2018–2023

NATURAL GAS ASSET MANAGEMENT CAPITAL INVESTMENT PLAN

Manitoba Hydro

EXECUTIVE SUMMARY

The Manitoba Hydro natural gas system uses over 9,800 kilometers of main to supply 275,000 customers and plays an important role in meeting Manitoba's energy needs. Our natural gas system has an excellent record of safety and reliability and our customers rely on natural gas availability.

This Plan is used to define and schedule the programs and projects needed to maintain safe and reliable operation, maintain regulatory compliance, and meet the needs of our customers. Installation of the current natural gas system began in 1955 and components of the system now require replacement or an increased level of inspection and maintenance. Planning for replacement of critical assets is necessary and increased inspections have identified issues which need to be addressed. System load growth will require installation of additional pipe and systems to meet increased system demands. Changes in technology provide opportunities to introduce selected system automation that will improve emergency response and provide operating advantages. Changing gas supply quality and pressures also need to be addressed to maintain system reliability. Opportunities to reduce the risk of major outages are being evaluated and implemented.

This Plan provides details of known programs and projects to be implemented in the next five years and potential future projects. The Plan will be reviewed and revised annually adjusting and/or adding new programs or projects and updating the scope or schedule as situations change or new information becomes available.

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ACRONYMS AND DEFINITIONS

Capacity – The maximum rate of flow that a device or system can supply at a stated condition. For Gas Planning purposes this refers to peak flow rate while maintaining adequate pressure and suitable velocities.

Connected Load – The total of the input ratings of all equipment and devices connected to one customer. The input rating is typically from nameplate rating or gas equipment supplier data sheets.

E&C – Engineering and Construction Division

eGIS – Enterprise Geographical Information System is the software/database which contains the records of all Manitoba Hydro piping networks.

High Pressure (HP) System – Gas system with operating pressure between 101 and 275 psig

ISD – In Service Date

Looping – The installation of a parallel pipes to increase the capacity of an existing system. Typically the new pipe is installed in the same easement or right of way as the existing pipe.

mcfh – thousands of standard cubic feet per hour (i.e. corrected for pressure and temperature). This is a measurement of instantaneous natural gas flow. For general reference, 1 mcfh can typically serve approximately 12 residential customers at peak winter weather conditions.

MER – Main Extension Request. A MER request is to add a new customer to the gas network and typically requires the extension of a gas main.

Medium Pressure (MP) System – A gas system with operating pressure between 0 and 100 psig typically used for delivery to the customer and often referred to as the "distribution system".

Pipeline – Refers to a pipe used to carry gas over longer distances typically at an elevated pressure.

psig – Pounds per square inch gauge. This is the measurement of system pressure as it would appear on a pressure gauge.

Primary Station – Refers to a regulating station connected to TransCanada Pipelines to provide supply to Manitoba Hydro (transfer point) and typically to a transmission pressure pipeline.

Redundant Capacity – Refers to the excess capacity in a natural gas pipe that is available to support the network in the event of an outage. Typically on two-way fed systems where if one pipe was interrupted (e.g. isolated for a leak), the redundant capacity would refer to the capacity of the second pipe to supply or back-feed the damaged pipe.

RSU – Remote Sensing Unit. The RSU is the equipment that measures and records pressure in the supply mains and communicates these pressure readings to a central Medium Pressure Monitoring System. The RSUs are located at selected locations through the MP system and provide information used in the hydraulic modeling of the piping network.

SCADA – Supervisory control and data acquisition system

Synergi – The hydraulic design software used for network capacity analysis.

Transmission Pressure (TP) System – Gas system with operating pressure greater than 275 psig, and often over 500 psig. These are the pipelines that are used to transport gas over longer distances and are used to supply local distribution systems.

Winter Design Condition – This is the gas flow conditions corresponding to the maximum expected load on the system under peak winter weather conditions (i.e. in Manitoba this is based on a [redacted] condition). 1d

1

INTRODUCTION

Manitoba Hydro's natural gas system provides safe and reliable delivery of natural gas to 275,000 customers, and plays an important role in the energy supply to Manitoba's residential, commercial and industrial customers. While Manitoba has been served by gas since 1883, installation of the current natural gas system began in 1955. To maintain the continued safe, reliable delivery of natural gas, projects have been identified to:

- Respond to customers requests for natural gas supply
- Maintain compliance with regulatory requirements
- Permit inspection of selected transmission pressure pipelines
- Replace aging assets
- Add further capacity to respond to load growth
- Provide improved system operation and control
- Respond to changing natural gas quality and supply pressures
- Respond to third party requirements for relocation of existing natural gas systems

The Five-Year Natural Gas Asset Management Plan for 2018 will assist with business planning needs, and will provide a vision and guiding document for the future.

The Marketing and Customer Service six-step risk management process was used to identify and prioritize the risks for each project identified in this report. The process evaluates the likelihood and consequence of an action or inaction to prioritize risk mitigation. This six-step risk management process is described in Appendix A.

FIGURE 1 – CONSTRUCTION OF A NEW PRESSURE REGULATING STATION

2 VISION AND STRATEGY

The Manitoba Hydro mission is to:

Create value for Manitobans by meeting our customers' expectations for the delivery of safe, reliable energy services at a fair price.

As the natural gas distribution utility of Manitoba Hydro, Centra Gas Manitoba ("Centra") supports this mission through work to:

- supply new customers,
- increase system capacity,
- support pipeline integrity activities,
- respond to changes in the quality of gas supplied,
- maintain compliance with applicable pipeline standards,
- maintain compliance with applicable Measurement Canada standards for metering,
- improve system reliability,
- address aging infrastructure issues, and
- relocate existing natural gas infrastructure to accommodate new municipal infrastructure projects.

Installation of Manitoba Hydro's current natural gas infrastructure started in 1955 and projects are planned to prepare key components of the pipeline for inspection to identify any repairs necessary to provide continued safe and reliable operation of the pipelines. Pipeline integrity programs are being performed to collect information on the condition of the system to provide guidance on remaining asset life. Replacement and upgrading of pressure regulating stations continues as part of a planned station renewal program.

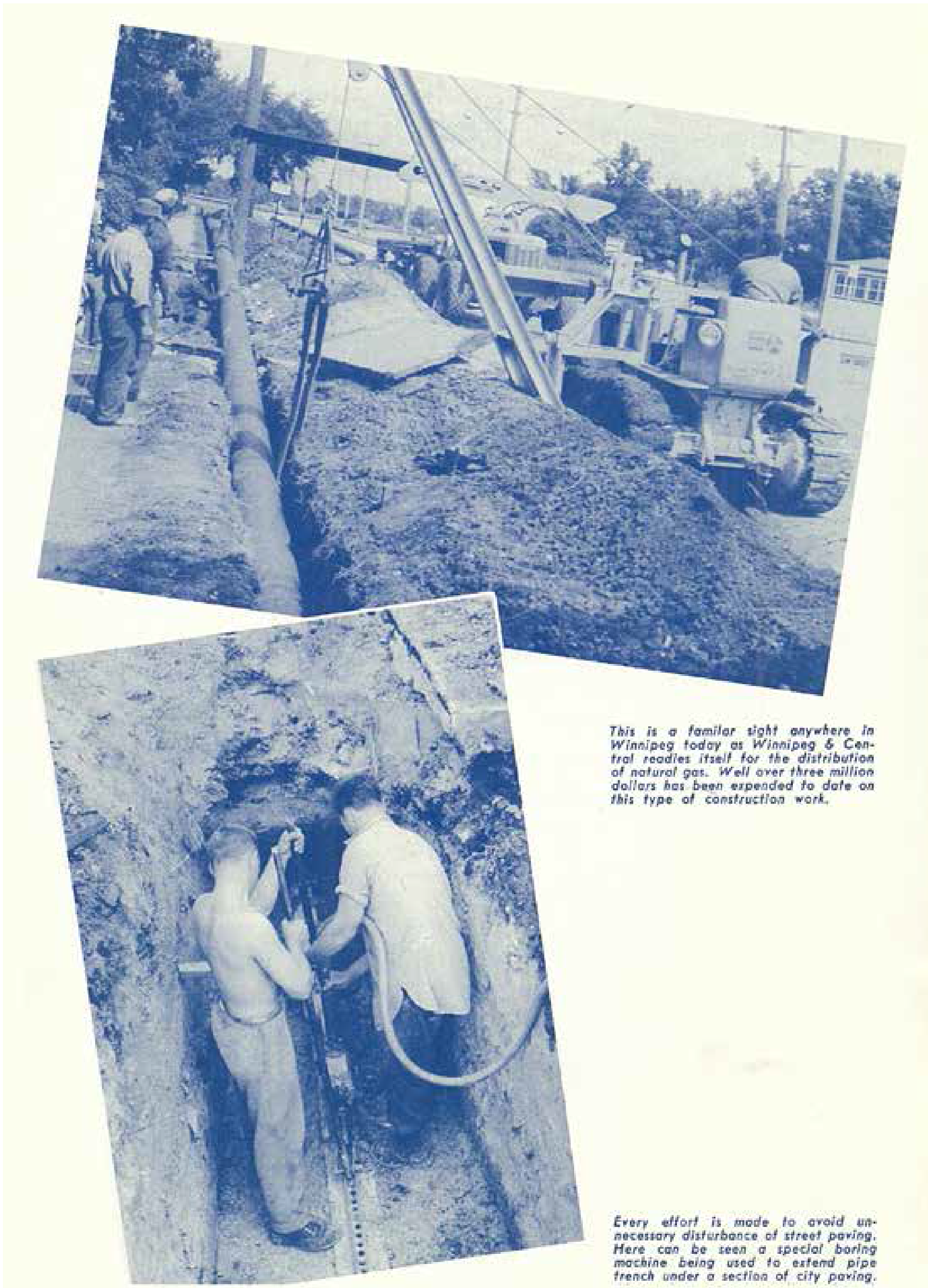
A natural gas outage can result in significant costs to both our customers and to Centra. Planning work is proceeding to better understand the vulnerabilities of each transmission pipeline system, and to develop plans to assist in returning a system to operation following an outage. This planning work has identified locations where the use of compressed natural gas (CNG) or liquid natural gas (LNG) can be used to support a community or system until pipeline gas is returned to service. The provision of pipeline valves and transmission piping have been identified for Steinbach and Portage la Prairie which are vulnerable to the loss of a single pipeline supply and are too large to practically support with CNG or LNG.

Centra completes many projects to respond to pipeline integrity which include the remediation of pipelines found with insufficient cover. This work reduces the potential for third party damages to shallow pipelines with the associated risk to personnel involved and a potential outage. Centra has also identified and are replacing failed pipeline valves. These valves provide an important ability to isolate damages or leaks.

For financial control, the Public Utilities Board (PUB) approved feasibility analyses are used in the evaluation and approval of new customer additions, while PUB approved franchise agreements are used to determine recoverable costs of natural gas infrastructure relocation needed to support municipal infrastructure work. Centra has introduced Copperleaf C55 to manage project approval workflows and will be using the Corporate Value Framework investment decision optimization capabilities of C55 to assist in project prioritization.

Centra recognizes the value to its customers for a safe and reliable natural gas distribution system and recognizes the challenges of dealing with an aging infrastructure that is buried and not readily accessible for inspection. In addition to the work historically performed, Centra will be increasing the work needed to better define the condition of the pipelines and develop long term plans for the life of the pipeline system.

VISION AND STRATEGY (CONTINUED)



This is a familar sight anywhere in Winnipeg today as Winnipeg & Central readies itself for the distribution of natural gas. Well over three million dollars has been expended to date on this type of construction work.

Every effort is made to avoid unnecessary disturbance of street paving. Here can be seen a special boring machine being used to extend pipe trench under a section of city paving.

FIGURE 2 – EXCERPTS FROM THE 1956 ANNUAL REPORT – WINNIPEG & CENTRAL GAS COMPANY

3 COST SUMMARY

The five year projected capital cost requirements are summarized below. Costs are shown as "Programs" and "Projects" with programs generally representing multiple, lower cost expenditures on similar ongoing work such as the installation of new services or replacement of natural gas meters.

