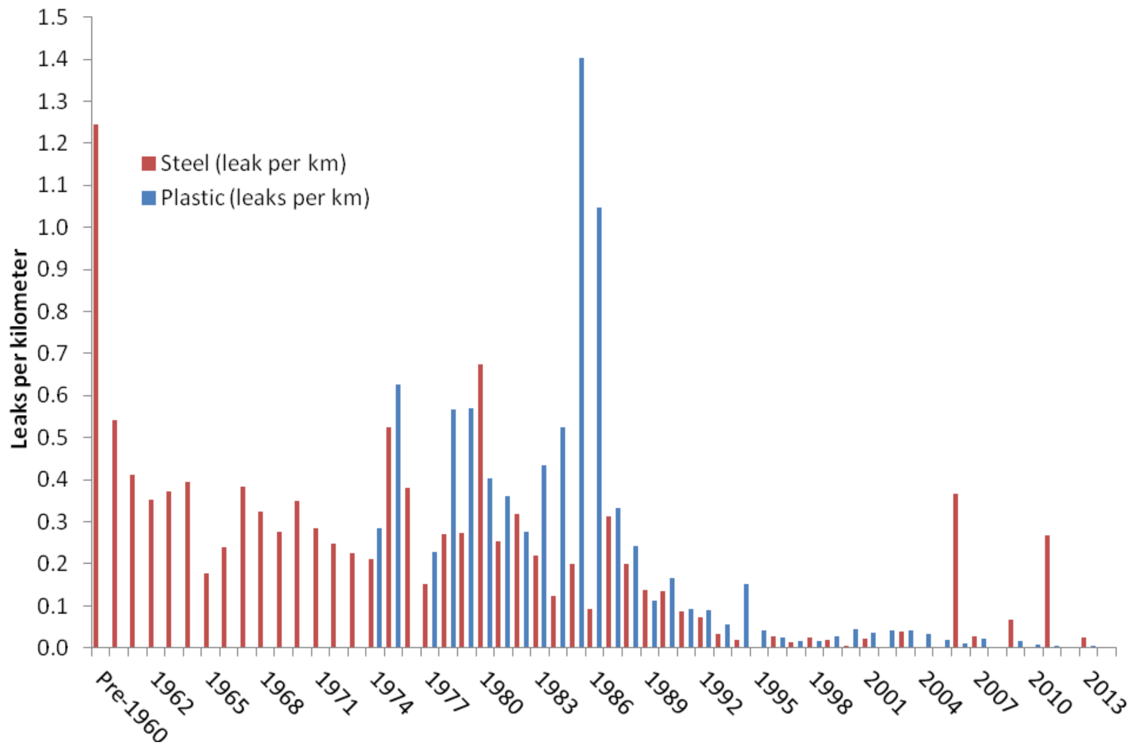



Figure 10: All recorded pipeline leaks per kilometer due to all causes, except 3rd contact caused leaks for the year installed.

Figure 10 demonstrates that steel pipelines older than the mid-1980s manifest a greater frequency of leaks more regularly than younger pipe, likely attributable to corrosion. Another, significant increase in leak rate is seen in pre-1960 steel pipelines. Since the record of below grade leaks is incomplete prior to the mid-1980, higher concentrations of below grades leaks would have actually occurred on pre-1980s pipe than shown in Figure 10. The intermittent spikes of leaks in 2006, 2009 and 2011 are attributed to construction based leaks and the low volumes of steel pipe installed in those years thus appearing as proportionally higher leaks per kilometer. As steel pipelines continue to age, an accelerating trend on degradation based leaks is expected for vintage steel pipelines due to the limitations of cathodic protection.

Figure 10 shows a significant increase in leak frequency due to construction defects on plastic pipelines prior to the mid-1980s. These leaks are due to construction defects associated primarily with the nuances of fusing polyethylene pipe, while a minority of leaks are associated with leaking service tee caps. Construction practices concerning the installation of polyethylene pipe became less error prone later in the 1980s as shown by fewer leaks. By the time of the large volume installation of polyethylene pipe during the rural gas project of the mid-1990s, far fewer construction defects were being created resulting in fewer leaks. Figure 8 shows this increase in polyethylene pipe installation.

It is recognized that the frequency of below grades leaks due to corrosion will escalate in the future, however, there currently is no reasonable means of estimating how rapidly an escalation will occur. The operating history of Manitoba Hydro natural gas pipelines has demonstrated that degradation type failures occur in a higher than proportional amount on pipelines in urban environments where the potential consequences of failure are higher as opposed to rural pipelines. This is due to the increased difficulty of maintain sufficient cathodic protection levels, influences from other infrastructure and higher amount of excavation activity around pipelines. This is observed through higher than proportional degradation failures of distribution pipelines than transmission pipelines.

Figure 11 below shows the distribution of below grade leaks suspected of corrosion since the year 2000.

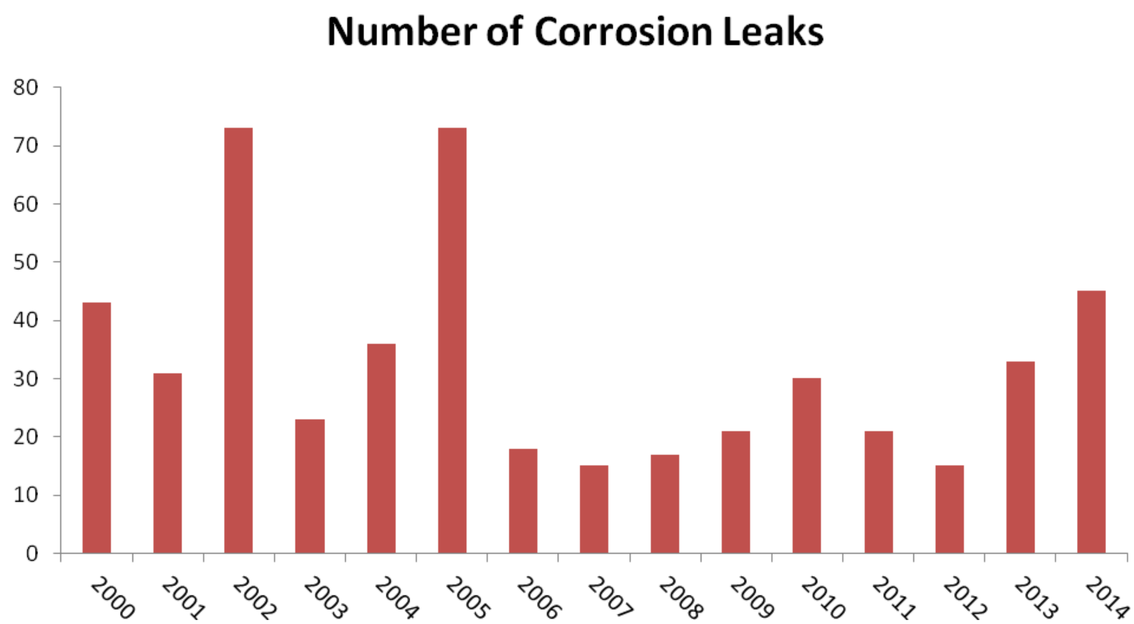



Figure 11: Distribution of corrosion leaks annually since the year 2000

No trend appears to be visible in the corrosion leak data. The year to year variations are attributable to the schedule of surveying different areas in the conducting of the triennial leak surveys. A total of 98% of these leaks occurred of medium and high pressure pipelines.

The pipeline integrity activities *Below Grade Leak Analysis* and *Pipeline System Risk Assessment Model* examine the frequency and concentration of below grade leaks suspected of corrosion. Other pipeline integrity activities are applied as appropriate to address high risk areas.

### *1.4.3 Pipeline Rupture*

The rupture of the La Salle NPS 12 transmission pipeline during a recertification test in 1964 is the only record of a Manitoba Hydro pipeline that has ruptured. The pipeline ruptured during a pneumatic pressure test at 7080 kPa (1027 psi). The cause of the failure was determined to be due to an existing manufacturing defect interacting with the heat affected zone of the long seam weld while under the high stress of the pressure test.[7] Figure 12 below shows the failure that occurred.

Figure 12: Rupture incident of La Salle NPS 12 transmission pipeline south of McGillivray Boulevard during pneumatic pressure test in 1964. Rupture occurred at 7080 kPa (1027 psi) corresponding to 57% SMYS.

The La Salle NPS 12 transmission pipeline was installed in 1957 as the first transmission pipeline to provide supply of natural gas to the City of Winnipeg and remains a vital supply route today. Once agricultural land, the pipeline has seen extensive residential, commercial and utility development. Based on a state of operation at above 30% SMYS, location and history, the La Salle NPS 12 pipeline was considered the highest risk to pipeline integrity among all Manitoba Hydro transmission pipelines and therefore the first priority for in-line

[7] Metallurgical Report of La Salle NPS 12 Transmission Pipeline Failure for GWG 1964, Page-Hersey Tubes

inspection. In-line inspection was conducted in the summer of 2015.[8] Transmission pipelines of a similar risk and have been planned for in-line inspection.

### *1.4.4 Replacement Rates*

When pipeline integrity activities are no longer considered sufficient to manage the risk that a pipeline poses, replacement is considered to mitigate risk.

#### 1.4.4.1 Transmission Pipelines

The current replacement rate for transmission pipelines is greater than 1000 year. Portions of transmission pipelines are replaced when required for roadway relocations or river crossings. In 1972 a 3.4 km portion of the Shilo transmission pipeline were replaced because manufacturing defects resulted in a significant amount of leaks. Such large replacements are rare.

#### 1.4.4.2 Steel High and Medium Pressure Mains

The current replacement rate for steel distribution mains is greater than 1000 years. Steel distribution mains may be replaced for the same reasons as transmission pipelines. However, in 2010, a replacement of 0.4 km of steel distribution mains and steel services was completed along Villeneuve Ave., in St. Norbert due to significant corrosion degradation. This is the only large scale replacement of its kind in recent history.

#### 1.4.4.3 Steel Services

A total of 174,216 steel services exist in Manitoba Hydro's system as of 2015. The current replacement rate of steel services is 342 years as of 2015.This is based on the average annual net reduction in steel services as part of regular operations which has consisted of an average reduction of 509 services per year since 2000. The average net annual reduction of steel services includes services that are replaced with plastic or are abandoned permanently.

[8] 2015-04044 In-Line Inspection of La Salle NPS 12 Transmission Pipeline

#### 1.4.4.4 Plastic Mains and Services

The replacement rate for plastic mains and services is greater than 1000 years. Plastic services and portions of plastic main are currently replaced when a leak in an area that is not readily repairable such as under a street. In these cases the original plastic service/portions of main is abandoned and a new service/main is installed.

## 1.5 Risk of Failure

### *1.5.1 Risk Assessment of Pipelines*

Manitoba Hydro has established a formal risk assessment process for pipelines. Risk management is a consistent and rational method of reducing overall risk to the pipeline network by identifying and focusing resources on pipe segments with the highest relative risk. Overall, risk assessment is a valuable tool for:

- Making effective choices among risk-reduction measures;
- Supporting specific operating and maintenance practices for pipelines subject to integrity hazards;
- Assigning priorities among inspection, monitoring, and maintenance activities; and
- Supporting decisions associated with modifications to pipelines, such as rehabilitation or changes in service.
- Identifying pipeline segments for a specific study

This pipeline integrity activity is referred to as the Pipeline Risk Assessment Model.[9] During the risk assessment process, pipelines are separated into segments sharing similar attributes (pipe material, internal pressure, cathodic protection history, etc). Then the highest ranked segments are further investigated to determine risk significance and assess risk reduction options.

Historical incident data and industry recognized risk weightings are used to assign each pipe segment a frequency analysis score and consequence analysis score which are then combined to determine the total risk score.