Projects are typically higher cost, with a nominal threshold of $1 million. Individual work items with a cost below $1 million can also be included as projects if they are a unique scope of work where designation as a project assists in tracking of the work or providing visibility to the project.

Projects are generally identified and well developed for a two year period. While it is known that projects will continue to be done in year's three to five, these have not been fully scoped or developed and a "Planning Item" is shown to reflect the continued requirement for funding as outlined in Section 5.13.

(Note: The Capital Expenditure Forecast (CEF) process to establish approved capital expenditures is performed with a different timeline than the preparation of this work. While the costs shown are representative, with ongoing efforts to provide the most accurate capital costs, the approved CEF numbers are the official capital costs and may differ from the values shown here.)

PROGRAMS	2018–19	2019–20	2020–21	2021–22	2022–23
New Business	$14,500 K	$14,800 K	$15,100 K	$15,400 K	$15,700 K
System Betterment – Relocations	$1,640 K	$1,040 K	$1,060 K	$1,080 K	$1,100 K
System Betterment – Integrity	$4,800 K	$4,890 K	$4,990 K	$5,090 K	$5,190 K
System Betterment – Capacity & Other	$990 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K
System Betterment – Measurement & Regulator Stations	$3,040 K	$3,100 K	$3,160 K	$3,230 K	$3,290 K
Meter Compliance Program	$2,510 K	$6,700 K	$6,834 K	$6,970 K	$7,110 K
Customer Service Operations – Capital	$1,220 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K
Gas Apparatus Maintenance & Control	$660 K	$670 K	$680 K	$700 K	$710 K
Corrosion Control	$370 K	$370 K	$380 K	$380 K	$390 K
Programs Subtotal	**$29,730 K**	**$34,050 K**	**$34,724 K**	**$35,430 K**	**$36,130 K**
PROJECTS	**2018–19**	**2019–20**	**2020–21**	**2021–22**	**2022–23**
Winnipeg Waverley West MP – Phase 2	$880 K	$1,990 K	$550 K	$0 K	$0 K
Steinbach TP Upgrade	$430 K	$1,430 K	$1,920 K	$330 K	$0 K
St. Andrew's Distribution Upgrade	$1,240 K	$0 K	$0 K	$0 K	$0 K
In-Line Inspection Program	$2,550 K	$1,640 K	$1,710 K	$520 K	TBD*
Cathodic Rectifier Remote Monitoring Devices	$490 K	$0 K	$0 K	$0 K	$0 K
GS-123 Brandon Primary Gate Station Upgrades	$1,900 K	$1220 K	$0 K	$0 K	$0 K
Portage la Prairie TP Main – Secure Gas Supply	$70 K	$450 K	$100 K	$960 K	$0 K
Distribution System Monitoring	$1,230 K	$670 K	$0 K	$0 K	$0 K
St. Pierre TP Upgrade	$360 K	$0 K	$0 K	$0 K	$0 K

COST SUMMARY (CONTINUED)

PROJECTS (continued)	2018–19	2019–20	2020–21	2021–22	2022–23
Red River TP Pipeline Replacement	$260 K	$1,340 K	$0 K	$0 K	$0 K
Addressing Encroachment on Pipelines	$100 K	$0 K	$0 K	$0 K	$0 K
Planning Item	$0 K	$1,650 K	$3,550 K	$6,000 K	$8,000 K
Projects Subtotal	**$9,510 K**	**$10,390 K**	**$7,830 K**	**$7,810 K**	**$8,000 K**
TOTAL COSTS	**$39,240 K**	**$44,440 K**	**$42,554 K**	**$43,240 K**	**$44,130 K**
Target Adjustment**	$(3,924) K	$(4,444) K	$(4,255) K	$(4,324) K	$(4,413) K
NET TOTAL COSTS	**$35,316 K**	**$39,996 K**	**$38,299 K**	**$38,916 K**	**$39,717 K**

*Future project scope and dollars are to be determined and are currently estimated and shown under "Planning Item" as summarized in Section 5.13.

**The Target Adjustment reduces forecasted capital spending to Corporate approved capital targets to account for year to year variations in the roll up of program spending and recognition that external factors (contractor availability, procurement of property and external approvals) can affect project delivery and total spending.

4 PROGRAMS

Nine programs have been established to suit the common capital activities performed annually by the different departments working on natural gas projects. Details of the programs follow.

4.1 NEW BUSINESS

PROGRAM DESCRIPTION

New Business is defined by ongoing work to support the numerous smaller capital investment projects for supplying natural gas to new customers. The method of gas supply to a new customer will be dependent on the type of customer, the magnitude of their gas load and the customer's location relative to existing natural gas infrastructure. The method of gas supply can include the installation of:

- a gas service between an existing gas main and the customer
- new distribution gas mains from a few meters to many kilometers in length
- a new urban residential development, often in conjunction with electrical and communication infrastructure
- farm taps (a local pressure regulating station that permits direct connection to a transmission pressure gas main)
- transmission pressure mains
- plough projects, which are a sub-set of new distribution mains used to describe projects where the pipe installation is by ploughing and usually involves larger projects with 5000 meters or more of main located in rural areas. This often includes installations to provide gas to new larger customers such as farm grain dryers, Hutterite colonies and other similar customers.

Service installations for the last several years were:

	2012/13	2013/14	2014/15	2015/16	2016/17
Residential	2499	2516	2408	2192	2518
Commercial	277	224	242	253	248
Total	2776	2740	2650	2445	2766

The Public Utilities Board ("PUB") requires that an economic feasibility analysis be performed for each project and that each project be economically feasible through projected revenues or through a customer contribution for the project.

The annual net New Business budget (customer contributions not included) is shown below.

NEW BUSINESS PROGRAM					
Annual Budget	2018–19	2019–20	2020–21	2021–22	2022–23
	$14,500 K	$14,800 K	$15,100 K	$15,400 K	$15,700 K

NEW BUSINESS (CONTINUED)

FIGURE 3 – PLOUGH PREPPED FOR INSTALLATION OF 114.3MM (4") POLYETHYLENE (PE) FOR A RURAL FARM SITE

FIGURE 4 – 219.1MM (8") POLYETHYLENE (PE) FOR A NEW CUSTOMER

4.2 SYSTEM BETTERMENT (SB)

PROGRAM DESCRIPTION

System Betterment projects are performed to maintain system reliability and safety as well as support the continued operation of the existing system. To assist in project tracking, system betterment projects are split into four categories:

Plant Relocates – Relocation of natural gas infrastructure including pipelines, services and stations requested by third parties such as Manitoba Infrastructure, cities and municipalities and private parties to permit the construction of new projects like roadways, municipal infrastructure, buildings and others.

Integrity – Pipeline integrity projects include a wide variety of projects to maintain safe, reliable operation of the pipeline system and can include projects that address issues with pipeline encroachment, condition monitoring, asset replacement, insufficient cover remediation, corrosion protection and removal of obsolete farm taps.

Capacity Upgrades – Capacity upgrade projects include the installation of new mains to support load growth, or balance load and pressures within an existing area of a natural gas network where continued load growth has consumed the available pipeline capacity.

Measuring & Regulating Stations – Pressure regulating and metering stations are upgraded periodically to maintain safe and reliable operation.

SYSTEM BETTERMENT PROGRAMS – ANNUAL BUDGET					
PROGRAM NAME	2018–19	2019–20	2020–21	2021–22	2022–23
SB Plant Relocates	$1,640 K	$1,040 K	$1,060 K	$1,080 K	$1,100 K
SB Integrity	$4,800 K	$4,890 K	$4,990 K	$5,090 K	$5,190 K
SB Capacity & Other	$990 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K
SB Measuring & Regulating Stations	$3,040 K	$3,100 K	$3,160 K	$3,230 K	$3,290 K
TOTAL SB COSTS	**$10,470 K**	**$10,270 K**	**$10,470 K**	**$10,690 K**	**$10,900 K**

SYSTEM BETTERMENT (SB) (CONTINUED)

FIGURE 5 – INSUFFICIENT COVER REMEDIATION ALONG A STREAM TRIBUTARY FOR A PIPELINE CROSSING

FIGURE 6 – PIG LAUNCHER FABRICATION

4.2A

SYSTEM BETTERMENT: RELOCATIONS

JUSTIFICATION

Typically, natural gas relocations are due to new municipal roadway or infrastructure construction, but can also be required for new developments, buildings and any construction in general. Examples include a new highway interchange, a new building to be constructed in conflict with the gas main, or a new drainage ditch which lowers the grade over a pipeline. Some of the current identified or ongoing projects include multiple main relocations for the Winnipeg Bus Rapid Transit (BRT) extension, and abandonment of gas mains along Taylor Avenue to accommodate the Waverley Underpass and related infrastructure work.

Manitoba Hydro is able to recover costs for relocation work under different agreements. Costs for work performed for municipalities and local governments are recovered based on the depreciated cost of the asset in compliance with PUB regulated franchise agreements. Cost recovery with Manitoba Infrastructure (MI) is based on a 50/50 share of actual costs, and cost recovery for a private developer or customer is the actual cost of the work.

Once the scope, costs and schedule have been agreed upon, Manitoba Hydro has an obligation to complete all of these projects within a reasonable timeframe.

SYSTEM BETTERMENT PROGRAMS – ANNUAL BUDGET					
	2018–19	2019–20	2020–21	2021–22	2022–23
SB Plant Relocates	$1,640 K	$1,040 K	$1,060 K	$1,080 K	$1,100 K

FIGURE 7 – PLANT RELOCATION DUE TO ROAD CONSTRUCTION PROJECT

4.2B

SYSTEM BETTERMENT: INTEGRITY

Integrity refers to the capability of all components of the pipeline system, composed of services, pipelines, and stations control points, to contain natural gas. Integrity activities manage the risk posed by hazards that have the potential to impair the pipeline system's integrity. Integrity activities that require capital expenditures are categorized in this report as follows:

Asset Replacement – Proactive asset replacement is required to replace aging infrastructure such as pipelines, stations, valves and services as they reach the end of their effective life.

Insufficient Cover Remediation – The legislated operating standards define minimum levels of ground cover over pipelines. Depth of cover surveys are performed on a regular basis and projects are performed on sections of pipeline that require remediation to obtain the required cover.

Corrosion Protection at Primary Stations – The absence of electrical isolation on the pipeline connecting TCPL and Manitoba Hydro facilities at primary stations has been identified at several locations. This absence can prevent the operation of cathodic protection systems at desired levels and projects to install electrical isolation are planned.

Farm Tap Removal – A review of farm tap installations have identified a number of farm taps that can be removed, eliminating the need for annual maintenance, integrity monitoring and future asset replacement.

SYSTEM BETTERMENT PROGRAMS – ANNUAL BUDGET					
SB Integrity	2018–19	2019–20	2020–21	2021–22	2022–23
	$4,800 K	$4,890 K	$4,990 K	$5,090 K	$5,190 K

Examples of some of the work performed within this program are provided in 4.2B.1 through 4.2B.7.

FIGURE 8 – PIPE DEFECT REPAIR

4.2B.1

SB INTEGRITY: CORRODING SERVICE ASSESSMENT AND REPLACEMENT PROGRAM

JUSTIFICATION

Steel service lines are subject to degradation modes that can reduce long-term operability. Unknown or unreported external contact, poor installation practices, and coating failures shorten the life of steel service lines by causing a leak resulting in a replacement of the service.

The distribution mains and services leak surveys have identified that a small percentage of steel service lines is reaching the end of its life sooner than other steel service lines due to corrosion. Cause of the premature corrosion failure is unknown but can be investigated through the removal and replacement of selected steel service lines. The original service line is to be examined for the extent of corrosion and field coating practices in order to analyze and predict corrosion leaks; original steel service lines would be replaced with plastic.

This program would also enable us to understand the nature of how Manitoba Hydro's steel distribution system ages, and plan for long-term asset replacement.