Frequency analysis is a measure of the likelihood of a pipeline failure occurring due to known hazards. A failure is any unplanned release of natural gas and does not necessarily result in a loss of supply to customers. The hazards considered in the pipeline system risk analysis for the Gas Asset Condition Assessment are:

- Corrosion and degradation hazards
- Material, manufacturing and construction hazards

[9] 2014-04005 Report on Pipeline Risk Assessment

Consequence analysis is an estimate of the severity of an incident.

### *1.5.2 Uncertainty of Pipeline Condition*

Condition monitoring is when the state of a pipeline is periodically assessed specifically with regards to degradation mechanisms. Benefits of performing condition monitoring and improving the certainty of asset health, specifically with regards to age dependent degradation include:

A. Continued confidence with regards to operating the transmission pipeline system safely and reliably. Confidence cannot be maintained with the current level of condition uncertainty.

B. Extension of life and deferral of capital investment. Findings from corrosion condition monitoring programs may defer capital for the replacement of transmission pipelines. The positive financial impact of a 5 year capital investment deferral [10] of the replacement cost of a major Manitoba Hydro transmission pipeline, is equivalent in the magnitude to the cost of performing ILI.[11] Therefore, if ILI extends the life of a major transmission pipeline by at least 5 years, the cost of ILI will have been recovered.

C. Continued positive customer perception of service with regards to reputation by prevention of failure incidents.

D. Required Meeting CSA Z662-15 requirements for condition monitoring. ILI meets the requirements for condition monitoring.

E. Contributing to the body of knowledge of where and how Manitoba Hydro's pipelines are deteriorating and thus improving the accuracy of risk assessment.

Condition monitoring activities provide a greater degree of certainty of asset condition through assessment. The following activities that address age dependent degradation, corrosion, include:

[10] Assuming a real Canadian long term debt interest rate of 2.82%.
[11] Assuming a lifecycle first time ILI cost that includes pipeline modification and inspection.

1. Close Interval Survey (CIS) (1990s to present): The CIS is performed periodically on transmission pipelines every 7 to 10 years. Results are used to assess the condition of cathodic sections and verify the adequacy of cathodic protection to prevent corrosion. Cathodic sections that have inadequate levels of cathodic protection have levels increased.

2. Stress corrosion cracking (SCC) assessment (1999 to 2002): This program was deactivated due to the absence of SCC evidence in the Manitoba Hydro Natural gas Distribution System. Investigations on the Manitoba Hydro pipeline system where carried out due to the presence of SCC on TCPL's pipelines. Investigations in the highest likelihood areas were carried out been 1999 and 2004. The aspects of SCC of interest to Manitoba Hydro that were investigated included the cracking of corrosion weakened pipe induced by pipeline pressures. The entire sample size for SCC has been completed.

3. External corrosion direct assessment (2002 to present): The ECDA program has been the primary tool used to conduct health monitoring of transmission pipelines since 2005. The program uses coating holidays as a proxy to hypothesize the existence of corrosion. The program has revealed that coating holidays are numerous and common place on Plains Western and Inter-City Gas coal tar pipelines. However, the lack of corrosion discovery in association with coating holidays is attributed to the effectiveness of the cathodic protection system on the pipeline sections examined. To date 47% of the pipelines in scope of the program have not been examined using ECDA.

4. In-line inspection (2015 to present): ILI was first implement by Manitoba Hydro in 2015. To date 1% of applicable pipelines by kilometer have been completed. ILI utilized sensors to detect specific indications of metal loss and deformation. The ILI project of 2015 identified severe corrosion under coating that was shielding cathodic protection.
   The Pipeline Integrity Group is currently developing a detailed ILI program plan for the next 5 years and conceptual plan for the next 15 years. This plan will outline the pipeline systems where ILI is appropriate and options for implementing ILI. Upon selection and adoption of an ILI option, the timeline to complete condition monitoring activities on

other pipeline systems will be reassessed. Overall, ILI provides the most certain results in comparison to other condition monitoring activities.

5. Coating shielding corrosion assessment activity (2016): Recently, ILI has revealed that uninhibited corrosion is occurring under disbonded joint coating which is shielding cathodic protection. The pilot project is a spin-off as a result of ILI findings. It is currently uncertain whether coating shielding corrosion is occurring on other transmission pipelines. However, there is nothing particularly unique about the La Salle NPS 12 transmission pipeline that would such that it is the only susceptible pipeline. The purpose of this activity is to gain further knowledge into the extent of coating shield corrosion on other transmission pipelines systems. Approximately 8 excavation are planned for 2016 to begin assessing coating shielding corrosion under similar circumstances as found by ILI.

   Coating shielding corrosion assessments are appropriate for pipelines where in-line inspection is not planned or will not be completed for some time and where coating may result in uninhibited corrosion. As assessments are completed of further pipelines, the full extent of this hazard will be more accurately quantified by the Pipeline System Risk Assessment Model. Additionally, corrosion defects will be removed from pipelines as found.

Figure 13 below represents the portion of transmission pipelines in the scope of the activities where existing condition monitoring specific to degradation have been completed. The total, 100%, is the equivalent amount of pipeline in the sample size of each activity.

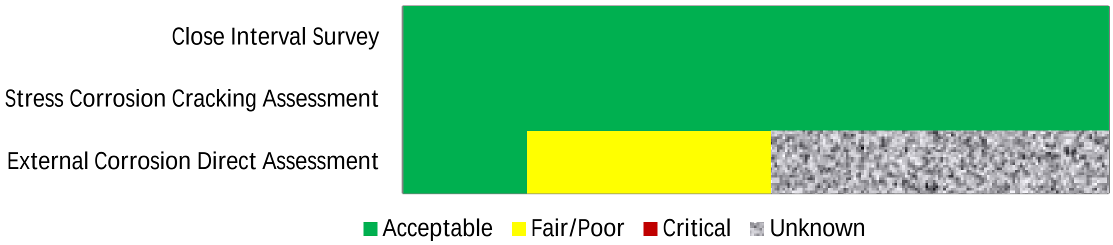



Figure 13: Percentage of unassessed asset condition of transmission pipelines based on findings from condition monitoring programs specific to degradation "soccer field". 100% represents that sample size of pipeline by km for each assessment methodology.

The grey areas in Figure 13 represent the portions of pipeline in the sample size of these programs where the condition has not been assessed and the asset health less uncertain.

Figure 14 below represents the portion of transmission pipelines in the scope of activities where new condition monitoring specific to degradation is recommended. The total, 100%, is the equivalent amount of pipeline in the sample size of each activity.

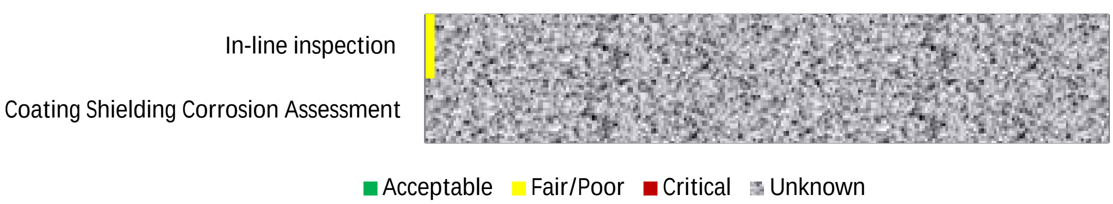



Figure 14: Percentage of unassessed asset condition of transmission pipelines based on findings from condition monitoring programs specific to degradation "soccer field". 100% represents that sample size of pipelines by km for each assessment methodology.

Since the condition monitoring activities shown in Figure 14 are newly proposed, they are included in the recommendation Section 1.7.

### *1.5.3 Asset Health*

Manitoba Hydro has established a health condition rating system for pipelines consisting of the Asset Condition Score. The Asset Condition Score is derived from the Corrosion and Construction / Material Defects scores of the Pipeline System Risk Assessment Model. The factors and weightings in this score are based on industry recommended values that have been tailored to be applicable to Manitoba Hydro natural gas pipelines. The Risk Assessment scores are reviewed periodically to incorporate nuances derived from pipeline integrity activities and industry developments.

The asset health 20 years in the future was estimated by modifying the current year Asset Condition Score based on the existing trends for older pipelines.

Assets are grouped into health index conditions by their asset conditions scores. The range of scores was selected by applying Manitoba Hydro's previous experience on a small number of pipelines to other pipelines with similar Asset Condition Scores.

As a result of the scoring method, assets within each health index condition group share typical asset condition score benchmarks including age, the amount of time cathodic protection levels were below target, the below grade leaks attributed to corrosion, and the below grade leaks attributed to construction / material defects.

#### *1.5.3.1 Transmission Pipeline Asset Health*

Figure 15 below shows the estimated current asset health and 20 year forecasted asset health for transmission pipelines.


Figure 15: Transmission Pipeline "Soccer Field"

Figure 15 indicates that no transmission assets are currently estimated to be in critical condition; this will increase to 3.7% in 20 years. The percentage of transmission assets in fair/poor condition is currently 4.2% and will increase to 26.5% in 20 years.

Table 4 below details the asset condition scores and typical benchmarks shared by assets in each health index condition category for transmission pipeline assets.

Table 4: Transmission Pipeline Asset Health Index

| Health Index Condition | Probability of Failure | Typical Asset Condition Score Characteristics |
|---|---|---|
| Critical | High | · Factors associated with vintage pipe<br>· History of cathodic protection time below target<br>· Presence of below grade leaks due to corrosion or construction / material defects |
| Fair/Poor | Medium | · Factors associated with older pipe<br>· Possibility of cathodic protection time below target<br>· Possibility of below grade leaks due to corrosion or construction / material defects |
| Acceptable | Low | · Factors associated with new and some older pipe<br>· Good cathodic protection history<br>· Good below grade leak history |

### 1.5.3.2 *High and Medium Pressure Asset Health*

Figures 16 and 17 below show the current asset health and 20 year forecasted asset health for distribution and service pipelines.


Figure 16: Gas Mains Pipeline "Soccer Field"

Figure 16 indicates that 0.8% of distribution pipeline assets are estimated in critical condition; this percentage will increase to approximately 2.8% in 20 years. The percentage of distribution assets in fair/poor conditions is currently 2.8% and will increase to 11.6% in 20 years.

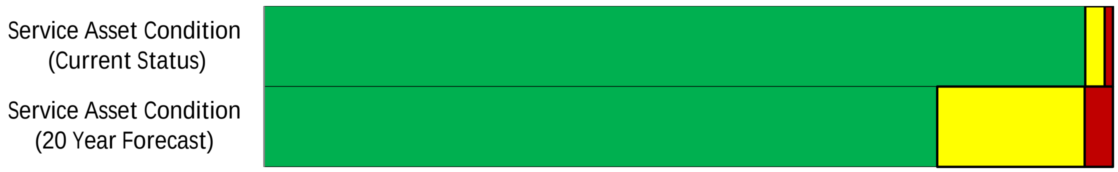



Figure 17: Service line "Soccer Field"

Figure 17 indicates that 1.0% of service line assets are estimated in critical condition; this percentage will increase to approximately 3.3% in 20 years. The percentage of service assets in fair / poor condition is currently 2.3% and will increase to 17.4% in 20 years.

Table 5 below details the asset condition scores and typical benchmarks shared by assets in each health index condition category.

Table 5: Distribution and Service Pipeline Asset Health Index

| Health Index Condition | Probability of Failure | Typical Asset Condition Score Characteristics |
|---|---|---|
| Critical | High | · Vintage Pipe<br>· Prevalence of cathodic protection time below target<br>· >4.6 below grade leaks due to corrosion or construction / material defects per kilometer. |
| Fair/Poor | Medium | · Older Pipe<br>· Prevalence of cathodic protection time below target<br>· >1.5 below grade leaks due to corrosion or construction / material defects per kilometer. |
| Acceptable | Low | · New and some older pipe<br>· Good cathodic protection history<br>· Good below grade leak history |

### *1.5.4 Risk Map*

Based on the observations made in this report, the following risk maps were developed based on the risk assessment methodology in Appendix D. The maps consider the anticipated impact aging pipelines will have on Manitoba Hydro with respect to the following criteria:

1. Financial
2. System Reliability
3. Safety, Employee and Public
4. Environment
5. Customer Value

The likelihood and consequence of each factor is plotted in the risk map and reflect current activities. 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 risk map.

### *1.5.4.1 Transmission Pipeline Risk Map and Risk Scoring*

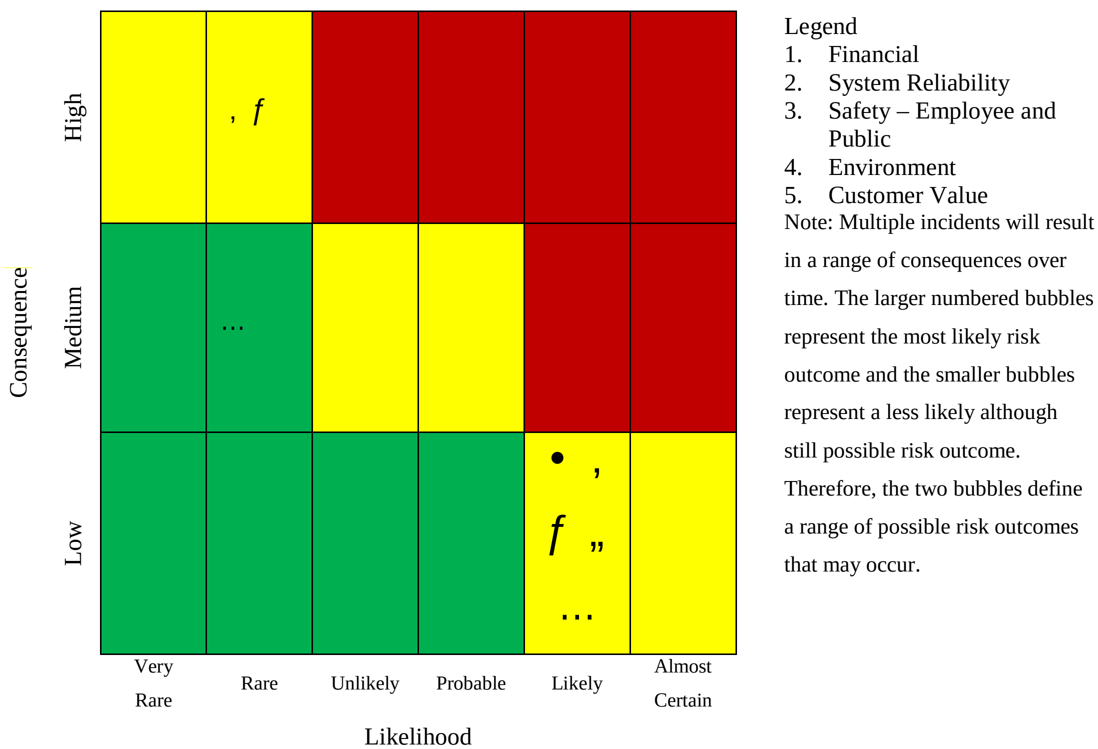


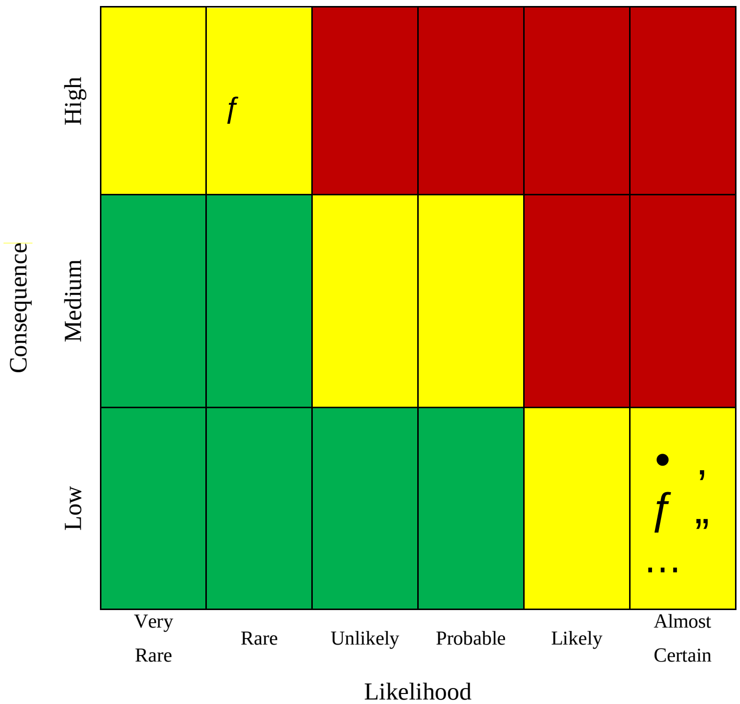

Figure 18: Transmission Pipeline Risk Map

1. <u>Financial:</u> In 20 years the investment gap to address transmission pipeline condition is $6 Million. This is the cost to do in-line inspection on all pipelines forecasted to reach critical condition in 20 years and replace 10% of them. The current conditions are estimates only; performing ILI is the most effective way to assess the health of a pipeline system. ECDA and Under Tape Corrosion Assessment assess health less exactly. During

an ILI project, the worst defects are visually inspected and repaired if necessary. ILI will support the continued safe operation of Manitoba Hydro's transmission pipelines.

2. System Reliability: Leaks on transmission pipelines can often be repaired without interrupting service resulting in a low consequence to customers. An incident resulting in an unplanned outage on any of the single feed transmission lines is anticipated to have a high impact if the gas supply cannot be maintained to customers although this would be rare.
3. Safety – Employee and Public: A number of transmission pipelines are predicted to reach critical condition in 20 years. With the majority of transmission pipelines operating below 30% SMYS, the majority of incidents will be leaks of low consequence. A transmission pipeline rupture would have a high impact to safety and reliability although this would be rare.
4. Environment: A transmission pipeline incident is anticipated to have a low impact to the environment.
5. Customer Value: A medium impact would be anticipated if the transmission pipeline ruptured attracting national media coverage although the likelihood is rare. A low impact would be anticipated as the result of a transmission pipeline leak.

### *1.5.4.2 High and Medium Pressure Risk Map and Risk Scoring*




1. Legend Financial
2. System Reliability
3. Safety – Employee and Public
4. Environment
5. Customer Value

Note: Multiple incidents will result in a range of consequences over time. The larger numbered bubbles represent the most likely risk outcome and the smaller bubbles represent a less likely although still possible risk outcome. Therefore, the two bubbles define a range of possible risk outcomes that may occur.

Figure 19: Distribution Pipeline Risk Map

1. Financial: In 20 years the investment gap to address distribution and service line condition is $15 Million and $13 Million respectively. This is the estimated cost to replace the pipelines predicted to be in critical condition and is dependent on further individual studies. While this study is assessing asset condition as a whole, it is known that there are a small number of individual areas that have already reached the end of their service life and require replacement now.
2. System Reliability: An unplanned outage to a distribution or service line would be anticipated to have a low impact as it would affect a smaller number of customers. The impact is compounded in areas experiencing multiple outages diminishing public confidence.
3. Safety – Employee and Public: A distribution or service line incident is anticipated to have a low impact to safety as they tend to be small leaks. The worst case scenario would be a distribution pipeline leak due to condition that found a path into a building and ignited resulting in a high impact, although this would be rare.

4. Environment: A distribution or service line incident is anticipated to have a low impact to the environment.
5. Customer Value: A distribution or service line incident is anticipated to have a low impact to customer value with none or minimal local media coverage.

## 1.6 Economic Evaluation of Pipeline Assets

Pipeline construction costs depend primarily on pipeline size and material type. Table 6 provides an overview of the pipeline asset value, current replacement rates, anticipated lifespan and replacement cost.

| Asset Pressure Class | Asset Pipeline Material | Quantity (km) | Life Expectancy (Years) | Replacement Rate (Years) | Unit Replacement Cost ($k/km) | Total Replacement Cost ($M) |
|---|---|---|---|---|---|---|
| Medium pressure | Steel service lines | 4529 | 120 - 150 | 342 | 30 - 160 | 174.1 |
| | Plastic service lines | 2349 | >200 | No replacement | 30 - 160 | 90.3 |
| | Steel pipelines | 3299 | 120 - 150 | No replacement | 30 -160 | 230.6 |
| | Plastic pipelines | 4152 | >200 | No replacement | 30 - 160 | 311.9 |
| High pressure | Steel pipelines | 198 | 120 - 150 | No replacement | 130 - 650 | 92.2 |
| | Plastic pipelines | 92 | >200 | No replacement | 30 - 160 | 6.9 |
| Transmission pressure | Steel pipelines | 1860 | 80 - 120 | No replacement | 130 - 650 | 508.0 |
| | | | | | | |
| **Total** | | **16,479** | | | **Avg. 85.8** | **1413** |

Table 6 Pipeline Economic Evaluation (No replacement refers to a negligible replacement amount)

## 1.7 Summary of Gaps and Recommendations

### 1.7.1 Transmission Pressure Pipelines

**Critical gap and deficiencies:** During analysis incomplete asset condition information was identified as a critical gap. Deficiencies as a result of a critical information gap include:

- The current condition monitoring activities do not allow for the detection of the degradation with sufficient time for remediation. This could adversely affect the safety and reliability of Manitoba Hydro's transmission pipelines.
- The current rate of condition monitoring is inadequate to identify the increasing age related degradation to provide for prevention of failures rather than reacting to failures on Manitoba Hydro's transmission pipeline assets.
- Insufficient condition monitoring precludes an accurate determination of the end of useful life and does not allow for the accurate investment planning of capital resources to replace pipelines.

**Recommendations:** The recommendations outlined below will address the critical information gaps outlined above within the next 10 years if implemented. Primarily these recommendations will address the largely unknown extent of corrosion hazards.

1. Develop a plan and provide additional resources for implementation of In-line Inspection (ILI) on a longer term basis. Currently, no budget is allocated for ILI. On a capital project by project basis, $2 to 5 M per year is recommended to modify pipelines for ILI and perform inspections over the next 20 years.
2. Develop a plan for and develop an integrity activity for assessing coating shielding corrosion. The existence of coating shielding corrosion has been recently confirmed and the extent is undetermined. A budget of $250,000 per year for the next 3 years is recommended.
3. Expand the plan and increase funding for External Corrosion Direct Assessment for pipelines. This will complete the detection and assessment of holiday corrosion on Manitoba Hydro's transmission pipelines. An additional budget allocation of $80,000 per year for the next 10 years is recommended in addition to the current budget of $60,000 per annum is allocated to study holiday corrosion through the ECDA program.
4. Replace pipeline systems where warranted and develop a long term capital investment plan to address aging infrastructure.

### 1.7.2 High and Medium Pressure Pipelines

**Gap:** During analysis of the asset the following gaps were identified:

- Pipelines and service lines are anticipated to warrant accelerated replacement rates as failure rates due to degradation are likely to increase at an undetermined time within the next 20 years.
- Based on current pipeline asset health forecasts, an average annual investment gap of $1.4M exists for high/medium pressure pipelines and service lines.

**Recommendations:** Replacement is recommended where:

1. Replacement of distribution and service lines where condition alone warrants.
2. Replacement of distribution and service lines where condition combined with age, damage prevention concerns, encroachment, capacity, or other factors collectively warrant.
3. Develop a long term capital investment plan to address aging infrastructure.

Natural Gas Asset Condition Assessment

# APPENDIX C - Services

September 28th, 2016

# 1. Services

Services are the final component of Manitoba Hydro's natural gas distribution system before natural gas is delivered a customer. Services are supplied by service lines and provide a means of controlling the delivery of natural gas to one or several customers. **S**ervices consist of a service riser, service valve, regulator, meter and associated piping, up to customer's piping, as shown in Figure 1 below.