RECOMMENDATION

Over a five-year period, replace an estimated 500 steel services in areas where higher-than-average concentrations of corrosion leaks are being experienced. The actual number of services to be replaced will be adjusted as appropriate based on the results of the investigation.

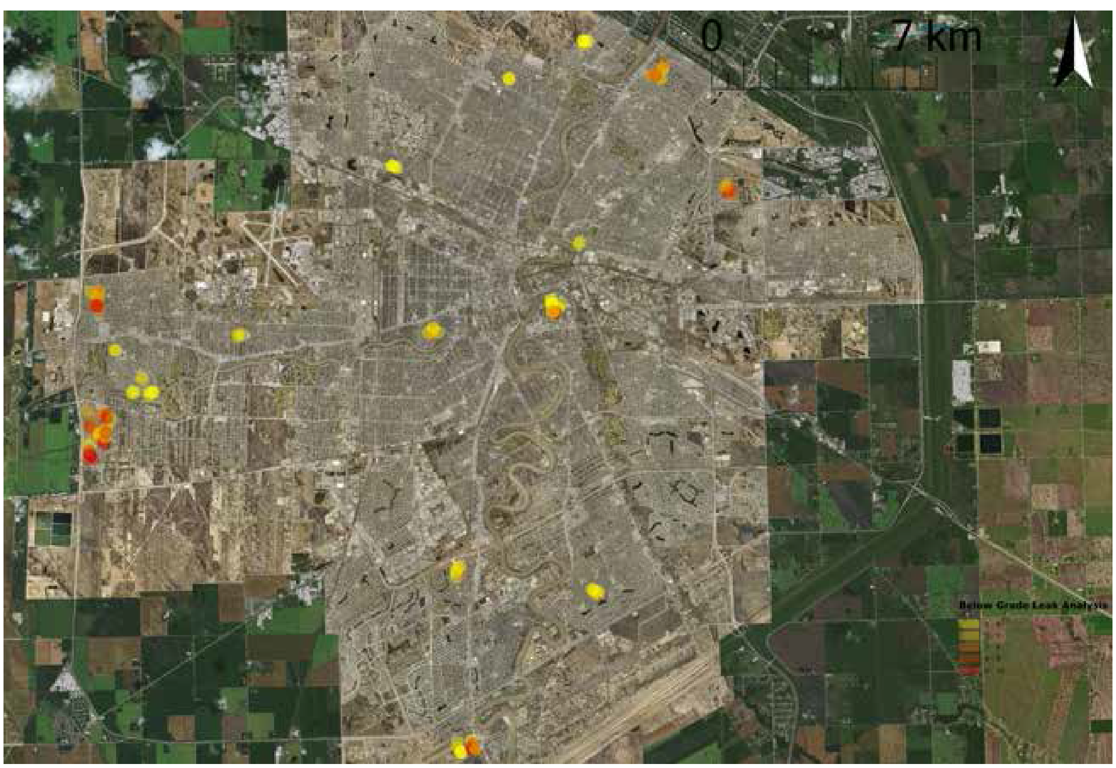


FIGURE 9 – CONCENTRATION OF LEAKS IN WINNIPEG DUE TO CORROSION

4.2B.2

SB INTEGRITY: COMMERCIAL SERVICE REPLACEMENTS

JUSTIFICATION

A number of issues have developed with existing commercial service installations:

1. Services with corrosion prevention deficiencies.
2. Ground movement that has caused stress on the service piping.
3. Service shut-off valves that are no longer readily accessible.
4. Services with stainless steel S-Tube fittings which have been found to be more susceptible to leaks.
5. Code violations such as insufficient clearances from over pressure relief vents.
6. Use of obsolete regulators and relief valves.

RECOMMENDATION

Continue to implement a service replacement program to remediate residential and commercial services with approximately 250 rehabilitations per year in to the foreseeable future.

FIGURE 10 – EXAMPLE OF COMMERCIAL SERVICE REQUIRING REPLACEMENT DUE TO CORROSION

4.2B.3

SB INTEGRITY: ISOLATION VALVE REPLACEMENTS

JUSTIFICATION

Isolation valves are used to isolate pipe sections to repair leaks/external pipe damage and to effectively complete maintenance and construction projects.

These valves allow a section of pipe to be effectively isolated, purged and flared as required. Inoperable valves can lead to employee and public safety risks, create the potential for a larger outage and can result in costly project delays.

RECOMMENDATION

Replace currently inoperable isolation valves and install new isolation valves where required to isolate the system for emergencies, maintenance and construction, and where required by standard. Typically one to three valves are identified for replacement each year however this can fluctuate significantly based on field maintenance findings.

FIGURE 11 – REPLACEMENT STATION ISOLATION VALVE

4.2B.4

SB INTEGRITY: INSUFFICIENT COVER REMEDIATION

JUSTIFICATION

Pipelines with insufficient cover do not meet standard requirements, and pose a greater risk to third party damages due to inadequate ground cover. Remediation of pipelines with insufficient cover is provided to maintain compliance with *CSA Z662 Oil and Gas Pipeline Systems.*

Depth of cover surveys are performed on a regular basis and projects are performed on sections of pipeline that require remediation to provide the required cover.

Additional segments of pipe with insufficient covers are sometimes reported by field staff or third parties.

Each year this information results in a number projects to address the insufficient cover through pipeline lowering, horizontal directional drill (HDD) replacements of water crossings or the installation of mechanical protection above the pipeline.

FIGURE 12 – INSUFFICIENT COVER REMEDIATION: INSTALLATION OF REPLACEMENT LINE (LEFT) AND INSTALLATION OF CONCRETE SLABS OVER PIPELINE (RIGHT)

4.2B.5

SB INTEGRITY: FARM TAP REMOVALS

JUSTIFICATION

Condition of the 210 farm taps in the natural gas system are periodically reviewed, and replacements are identified due to equipment obsolescence, lack of capacity or other deficiencies. Farm taps require annual maintenance and monitoring, and represent a future asset replacement liability. Options to a straight replacement were evaluated.

A cost benefit analysis was used to evaluate each farm tap identified to compare the net present value of operating and maintenance costs to the costs associated with eliminating the farm tap. It was determined to be feasible to abandon 23 farm taps identified to require replacement by extending the natural gas distribution system piping to provide a different source of supply to the affected customers or through combining customers on four new farm taps.

RECOMMENDATION

The current list of farm taps that require replacement are intended to be completed in a three-year period commencing in the 2018 construction season.

FIGURE 13 – FARM TAP

4.2B.6

SB INTEGRITY: FARM TAP REPLACEMENTS – REGULATORS

JUSTIFICATION

An asset review identified farm taps across Manitoba requiring regulation replacement due to obsolescence. Pressure regulator life cycles often exceed 30 years of service. As manufacturers change, equipment design and product lines are discontinued over time. For example, Fisher 621 regulators were widely used on farm taps in the gas distribution system and have been discontinued. Many of the farm taps are constructed as welded assemblies and use only a single regulator run. Failure of an obsolete regulator may result in a lengthy outage to the customer(s) if repair of the existing regulator is not possible and a new regulator needs to be welded into place.

RECOMMENDATION

Assess the overall condition of farm taps having obsolete regulation. Identify scale of replacement, and plan internal and external resources accordingly. The upgrade scope may include relocation, new guards or an entirely new assembly based on condition assessment results.

The current list of Farm Taps that require replacement are intended to be completed in a three-year period commencing in the 2019 construction season.

FIGURE 14 – FARM TAP REQUIRING UPGRADE

4.2B.7

SB INTEGRITY: ILE DES CHÊNES GS-017 INLET REPLACEMENT

JUSTIFICATION

Manitoba Hydro's Ile des Chênes Primary Station (GS-017) is supplied by a 460m pipeline from TransCanada Pipeline's (TCPL) Ile des Chênes terminal. Being upstream of the pressure regulation at GS-017, this section of pipeline operates at full TCPL supply pressure of up to 880 psi at all times. The pipeline was installed in 1962 and is not recommended for in-line inspection as the costs to modify the line to permit and perform an in-line inspection will equal or exceed the costs to replace the pipeline. This pipeline is and will continue to be a critical supply link to the City of Winnipeg pipeline system.

RECOMMENDATION

Replace the 460m of pipeline with a new NPS 16 steel pipeline from the point of transfer with TCPL to within GS-017. Design for this project will commence in 2019, with installation in 2020.

FIGURE 15 – 460 M OF NPS 16 PIPELINE FROM TCPL TO GS-017

4.2C SYSTEM BETTERMENT: CAPACITY AND OTHER

Capacity upgrade projects include the installation of new mains to support load growth, or balance load and pressures within an existing area of a natural gas network where continued load growth has used the available pipeline capacity. Load forecasts for the next 20 years are based on historical load growth rates and extrapolated to a peak winter design condition of [redacted] using Synergi Hydraulic modeling software.

Trends in gas load (such as furnace and hot water tank replacements) have been accounted for in the load growth forecasts. However, variables such as an economic boom or slowdown, or the addition of new large-scale industrial customers are unpredictable and could either speed up or slow down the need to install gas infrastructure.

The Winnipeg system serves approximately 80% of Manitoba Hydro's natural gas customers. The Winnipeg gas load is currently forecast to grow at a non-compounding rate of 1.1% per year over the next 20 years. In rural Manitoba the forecast gas load growth varies between 1.0% to 2.5% per year depending on the area and community. 1d

This work is provided to maintain adequate system pressures and capacity to provide reliable service to the customers supplied by the pipeline network. Typically several projects are completed on a yearly basis.

SYSTEM BETTERMENT PROGRAMS – ANNUAL BUDGET					
	2018–19	2019–20	2020–21	2021–22	2022–23
SB Capacity & Other	$990 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K

FIGURE 16 – INSTALLATION OF NPS 6 PE MAIN UNDER BUNNS CREEK AT HENDERSON HIGHWAY, WINNIPEG

4.2D

SYSTEM BETTERMENT: MEASUREMENT AND REGULATOR STATIONS

Upgrades have been identified to improve the control and operation of the Manitoba Hydro natural gas system. The primary concerns relate to:

System Isolation – Isolation valves enable emergency and maintenance isolation of pipeline segments. The ability to effectively isolate portions of the system can ultimately impact the speed of response and reduce the size and duration of a gas outage.

System Monitoring – Monitoring systems enable observation of the natural gas system to assess its health and performance. Examples of data use include:

- Real time troubleshooting and identification of system problems
- Historic data analysis to identify issues and operational patterns
- Load forecasting and work scheduling
- Capital project design basis and justification

Currently the supervisory control and data acquisition (SCADA) system is used to monitor TP and HP system operation.

Winnipeg HP Pressure Control – All network pressure control systems are currently fixed pressure (mechanical regulators) with the exception of four HP pressure control loops in the City of Winnipeg.

SYSTEM BETTERMENT PROGRAMS – RECOMMENDED ANNUAL BUDGET					
	2018–19	2019–20	2020–21	2021–22	2022–23
SB Measuring & Regulating Stations	$3,040 K	$3,100 K	$3,160 K	$3,230 K	$3,290 K

Examples of some of the work performed within this program are provided in 4.2D.1 through 4.2D.6.