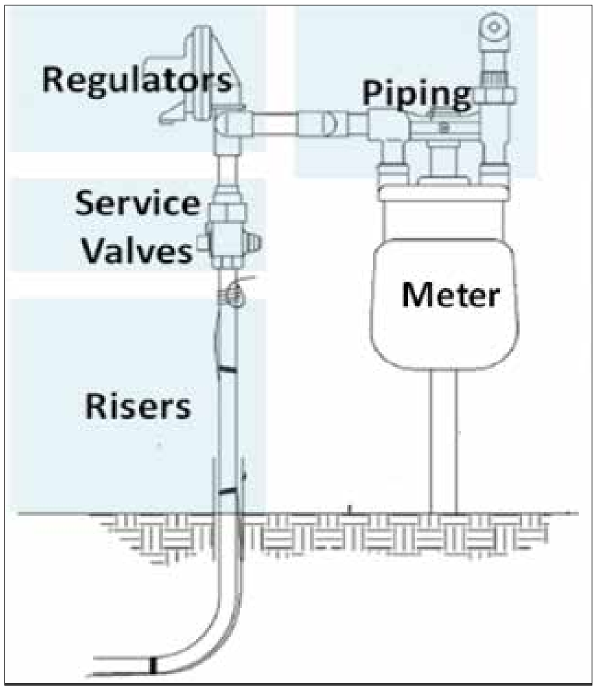



Figure 1: Current standard residential service with major components.

Overall, Manitoba Hydro categorizes services into 3 types. These are typically determined by the type of customer they serve and include residential, commercial and industrial services. Examples of the commercial and industrial services are shown in Figure 2 below.

Figure 2: Example of large industrial service (left) and large commercial service (right)

## 1.1 Demographics and Major Components of Services

Manitoba Hydro utilizes the Service Facilities Management (SFM) system to capture service line related facility information from the service tee to the relief. The following demographics were compiled from SFM.

### 1.1.1 Services

Services with a steel service line differ from services with a polyethylene (plastic) service line, primarily being different risers and riser supports. Services are thus categorized by the type of the service line material.

Table 1: Service Risers by Material Type (as of April 2016)

| Service Type | # of Services | % of Total |
|---|---|---|
| Steel | 178,645 | 67% |
| Polyethylene | 89,060 | 33% |
| **Grand Total** | **267,705** | **100%** |

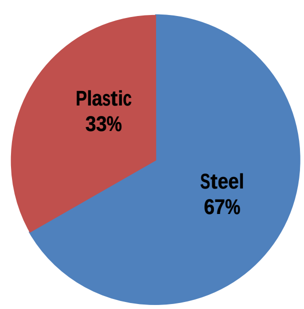


Table 2: Service Risers by Material Type and Size

| Nominal Pipe Size | Polyethylene | Steel | Total |
|---|---|---|---|
| 0.5" - 1.5" | 87,138 | 173110 | 260,248 |
| 2" - 8" | 1,911 | 5,205 | 7,116 |
| Unknown | 11 | 330 | 341 |
| **Total** | **89,060** | **178,645** | **267,705** |

Table 3: Service risers by age of first install

| Age of Service (yrs) | Number of Services | % of Total |
|---|---|---|
| 0-10 | 27,529 | 10% |
| 11-20 | 31,605 | 12% |
| 21-30 | 59,994 | 22% |
| 31-40 | 42,148 | 16% |
| 41-50 | 59,764 | 22% |
| 51-60 | 44,914 | 17% |
| >60 | 1,751 | 1% |
| | **267,705** | **100%** |

Table 3 shows that 80% of services are at least 20 years old.

Figure 1: Service Line by Material Type and Pipe Install Year

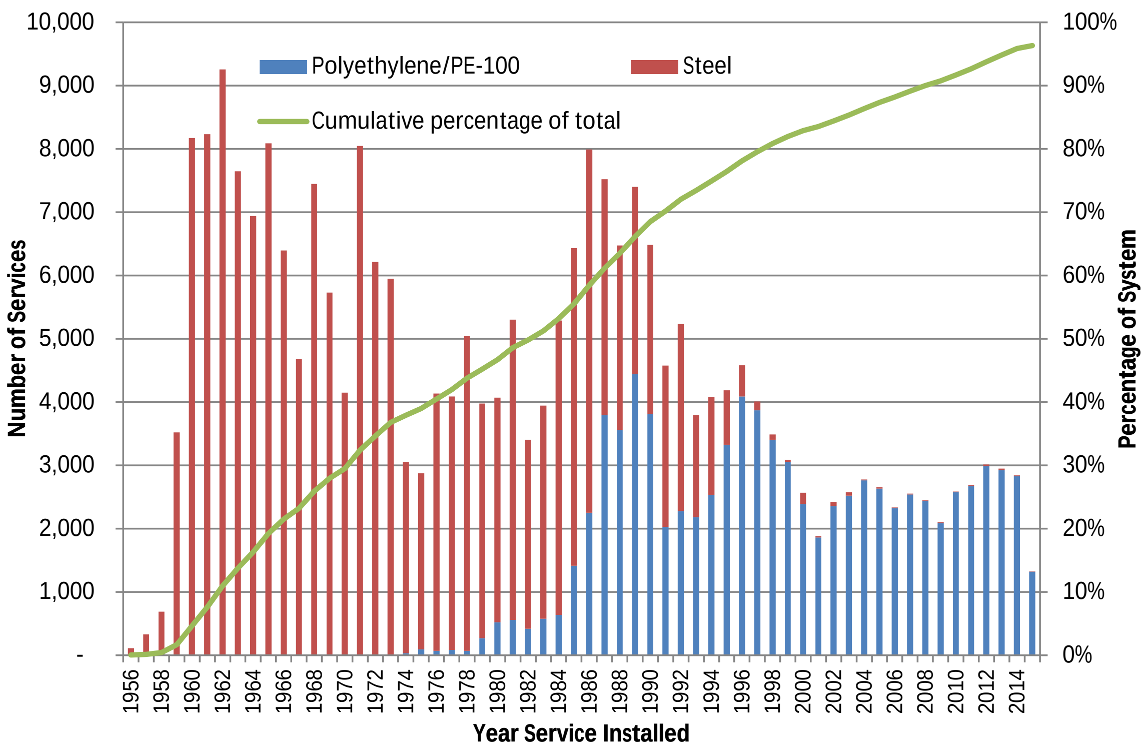


Figure 1 shows the original installed date of services. Manitoba Hydro's Gas Operations is customer focused. Current systems track meter age at a customer's location, but there is no tracking of individual asset components such as meter stop, riser, or piping. This leads to a unique situation. For example, there may be customers with an original install date of 1960. Subsequently, the riser, meter stop, regulator and piping may have each been replaced at one time or another. Still, records show the original install date we when the customer was first connected. No asset focused records or asset tracking is currently in place. Risers are expected to typically be the oldest component on a service.

### 1.1.2 Risers

Gas services include the portion of pipe that transitions from below ground to above ground piping. This portion of piping also referred to as a riser comes in a variety of materials and configurations. The riser is attached to and is a part of steel service line or polyethylene service line to convey gas. Manitoba Hydro's natural gas distribution system contains both steel and polyethylene service lines with a variety of different riser designs.

The majority of riser types are unknown because historically the priority was maintenance while inventory measurements were secondary.  Installed risers include 34% on a polyethylene service line and 66% steel.

Table 4: Risers by Type

| | | **Service line** | | |
|---|---|---|---|---|
| | | Steel | Polyethylene | **Total** |
| **Riser** | Steel | 178,645 | 3,816 | **182,461** |
| | Anodeless | | 42,400 | **42400** |
| | Unknown | | 42,844 | **42,844** |
| | **Total** | **178,645** | **89,060** | **267,705** |

### 1.1.3 Service Valves

Service valves or meter stops provide a shut off to the meter set on the riser at a customer's service location. Meter stops are installed on a riser and may differ depending on the size of riser. Typical residential meter stops are frequently referred to as Lub-o-seals (Mueller brand).

Service valves or meter stops are installed on all risers to provide a shut off valve at the customer's service location. Typical residential service valves come in insulated and non-insulated versions and are primarily threaded plug valves with some ball valves installed in recent years. They are insulated so that the meter set doesn't interfere with the cathodic protection of the distribution system. Residential service valves as shown in Figure 2 also have a lock wing which allows Manitoba Hydro to restrict access to the shutoff. The service valve is a mechanical fitting with a brass key or plug which is turned to operate. The brass key turns to operate and lubricated "O-rings" provide for a gas tight seal and a smooth operation. Service valves can be re-lubricated for maintenance and continued operation.

Valves to control large commercial services are typically 4" and larger. They are flanged valves or flanged ball valves which also require regular maintenance to ensure effective operation.

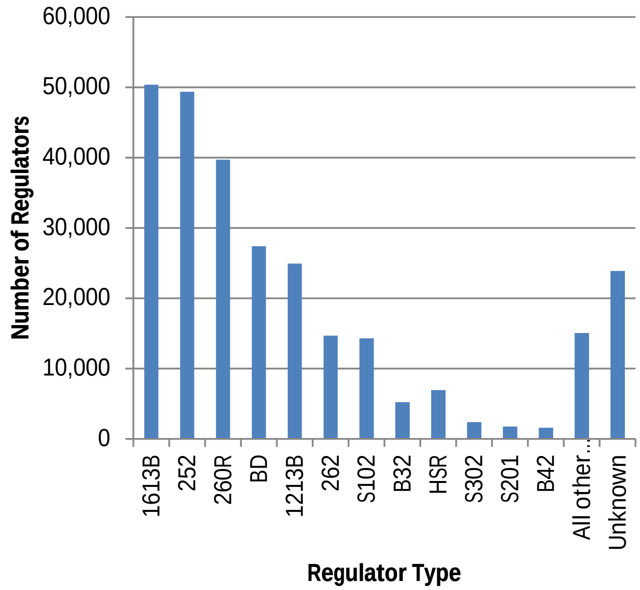
Figure 2: Residential service valve


### 1.1.4 Regulators

A regulator or pressure regulator is a device, either adjustable or nonadjustable, for controlling and maintaining within acceptable limits, a uniform outlet pressure. All gas services include a pressure regulator as a part of the piping after the meter stop valve. The pressure regulator provides gas at the appropriate pressure for metering and for delivery to the customer.

Table 6: Regulators by Type (as of September 15, 2016)

| Regulator Type | Number of Regulators | % of Total |
|---|---|---|
| BD | 27,395 | 10% |
| Unknown | 23,908 | 9% |
| S102 | 14,333 | 5% |
| B32 | 5261 | 2% |
| HSR | 6970 | 2% |
| S302 | 2421 | 1% |
| S201 | 1770 | 1% |
| B42 | 1593 | 1% |
| 252 | 49,387 | 18% |
| 260R | 39,726 | 14% |
| 262 | 14,707 | 5% |
| 1213B | 24,942 | 9% |
| 1613B | 50,399 | 18% |
| Other Regs | 15,061 | 5% |
| **Total** | **277,873** | **100%** |




## 1.1.5 Piping

Piping is defined as all piping after the meter stop and before the tie in to the customer's piping. It forms the final piece of a meter set with regulation. The piping contains straight pipe nipples and fittings made of malleable steel. The piping can also include vent piping, supports or bypass piping. All new residential services are built to Manitoba Hydro standards and contain a defined set of materials.

Services installed prior to the year 2000 were built under a previous standard. All services and all associated piping built since the year 2000 conform to the current Manitoba Hydro standard. All outside services installed since 2000 are built with piping swing joints on the low pressure side of the meter set design. This has proven to reduce the frequency and severity of leak occurrence.

Table 7: Services by Original Installation Date

| Installed < 2000 | Installed >2000 | Total |
|---|---|---|
| 227,918 | 39,787 | 267,705 |
| 85% | 15% | 100% |

Piping on a service is typically replaced when regulators are replaced.