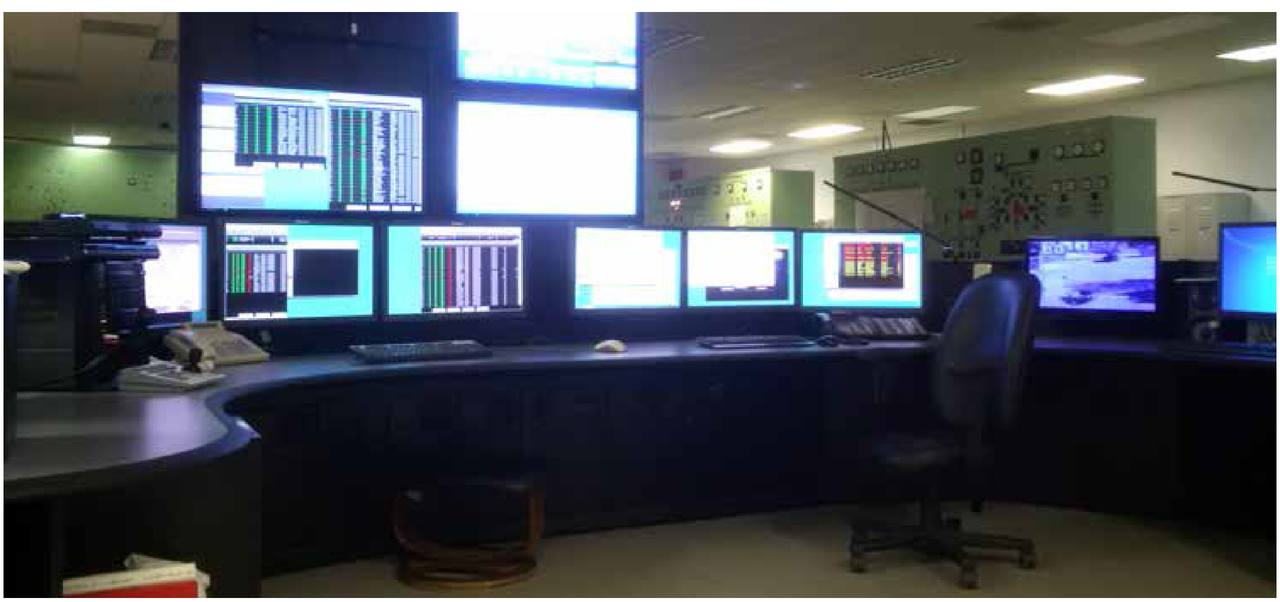


FIGURE 17 – SCADA SYSTEM CONTROL CENTRE

4.2D.1

SB MEASUREMENT & REGULATOR STATIONS: EMERGENCY RESPONSE – AUTOMATED ISOLATION VALVES

JUSTIFICATION

The transmission pipelines supplying Winnipeg require installation of automated, emergency shut down (ESD) valves for remote isolation. Currently, emergency response to an unexpected gas release (leak or rupture) would require a site visit and manual valve operation to isolate the segment. ESD valves that are integrated into the SCADA system will expedite damage isolation minimizing safety, environmental and reliability concerns.

RECOMMENDATION

Install automated ESDs on the three transmission pipelines supplying Winnipeg. The installations will enable remote system isolation between the primary gate station outlet (at the TCPL source) and all branches to downstream stations, isolating each pipeline from both its source and the downstream distribution network. Automated isolation valves are recommended on the following systems:

- La Salle pipeline – GS-020 Fort Whyte station inlet valve automation; ISD 2019
- Ile des Chênes pipeline and primary station – GS-017 station upgrades and automation; ISD 2020
- Oak Bluff pipeline and primary station – GS-030 station upgrades and automation; ISD 2022

FIGURE 18 – T16-006 ACTUATED PIPELINE ISOLATION VALVE, IDC PIPELINE

4.2D.2

SB MEASUREMENT & REGULATOR STATIONS: EMERGENCY RESPONSE – D-VALVE UPGRADES

JUSTIFICATION

The Winnipeg Transmission Pressure (TP) and High Pressure (HP) gas networks are segmented with valves to facilitate maintenance and emergency pipeline isolation.

Installation of the proposed valves will enable HP pipeline segmentation while maintaining station operation. This can prevent loss of system gas supply and improve system reliability.

RECOMMENDATION

Install D-Valve arrangements on the inlets of RS-027 in the 2018 construction season, and RS-046 in the 2019 construction season. This provides HP segment isolation on either side of the stations, while maintaining gas supply to the downstream distribution network.

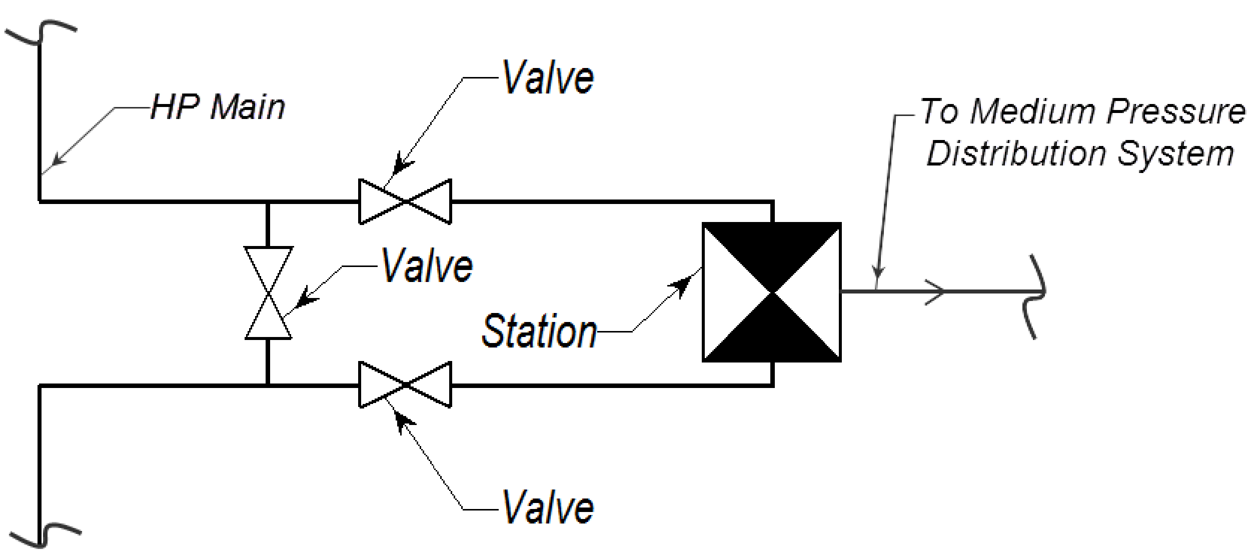


FIGURE 19 – TYPICAL D-VALVE ARRANGEMENT

4.2D.3

SB MEASUREMENT & REGULATOR STATIONS: STATION AUTOMATION

JUSTIFICATION

Station automation encompasses valve and regulator hardware installation that enables remote control. Increasing equipment connectivity to the Gas SCADA system will reduce maintenance labour, improve the speed of emergency response, and reduce the extent and duration of outages. Specific advantages are:

- Reduced labour hours for crews to respond to an emergency situation where the condition could have been mitigated by the use of automated equipment.
- Reduced labour hours to change the pressure setting on regulators. Currently, GAM&C staff must travel to some station sites to do seasonal adjustments on the station regulation equipment. These adjustments typically take two or three visits in each of the heating and non-heating shoulder months to stage the adjustments.
- Quicker acknowledgment of a system or equipment problem.
- Reduced response time and the potential for less damage as a result of quicker notification and therefore reduced response time in an emergency situation.

RECOMMENDATION

Upgrade equipment and control hardware in one to two regulation stations per year to provide remote pressure control and emergency shut-down (ESD) capability. This allows SCADA operators in the Grant Avenue Control Centre to adjust system parameters when responding to real time operating scenarios. The following functions require automation:

- Regulation stations – remote control of outlet pressure and shut-off of gas flow.
- Line heaters and pilot heaters – remote control of gas temperature and on/off control.
- Odourizers – remote shut-off.

The highest priority stations requiring automated control are:

- Southloop primary gate stations
    - GS-146 Dominion City, ISD 2019
    - GS-136 Oakville, ISD 2020

4.2D.4

SB MEASUREMENT & REGULATOR STATIONS: ICE MITIGATION – LINE HEATER INSTALLATIONS

Abundant shale gas from deposits, such as the Marcellus Play in Pennsylvania, is impacting the direction and composition of gas flow in pipelines throughout North America.

Historically, Manitoba's gas supply was sourced solely from the Western Canadian Sedimentary Basin which produces sweet, dry natural gas with a consistent composition. Since November 2012, TCPL has changed their mainline pipeline operations to enable south-north flow sourcing natural gas from the United States. This shale gas contains increased moisture and hydrate levels which are adversely affecting operations in areas of our distribution network.

Additional operational impacts may be observed as the Marcellus Play expands, and as new shale deposits are developed (example: the Bakken Formation in North Dakota, Saskatchewan and Manitoba).

JUSTIFICATION

Elevated moisture and hydrate levels in natural gas increase probability of ice formation at pressure reduction facilities. Heating the natural gas flow prior to pressure reduction mitigates the risk of freezing from the Joules-Thompson effect. Installation of a line heater is the primary mitigation method for operational issues stemming from internal and external ice formation.

A risk ranking system and matrix were developed to prioritize the installation locations. This risk framework considers various factors including vulnerability of freezing, the number of customers served, and remoteness of site.

FIGURE 20 – EXTERNAL EQUIPMENT ICE FORMATION

SB MEASUREMENT & REGULATOR STATIONS: ICE MITIGATION – LINE HEATER INSTALLATIONS (CONTINUED)

RECOMMENDATION

Install line heaters at stations with the highest risk of moisture or hydrate freezing due to changes in natural gas composition or operational need.

Install two to three heaters per year over the next 20 years.

PRIORITY	STATION	ISD
1	GS-103 Russell	2018
2	GS-010 Stonewall	2018
3	GS-143 Altona	2018
4	GS-182 Angle Road	2019
5	GS-137 Carman	2019
6	GS-130 MacGregor Primary	2019
7	GS-149 Morris	2020
8	GS-111 Miniota Primary	2020
9	GS-136 Oakville Primary	2020
10	GS-014 Beausejour	2021
11	GS-153 St. Pierre Primary	2021
12	GS-124 Brandon City Gate	2021

FIGURE 21 – SCHEDULED LINE HEATER SITES

Note: Actual installation locations may vary depending on operational issues experienced going forward.

FIGURE 22 – LINE HEATER

4.2D.5

SB MEASUREMENT & REGULATOR STATIONS: STATION REPLACEMENTS

JUSTIFICATION

Pressure regulating stations are upgraded on an as-required basis. The 209 pressure regulating stations are periodically assessed to identify any required upgrade to maintain safe and reliable function.

Improvements may include equipment and valve upgrades, electrical service upgrades, building replacement, fence and site restoration.

RECOMMENDATION

Upgrade three to four regulation stations annually to ensure station assets are replaced in an acceptable timeframe.

The highest priority station replacements are:

ISD 2018	ISD 2019	ISD 2020
GS-018a Landmark Station	GS-151 Twin Creeks Station	GS-128 Carberry Station
GS-008 Gimli Station	GS-012 Garson Station	GS-124 Brandon 1 Station
GS-120 Minnedosa Station	RS-042 Oakbank Station	GS-003 Transcona Station
GS-012 Garson Station		GS-002 St. Norbert Station Abandonment

FIGURE 23 – EXISTING GS-018A LANDMARK PRIMARY GATE STATION, 2018 UPGRADE PLANNED

4.2D.6

SB MEASUREMENT & REGULATOR STATIONS: LINE HEATER REPLACEMENTS

JUSTIFICATION

Replacing three existing indirect-fired bath heaters will improve reliability and reduce maintenance and operating costs. These bath line heaters range in age from 38 to 56 years old and have reached the end of their service life. Equipment age has resulted in increased cost of operation and maintenance and reduced serviceability.

The heaters have been modified significantly since original installation, complicating troubleshooting and repairs. Bath heaters are a dated technology having lower efficiency than other available heat technologies. These heaters are likely operating within a 40–50% efficiency range.

New vacuum boiler heaters will improve reliability, reduce operation and maintenance costs and reduce fuel consumption costs with an increased efficiency range of 75–80%.

RECOMMENDATION

Replace the following indirect bath heaters:

- GS-020 Fort Whyte line heater (installed in 1961); ISD 2018
- GS-003 Transcona (installed in 1979); ISD 2019
- GS-001 City Gate (installed in 1972); ISD 2020

FIGURE 24 – GS-020 FORT WHYTE BATH HEATER WITH SECONDARY CONTAINMENT

4.3 NATURAL GAS METER COMPLIANCE PROGRAM

PROGRAM DESCRIPTION

Manitoba Hydro has been accredited by Measurement Canada with the authority to perform verification and/or reverification of natural gas meters under the Electricity and Gas Inspection Act, and Electricity and Gas Inspection Regulations. The Act and Regulations set forth the rules for measurement of natural gas provided for sale, and requires that meters used by utilities for the sale of natural gas be exchanged periodically for meter testing and verification to ensure accurate measurement, for replacement of a defective or broken meter, and for meter testing to monitor compliance with the requirements of the Act.