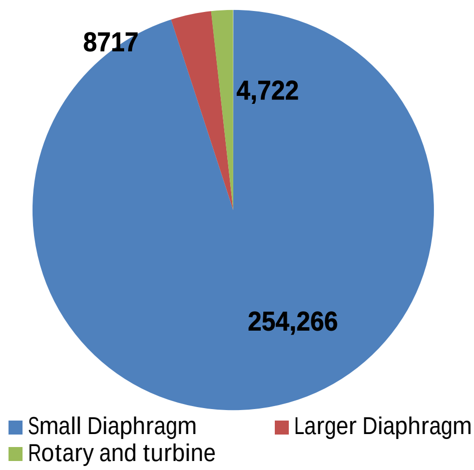
### 1.1.6 Meters

Meters measure the volume of natural gas conveyed to a customer for billing purposes. Meters are governed by Measurement Canada regulations, which mandate frequent replacement. Commercial and industrial meters are refurbished or replaced at most every 20 years. Residential meters are replaced on a batch sampling basis. As a result, degradation mechanisms are not applicable to meters and are not necessary to discuss further in this report.

Meters size can be used as a proxy to understand the service piping associated with the meter.

Table 8: Meters by Type

| Meter Type | # of Meters | % |
|---|---|---|
| Small Diaphragm (200 series) | 254,266 | 95% |
| Larger Diaphragm (Commercial) | 8,717 | 3% |
| Rotary and turbine (Large commercial & Industrial) | 4,722 | 2% |
| **Grand Total** | **267,705** | **100%** |




Some small businesses use the 200 series meters. Commercial installations use 400, 600 and 1000 series meters. ‘All other meters’ include rotary meters and turbines.

Initially, meters were installed inside for billing accuracy because in the early days, meters were not temperature compensated. With the advent of temperature compensated meters, the practice evolved to installing the meters outside. There are a significant number of customer requests to move inside meters outdoors. Inside meters contribute to unreliable meter reads which lead to inaccurate billing.

Table 9: Percent of Gas Meters Located Inside and Outside

| Inside | Outside |
|---|---|
| 20% | 80% |

About 81% of all residential gas meters are located outside. 77% of Commercial (et al) gas meters are located outside.

Table 10: Percent of Gas Meters by Premise Category

| Residential | Commercial/Industrial/Other |
|---|---|
| 90% | 10% |

## 1.2 Hazards Specific to Degradation Mechanisms

A hazard is any influence that increases the likelihood of occurrence of an adverse effect. Manitoba Hydro recognizes 6 primary types of hazards to its natural gas system. These hazards have been identified with consideration for governing regulations and standards, industry experience, and corporate operating history. The hazards and sub-hazards are based on categories and definitions from the Canadian Gas Association (CGA). These hazards are incorporated into Manitoba Hydro's risk assessment initiatives as applicable. This appendix focuses on only the hazards that are applicable to the degradation of services consisting of:

- Corrosion and degradation hazards (metal loss corrosion)
- Natural and outside forces hazards (soil movement)
- Equipment malfunction (inadequacy of equipment)

Service components such as risers, service valves, regulators and piping are subject to a number of degradation factors. These degradation factors can serve to greatly reduce the purpose and effectiveness of the component and in some cases could lead to failure of a component. Each of the components and degradation mechanisms are outlined below.

### 1.2.1 Risers

There are many factors which impact the integrity of a natural gas riser. A total of 178,645 (67%) of service lines in the Manitoba Hydro distribution system are steel material. These risers have an extruded polyethylene coating (yellow jacket) which is a continuous sheath of high density polyethylene extruded over an asphalt adhesive. The coating is effective for buried pipeline applications, but is subject to degradation from environmental impacts such as ultraviolet degradation and delaminating due to water ingress. Exposure to sunlight can lead to blistering or cracking and releasing from the asphalt adhesive as shown in Figure 3 below. New risers installed in concrete are installed with sleeving. Sleeving consists of a polyethylene pipe installed around the riser for protection.

Figure 3: Blistering and cracked coating of risers without sleeving

Some risers are field wrapped with a polyethylene tape. Wrapping deficiencies are a contributing degradation mechanism related to risers. Unwrapped steel service risers or incorrectly wrapped risers can lead to corrosion leaving the strength of the riser compromised. Badly corroded risers can be replaced by cutting out the corroded section and welding an extension of pipe.

This impact is further compounded when moisture becomes trapped and leads to pipe corrosion as shown in Figure 4 below. Corrosion often occurs at ground level where the riser and coating is in direct contact with ground fill which can also be abrasive on the coating. Manitoba Hydro's current standard requires a sleeve be installed to protect the riser when concrete or asphalt is surrounding the riser. There have been numerous instances of damaged wrapping and piping where external contact has occurred. For example, grass trimmers contact riser piping along buildings, damaging and eroding the integrity of the wrapping over time.

Figure 4: Above grade unsleeved riser with pipe corrosion under coating

The location of the riser is also a contributing factor to riser degradation. In particular, when installed in high traffic areas prone to salt spray and snow clearing. In Winnipeg, services with a front service orientation on regional streets such as those found on Selkirk Avenue, Logan Avenue and Corydon Avenue are all subject to corrosive elements from street clearing and general traffic. Service risers in backlanes along streets such as Portage Avenue have also been subjected to salt spray and snow pack that has negatively impacted the riser condition.

Figure 5: Below grade entry riser in concrete facing a high traffic area (left) and riser in concrete with degraded wrapping, corrosion and strain facing high-traffic area

Where risers are wrapped with polyethylene tape, improper wrapping can also be a contributing factor to riser corrosion. Wrapping should be done in an overlap manner so that moisture can flow down over the sheathed wrapping. If wrapping is done in the wrong direction, it can actually provide a conduit for moisture accumulation and eventual corrosion. Risers are also subject to the soil movement. Although this is not a degradation mechanism, soil movement has the potential to accelerate corrosion based degradation failures.

Figure 6: Corroded riser in concrete with below grade entry and delaminated coating

Soil types with mixed clay based soils tend to lead to ground movement which impacts a riser. Manitoba Hydro previously operated a riser rehabilitation program that focused on high risk risers identified through a survey of risers and meter set piping. The age and season of installation were considered in identifying high risk risers. Winter riser installations are most troublesome due to frozen backfilling material. During dry season conditions when clay soil dries and shrink causing riser settlement, a number of riser failures have led to uncontrolled releases of natural gas which pose a safety risk for the public and employees. High risk risers that have been identified have been rehabilitated.

Soil movement can also lead to strain on pipe fittings and other piping components. Ongoing maintenance of risers includes completing raise and straightens to remove strain from the downstream piping on a riser. A 'Raise and Straighten' is a task which involves rebuilding the piping and swing joints to design standard. This allows for the meter set to pivot and swing as designed for Manitoba soil conditions. The benefit of this task is that it puts the swing portion of the meter set on the lower pressure side of the regulator, thus reducing the risk associated with leaks.

Raise and straightens are considered lower priority work and subject to available resources.

Figure 7: Riser in tree – accessibility issue with severe corrosion on inside meter set

Risers which have sunk and no longer provide adequate ground clearance for service valves (150 mm of less above grade) require upgrade. Access is required to provide emergency shut offs. Sunken risers are subject to strain which can lead to leaks. In the event that these components are buried, they also become subject to degradation by corrosion. Remediation is typically conducted by welding a portion of pipe onto a riser to extend the current riser and a new service valve is installed to meet current standard.

A subset of steel service risers consist of “S” tube risers which are also subject to settling and prone to leaks on compression fittings. “S” tube risers are pre-manufactured risers that are attached to polyethylene service lines. “S” tubes are intended to allow movement for soil settlement by the design by allowing the tube to flex. However, when risers settled to the limit of the “S” tube’s capability, leaks can occur on compression fittings and valves may become inaccessible. The risers are not attached to a foundation or wall and require replacement when they sink and leave the service valve inaccessible.

Figure 8: Residential service with “S” tube riser.

All new installations on polyethylene services include a riser which is double bracketed to the foundation wall which eliminates any further movement above the service valve. Additionally, polyethylene service lines are installed with slack below grade to allow for movement.

### 1.2.2 Service Valves

Degradation of service valves, also known as meter stops, can occur in multiple ways. Service valves at a residential service address are operated infrequently which can lead to drying of the valve grease and difficulty to operate. When technicians experience difficulty turning valves, the valve is first lubricated before attempting to turn again. In an effort to turn seized valves, the internal brass key may be snapped as shown in Figure 9, resulting in an uncontrolled release of gas. Operating valves in the winter time, when the valve grease gets extremely cold, also leads to minor leaks which are repaired with re-lubrication. Valves are equipped with a tapped port to insert additional grease. However, even with the best efforts, grease does not always get distributed to all portions of the valve. Valve operation can still be difficult and ineffective.

Figure 9: Damaged lub-o-seal valve

Extreme strain on a service riser can lead to a service valve snapping off. The male threads that enter the service valve provide a weak point on a strained service. Snapped services led to a riser rehabilitation program to ensure risers provided adequate clearance and eliminated strain on a service riser. Manitoba Hydro has experienced snapped service risers at the service valve on ¾”, 1 ¼”, 2” and 4” services.

Service valves, like all other threaded fittings, can result in minor above grade gas leaks. Insulated meter stops in particular are prone to leaking at the joint of the nylon insulator and the brass nut as shown in Figure 10. Leaks can be repaired by replacing the insulated meter stop top nut. A service valve is an integral safety device that requires access to shut off. Sinking of the riser from settlement can also lead to buried service valves which then require the raising of the service riser. Accessibility of the shutoff is a requirement and an important safety precaution in the event of fire. Manitoba Hydro treats inaccessible shutoffs as a higher priority maintenance item.

Figure 10: Insulated residential service valves (red circle indicates insulation)

Large commercial service valves or iron plug valves are used on services greater than 4” in size. These 1/4 turn valves are generally bolted onto a flange welded to a service riser. Iron plug valves can be greased to ensure normal operation. Manitoba Hydro does not currently have a valve maintenance program in place for customer meter stop valves.

Figure 11: Large commercial valve

Commercial valves require greasing to maintain operational function. Valves in proximity to moisture, salt, and other adverse environmental elements are prone to seizing, leaks and corrosion. These conditions contribute to a high rate of malfunction. Due to corrosive environments sometimes present in industrial and commercial applications, degradation risks are heightened.

Current lub-o-seals provided by Mueller contain neoprene gaskets and do not require regular maintenance and greasing. Some Nordstrom commercial and industrial valves require maintenance and sealant replacement to ensure their ¼ turn shut off is functional.

A variety of valve maintenance work is required. Valves are greased when tight and replaced when leaking or cracked. At times lub-o-seals are buried, requiring excavation so that gas can be shut off. Furthermore, customers may block access to valves with decks and other building appendages.

All, but the oldest of valves have locking ears as shown in Figure 12.

Figure 12: Locking Ear

### 1.2.3 Regulators

Regulators have proven to be extremely reliable devices, even at 50 years of age. An engineering report[1] was conducted on aging pressure regulators to determine if there was any impact on performance or safety. The majority of regulators tested were found to be performing within acceptable limits. The report also found that over 150,000 of the regulators were greater than 25 years of age. Typically, regulators will continuously leak slightly (weep) out of built in relief vents when they have reached end of life. Manitoba Hydro addresses minor gas leaks on regulators by replacing the regulators. In 2014, nearly 1200 minor gas leaks related to weeping regulators were resolved through replacement.

Manitoba Hydro utilizes contractors who perform leak surveys to find the leaks on regulator reliefs. Customer Service personnel attend these leak calls to assess the situation. When it is determined that the issue is not related to static gas build up and the regulator continues to leak, it is replaced.

Figure 13: Typical residential regulator

Currently, regulator maintenance is performed on an adhoc basis as issues are identified. Maintenance is required when degradation modes lead to regulator leaks, salt spray and corrosive industrial environments, nonconformance issues, set points are lost or are missing components.

[1] Testing and Evaluation of Residential and LGS Service Regulators, T. Starodub (2013).

Reports are run to identify leaking regulators and are scheduled for replacement based on severity.

In Manitoba's climate, early spring thaws which lead to melting snow off roof tops can accumulate on meter sets and regulators. Colder nighttime temperatures can then lead to regulators freezing over as shown in Figure 14. This condition can be hazardous if the relief feature of regulator cannot operate and could result in system rated gas pressure entering a residence.[2]

Figure 14: Frozen over relief vent on residential meter set

### 1.2.4 Piping

The degradation of piping components is generally related to movement of a service riser. Manitoba Hydro's piping standard takes into consideration movement by incorporating swing

[2] 2013-04050 Residential Regulator Vent Blockage Report

joints. Without swing joints, strain caused by ground settlement as shown in Figure 15 can lead to snapped fittings or risers.

Figure 15: Residential service with inadequate swing joints causing strain on piping

Movement on the joint fittings can lead to minor fitting leaks which may need to be repaired. Excessive riser movement beyond the capability of the swing joints to handle also leads to stress on the riser and meter set piping and fittings. Manitoba Hydro's design standard has evolved to more effectively deal with minor leaks. Fittings such as street elbows and dresser elbows have been removed from new standards due to frequent leaks. Also, the standard piping configuration has changed to place the regulator closer to the meter stop, thereby reducing the pressure of gas flowing through more fittings at lower pressure. The change has resulted in fewer fitting leaks found through the annual leak surveys.

Fittings are also subject to degradation from outside elements as some threaded fittings can become seized and unable to turn or operate. Fittings such as street elbows and meter sockets have become seized to the point that they needed to be forcefully removed.  Seized fittings that no longer move are also subject to tremendous pressure from strain and can fail or snap resulting in an uncontrolled release of gas. This can be exacerbated by manufacturing defects such as pinholes or threading deformities.

Swing joints can also be compromised when auxiliary or customer piping is added past the outlet of the meter. If a swing joint for the auxiliary piping is not installed, it can compromise the swing installed originally in the meter set piping and lead to strain on other fittings and eventual failure of a fitting. Figure 16 illustrates auxiliary piping which impedes the ability of the meter set to move on the swing joints.

Figure 16: Auxiliary piping impeding swing joint movement

The wall pipe which extends from outside to the inside of a service address is also subject to degradation. Wall pipes on older services often entered the service address below the ground and into a basement. The services are known as below grade entries and an example is shown in Figure 17 below.

Figure 17: Commercial Regulator with Inside Meter Riser installation below grade entry

Unprotected steel pipe that is buried is subject to corrosion, if not adequately coated or cathodically protected.

## 1.3 Inspection and Maintenance Practices

### 1.3.1 Risers

The degradation mechanism for risers is primarily corrosion and related to the degraded or damaged coating. The consequences of degradation could range from a small gas leak to snapping of a riser which leads to an uncontrolled release of natural gas.

There is no individual dedicated survey of risers currently being conducted. Issues with risers are generally reported through 1 of 4 methods:

- the tri-annual Distribution Mains and Services leak survey,
- by meter reading staff who visit outside meters,
- by staff attending to regular customer requested work or
- by performing mandated meter exchanges.

Work orders are then created to address the deficiency found based on priority.

Historically, Manitoba Hydro has addressed service risers that were considered higher priority through the Riser Rehabilitation program. The Riser Rehabilitation program resulted in upgrades to 19,179 risers between 2000 and 2010. The risers and meter set piping were assessed and ranked in terms of the risk of failure. All high priority calls were completed. Approximately, 1000 very low priority locations were not addressed. Where inside meters existed, meters were also moved outside through the Riser Rehabilitation program. Appendix A1: Maintenance Repair Activity outlines riser related maintenance and repairs over the last five years from 2011 to 2015.

For steel risers with wall loss due to corrosion, new approved wrapping materials are available to rehabilitate the riser. These maintenance activities can effectively extend the life of the riser. Maintaining cathodic protection levels on the distribution system also serve to protect against riser corrosion below grade level.

Anodeless service risers, installed with polyethylene service lines, represent a design improvement that has eliminated many of the riser related deficiencies associated with steel risers. These risers utilize a steel pipe protective casing with the polyethylene pipe inside and the riser. Riser are also double bracketed and bolted to the outer foundation wall. These risers have a flexible section below grade which ensures that settling issues no longer occur. Past maintenance practices consisted of excavating and raising the services, but it has become more cost effective to replace and upgrade service lines.

### 1.3.2 Service Valves

The infrequent operation of service valves or meter stops creates a situation where the internal grease and lubrication system of the valve is at risk of deterioration and may cause leaks or seizing. This is a contributing factor to potential failure of these mechanical fittings. Failure of the fitting occurs when a technician attempts to turn the valve and the internal mechanism fails. Maintenance and replacement of valves is determined by the assessment of the technician. There is currently no specified inspection program related to service valves or meter stops of any size. Service valves are operated to shut off the supply of natural gas to a residence or service address. This will typically occur when changing a meter, conducting service work on an appliance, responding to an emergency or disconnecting a service. If a service valve is not operational, a technician lubricates the service valve on an as needed basis or potentially may be required to dig up the service tee to turn off gas.

Providing accessibility to a service valve is the primary maintenance related activity on the asset. Risers which settle pull down the service valve, in some cases burying it in the ground leaving the shutoff inaccessible. A total of 892 service valve raises were completed over a five year period from 2011 to 2015. Service valve raises require extending the riser by welding on a portion of pipe. Manitoba Hydro also rectified a further 144 installations over the same five year period where service valves were inaccessible due to customer owned buildings or decks.

There are currently 300 open work orders for service valve raises. A total of 2152 service valve raise and straighten work orders have been completed between 2000 and August 2016.

### 1.3.3 Regulators

A natural gas regulator is an adjustable mechanical device that measures, restricts and maintains a constant downstream pressure of natural gas. Regulators have proven to be very reliable components and operate in all extreme temperatures. Regulators greater than 16 years of age which have been installed under an older standard are being upgraded through the meter exchange program. Approximately 30% of meter exchanges are accompanied by a full meter set rebuild including upgrading of the regulator. Regulators are inspected for leaks as a part of the Distribution Mains and Services leak survey. Leaks on regulators are identified and noted on service calls. Regulator leaks are usually considered “A” leaks based on the severity of the leak, but are repaired at a higher priority than other minor fitting leaks. Meter readers are also are trained to look for meter set and regulator freeze over. Remediation may include installing splash guards to protect a regulator from freeze over. There are currently 130 open work orders for grade ‘A’ leaks above grade

Meter reading staff have been instructed to report missing regulator caps to internal departments. Missing caps can impair operation of the internal relief valve and can allow dirt and debris to enter the spring case. These are scheduled for repair through the Operational Support Services (OSS) department. When regulators are non-serviceable or non-reparable, they are replaced. Currently, Manitoba Hydro does not always replace regulators when meters are changed.

### 1.3.4 Piping

Although no formalized maintenance program exists to specifically address meter set piping, piping is currently replaced and upgraded alongside other maintenance work. Visual inspections and calls to correct deficiencies are carried out by staff performing leak surveys, cathodic protection inspections and meter readings when appropriate. Summer students have been tasked with addressing high traffic and profile areas to paint and inspect risers. Manitoba Hydro conducted a survey of below grade entries utilizing pipe to soil readings to measure the state of cathodic protection on these wall pipes. The survey or study prioritized services based on a risk matrix and work began to rehabilitate these services often resulting in a complete new upgrade to the piping.[3]

There are currently 1604 open residential and commercial below grade entry work orders in the Banner system. Commercial below grades entries are currently rehabilitated with internal resources, while residential below grade entries are being addressed with an external contractor.

[3] 2013-04037 Survey and Analysis of Downtown Commercial Services

This external contractor is also addressing all known services where auxiliary piping has compromised swing joints.

## 1.4 Health Index and Asset Condition

### 1.4.1 Service Asset Health

Figure 18 below shows the current and 20 year forecasted asset health for services. The quantity of assets in a state of fair/poor and critical will increase in the next 20 years based on the current rate of replacement. At this current rate, it will take over 100 years to replace all riser assets.

Figure 18: Services "Soccer Field"

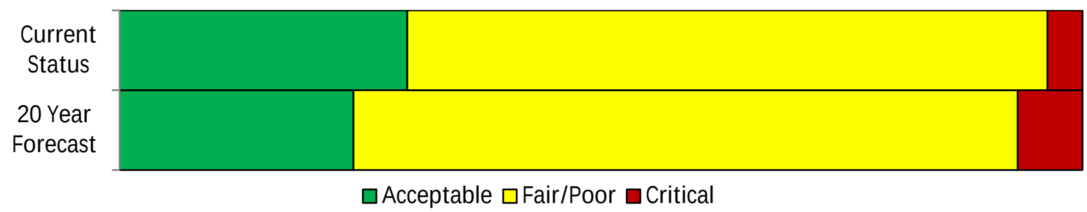



Table 12 below indicates the service asset health condition characteristics.

Table 12: Design Criteria for Service Asset Health Index

| Health Index Condition | Probability of Failure | Typical Asset Condition Score Characteristics |
|---|---|---|
| Critical | High | · Riser is delaminated and exhibits corrosion flaking or strain. Riser has settled putting strain on pipe.<br>· Valve is damaged (ears are broken) or seized.<br>· Regulator is continually leaking or corroded or does not provide set pressure.<br>· Piping shows severe signs of strain or corrosion. |
| Fair/Poor | Medium | · Riser coating has signs of fading, peeling or cracking.<br>· Valve requires greasing.<br>· Regulator is older than 25 years or shows minor pitting. May vary slightly in pressure point.<br>· Piping is not at current standard designed to prevent strain. |
| Acceptable | Low | · Riser has continuous coating, coverage and shows minor signs of surface corrosion.<br>· Valve turns smoothly, is insulated and ears are intact.<br>· No stress on meter set.<br>· Regulator provides required pressure. |

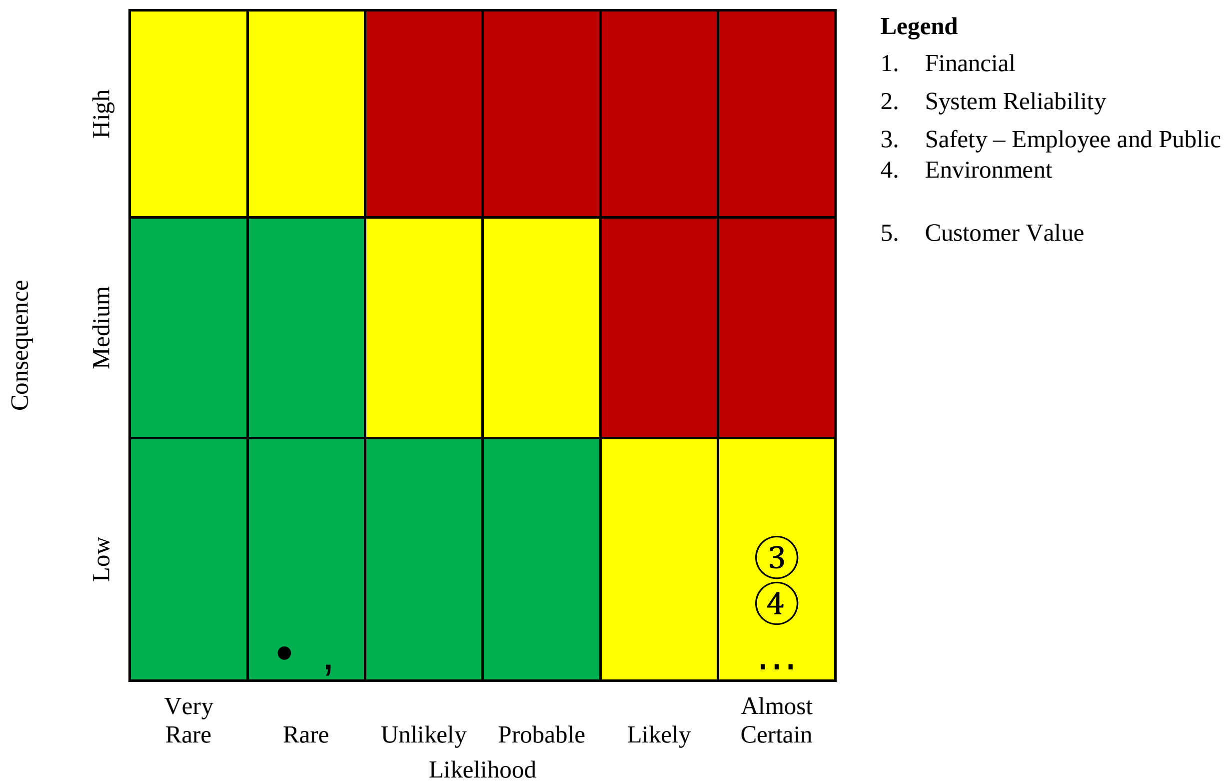
### 1.4.2 Risk Map

Based on the observations made in this report, the risk map shown in Figure 19 was developed. The matrix considers the anticipated impact service failures will have on Manitoba Hydro with respect to the following criteria:

1. Financial Impact
2. Reliability Impact
3. Safety – employee and public
4. Environment
5. Customer Value

The probability and consequence of each factor is plotted in the risk map. 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 A1 of this report.