Manitoba Hydro follows Measurement Canada sampling inspection procedures and specifications, and conducts an annual meter compliance program to extend the seal period of meters in-service.

There are two components to the Natural Gas Meter Compliance Program capital costs:

Meter Purchase/Refurbishment – This cost is for the purchase of new meters and refurbishment of existing meters for reuse. Costs are based on the total number of meters with seals expiring in a particular year.

Meter Installation – The second component is for the labour to install the meters requiring replacement. Costs are based on the number of meters that are due for replacement in the fiscal year as well as a portion of time for meters being fixed in conjunction with the meter raise & straighten portion of the program.

NATURAL GAS METER COMPLIANCE PROGRAM				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$2,510 K	$6,700 K	$6,834 K	$6,970 K	$7,110 K

NATURAL GAS METER COMPLIANCE PROGRAM (CONTINUED)

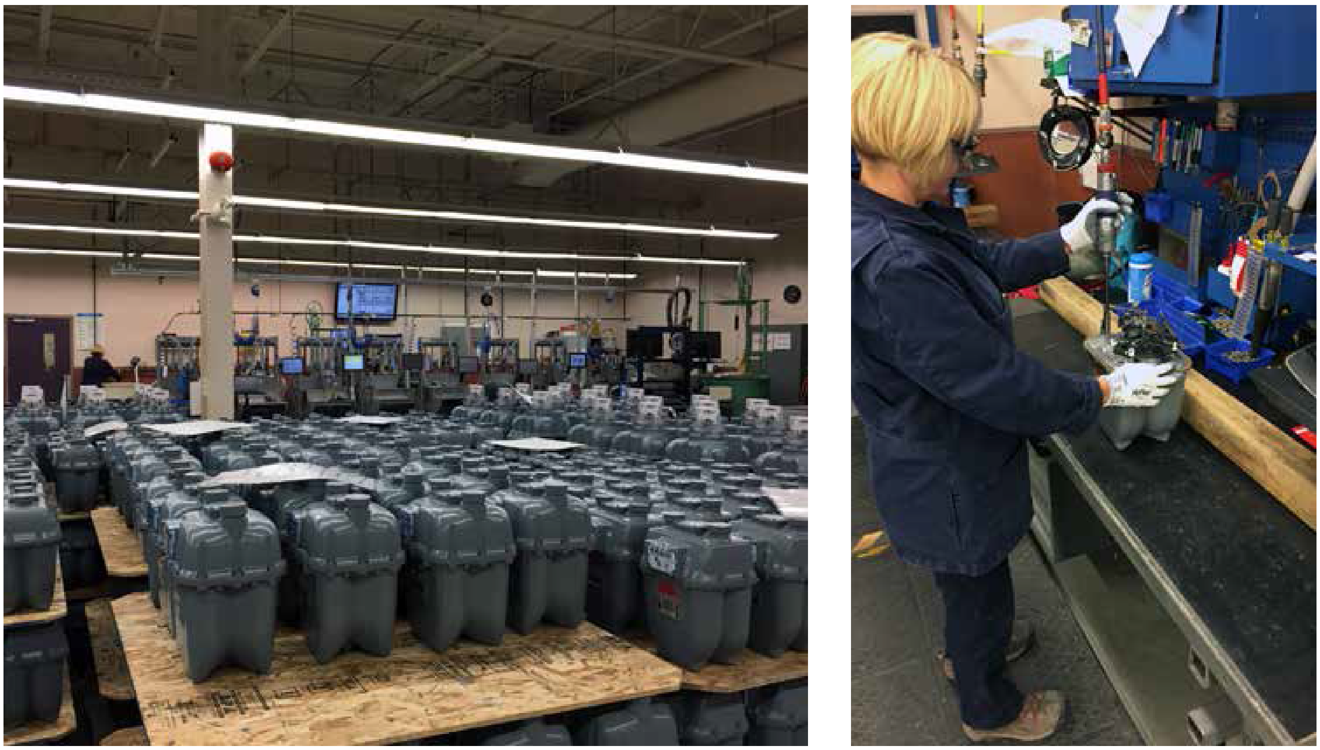


FIGURE 25 – METER SHOP

4.4 CUSTOMER SERVICE OPERATIONS (CSO) – OTHER CAPITAL

PROGRAM DESCRIPTION

An overall Customer Service Operations (CSO) program is required for maintenance, protection and upgrade of the existing and new service meter requests throughout the province. Budget values are based on previous history as the work is largely customer driven. The program is made up of the following components:

Leak Upgrades – Includes material and labour costs to install new pipe in order to fix natural gas leaks at meters.

Service Guard Installation – Includes the cost of labour and material for the installation of new service guards to protect meters and natural gas infrastructure.

Non-conformance Upgrades – Includes the material and labour costs associated with upgrading or modifying natural gas services and meter sets to comply with applicable codes and standards.

Load Changes and Natural Gas Meter Modifications – Includes material and labour incurred to accommodate increased or decreased customer load requirements for the modifications required on the service and meter.

CUSTOMER SERVICE OPERATIONS (CSO) – OTHER CAPITAL				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$1,220 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K

FIGURE 26 – COMMERCIAL SERVICE UPGRADE

4.5 GAS APPARATUS MAINTENANCE & CONTROL (GAM&C)

PROGRAM DESCRIPTION

Gas Apparatus Maintenance and Control (GAM&C) is responsible for the maintenance, operation, control and monitoring of Manitoba Hydro's natural gas system.

This program covers the purchase and installation of odourization equipment used to odourize natural gas to make leaks detectable by smell for safety purposes. It also covers the replacement of all station-related equipment such as regulators, pilots, gauges and valves as a result of obsolescence or degradation.

In addition to the mechanical equipment used in the station, GAM&C operates and maintains a Supervisory Control and Data Acquisition (SCADA) System to assist in providing the safe operation and control of the natural gas system in the province. The SCADA system requires the replacement of obsolete Programmable Logic Controllers (PLCs) and Remote Telemetry Units (RTUs), field radio networking and telecommunications equipment. Updated equipment is required to ensure reliable communications, monitoring and control as well as compliance with evolving industrial control system (ICS) cyber-security standards.

GAS APPARATUS MAINTENANCE & CONTROL (GAM&C)				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$660 K	$670 K	$680 K	$700 K	$710 K

An example of the work performed within this program are provided in 4.5A.

FIGURE 27 – MAINTENANCE OF GAS PRESSURE REGULATION EQUIPMENT IN A REGULATING STATION

4.5A

GAM&C: SCADA UPGRADE – IMPROVE MONITORING

JUSTIFICATION

All of the primary gate stations in Manitoba are monitored on SCADA, and approximately half of the regulator stations are monitored. Few of the gate stations and very few of the regulator stations currently have monitoring.

SCADA provides the Control Centre with up-to-date information regarding the health of the natural gas system. With additional stations monitored by SCADA, the visibility of issues on the system would be more readily detectable.

The benefits of improved detection can be summarized:

- Quicker acknowledgment of a system or equipment problems
- Quicker dispatch of repair crews in the event of an emergency
- Reduced response time and the potential for less damage and a smaller or shorter duration loss of service

RECOMMENDATION

Install SCADA monitoring at gate and regulator stations currently without monitoring.

Install SCADA monitoring at 14 gate stations and 35 regulator stations on the Winnipeg networks, and 21 regulator stations in the rural networks across Manitoba.

FIGURE 28 – PRESSURE MONITORING AT ST. NORBERT PRIMARY

4.6 CORROSION CONTROL

JUSTIFICATION

A substantial amount of natural gas pipe was installed in the 1960's and 1970's when gas distribution in Manitoba was rapidly expanding. The steel transmission and distribution piping is protected by cathodic protection systems. In some instances, the existing cathodic protection systems are not able to protect the piping adequately due to changing ground conditions and aging coating. In these instances, additional impressed current protection systems must be installed. Failure to supplement the existing cathodic protection systems will result in inadequate corrosion protection and the possibility of leaks due to corrosion. This could lead to unsafe and unreliable operation and premature replacement of buried piping. The additional protection will extend the life of the plant.

RECOMMENDATION

An annual investment in the operation and maintenance of the cathodic protection systems is required to ensure the steel transmission and distribution piping system are protected.

CORROSION CONTROL				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$370 K	$370 K	$380 K	$380 K	$390 K

FIGURE 29 – RECTIFIER AND JUNCTION BOX

5 PROJECTS

Projects are typically defined by a dollar threshold of $1 million. However, work with costs lower than this threshold can be raised as a project if it is deemed out of the ordinary or does not fit under a program.

5.1 WINNIPEG WAVERLEY WEST MP – PHASE 2

JUSTIFICATION

Currently, the medium pressure gas network in the Waverley West area is operating near capacity. This upgrade is required to support growth in the Waverley West neighborhood.

In recent years, the Waverley West neighbourhood has experienced strong growth with the addition of several subdivisions including South Pointe, Bridgewater Forest and Bridgewater Lakes.

Once complete, the in-fill load is expected to add approximately 375 mcfh of gas load. The existing gas distribution network cannot support this increased load without system upgrades to provide new gas supply from the existing pipelines to the edge of the easement.

RECOMMENDATION

Install a new natural gas supply and distribution main to feed the Waverley West development.

- The new gas supply will consist of a new connection to TransCanada Pipeline's Mainline located at Waverley Street just south of the Perimeter Highway.
- The new distribution main operating at 55 psig will consist of 12 NPS steel pipe along Waverley Street.

WINNIPEG WAVERLEY WEST – PHASE 2				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$880 K	$1,990 K	$550 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Almost Certain	Risk Rating	9A

WINNIPEG WAVERLEY WEST MP – PHASE 2 (CONTINUED)

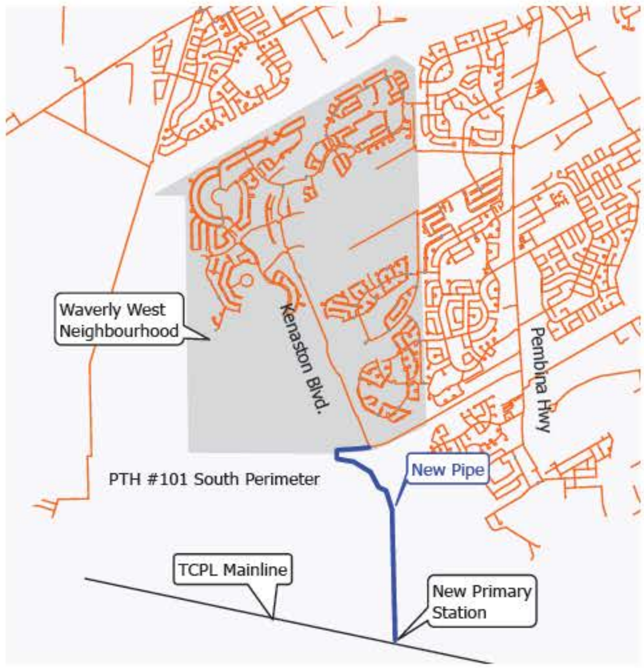


FIGURE 30 – WAVERLEY WEST MP UPGRADES

FIGURE 31 – WAVERLEY WEST PHASE 1 UTILIZED NPS 8 POLYETHYLENE PIPE

5.2 STEINBACH UPGRADE

JUSTIFICATION

The City of Steinbach has experienced strong residential and commercial growth and continues to grow at a higher rate than other parts of Manitoba. Steinbach continues to attract major industries and retailers which further drive the city's residential growth; this growth has a related increase in gas load.