Figure 19: Natural Gas Riser Asset Risk Map and Risk Scoring




1. Financial: An acceleration in the number of risers that reach end of life and require replacement could result in a low financial consequence.
2. System Reliability: A riser failure due to degradation resulting in loss of service to significant number of customers is unlikely and if occurs, would be addressed immediately.
3. Safety – Employee and public: Every year gas blowing occurs due to riser degradation which carries with it a safety risk for employee and public injury.

4. Environment: Riser leaks and ruptures are a regular occurrence which releases natural gas into the atmosphere and dissipates.
5. Customer Value: Restoration of service within a few hours and impact to single customer.

## 1.5 Economic Evaluation

Replacement costs depend on riser size and material type. Table 13 provides an overview of the gas service asset value, current replacement rates, and anticipated lifespan.

Table 13: Economic Evaluation (For more detailed information see Appendix A1)

| Asset Class | Quantity | Life Expectancy (Years) | Replacement Rate (Years) | Current Unit Replacement Cost ($) | Total Replacement Cost ($M) |
|---|---|---|---|---|---|
| Service with riser smaller than 1 inch | 247,452 | 25-70 | 80 | 215 – 260<br>Avg. 237 | 58.6 |
| Service with riser equal to or greater than 1 inch | 20,253 | 25-70 | 80 | 215 – 8626<br>Avg. 987 | 20 |
| | | | | | |
| **Total** | **267,705** | | | **Avg. 294** | **78.6** |

## 1.6 Recommendations

During the asset analysis, the following gaps were identified. Recommendations are made to address these gaps.

**High Priority**

Gap: A number of identified maintenance requirements and initiatives are not completed or are not undertaken due to available funding and resources being focused on other areas on a priority basis. A gap in funding and resources exists to conduct the recommended maintenance on services to address growing degradation. This maintenance gap includes:

- Below grade entry rehabilitation project lagging behind target activity level.
- There is no regular valve maintenance on service valves. Consequently, valves can be found inoperable or fail during operation.
- Degradation on risers and service piping is occurring more than is being addressed and some degradation issues on risers and service piping is being addressed only upon failure.
- There is no established program to systematically replace regulators. The current replacement rate of 60 years is inadequate to meet the recommended replacement rate of 25 years[4].

Recommendation:

To address the increasing degradation and the gaps identified, it is recommended that additional funding and resources be allocated to maintenance and rehabilitation projects. This would include:

- Establishing a maintenance program to service and lubricate all 2” and larger service valves, particularly the high-traffic areas as they are at greater risk of corrosive seizure due to salt spray.
- Establish a maintenance program to ensure valves meet minimum ground clearances.
- Establish a program to address degradation, particularly above grade corrosion on risers and service piping.

[4] 2013 - Testing and Evaluation of Residential and LGS Service Regulators.

- To address riser strain and fittings prone to leaks, upgrade inside meter services by relocating the meter outside.
- Establish a program for replacing regulators to meet the required replacement rate of 25 years.

**Medium Priority**

Gap: Plant records are not sufficient for asset management and maintenance beyond traditional activities. Examples of this include:

- The records for service risers (size, material etc.) are inadequate and incomplete.
- Records on service valves are largely non-existent.

Recommendation:

Develop improved, more detailed records of components of services enabling improved analysis, planning and program administration. This includes additional data gathering.

# Appendix A - Maintenance Repair Activity

## A.1 Services Valuation

| | Number of Services | | | Plastic | | | | Steel | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Service Size | Plastic | Steel | Grand Total | Material Cost | Labour Cost | Total Cost | Valuation | Material Cost | Labour Cost | Total Cost | Valuation | Grand Total |
| 1/2" | 43,481 | | 43,481 | $ 160.00 | $ 90.75 | $ 250.75 | $ 10,902,860.75 | | | $ - | $ - | $ 10,902,860.75 |
| 5/8" | | 216 | 216 | | | $ - | $ - | $ 125.00 | $ 90.75 | $ 215.75 | $ 46,602.00 | $ 46,602.00 |
| ¾" | 41,809 | 161,946 | 203,414 | $ 170.00 | $ 90.75 | $ 260.75 | $ 10,901,696.75 | $ 125.00 | $ 90.75 | $ 215.75 | $ 34,939,849.50 | $ 45,841,546.25 |
| 1" | 144 | 436 | 580 | $ 170.00 | $ 90.75 | $ 260.75 | $ 37,548.00 | $ 125.00 | $ 90.75 | $ 215.75 | $ 94,067.00 | $ 131,615.00 |
| 1.25" | 1,710 | 10,833 | 12,543 | $465.00 | $ 180.00 | $ 645.00 | $ 1,102,950.00 | $ 400.00 | $ 180.00 | $ 580.00 | $ 6,283,140.00 | $ 7,386,090.00 |
| 1.5" | 5 | 9 | 14 | $ 620.00 | $ 484.00 | $ 1,104.00 | $ 5,520.00 | $ 500.00 | $ 480.00 | $ 980.00 | $ 8,820.00 | $ 14,340.00 |
| 2" | 1,857 | 4,995 | 6,852 | $ 620.00 | $ 484.00 | $ 1,104.00 | $ 2,050,128.00 | $ 500.00 | $ 480.00 | $ 980.00 | $ 4,895,100.00 | $ 6,945,228.00 |
| 3" | 4 | 129 | 133 | $ 1,850.00 | $ 6,776.00 | $ 8,626.00 | $ 34,504.00 | $ 1,600.00 | $ 6,776.00 | $ 8,376.00 | $ 1,080,504.00 | $ 1,115,008.00 |
| 4" | 49 | 74 | 123 | $ 1,850.00 | $ 6,776.00 | $ 8,626.00 | $ 422,674.00 | $ 1,600.00 | $ 6,776.00 | $ 8,376.00 | $ 619,824.00 | $ 1,042,498.00 |
| 6" | 1 | 5 | 6 | $ 1,850.00 | $ 6,776.00 | $ 8,626.00 | $ 8,626.00 | $ 1,600.00 | $ 6,776.00 | $ 8,376.00 | $ 41,880.00 | $ 50,506.00 |
| 8" | | 2 | 2 | | | $ - | $ - | $ 1,600.00 | $ 6,776.00 | $ 8,376.00 | $ 16,752.00 | $ 16,752.00 |
| Total | 89,050 | 178,645 | 267,705 | | | | $ 25,469,375.75 | | | | $ 48,097,736.00 | $ 73,567,111.75 |