Steinbach is the third-largest city in Manitoba, and is the largest city in Manitoba not having a secondary gas supply. The proposed upgrade will increase the available supply to the community while providing a secondary supply. This secondary supply will reduce or eliminate the possibility of an outage in the community.

RECOMMENDATION

Install a new gas supply to feed the City of Steinbach.

Install a new 6 NPS steel transmission pressure (TP) pipeline from the existing Hanover transmission line located southwest of Steinbach (9.9 km), to a new Steinbach pressure regulating station with distribution mains (5.1 km of 8 NPS) connecting to the existing gas distribution system.

STEINBACH UPGRADE				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$430 K	$1,430 K	$1,920 K	$330 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Almost Certain	Risk Rating	9A

FIGURE 32 – STEINBACH TP UPGRADE

5.3

ST. ANDREW'S DISTRIBUTION UPGRADE

JUSTIFICATION

The St. Andrew's area lacks available distribution capacity while the natural gas load growth continues to rise. Load growth in this region has resulted in portions of the network falling below minimum Natural Gas Planning Guideline pressures. A natural gas upgrade in this area will:

1. Increase capacity of the St. Andrews distribution network.
2. Provide a backbone for known and future load growth north and west of the Liss Road Station.
3. Free up capacity in the neighbouring networks north and south of St. Andrews (West St. Paul and Selkirk).
4. Permit abandonment of gate station GS-027.

RECOMMENDATION

Install a new natural gas distribution main in the RM of St. Andrews complete with removal of farm tap and tie-ins.

- The new medium pressure distribution main will consist of approximately six kilometres of 8 NPS polyethylene pipe running northwest from the existing Liss Road station GS-043.
- GS-027 and a small section of 2 NPS distribution main will be abandoned and the new 8 NPS main will be tied in to existing 2 NPS mains in two locations.

DISTRIBUTION SYSTEM MONITORING				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$1,230 K	$672 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	Medium	Likelihood	Unlikely	Risk Rating	5B

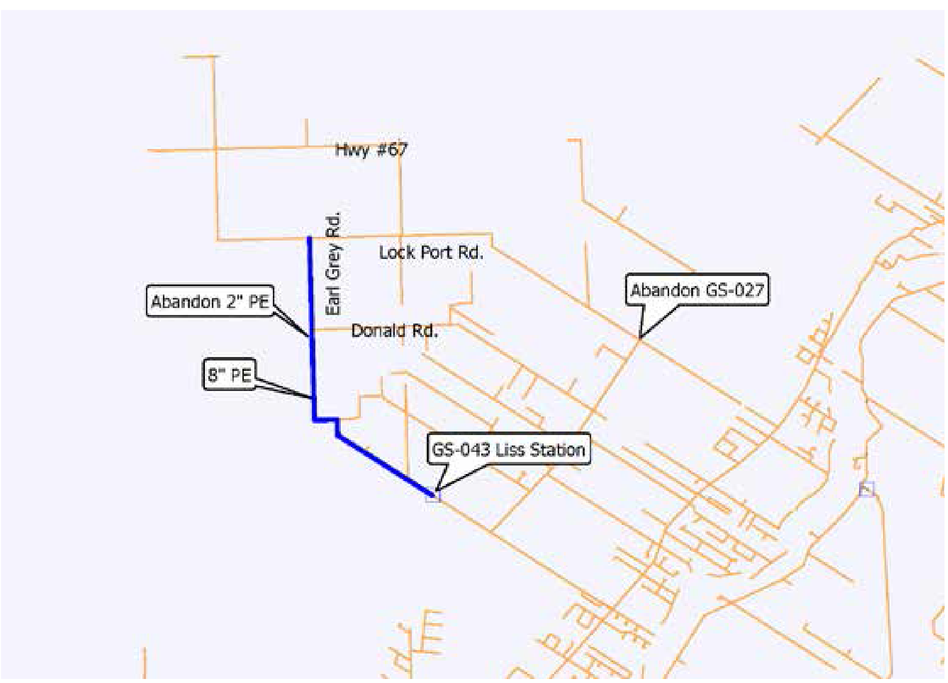


FIGURE 33 – ST. ANDREWS DISTRIBUTION UPGRADE

5.4 IN-LINE INSPECTION PROJECTS

JUSTIFICATION

Application of in-line inspection to all large diameter pipelines will provide data for the effective, safe and efficient management of the pipeline replacement program while permitting any defects identified to be addressed.

Some of the transmission pipelines in the Manitoba Hydro system are 60 years old. As a fully buried asset, pipelines are not readily accessible for inspection and testing. In-line inspection involves the installation of an instrumentation package that can detect dents, measure wall thickness, identify areas of corrosion and pipe wall loss and provide other characteristics of the pipeline.

The instrumentation package is run through the length of the pipeline capturing information on the pipe condition. This provides valuable data on the condition, integrity and the degradation mode of Manitoba Hydro's steel pipelines. This data will allow pipeline issues to be proactively identified and remediated, and assist in extending the life of inspected pipelines and help predict the end-of-life for all pipelines. Inline inspection has been successfully used at Manitoba Hydro with the 2015 inline inspection of the La Salle 12 NPS pipeline.

RECOMMENDATION

Implement ongoing annual inline pipeline inspection projects. Pipeline systems require modifications to be prepared for in-line inspection. Once the modifications are complete, an in-line inspection tool is inserted inside the pipeline and is capable of detecting metal loss due to corrosion and dents due to damage. Once the inspection is completed, fitness for continued use of the pipeline is evaluated.

IN-LINE INSPECTION PROJECTS				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$2,550 K	$1,640 K	$1,710 K	$520 K	TBD*

RISK ANALYSIS					
Consequence	High	Likelihood	Unlikely/ Rare	Risk Rating	8B

*Future project scope and dollars are to be determined and are currently estimated and shown under "System Betterment Planning Item" as summarized in Section 5.

	PIPELINE	ISD
1	Ile des Chênes NPS 16 GS-017 to GS-003	2018
2	La Salle NPS 8 GS-015 to GS-020	2018
3	Ile des Chênes NPS 12 GS-024 to GS-004	2019
4	Ile des Chênes NPS 12 T12-008 to T8-019	2019
5	Brandon NPS 10 FOR T10-002 to BDN T10-005	2019
6	Winnipeg North NPS 8 GS-004 to Netley Rd	2020
7	Brandon NPS 6 Unodourized GS-123 to GS-124	2021
8	Parkland NPS 6 GS-103 to GS-110	2022

IN-LINE INSPECTION PROJECTS (CONTINUED)

FIGURE 34 – LOADING OF IN-LINE INSPECTION TOOL AFTER PIPELINE INSPECTION

FIGURE 35 – PIG LAUNCHER INSTALLATION

5.5 CATHODIC RECTIFIER REMOTE MONITORING DEVICES

JUSTIFICATION

The monitoring of cathodic rectifiers is vital for maintaining the integrity of the steel pipelines. Cathodic rectifiers are used to protect steel pipeline systems by impressing a current on the pipeline and reducing the potential for pipeline corrosion. There are 92 cathodic rectifiers in the Manitoba Hydro natural gas system and it is estimated that the number of rectifiers will increase by 25% over the few years. Rectifier operation is monitored for normal operation through site visits to each rectifier on a regular schedule. The majority of the rectifiers are installed on transmission pipelines located in rural areas and there is a significant time commitment to travel to these sites.

The installation of an automated system that can monitor the rectifier operation and communicate system performance will eliminate the requirement for site visits to the rectifier sites for monitoring. This project will improve operational efficiency for Manitoba Hydro personnel around the province by reducing the workload, associated with cathodic monitoring and freeing up staff for higher priority activities. A net reduction in staff time and costs will be realized.

The down time (time of the rectifiers out service) will be reduced as the remote monitoring devices will provide alarms by exception in real time, allowing a faster response from corrosion technicians, reducing the risk of corrosion.

RECOMMENDATION

Install Remote Monitoring Devices (RMD) to:

- improve operational efficiency by the automation of the monitoring of the cathodic rectifiers performance/status and measurement of cathodic reads.
- increase safety of MH personnel as they won't need to travel long distances to each of the 92 cathodic rectifiers to collect the operational information.

CATHODIC RECTIFIER REMOTE MONITORING DEVICES				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$490 K	$0 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	Medium	Likelihood	Possible	Risk Rating	5A

CATHODIC RECTIFIER REMOTE MONITORING DEVICES (CONTINUED)

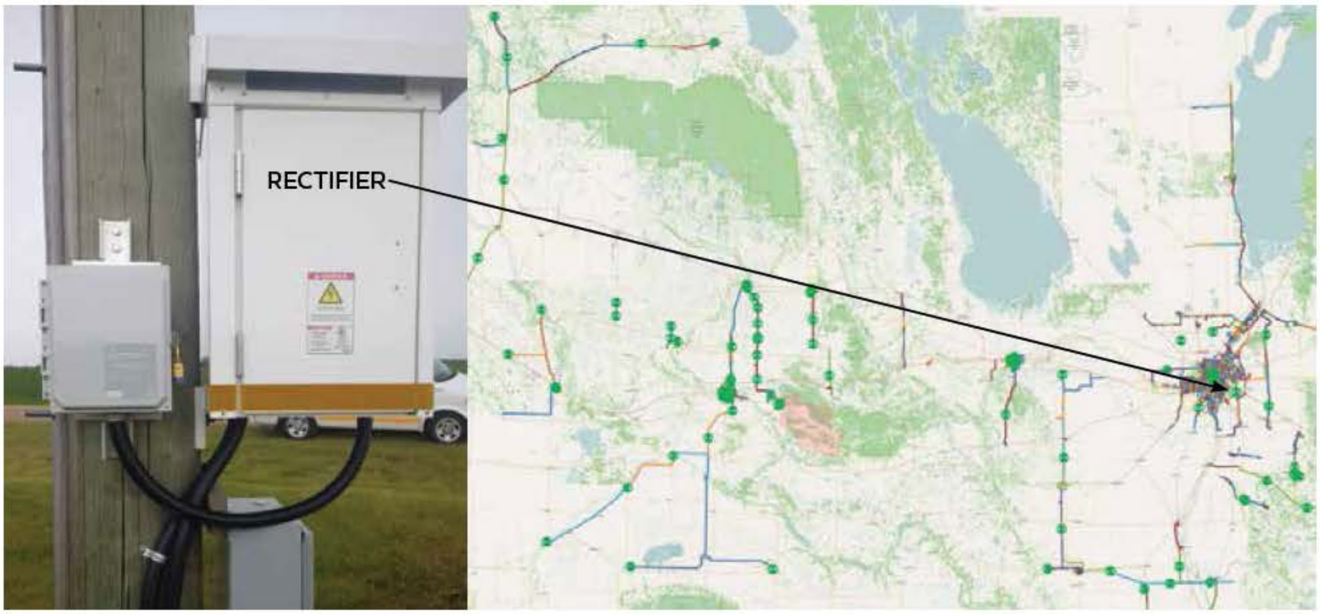


FIGURE 36 – DISTRIBUTION OF RECTIFIERS IN THE PROVINCE

Note: Green dots represent the location of rectifiers on the natural gas pipeline system

5.6 GS-123 BRANDON PRIMARY GATE STATION UPGRADES

JUSTIFICATION

Brandon Primary GS-123 is a critical asset in the western gas distribution network and supplies the City of Brandon and communities south of Brandon, GS-109 Brandon Generating Station, Koch Industries, and Husky Ethanol. GS-123 was constructed in 1957 and the last major regulation upgrade was performed in 1987.

When originally constructed GS-123 supplied a single 10-inch transmission main. In response to increased need for natural gas, additional mains have been added and GS-123 currently supplies five transmission mains (2-NPS 12, 1-NPS 10, 1-NPS 6 and 1-NPS 4). Various additions over time have resulted in a complex station layout, which is challenging to understand and operate.