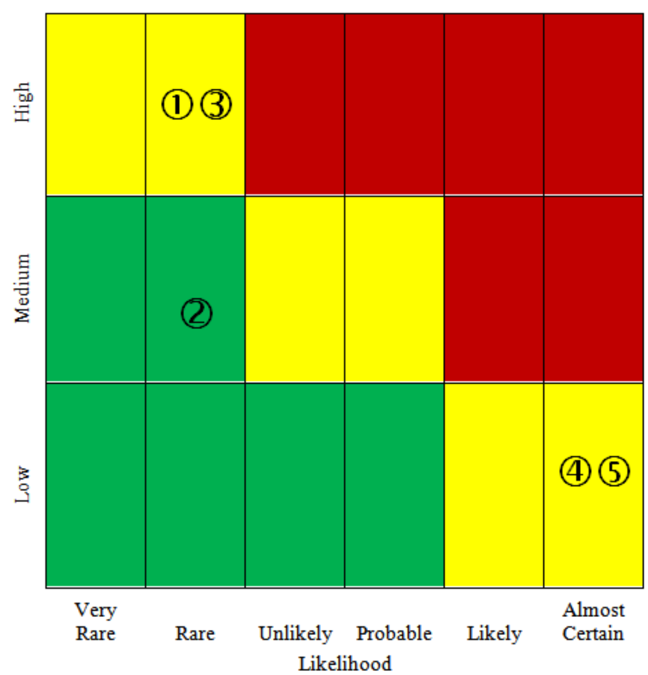
## A.2 Maintenance Repair Activity

| | | Current Pending April 2016 | 2011 | 2012 | 2013 | 2014 | 2015 | 2011-2015 TOTAL |
|---|---|---|---|---|---|---|---|---|
| **Riser** | | **129** | **387** | **336** | **2,248** | **411** | **474** | **3,856** |
| DBAG | Damage Blowing Above Grade | - | 13 | 13 | 17 | 10 | 6 | 59 |
| DNAG | Damage Not Blowing Above Grade | - | 3 | 4 | 2 | 4 | 4 | 17 |
| RICN | Riser In Concrete | 46 | - | - | 10 | 7 | 16 | 33 |
| RRCC | Riser Rehab | - | - | - | 25 | - | 1 | 26 |
| RRCG | Riser Rehab | - | - | 1 | 267 | - | - | 268 |
| RRCO | Riser Rehab | - | 18 | 19 | 1,178 | - | - | 1,215 |
| RRGC | Riser Rehab | - | - | - | 11 | - | - | 11 |
| RRGM | Riser Rehab | - | - | 1 | 52 | - | - | 53 |
| RRMC | Riser Rehab | - | - | - | 14 | - | - | 14 |
| RRMG | Riser Rehab | - | - | - | 75 | - | - | 75 |
| RRMO | Riser Rehab | - | 1 | - | 41 | - | - | 42 |
| RRSG (MANT) | Riser Rehab | - | - | - | 29 | - | - | 29 |
| RRSG (GDM) | Riser Rehab | - | - | - | 2 | - | - | 2 |
| RRSN | Riser Rehab | - | - | 1 | 23 | - | - | 24 |
| RRSO (MANT) | Riser Rehab | - | - | - | 49 | - | - | 49 |
| RRSO (GDM) | Riser Rehab | - | - | - | 4 | - | - | 4 |
| RRPI | Riser Rehab | - | 1 | - | - | - | - | 1 |
| RWRP | Riser to be Wrapped | - | - | - | 3 | 6 | 5 | 14 |
| SLRE | Service Line Repair | 4 | 13 | 11 | 10 | 10 | 17 | 61 |
| SLRS | Service Line Raise | - | 3 | 1 | 1 | - | 2 | 7 |
| MSIN | Meter Set Install | 65 | 154 | 214 | 358 | 304 | 340 | 1,370 |
| MSRL | Meter Set Relocate | 1 | 25 | 19 | 12 | 11 | 19 | 86 |
| MSRP | Meter Set Replace | 13 | 110 | 51 | 65 | 59 | 63 | 348 |
| OMPI | Outside Meter Set Preinspection | - | 46 | 1 | - | - | 1 | 48 |
| **Service Valves** | | **47** | **267** | **241** | **234** | **257** | **289** | **1,288** |
| SVIN | Service Valve Install | - | 3 | 1 | 3 | - | - | 7 |
| SVRE | Service Valve Repair | 5 | 13 | 15 | 14 | 30 | 25 | 97 |
| SVRP | Service Valve Replace | 22 | 29 | 29 | 21 | 29 | 35 | 143 |
| SVRS | Service Valve Raise | 18 | 211 | 154 | 121 | 190 | 216 | 892 |
| SNSO | Service Non Conformance Shutoff Inacce | 2 | 11 | 42 | 73 | 7 | 11 | 144 |
| SNEN | Service Non Conformance Enclosure | - | - | - | 2 | 1 | 2 | 5 |
| **Regulator** | | **190** | **886** | **997** | **741** | **854** | **1,027** | **4,505** |
| ADLD | Added Load | 47 | 130 | 161 | 166 | 163 | 214 | 834 |
| CVIN | Code Violation | - | - | 56 | - | 15 | - | 71 |
| LDCH | Load Change | 5 | - | - | 3 | 30 | 34 | 67 |
| LDCN | Load Consolidation | - | 11 | 11 | 3 | 6 | 4 | 35 |
| SNVC | Servcie Non Conformance Reg Venting | 12 | - | 3 | 12 | - | 2 | 17 |
| TCRL | TC Meter Relocate | 70 | 423 | 449 | 309 | 420 | 511 | 2,112 |
| 8275 | 8275 Upgrade | - | - | - | - | - | - | - |
| EXTR | External Relief Program | - | - | - | - | - | - | - |
| INTR | Internal Relief Program | - | 2 | - | - | - | - | 2 |
| PRCH | Pressure Change | 5 | 24 | 32 | 48 | 14 | 16 | 134 |
| RGRE | Reg Repair | 12 | 106 | 100 | 93 | 109 | 109 | 517 |
| RGRP | Reg Replace | 37 | 185 | 185 | 107 | 92 | 132 | 701 |
| RVRP | Relief Valve Repair | 2 | 5 | - | - | 5 | 5 | 15 |
| **Piping** | | **1,068** | **2,768** | **2,794** | **2,868** | **5,007** | **3,765** | **17,202** |
| LAAG | Leak Above Ground A Leak | 40 | 159 | 305 | 188 | 264 | 437 | 1,353 |
| LAGM | Leak Above Ground A Leak GDM | 23 | 108 | 95 | 138 | 68 | 75 | 484 |
| LBAG | Leak Above Ground B Leak | - | 20 | 15 | 13 | 18 | 7 | 73 |
| LCAG | Leak Above Ground C Leak | 1 | 19 | 18 | 15 | 12 | 14 | 78 |
| BGER | Below Grade Entry Rehab | 3 | 76 | 73 | 77 | 76 | 68 | 370 |
| CLAA | Contractor Found A Leak | 658 | 1,185 | 1,446 | 1,580 | 3,610 | 1,949 | 9,770 |
| CLAM | Contractor Found A Leak GDM | 16 | 4 | 9 | 21 | 36 | 56 | 126 |
| CLBA | Contractor Found B Leak Above Grade | 2 | 2 | - | - | 3 | 3 | 8 |
| CLCA | Contractor Found C Leak Above Grade | - | 2 | 1 | 1 | 7 | 8 | 19 |
| MSRE | Meter Set Repair | 1 | 36 | 29 | 20 | 28 | 21 | 134 |
| MSRM | Meter Set Remove | 3 | 68 | 56 | 20 | 32 | 23 | 199 |
| MSRS | Meter Set Raise & Straighten | 220 | 489 | 613 | 622 | 612 | 894 | 3,230 |
| OMCW | Aux Piping Outside Meter Set Concrete | - | 5 | - | - | - | - | 5 |
| OMRC | Aux Piping Outside Meter Set Concrete R | - | 4 | - | - | 1 | - | 5 |
| OMRN | Aux Piping Outside Meter Set Concrete R | 14 | 125 | 3 | 6 | 1 | 3 | 138 |
| OMRW | Aux Piping Outside Meter Set Rehab We | 2 | 300 | - | 1 | - | - | 301 |
| PPRL | Piping Relocate | - | 1 | 2 | - | 2 | 1 | 6 |
| SERE | Service Entry Repair | 1 | 9 | 11 | 2 | 4 | - | 26 |
| SERL | Service Entry Relocate | - | 2 | 1 | - | 1 | - | 4 |
| VLIN | Vent Line Install | 52 | 128 | 88 | 79 | 76 | 56 | 427 |
| VLRE | Vent Line Repair | 4 | 14 | 11 | 8 | 9 | 13 | 55 |
| VLRL | Vent Line Relocate | 2 | 4 | 10 | 3 | 7 | 16 | 40 |
| VLRP | Vent Line Replace | 5 | 8 | 8 | 12 | 9 | 4 | 41 |
| PFAB | Pre Fab Meter Set | 21 | - | - | 62 | 131 | 117 | 310 |
| **TOTAL** | | **1,434** | **4,308** | **4,368** | **6,091** | **6,529** | **5,555** | **26,851** |

Natural Gas Asset Condition Assessment

# APPENDIX D – Risk Assessment Methodology

October 4th, 2016



## 1.1 Risk Assessment Methodology

This report uses the Customer Service & Distribution six-step methodology to indentify and manage the risks associated with a natural gas system[1]. Risk is used to evaluate hazards and is the compound consideration of likelihood and consequence. A reduction of either likelihood or consequence results in a reduction of risk. The likelihood criteria, consequence criteria and risk map are shown below.

## 1.2 Likelihood Criteria

Likelihood is the probability of occurrence of an adverse effect. It is a compound consideration of two constituent influences:

- Influences that maintain a desired attribute and,
- Influences that disturb a desired attribute.

An increase in likelihood of an influence that disturbs a desired attribute or a decrease in frequency of an influence that maintains a desired attribute, increases the likelihood of occurrence of an adverse effect. The nature of likelihood may either be based on actual experience or probabilistic estimation.

| Descriptor | Qualifier | Quantifier |
|---|---|---|
| Almost Certain | The event will occur on an annual basis. | Once a year or more frequently |
| Likely | The event has occurred several times or more in a decade. | Once every 3 years |
| Possible | The event might occur once in a decade. | Once every 10 years |
| Unlikely | The event does occur somewhere from time to time. | Once every 30 year |
| Rare | Have heard of something like this occurring elsewhere. | Once every 100 years |
| Very Rare | Have never heard of this happening. | Once every 1000 years |

[1] Customer Service & Distribution Risk Management Process

## 1.3 Consequence Rating Criteria

Consequence is the consideration of the severity of an adverse effect that is brought to fruition by a hazard.

| Consequence | Measure | Rating |
|---|---|---|
| Financial | Net Income / capital investment: | Low - $0-$50 Million |
| | | Medium - $51- $150 Million |
| | | High - > $150 Million |
| System Reliability | Domestic Customers: | Low – Outage affecting 50 customers for 4 hours. Not life threatening. |
| | | Medium – Outage affecting 500 customers for up to 24 hours. Have ability to serve critical loads. Not life threatening (critical loads served). |
| | | High – Do not have capacity to serve Manitoba load for extended period of time. Life threatening. Loss of public confidence. |
| | MW Generation or Interconnection capacity: | Low – NERC level 1, in compliance with industry reliability standards. |
| | | Medium – Loss of 2000 MW. NERC level 2 – load management procedures in effect. In compliance with industry reliability standards. |
| | | High – Loss of >2000 MW. NERC level 3 – firm load interruption imminent or in progress; and/or non compliance with industry reliability standards.. |
| Safety Employee and Public | High risk accidents, severity rate, frequency rate and public contacts: | Low - Minor injuries, in compliance with laws and standards. |
| | | Medium - disabling injuries, in compliance with laws and industry standards. |
| | | 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: | 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. |

Appendix D – Risk Methodology of Natural Gas Asset Condition Assessment

| Consequence | Measure | Rating |
|---|---|---|
| | | 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 retail electricity rates. | Low – no rate increase |
| | | Medium – annual increase of <10% |
| | | High – Annual increase of >10% |
| | Customer perception of service with regard to reliability and quality service: | Low - Restoration service within 4 hours, no threat to public safety, <1.3 outages/customer/year, provision of energy related services. |
| | | Medium - Restoration service within 24 hours with no threat to public safety. 2 outages/customer/year |
| | | High - Outage for extended period of time. Life threatening. Loss of public confidence. |
| | Customer perception of service with regard to reputation: | Low - Local media coverage with negligible impact on stakeholders |
| | | Medium - A highly visible event attracting national media coverage; and/or a moderate negative impact on stakeholders. |
| | | High - A highly visible event attracting international media coverage or environmental concern; and/or a significant negative impact on stakeholders such as breach of privacy, contractual obligation or environmental stewardship. |

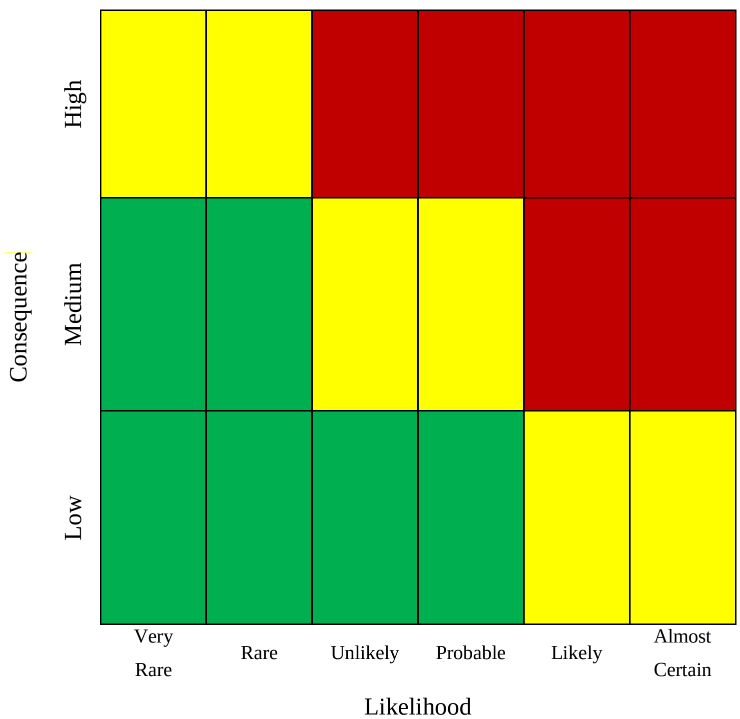
## 1.4 Hazards and the Approach to Control

A hazard is any influence that increases the likelihood of occurrence of an adverse effect. The primary influences are those that could result in a release of gas from the piping system or those that could impact the detection, flow rate, duration or migration of such a release. In this consideration of risk, unless the consequence posed is sufficiently low, the hazard is considered as requiring control. Hazards are controlled operationally by addressing the constituent influences of frequency. Pipeline integrity activities either increase influences that maintain a desired attribute when necessary and/or decrease influences that disturb a desired attribute.

For example, adequate cover is an influence that maintains the integrity of buried pipelines, a general desired attribute. The restoration of adequate cover following the loss of cover increases the maintaining influence on a buried pipeline. Additionally, the application of safe excavation procedures during the restoration project decreases the disturbance of a buried pipeline. This methodology, employed for the purposes of avoiding a line hit, reduces risk by decreasing the degree of anticipation of a line hit.

## 1.5 Risk Map

Each project can be plotted on the Risk Map according to their associated risk rating. The Risk Map is colour-coded with red, yellow and green segments. According to the Risk Management Process the coloured segments imply the following level of consideration:




Legend

1. Financial
2. System Reliability
3. Safety – Employee and Public
4. Environment
5. Customer Value

**Red:** The risk has become critical to business operations and requires day to day senior management attention. If not resolved quickly, it could have catastrophic impacts on the organization.

**Yellow:** There are or appears to be some emerging issues that need to be closely monitored and addressed. Additional action is required to bring the risk back to the established tolerance. Management has time to respond in an orderly manner.

**Green:** No additional action required at this time as the risk is under control and is not subject to significant change.