Key operational issues include:

- Axial flow regulation issues stemming from ice formation.
- Metering is located downstream of pressure regulation which increases rotor exposure to icing and mechanical damage.
- Heaved building foundations and building disrepair, increasing risk of equipment damage in a severe weather event.
- There is no check metering of the Koch Industries gas flow.
- Aging, unsupported PLC hardware which must be upgraded to support station automation and provide reliable communication and control.
- The odourant facilities are undersized to serve the western distribution network.
- Overpressure protection is provided by large, NPS 8 relief valves which have high maintenance costs and the potential to negatively impact the environment.

RECOMMENDATION

Upgrade GS-123 Brandon Primary to improve reliability, reduce maintenance costs, reduce greenhouse gas emissions and optimize land use. The proposed changes will also provide increased system capacity to meet 30 year projected loads.

The scope of work includes installing a new inlet pipe from TransCanada Pipelines, a 12-inch inlet manifold, new station equipment, revised overpressure protection methodology and in-line inspection apparatus. Automated station control will reduce human resources needed to adjust system operation under normal or emergency conditions.

Construction will be completed in two phases to minimize risk since this station is the sole gas feed for the Brandon region.

GS-123 BRANDON PRIMARY GATE STATION UPGRADES				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$1,900 K	$1,220 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Possible	Risk Rating	8A

GS-123 BRANDON PRIMARY GATE STATION UPGRADES (CONTINUED)

FIGURE 37 – EXISTING GS-123 REGULATION PIPE ASSEMBLY AND CONCRETE FOUNDATION

5.7 PORTAGE LA PRAIRIE TP MAIN – SECURE GAS SUPPLY

JUSTIFICATION

The City of Portage la Prairie is the fourth-largest city in Manitoba supplied with natural gas. The system was constructed as a single feed system and it is vulnerable to a single failure or damage that could potentially result in an outage for all downstream customers. Major portions of the pipeline were installed in 1957 and 1962. While there are no known pipeline integrity concerns, the pipeline system has not been assessed for corrosion and would be susceptible to corrosion mechanisms observed on other Manitoba Hydro pipelines.

The number of customers in the community and associated gas supply requirements exceeds the supply abilities of an alternate trucked-in gas supply. The proposed modifications maintains the use of the existing assets while providing valves and a second river crossing that will permit a single transmission pipeline damage or failure to be isolated while maintaining gas supply to the customers.

RECOMMENDATION

Provide pipeline modifications and additions to reduce the number of customers that may lose gas service in the event of a pipeline damage or failure. In 2019, add pipeline isolation valves on the parallel 114.3 mm transmission pipelines and on the 168.3 mm transmission pipeline at GS-182. In 2021, install a second 168.3 mm transmission pressure river crossing of the Assiniboine River with associated valves.

PORTAGE LA PRAIRIE TRANSMISSION PRESSURE MAIN – SECURE GAS SUPPLY				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$70 K	$450 K	$100 K	$960 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Rare	Risk Rating	8A

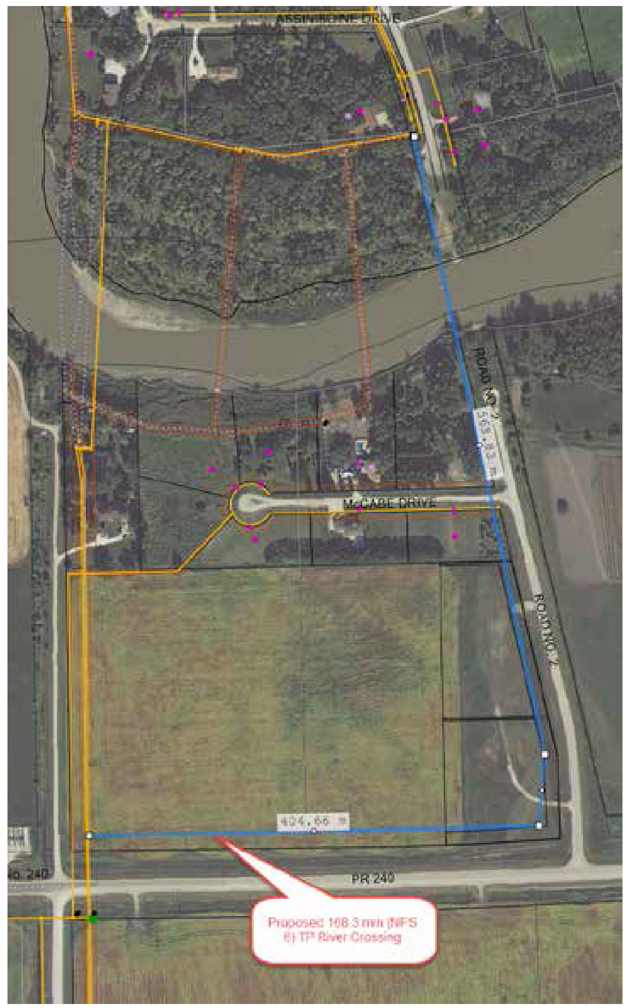


FIGURE 38 – PROPOSED SECOND ASSINIBOINE RIVER CROSSING

5.8 DISTRIBUTION SYSTEM MONITORING

JUSTIFICATION

Pressure data is essential to the natural gas modeling process. The data is used to calibrate the hydraulic models to actual conditions to ensure that optimum capacity in the gas system is being maintained.

Accuracy in the hydraulic models allows Manitoba Hydro to provide the most cost-effective systems to our customers.

In emergency situations, the monitoring system allows engineers and operators to monitor how the gas network is responding to a leak and the emergency response.

RECOMMENDATION

Provide a Medium Pressure (MP) Monitoring System consisting of 200 remote pressure sensing units and associated communication and data management systems.

The MP Monitoring System will measure and record natural gas pressure on the distribution system and will be measured at the ends of the system or at customer delivery locations. It will integrate with established Manitoba Hydro software, security and hardware requirements.

DISTRIBUTION SYSTEM MONITORING				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$1,230 K	$672 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	Medium	Likelihood	Unlikely	Risk Rating	5B

FIGURE 39 – REMOTE SENSING UNIT

FIGURE 40 – REMOTE SENSING UNIT

5.9 ST. PIERRE TP UPGRADE

JUSTIFICATION

The St. Pierre transmission pressure (TP) pipeline is at capacity. Currently, there are two temporary measures in place to address the overloading.

First, in 2010 the rural load at the Grunthal Border Station (GS-155) was shifted over to the Hanover network; and second, the pipeline is operating at a pressure above the minimum Tariff supply pressure from TransCanada Pipelines (TCPL) to extend capacity.

Over the last several years growth in this area has been strong and, even with temporary measures in place, this pipeline no longer has sufficient capacity to support new customers.

The upgrade will provide capacity for 20 years of forecast growth and provide support to the Hanover rural network while operating at TCPL Tariff supply pressure.

RECOMMENDATION

Install a new pipeline parallel to the existing St. Pierre pipeline (looping) in the same easement.

The upgrade consists of 4.1 km of 6 NPS steel TP pipeline from the St Pierre Primary (GS-153) to GS-154 at St. Pierre-Jolys. 3.5 km of 4 NPS steel TP pipeline will then continue from GS-154 to a location approximately 5 km from Grunthal.

The majority of this project was completed and put in service in the 2017 summer construction season. An approximate 600m section remains to be installed with a control valve structure.

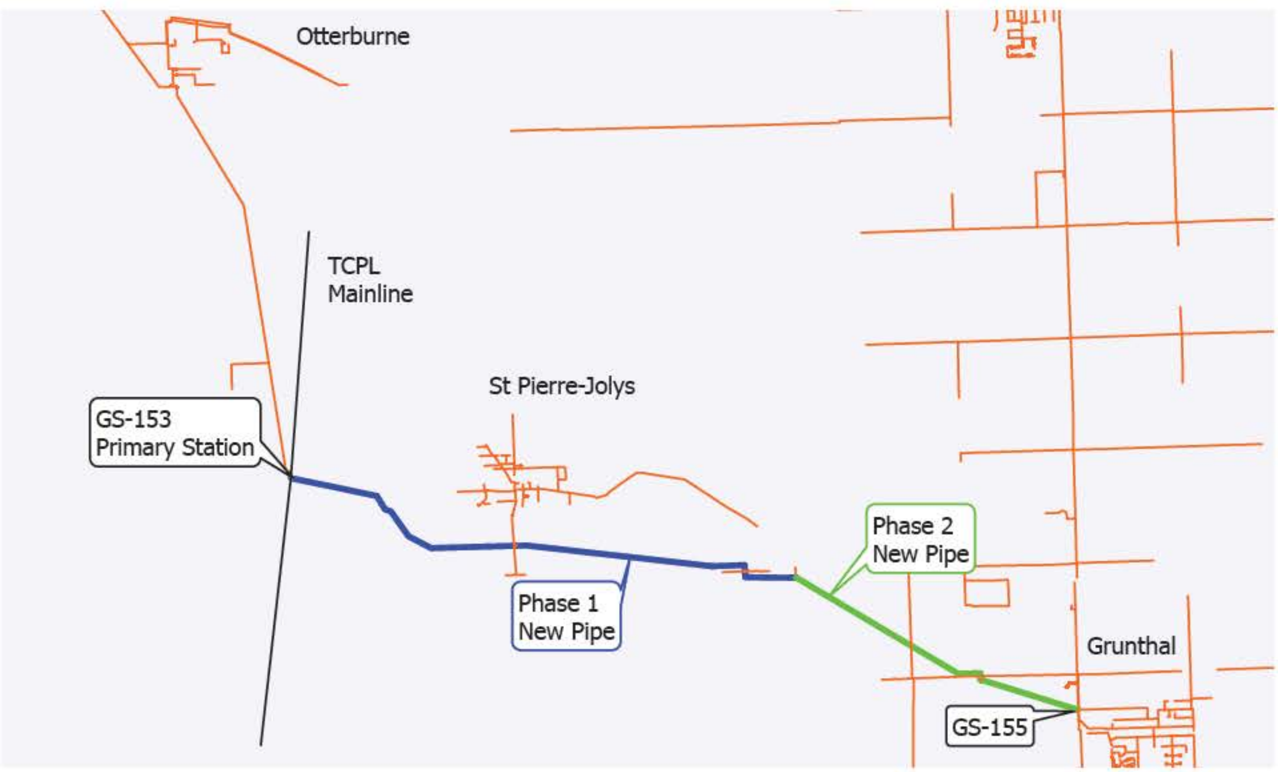


FIGURE 41 – ST PIERRE TP UPGRADE

ST. PIERRE TP UPGRADE (CONTINUED)

ST. PIERRE TRANSMISSION PRESSURE UPGRADE				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$360 K	$0 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Almost Certain	Risk Rating	9A

FIGURE 42 – ST. PIERRE 114.3MM (4") TRANSMISSION PRESSURE UPGRADE

5.10

RED RIVER AT LETELLIER TP PIPELINE REPLACEMENT

JUSTIFICATION

Currently, there are two NPS 4 transmission pressure (TP) pipelines crossing under the Red River between Letellier and Dominion City. The area of the crossings is known to be geotechnically unstable and Manitoba Hydro has previously had to repair a pipeline leak on a fitting damaged due to slope movement.

If further bank failures occur, it is possible that one or both pipeline crossings may become inoperable. This would compromise Manitoba Hydro's ability to operate the Southwest Transmission Loop.

In 2009, Manitoba Infrastructure replaced a bridge in the area due to concerns over geotechnical instabilities. They have also completed bank stabilization in the vicinity, though not close enough to the pipelines to currently benefit Manitoba Hydro.

RECOMMENDATION

- Install new transmission pipeline crossings below predicted slope failures or at a location that has had bank stabilization performed by Manitoba Infrastructure.
- Take the opportunity to examine the feasibility of installing control valves to independently operate the river crossings.

RED RIVER TRANSMISSION PRESSURE PIPELINE REPLACEMENT				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$260 K	$1,340 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Possible	Risk Rating	8A

FIGURE 43 – HORIZONTAL DIRECTIONAL DRILLING

5.11 ADDRESSING ENCROACHMENT ON PIPELINES

JUSTIFICATION

Development and growth of communities in the 50-plus years since the original installation of some natural gas pipeline installations has seen houses and other construction in close proximity to Manitoba Hydro transmission pressure (TP) pipelines. While these pipelines were originally installed through open fields, some now run through residential developments.

Development adjacent to pipelines will increase the potential for pipeline damages caused by third party work and increased building densities near the pipeline increase the potential personal or property consequences of a pipeline failure incident. Operational changes such as reducing operating pressure can be used to reduce consequences of damage but this will reduce the pipeline capacity and may not be an option at all locations.

Manitoba Hydro has completed an evaluation of all TP pipelines NPS 6 and larger and identified two projects to obtain property to widen existing easements and provide increased separation from the existing pipelines to the edge of the easement. One project has been completed and the second project is being planned. Having the wider easement in place will provide greater control over the development that can occur near the pipeline.

RECOMMENDATION

Obtain additional property easements for approximately 21 kilometers of TP pipelines on the Brandon pipelines.

ADDRESSING ENCROACHMENT ON PIPELINES				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$100 K	$0 K	TBD*	TBD*	$0 K

*Future project scope and dollars are to be determined and are currently estimated and shown under “Planning Items” as summarized in Section 5.13.

RISK ANALYSIS					
Consequence	High	Likelihood	Possible	Risk Rating	8A

ADDRESSING ENCROACHMENT ON PIPELINES (CONTINUED)

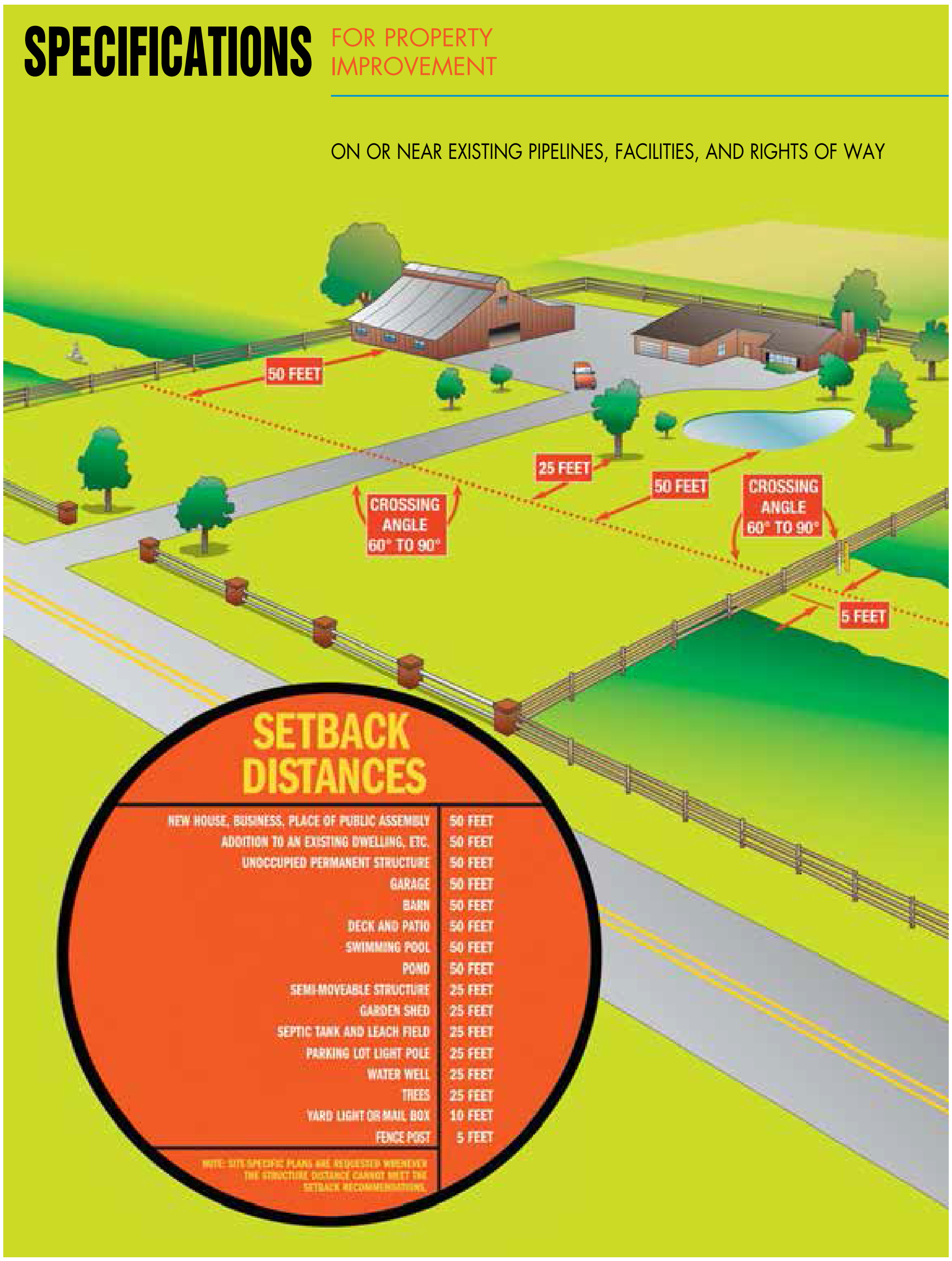


FIGURE 44 – GUIDELINES FOR DEVELOPMENT NEAR PIPELINES

5.12 WINNIPEG HP INTERCONNECTION – INKSTER BOULEVARD TO KING EDWARD STREET

JUSTIFICATION

A hydraulic planning analysis of the City of Winnipeg natural gas system has identified a vulnerability associated with the loss of one of the three major transmission gas supplies to Winnipeg during winter conditions. The analysis indicates that the available capacity of the remaining transmission pipelines would be sufficient to meet the full supply requirements but that there are restrictions in the Winnipeg high pressure (HP) distribution system that would limit the ability to distribute the gas and outages could occur depending on temperature conditions and system load.

Installation of a new HP pipeline between existing pipelines at Inkster Boulevard and King Edward Street will add significant capacity to the Winnipeg (HP) distribution system and provide operational flexibility to respond to unplanned disruptions in the natural gas supply. The Inkster Boulevard to King Edward Street interconnection will improve the ability to flow gas from the west side of Winnipeg (gas supplied by the Oak Bluff TP pipeline) into the downtown and inner city areas, if required.

RECOMMENDATION

Install a new high pressure main (approximately 6.2 km) to interconnect two existing high pressure pipelines in northwest Winnipeg to strengthen the HP supply network in this area.

The interconnection will extend from Inkster Boulevard (RS-046) to a location near RS-023 on King Edward St.

WINNIPEG HIGH PRESSURE INTERCONNECTION – INKSTER BOULEVARD TO KING EDWARD STREET				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$0 K	$350 K*	$3,150 K*	$0 K	$0 K

*Future project scope and dollars are to be determined and are currently estimated and shown under "Planning Items" as summarized in Section 5.13.

RISK ANALYSIS					
Consequence	High	Likelihood	Possible	Risk Rating	8A

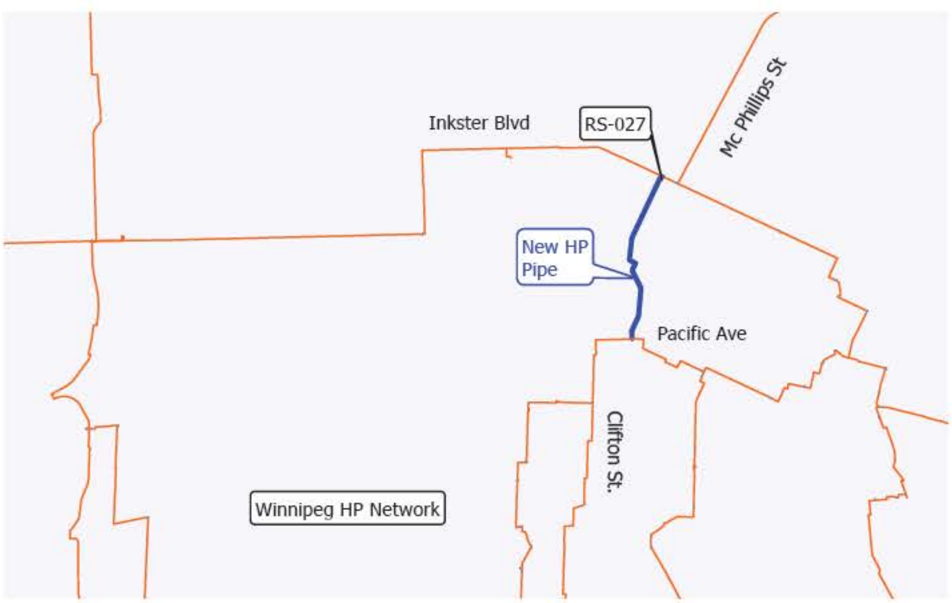


FIGURE 45 – WINNIPEG NW HP INTERCONNECTION

5.13 PLANNING ITEMS

All but the largest, most complex natural gas projects requiring an environmental license and extensive procurement of property can be planned, designed, constructed and energized in three years or less. In the development of a five year capital plan, the greatest certainty of projects will be in year one with the least in year five.

This recognizes that for projects with shorter time lines, not all projects that will be performed in years three, four or five of the plan have been identified, vetted and approved for implementation at this time. However, the lack of these identified projects does not indicate that the capital requirements for years three, four or five are expected to drop from year one and year two.

To avoid an incorrect indication that there will be a reduced capital requirement in the longer term, planning items are used in the budget to estimate the value of these future projects based on recent requirements.

As the time horizon advances, planning and approval of identified capital projects will use the funds shown as planning items.

An initiative to install advanced metering infrastructure (AMI) is currently in planning stages and has been shown as a separate line item in the planning items below.

PLANNING ITEMS					
Annual Budget System Betterment	2018–19	2019–20	2020–21	2021–22	2022–23
	$0 K	$1,650 K	$3,550 K	$6,000 K	$8,000 K
Annual Budget AMI	2018–19	2019–20	2020–21	2021–22	2022–23
	$0 K	$0 K	$16,600 K	$21,400 K	$20,900 K

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CONCLUSIONS

The following conclusions were made:

1. A long term capital plan is required for Manitoba Hydro's natural gas system. This report identifies all of the programs as well as planned and potential capital projects and prioritizes the projects based on risk rating.
2. This report will be updated annually to adjust programs as required and as new risks are identified and projects are completed.
3. The known system risks, proposed projects and 5-year budgets are summarized in Section 3.
4. The Marketing & Customer Service Risk Management Process was used to prioritize the projects as described in Appendix A.
5. Gas load for the province is expected to grow by approximately 1.1% per year for the next five years. As supplying gas to our customers is the primary functions of a gas distribution company our gas system must accommodate this gas load growth.

APPENDIX A

RISK ASSESSMENT METHODOLOGY

This report uses the Marketing and Customer Service six-step methodology to identify and manage the risks associated with a natural gas system. The Risk Rating Criteria, Likelihood Criteria and Risk Map are shown below.

TABLE A-1 RISK RATING CRITERIA

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 MH 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.
		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.

RISK ASSESSMENT METHODOLOGY (CONTINUED)

TABLE A-1 RISK RATING CRITERIA (CONTINUED)

CONSEQUENCE	MEASURE	RATING
Customer Value	Customer perception of service with regard to retail electricity rates	**Low** – No rate increase
		Medium – Annual increase of <10%
		High – Annual increase >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 or environmental concern; 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.

TABLE A-2 LIKELIHOOD CRITERIA

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 years
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

RISK ASSESSMENT METHODOLOGY (CONTINUED)

FIGURE A-1 RISK MAP

Risk Map

Consequence						
High	6B	6A	8B	8A	9B	9A
Medium	3B	3A	5B	5A	7B	7A
Low	1B	1A	2B	2A	4B	4A
Likelihood	**Very Rare** (1 in 1000 yrs)	**Rare** (1 in 100 yrs)	**Unlikely** (1 in 30 yrs)	**Possible** (1 in 10 yrs)	**Likely** (1 in 3 yrs)	**Almost Certain** (Yearly or more)

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:

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.

Manitoba Hydro